OSHAWA POWER

Exhibit 2:
Rate Base



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ATTACHMENTS

Attachment 2-1: 2026-2030 Oshawa Power Distribution System Plan

2.1 RATE BASE

2.1.1 Overview

The Rate Base underlying the revenue requirement sought in this Application has been determined on a basis consistent with Chapter 2 of the Filing Requirements for Electricity Distribution Rate Applications - 2025 Edition for 2026 Rate Applications issued on December 9, 2024 (the Filing Requirements). In accordance with the Filing Requirements, Oshawa PUC Networks Inc. (Oshawa Power) has calculated the rate base as an average of the 2026 Test Year opening and 2026 Test Year closing net capital balances, plus a working capital allowance of 7.5% of the sum of the cost of power (COP) and controllable expenses. Oshawa Power has not completed a lead-lag study or equivalent analysis to support a different rate and has submitted this Application using the default value of 7.5%, consistent with the OEB's letter of June 3, 2015 and the Filing Requirements.

The net fixed assets include those distribution assets that are associated with activities that enable the conveyance of electricity for distribution purposes. The rate base calculation excludes any non-distribution assets. The variance analysis below is based on in-service additions. Oshawa Power's rate base calculation excludes Work In Progress (WIP) as well as inventory held for capital projects. Oshawa Power has not applied for, nor received, any Incremental Capital Module (ICM) adjustments. Controllable expenses include operations, maintenance, billing and collecting, community relations, and administration expenses.

2.1.2 Summary of Rate Base

Oshawa Power has calculated its 2026 Test Year Rate Base to be $183,958,685, an increase over its 2021 OEB Approved Rate Base of $146,752,101. This increase in Rate Base of $37,206,584 is primarily attributed to an increase in the average net book value of Capital Assets of $35,594,208.

Oshawa Power has provided a summary of its rate base calculations for the 2021 OEB Approved, 2021 to 2024 Actuals and Forecast 2025 Bridge Year and 2026 Test Year in Table 2-1 below and on the Working Capital Allowance in Table 2-2.

Table 2-1: Rate Base Continuity Schedule ($000's)

Summary of Rate Base $000's		2021 OEB Approved	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Bridge	2026 Test	2026 Test vs. 2021 OEB Approved
Gross Fixed Assets (opening balance)		233,570	232,585	243,088	253,162	270,706	278,233	294,024	60,454
Gross Fixed Assets (closing balance)		243,595	243,088	253,162	270,706	278,233	294,024	309,425	65,830
Gross Fixed Assets (average)		**238,582**	**237,836**	**248,125**	**261,934**	**274,470**	**286,128**	**301,724**	**63,142**
Accumulated Depreciation (opening balance)		(100,277)	(101,450)	(105,391)	(110,175)	(114,761)	(120,469)	(126,376)	(26,099)
Accumulated Depreciation (closing balance)		(103,754)	(105,391)	(110,175)	(114,761)	(120,469)	(126,376)	(132,750)	(28,996)
Accumulated Depreciation (average)		**(102,016)**	**(103,421)**	**(107,783)**	**(112,468)**	**(117,615)**	**(123,423)**	**(129,563)**	**(27,548)**
Net Fixed Assets (average)	A	**136,567**	**134,416**	**140,342**	**149,466**	**156,855**	**162,706**	**172,161**	**35,594**
Working Capital Base		135,804	99,105	118,023	122,710	130,744	137,386	157,303	21,498
Working Capital Rate %		7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	0.00%
Working Capital Allowance	B	**10,185**	**7,433**	**8,852**	**9,203**	**9,806**	**10,304**	**11,798**	**1,612**
Rate Base	A + B	**146,752**	**141,849**	**149,193**	**158,670**	**166,661**	**173,010**	**183,959**	**37,207**

Table 2-2: Working Capital Allowance ($000's)

Working Capital Allowance $000's	2021 OEB Approved	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Bridge	2026 Test
Operations	2,891	2,428	2,613	3,144	2,833	2,566	4,003
Maintenance	1,350	997	1,104	1,175	1,442	1,295	1,350
Billing and Collecting	3,500	2,863	3,254	3,950	4,900	4,767	5,247
Community Relations	239	230	298	422	271	336	394
Administration & General	5,885	6,782	7,111	7,072	9,354	10,261	11,278
Property Taxes	152	136	168	137	156	161	165
Total Controllable Expenses	**14,018**	**13,436**	**14,548**	**15,901**	**18,956**	**19,386**	**22,437**
Cost of Power	121,786	85,669	103,475	106,808	111,788	118,000	134,866
Working Capital Base	**135,804**	**99,105**	**118,023**	**122,710**	**130,744**	**137,386**	**157,303**
Working Capital Rate %	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%
Working Capital Allowance	**10,185**	**7,433**	**8,852**	**9,203**	**9,806**	**10,304**	**11,798**

2.1.3 Rate Base Variance Analysis

Tables 2-3 and 2-4 below illustrate the variances from year to year for each rate base and working capital component for 2021 OEB Approved, 2021 through 2024 Actuals, and

Forecast 2025 Bridge Year and 2026 Test Year, followed by a brief narrative of the changes. More details related to capital expenditures can be found in the gross assets variance analysis later in this Exhibit in section 2.2.

Table 2-3: Variances in Year Over Year Rate Base ($000's)

Rate Base Variance Analysis ($000's)		2021 Actual vs. 2021 OEB Approved	2022 Actual vs. 2021 Actuals	2023 Actual vs. 2022 Actuals	2024 Actual vs. 2023 Actuals	2025 Bridge vs. 2024 Actuals	2026 Test vs. 2025 Bridge
Gross Fixed Assets (opening balance)		(985)	10,502	10,074	17,545	7,526	15,791
Gross Fixed Assets (closing balance)		(507)	10,074	17,545	7,526	15,791	15,401
Gross Fixed Assets (average)		(746)	10,288	13,809	12,535	11,659	15,596
Accumulated Depreciation (op. balance)		(1,173)	(3,941)	(4,784)	(4,585)	(5,708)	(5,907)
Accumulated Depreciation (clos. balance)		(1,637)	(4,784)	(4,585)	(5,708)	(5,907)	(6,374)
Accumulated Depreciation (average)		(1,405)	(4,362)	(4,685)	(5,147)	(5,808)	(6,141)
Net Fixed Assets (average)	**A**	**(2,151)**	**5,926**	**9,125**	**7,388**	**5,851**	**9,455**
Working Capital Base		(36,700)	18,919	4,686	8,034	6,642	19,917
Working Capital Rate %		7.5%	7.5%	7.5%	7.5%	7.5%	7.5%
Working Capital Allowance	**B**	**(2,752)**	**1,419**	**351**	**603**	**498**	**1,494**
Rate Base	**A + B**	**(4,904)**	**7,345**	**9,476**	**7,991**	**6,349**	**10,949**

Table 2-4: Variances in Working Capital Allowance

Working Capital Allowance Variance Analysis	2021 Actual vs. 2021 OEB Approved	2022 Actual vs. 2021 Actuals	2023 Actual vs. 2022 Actuals	2024 Actual vs. 2023 Actuals	2025 Bridge vs. 2024 Actuals	2026 Test vs. 2025 Bridge
Operations	(463,307)	185,597	530,690	(310,790)	(267,532)	1,437,405
Maintenance	(352,958)	106,701	71,797	266,829	(146,927)	54,407
Billing and Collecting	(637,740)	391,339	695,791	949,789	(132,566)	480,294
Community Relations	(8,807)	67,388	124,601	(151,810)	65,073	58,372
Administration & General	896,893	328,533	(38,502)	2,281,817	907,224	1,016,299
Property Taxes	(16,437)	32,661	(30,982)	18,515	4,695	4,014
Total Controllable Expenses	**(582,355)**	**1,112,219**	**1,353,394**	**3,054,349**	**429,966**	**3,050,789**
Cost of Power	(36,117,471)	17,806,350	3,332,926	4,979,991	6,211,933	16,866,266
Working Capital Base	**(36,699,827)**	**18,918,569**	**4,686,320**	**8,034,339**	**6,641,899**	**19,917,055**
Working Capital Rate %	No change	No change	No change	No change	No change	No change
Working Capital Allowance	**(2,752,487)**	**1,418,893**	**351,474**	**602,575**	**498,142**	**1,493,779**

2021 Actual versus 2021 OEB Approved ($000's)

The total rate base for 2021 Actual was $141,849, or $4,904 lower than 2021 OEB Approved. The decrease was primarily attributable to a decrease in net fixed asset additions as well as a decrease in the working capital allowance largely related to a lower than expected COP.

2022 Actual versus 2021 Actual ($000's)

The total rate base for 2022 Actual was $149,193, or $7,345 higher than 2021 Actual. The increase is primarily attributable to increased net fixed asset additions and increased working capital allowance from a higher COP.

2023 Actual versus 2022 Actual ($000's)

The total rate base for 2023 Actual was $158,670, or $9,476 higher than 2022 Actual. The increase is primarily attributable to increased net fixed asset additions and increased working capital allowance from a higher COP.

2024 Actual versus 2023 Actual ($000's)

The total rate base for 2024 Actual was $166,661, or $7,991 higher than 2023 Actual. The increase is primarily attributable to increased net fixed asset additions and increased working capital allowance from a higher COP.

2025 Bridge Year versus 2024 Actual ($000's)

The total rate base forecast for the 2025 Bridge Year is $173,010, or $6,349 higher than 2024 Actual. The increase is primarily attributable to increased net fixed asset additions and increased working capital allowance from a higher COP.

2026 Bridge Year versus 2025 Test Year ($000's)

The total rate base forecast for the 2026 Test Year $183,959, or $10,949 higher than the 2025 Bridge Year. The increase is primarily attributable to increased net fixed asset additions and increased working capital allowance from a higher COP.

2.2 FIXED ASSET CONTINUITY SCHEDULES AND VARIANCE ANALYSIS

2.2.1 Fixed Asset Continuity Schedules

Oshawa Power has provided Fixed Asset Continuity Schedules (Appendix 2-BA) for 2021 OEB Approved, Actuals 2021 through 2024, the 2025 Bridge Year and 2026 Test Year. The opening and closing balances of gross assets and accumulated depreciation used to calculate the fixed asset component of rate base correspond to the respective balances before WIP in the fixed asset continuity statements.

Oshawa Power has adjusted its continuity schedule for rate base purposes to account for an asset retirement obligation (ARO) beginning in 2017 to decommission buildings located at 100 Simcoe Street South no later than November 30, 2028. Appendix 2-BA includes an additional row to remove the ARO for rate base purposes and an additional row to add the depreciation expense.

These schedules are provided in Tables 2-5 to 2-10 below.

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Table 2-5: Fixed Assets Continuity Schedule 2021 Actual (Appendix 2-BA)

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	$ 4,136,705			$ 4,136,705	-$ 248,202	-$ 165,468		-$ 413,670	$ 3,723,035
12	1611	Computer Software (Formally known as Account 1925)	$ 2,563,975			$ 2,563,975	-$ 2,272,811	-$ 154,949		-$ 2,427,760	$ 136,215
CEC	1612	Land Rights (Formally known as Account 1906)				$ -				$ -	$ -
N/A	1805	Land	$ 293,875			$ 293,875				$ -	$ 293,875
47	1808	Buildings	$ 5,750,756	$ 59,064		$ 5,809,820	-$ 761,086	-$ 70,956		-$ 832,042	$ 4,977,778
13	1810	Leasehold Improvements				$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV				$ -				$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 26,988,018	$ 1,236,768		$ 28,224,786	-$ 9,994,948	-$ 609,451		-$ 10,604,399	$ 17,620,387
47	1825	Storage Battery Equipment				$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 56,362,068	$ 7,615,166	-$ 269,272	$ 63,707,962	-$ 15,276,244	-$ 1,285,805	$ 201,475	-$ 16,360,573	$ 47,347,388
47	1835	Overhead Conductors & Devices	$ 28,402,759	-$ 473,564	-$ 271,627	$ 27,657,568	-$ 9,053,753	-$ 368,055	$ 177,363	-$ 9,244,446	$ 18,413,123
47	1840	Underground Conduit				$ -				$ -	$ -
47	1845	Underground Conductors & Devices	$ 61,507,401	$ 1,815,060		$ 63,322,461	-$ 22,041,212	-$ 1,374,949		-$ 23,416,161	$ 39,906,301
47	1850	Line Transformers	$ 65,349,882	$ 1,805,108	-$ 1,090,527	$ 66,064,463	-$ 33,081,781	-$ 1,262,854	$ 990,493	-$ 33,354,142	$ 32,710,322
47	1855	Services (Overhead & Underground)				$ -				$ -	$ -
47	1860	Meters				$ -				$ -	$ -
47	1860	Meters (Smart Meters)	$ 14,152,321	$ 1,414,064	-$ 387,785	$ 15,178,601	-$ 8,867,465	-$ 557,248	$ 349,006	-$ 9,075,706	$ 6,102,894
N/A	1905	Land				$ -				$ -	$ -
47	1908	Buildings & Fixtures				$ -				$ -	$ -
13	1910	Leasehold Improvements	$ 1,097,704	$ 459,238		$ 1,556,942	-$ 1,011,550	-$ 98,900		-$ 1,110,450	$ 446,492
8	1915	Office Furniture & Equipment (10 years)	$ 800,129	$ 670		$ 800,799	-$ 729,124	-$ 14,148		-$ 743,272	$ 57,527
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 3,246,867	$ 746,180		$ 3,993,047	-$ 2,857,711	-$ 241,954		-$ 3,099,665	$ 893,382
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
10	1930	Transportation Equipment	$ 5,559,353		-$ 30,458	$ 5,528,895	-$ 3,604,587	-$ 315,538	$ 20,740	-$ 3,899,385	$ 1,629,510
8	1935	Stores Equipment	$ 30,767			$ 30,767	-$ 25,855	-$ 893		-$ 26,748	$ 4,019
8	1940	Tools, Shop & Garage Equipment	$ 2,876,986	$ 122,971		$ 2,999,957	-$ 2,549,401	-$ 99,264		-$ 2,648,665	$ 351,292
8	1945	Measurement & Testing Equipment	$ 1,586,319	-$ 237,335		$ 1,348,984	-$ 778,558	-$ 108,274		-$ 886,832	$ 462,152
8	1950	Power Operated Equipment				$ -				$ -	$ -
8	1955	Communications Equipment	$ 514,799			$ 514,799	-$ 377,902	-$ 34,570		-$ 412,472	$ 102,327
8	1955	Communication Equipment (Smart Meters)	$ 96,488			$ 96,488	-$ 96,488			-$ 96,488	$ -
8	1960	Miscellaneous Equipment	$ 287,043	-$ 3,187		$ 283,856	-$ 57,319	-$ 13,100		-$ 70,419	$ 213,437
47	1970	Load Management Controls Customer Premises	$ 107,035			$ 107,035	-$ 107,035			-$ 107,035	$ -
47	1975	Load Management Controls Utility Premises	$ 2,363,588	$ 40,507		$ 2,404,095	-$ 1,320,821	-$ 99,969		-$ 1,420,790	$ 983,305
47	1980	System Supervisor Equipment	$ 293,582			$ 293,582	-$ 293,583			-$ 293,583	-$ 1
47	1985	Miscellaneous Fixed Assets				$ -				$ -	$ -
47	1990	Other Tangible Property				$ -				$ -	$ -
47	1995	Contributions & Grants				$ -				$ -	$ -
47	2440	Deferred Revenue [5]	-$ 51,783,045	-$ 2,048,875		-$ 53,831,920	$ 13,957,120	$ 1,196,433		$ 15,153,553	-$ 38,678,367
	2005	Property Under Finance Lease [7]	$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 232,585,376**	**$ 12,551,835**	**-$ 2,049,668**	**$ 243,087,543**	**-$ 101,450,315**	**-$ 5,679,912**	**$ 1,739,078**	**-$ 105,391,150**	**$ 137,696,393**
		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	**$ 232,585,376**	**$ 12,551,835**	**-$ 2,049,668**	**$ 243,087,543**	**-$ 101,450,315**	**-$ 5,679,912**	**$ 1,739,078**	**-$ 105,391,150**	**$ 137,696,393**
		Construction Work In Progress	$ 5,024,136	-$ 764,644		$ 4,259,492				$ -	$ 4,259,492
		Total PP&E	**$ 237,609,512**	**$ 11,787,191**	**-$ 2,049,668**	**$ 247,347,035**	**-$ 101,450,315**	**-$ 5,679,912**	**$ 1,739,078**	**-$ 105,391,150**	**$ 141,955,885**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable [6]									
		Total						**-$ 5,679,912**			

Gross Fixed Assets (average) for Rate Base	$ 237,836,459
Accumulated Depreciation (average)	-$ 103,420,733
Net Fixed Assets (average)	$ 134,415,727
Less: *Fully Allocated Depreciation*	

10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	$ 1,196,433
			Net Depreciation	**-$ 6,876,345**

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Table 2-6: Fixed Assets Continuity Schedule 2022 Actual (Appendix 2-BA)

Accounting Standard: MIFRS
Year: 2022

CCA Class [2]	OEB Account [3]	Description [3]	Cost				Accumulated Depreciation				Net Book Value
			Opening Balance [8]	Additions [4]	Disposals [6]	Closing Balance	Opening Balance [8]	Additions	Disposals [6]	Closing Balance	
	1609	Capital Contributions Paid	$ 4,136,705	$ 38,995		$ 4,175,700	-$ 413,670	-$ 186,101		-$ 599,771	$ 3,575,929
12	1611	Computer Software (Formally known as Account 1925)	$ 2,563,975	$ 26,657		$ 2,590,632	-$ 2,427,760	-$ 172,331		-$ 2,600,091	-$ 9,459
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 293,875			$ 293,875	$ -			$ -	$ 293,875
47	1808	Buildings	$ 5,809,820	$ 37,475		$ 5,847,295	-$ 832,042	-$ 108,423		-$ 940,465	$ 4,906,830
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 28,224,786	$ 87,263		$ 28,312,049	-$ 10,604,399	-$ 623,524		-$ 11,227,923	$ 17,084,126
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 63,707,962	$ 730,119	-$ 183,615	$ 64,254,466	-$ 16,360,573	-$ 1,227,885	$ 171,932	-$ 17,416,527	$ 46,837,940
47	1835	Overhead Conductors & Devices	$ 27,657,568	$ 2,583,235	-$ 343,897	$ 29,896,906	-$ 9,244,446	-$ 474,591	$ 306,910	-$ 9,412,127	$ 20,484,779
47	1840	Underground Conduit	$ -			$ -	$ -			$ -	$ -
47	1845	Underground Conductors & Devices	$ 63,322,461	$ 5,123,494		$ 68,445,955	-$ 23,416,161	-$ 1,696,134		-$ 25,112,295	$ 43,333,661
47	1850	Line Transformers	$ 66,064,463	$ 1,715,380	-$ 785,487	$ 66,994,356	-$ 33,354,142	-$ 1,179,570	$ 751,894	-$ 33,781,818	$ 33,212,538
47	1855	Services (Overhead & Underground)	$ -			$ -	$ -			$ -	$ -
47	1860	Meters	$ -			$ -	$ -			$ -	$ -
47	1860	Meters (Smart Meters)	$ 15,178,601	$ 633,762	-$ 12,906	$ 15,799,457	-$ 9,075,706	-$ 485,537	$ 6,453	-$ 9,554,790	$ 6,244,666
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ 1,556,942	$ 155,379		$ 1,712,321	-$ 1,110,450	-$ 189,716		-$ 1,300,166	$ 412,155
8	1915	Office Furniture & Equipment (10 years)	$ 800,799	$ 5,110		$ 805,909	-$ 743,272	-$ 15,736		-$ 759,008	$ 46,901
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 3,993,047	$ 549,188		$ 4,542,235	-$ 3,099,665	-$ 275,445		-$ 3,375,110	$ 1,167,125
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 5,528,895	$ 438,284		$ 5,967,179	-$ 3,899,385	-$ 268,402		-$ 4,167,787	$ 1,799,392
8	1935	Stores Equipment	$ 30,767			$ 30,767	-$ 26,748	-$ 893		-$ 27,641	$ 3,126
8	1940	Tools, Shop & Garage Equipment	$ 2,999,957	$ 107,939		$ 3,107,896	-$ 2,648,665	-$ 107,983		-$ 2,756,648	$ 351,248
8	1945	Measurement & Testing Equipment	$ 1,348,984	$ 190,431		$ 1,539,415	-$ 886,832	-$ 150,435		-$ 1,037,267	$ 502,148
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 514,799			$ 514,799	-$ 412,472	-$ 27,107		-$ 439,579	$ 75,220
8	1955	Communication Equipment (Smart Meters)	$ 96,488			$ 96,488	-$ 96,488			-$ 96,488	$ -
8	1960	Miscellaneous Equipment	$ 283,856			$ 283,856	-$ 70,419	-$ 9,988		-$ 80,407	$ 203,449
47	1970	Load Management Controls Customer Premises	$ 107,035			$ 107,035	-$ 107,035			-$ 107,035	$ -
47	1975	Load Management Controls Utility Premises	$ 2,404,095	$ 178,672		$ 2,582,767	-$ 1,420,790	-$ 110,170		-$ 1,530,960	$ 1,051,807
47	1980	System Supervisor Equipment	$ 293,582			$ 293,582	-$ 293,583			-$ 293,583	-$ 1
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue [5]	-$ 53,831,920	-$ 1,201,222		-$ 55,033,142	$ 15,153,553	$ 1,288,832		$ 16,442,385	-$ 38,590,757
	2005	Property Under Finance Lease [7]	$ -	717,591		$ 717,591	$ -	- 426,843		-$ 426,843	$ 290,748
		Sub-Total	**$ 243,087,543**	**$ 12,117,752**	**-$ 1,325,904**	**$ 253,879,390**	**-$ 105,391,150**	**-$ 6,447,982**	**$ 1,237,188**	**-$ 110,601,944**	**$ 143,277,447**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*				$ -				$ -	$ -
		Less Retirement Obligation included in Assets		-	717,591	-$ 717,591		426,843		$ 426,843	-$ 290,748
		Total PP&E for Rate Base Purposes	**$ 243,087,543**	**$ 11,400,161**	**-$ 1,325,904**	**$ 253,161,799**	**-$ 105,391,150**	**-$ 6,021,139**	**$ 1,237,188**	**-$ 110,175,101**	**$ 142,986,698**
		Construction Work In Progress	$ 4,259,492	$ 3,082,232		$ 7,341,724				$ -	$ 7,341,724
		Total PP&E	**$ 247,347,035**	**$ 14,482,393**	**-$ 1,325,904**	**$ 260,503,523**	**-$ 105,391,150**	**-$ 6,021,139**	**$ 1,237,188**	**-$ 110,175,101**	**$ 150,328,422**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable [6]									
		Add Asset Retirement Obligation Depreciation Expense						- 426,843			
		Total						**-$ 6,447,982**			

Gross Fixed Assets (average) for Rate Base	$ 248,124,671	**Accumulated Depreciation (average)** -$ 107,783,125
		Net Fixed Assets (average) $ 140,341,546
		Less: *Fully Allocated Depreciation*
10	Transportation	Transportation
8	Stores Equipment	Stores Equipment
47	Deferred Revenue	Deferred Revenue $ 1,288,832
		Net Depreciation **-$ 7,736,814**

Table 2-7: Fixed Assets Continuity Schedule 2023 Actual (Appendix 2-BA)

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	$ 4,175,700	$ 7,343		$ 4,183,043	-$ 599,771	-$ 159,742		-$ 759,513	$ 3,423,530
12	1611	Computer Software (Formally known as Account 1925)	$ 2,590,632	$ 997,537		$ 3,588,169	-$ 2,600,091	-$ 240,036		-$ 2,840,127	$ 748,042
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 293,875			$ 293,875	$ -			$ -	$ 293,875
47	1808	Buildings	$ 5,847,295	-$ 268,327		$ 5,578,968	-$ 940,465	-$ 85,555		-$ 1,026,020	$ 4,552,948
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 28,312,049	-$ 10,085		$ 28,301,964	-$ 11,227,923	-$ 621,988		-$ 11,849,911	$ 16,452,053
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 64,254,466	$ 4,389,724	-$ 218,170	$ 68,426,020	-$ 17,416,527	-$ 1,370,202	$ 193,387	-$ 18,593,341	$ 49,832,678
47	1835	Overhead Conductors & Devices	$ 29,896,906	$ 5,551,126	-$ 429,839	$ 35,018,193	-$ 9,412,127	-$ 521,316	$ 406,832	-$ 9,526,611	$ 25,491,582
47	1840	Underground Conduit	$ -			$ -	$ -			$ -	$ -
47	1845	Underground Conductors & Devices	$ 68,445,955	$ 4,088,583		$ 72,534,538	-$ 25,112,295	-$ 1,469,838		-$ 26,582,133	$ 45,952,406
47	1850	Line Transformers	$ 66,994,356	$ 4,742,056	-$ 849,516	$ 70,886,896	-$ 33,781,818	-$ 1,319,764	$ 822,513	-$ 34,279,069	$ 36,607,828
47	1855	Services (Overhead & Underground)	$ -			$ -	$ -			$ -	$ -
47	1860	Meters	$ -			$ -	$ -			$ -	$ -
47	1860	Meters (Smart Meters)	$ 15,799,457	$ 734,746	-$ 10,853	$ 16,523,350	-$ 9,554,790	-$ 537,010	$ 5,426	-$ 10,086,374	$ 6,436,976
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ 1,712,321	$ 328,161		$ 2,040,482	-$ 1,300,166	-$ 410,073		-$ 1,710,239	$ 330,243
8	1915	Office Furniture & Equipment (10 years)	$ 805,909	$ 3,654		$ 809,563	-$ 759,008	-$ 14,423		-$ 773,431	$ 36,132
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 4,542,235	$ 337,341		$ 4,879,576	-$ 3,375,110	-$ 343,869		-$ 3,718,979	$ 1,160,597
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 5,967,179	$ 767,520	-$ 555,893	$ 6,178,806	-$ 4,167,787	-$ 271,179	$ 555,893	-$ 3,883,073	$ 2,295,733
8	1935	Stores Equipment	$ 30,767			$ 30,767	-$ 27,641	-$ 893		-$ 28,534	$ 2,233
8	1940	Tools, Shop & Garage Equipment	$ 3,107,896	$ 104,835		$ 3,212,731	-$ 2,756,648	-$ 122,994		-$ 2,879,642	$ 333,089
8	1945	Measurement & Testing Equipment	$ 1,539,415	$ 169,214		$ 1,708,629	-$ 1,037,267	-$ 170,414		-$ 1,207,681	$ 500,948
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 514,799			$ 514,799	-$ 439,579	-$ 19,316		-$ 458,895	$ 55,904
8	1955	Communication Equipment (Smart Meters)	$ 96,488			$ 96,488	-$ 96,488			-$ 96,488	$ -
8	1960	Miscellaneous Equipment	$ 283,856	-$ 31,566		$ 252,290	-$ 80,407	-$ 3,663		-$ 84,070	$ 168,220
47	1970	Load Management Controls Customer Premises	$ 107,035			$ 107,035	-$ 107,035			-$ 107,035	$ -
47	1975	Load Management Controls Utility Premises	$ 2,582,767	$ 276,970		$ 2,859,737	-$ 1,530,960	-$ 173,758		-$ 1,704,718	$ 1,155,019
47	1980	System Supervisor Equipment	$ 293,582			$ 293,582	-$ 293,583			-$ 293,583	-$ 1
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue [5]	-$ 55,033,142	-$ 2,579,863		-$ 57,613,005	$ 16,442,385	$ 1,286,519		$ 17,728,904	-$ 39,884,101
	2005	Property Under Finance Lease [7]	$ 717,591	- 9,267		$ 708,325	-$ 426,843	- 74,234		-$ 501,077	$ 207,248
		Sub-Total	**$ 253,879,390**	**$ 19,599,702**	**-$ 2,064,271**	**$ 271,414,822**	**-$ 110,601,944**	**-$ 6,643,748**	**$ 1,984,051**	**-$ 115,261,640**	**$ 156,153,182**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*				$ -				$ -	$ -
		Less Asset Retirement Obligation included in Assets	-$ 717,591	9,267		-$ 708,325	$ 426,843	74,234		$ 501,077	-$ 207,248
		Total PP&E for Rate Base Purposes	**$ 253,161,799**	**$ 19,608,969**	**-$ 2,064,271**	**$ 270,706,497**	**-$ 110,175,101**	**-$ 6,569,514**	**$ 1,984,051**	**-$ 114,760,563**	**$ 155,945,934**
		Construction Work In Progress	$ 7,341,724	-$ 1,584,877		$ 5,756,847				$ -	$ 5,756,847
		Total PP&E	**$ 260,503,523**	**$ 18,024,092**	**-$ 2,064,271**	**$ 276,463,344**	**-$ 110,175,101**	**-$ 6,569,514**	**$ 1,984,051**	**-$ 114,760,563**	**$ 161,702,781**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable [6]						-			
		Add Asset Retirement Obligation Depreciation Expense						74,234			
		Total						**-$ 6,643,748**			

Gross Fixed Assets (average) for Rate Base	$	261,934,148
Accumulated Depreciation (average)	-$	112,467,832
Net Fixed Assets (average)	$	149,466,316

Less: *Fully Allocated Depreciation*

10		Transportation	
8		Stores Equipment	
47		Deferred Revenue	$ 1,286,519
		Net Depreciation	**-$ 7,930,267**

Table 2-8: Fixed Assets Continuity Schedule 2024 Actual (Appendix 2-BA)

Accounting Standard: MIFRS
Year: 2024

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	$ 4,183,043			$ 4,183,043	-$ 759,513	-$ 167,322		-$ 926,835	$ 3,256,208
12	1611	Computer Software (Formally known as Account 1925)	$ 3,588,169	$ 513,101		$ 4,101,270	-$ 2,840,127	-$ 471,170		-$ 3,311,297	$ 789,973
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 293,875			$ 293,875	$ -			$ -	$ 293,875
47	1808	Buildings	$ 5,578,968			$ 5,578,968	-$ 1,026,020	-$ 101,190		-$ 1,127,210	$ 4,451,758
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 28,301,964	$ 2,237,931		$ 30,539,895	-$ 11,849,911	-$ 688,217		-$ 12,538,128	$ 18,001,767
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 68,426,020	$ 3,836,408	-$ 113,228	$ 72,149,200	-$ 18,593,341	-$ 1,440,153	$ 100,953	-$ 19,932,541	$ 52,216,659
47	1835	Overhead Conductors & Devices	$ 35,018,193	-$ 1,141,559	-$ 86,759	$ 33,789,875	-$ 9,526,611	-$ 604,211	$ 74,034	-$ 10,056,788	$ 23,733,087
47	1840	Underground Conduit	$ -			$ -	$ -			$ -	$ -
47	1845	Underground Conductors & Devices	$ 72,534,538	$ 4,562,600		$ 77,097,138	-$ 26,582,133	-$ 1,492,389		-$ 28,074,522	$ 49,022,617
47	1850	Line Transformers	$ 70,886,896	$ 2,548,296	-$ 627,240	$ 72,807,952	-$ 34,279,069	-$ 1,354,067	$ 457,148	-$ 35,175,988	$ 37,631,965
47	1855	Services (Overhead & Underground)	$ -			$ -	$ -			$ -	$ -
47	1860	Meters	$ -			$ -	$ -			$ -	$ -
47	1860	Meters (Smart Meters)	$ 16,523,350	$ 802,296	-$ 81,913	$ 17,243,733	-$ 10,086,374	-$ 563,339	$ 77,778	-$ 10,571,935	$ 6,671,799
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ 2,040,482			$ 2,040,482	-$ 1,710,239	-$ 166,503		-$ 1,876,742	$ 163,740
8	1915	Office Furniture & Equipment (10 years)	$ 809,563			$ 809,563	-$ 773,431	-$ 13,049		-$ 786,480	$ 23,083
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 4,879,576	$ 40,261		$ 4,919,837	-$ 3,718,979	-$ 336,631		-$ 4,055,610	$ 864,227
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 6,178,806	$ 60,978	-$ 368,478	$ 5,871,306	-$ 3,883,073	-$ 295,289	$ 306,593	-$ 3,871,769	$ 1,999,537
8	1935	Stores Equipment	$ 30,767			$ 30,767	-$ 28,534	-$ 893		-$ 29,427	$ 1,340
8	1940	Tools, Shop & Garage Equipment	$ 3,212,731	$ 24,874		$ 3,237,605	-$ 2,879,642	-$ 112,085		-$ 2,991,727	$ 245,878
8	1945	Measurement & Testing Equipment	$ 1,708,629	$ 143,653		$ 1,852,282	-$ 1,207,681	-$ 135,783		-$ 1,343,464	$ 508,818
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 514,799			$ 514,799	-$ 458,895	-$ 19,316		-$ 478,211	$ 36,588
8	1955	Communication Equipment (Smart Meters)	$ 96,488			$ 96,488	-$ 96,488			-$ 96,488	$ -
8	1960	Miscellaneous Equipment	$ 252,290			$ 252,290	-$ 84,070	-$ 6,647		-$ 90,717	$ 161,573
47	1970	Load Management Controls Customer Premises	$ 107,035			$ 107,035	$ 107,035			-$ 107,035	$ -
47	1975	Load Management Controls Utility Premises	$ 2,859,737	$ 31,082		$ 2,890,819	-$ 1,704,718	-$ 155,739		-$ 1,860,457	$ 1,030,362
47	1980	System Supervisor Equipment	$ 293,582			$ 293,582	-$ 293,583			-$ 293,583	-$ 1
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue [5]	-$ 57,613,005	-$ 4,856,085		-$ 62,469,090	$ 17,728,904	$ 1,399,017		$ 19,127,921	-$ 43,341,169
	2005	Property Under Finance Lease [7]	$ 708,325	53,801		$ 762,126	-$ 501,077	- 5,193		-$ 506,269	$ 255,856
		Sub-Total	**$ 271,414,822**	**$ 8,857,637**	**-$ 1,277,618**	**$ 278,994,841**	**-$ 115,261,640**	**-$ 6,730,169**	**$ 1,016,508**	**-$ 120,975,301**	**$ 158,019,540**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		***Less Other Non Rate-Regulated Utility Assets** (input as negative)*				$ -				$ -	$ -
		Less Asset Retirement Obligation included in Assets	-$ 708,325	- 53,801		-$ 762,126	$ 501,077	5,193		$ 506,269	-$ 255,856
		Total PP&E for Rate Base Purposes	**$ 270,706,497**	**$ 8,803,836**	**-$ 1,277,618**	**$ 278,232,715**	**-$ 114,760,563**	**-$ 6,724,976**	**$ 1,016,508**	**-$ 120,469,032**	**$ 157,763,684**
		Construction Work In Progress	$ 5,756,847	$ 16,672,695		$ 22,429,542				$ -	$ 22,429,542
		Total PP&E	**$ 276,463,344**	**$ 25,476,531**	**-$ 1,277,618**	**$ 300,662,257**	**-$ 114,760,563**	**-$ 6,724,976**	**$ 1,016,508**	**-$ 120,469,032**	**$ 180,193,226**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable [6]									
		Add Asset Retirement Obligation Depreciation Expense						- 5,193			
		Total						**-$ 6,730,169**			

Gross Fixed Assets (average) for Rate Base	$ 274,469,606	**Accumulated Depreciation (average)** -$ 117,614,798
		Net Fixed Assets (average) $ 156,854,809
		Less: *Fully Allocated Depreciation*

10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	$ 1,399,017
			Net Depreciation	**-$ 8,129,186**

Table 2-9: Fixed Assets Continuity Schedule 2025 Bridge Year (Appendix 2-BA)

Accounting Standard: MIFRS
Year: 2025

CCA Class [2]	OEB Account [3]	Description [3]	Cost				Accumulated Depreciation				Net Book Value
			Opening Balance [8]	Additions [4]	Disposals [6]	Closing Balance	Opening Balance [8]	Additions	Disposals [6]	Closing Balance	
	1609	Capital Contributions Paid	$ 4,183,043			$ 4,183,043	-$ 926,835	-$ 167,322		-$ 1,094,157	$ 3,088,886
12	1611	Computer Software (Formally known as Account 1925)	$ 4,101,270	$ 2,171,200		$ 6,272,470	-$ 3,311,297	-$ 870,143		-$ 4,181,440	$ 2,091,030
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 293,875			$ 293,875	$ -			$ -	$ 293,875
47	1808	Buildings	$ 5,578,968			$ 5,578,968	-$ 1,127,210	-$ 103,232		-$ 1,230,442	$ 4,348,526
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 30,539,895	$ 2,517,183		$ 33,057,078	-$ 12,538,128	-$ 618,216		-$ 13,156,344	$ 19,900,734
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 72,149,200	$ 3,317,685	-$ 223,686	$ 75,243,200	-$ 19,932,541	-$ 1,548,713	$ 188,931	-$ 21,292,322	$ 53,950,878
47	1835	Overhead Conductors & Devices	$ 33,789,875	$ 2,484,533	-$ 348,454	$ 35,925,954	-$ 10,056,788	-$ 636,916	$ 297,035	-$ 10,396,669	$ 25,529,285
47	1840	Underground Conduit	$ -			$ -	$ -			$ -	$ -
47	1845	Underground Conductors & Devices	$ 77,097,138	$ 3,520,190		$ 80,617,329	-$ 28,074,522	-$ 1,839,433		-$ 29,913,955	$ 50,703,374
47	1850	Line Transformers	$ 72,807,952	$ 3,859,577	-$ 908,510	$ 75,759,020	-$ 35,175,988	-$ 1,397,527	$ 854,967	-$ 35,718,548	$ 40,040,472
47	1855	Services (Overhead & Underground)	$ -			$ -	$ -			$ -	$ -
47	1860	Meters	$ -			$ -	$ -			$ -	$ -
47	1860	Meters (Smart Meters)	$ 17,243,733	$ 559,563	-$ 137,181	$ 17,666,116	-$ 10,571,935	-$ 516,405	$ 120,295	-$ 10,968,045	$ 6,698,071
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ 2,040,482	$ 50,000		$ 2,090,482	-$ 1,876,742	-$ 103,996		-$ 1,980,738	$ 109,744
8	1915	Office Furniture & Equipment (10 years)	$ 809,563			$ 809,563	-$ 786,480	-$ 11,752		-$ 798,232	$ 11,331
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 4,919,837	$ 531,000		$ 5,450,837	-$ 4,055,610	-$ 392,035		-$ 4,447,645	$ 1,003,192
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 5,871,306	$ 150,000		$ 6,021,306	-$ 3,871,769	-$ 244,040		-$ 4,115,809	$ 1,905,497
8	1935	Stores Equipment	$ 30,767			$ 30,767	-$ 29,427			-$ 29,427	$ 1,340
8	1940	Tools, Shop & Garage Equipment	$ 3,237,605	$ 100,456		$ 3,338,061	-$ 2,991,727	-$ 99,654		-$ 3,091,381	$ 246,680
8	1945	Measurement & Testing Equipment	$ 1,852,282	$ 120,950		$ 1,973,232	-$ 1,343,464	-$ 108,950		-$ 1,452,413	$ 520,819
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 514,799			$ 514,799	-$ 478,211	-$ 19,315		-$ 497,526	$ 17,273
8	1955	Communication Equipment (Smart Meters)	$ 96,488			$ 96,488	-$ 96,488			-$ 96,488	$ -
8	1960	Miscellaneous Equipment	$ 252,290	$ 130,000		$ 382,290	-$ 90,717	-$ 22,878		-$ 113,595	$ 268,695
47	1970	Load Management Controls Customer Premises	$ 107,035			$ 107,035	-$ 107,035			-$ 107,035	$ -
47	1975	Load Management Controls Utility Premises	$ 2,890,819	$ 240,000		$ 3,130,819	-$ 1,860,457	-$ 166,708		-$ 2,027,165	$ 1,103,654
47	1980	System Supervisor Equipment	$ 293,582			$ 293,582	-$ 293,583			-$ 293,583	-$ 1
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue [5]	-$ 62,469,090	-$ 2,343,374		-$ 64,812,464	$ 19,127,921	$ 1,498,681		$ 20,626,602	-$ 44,185,861
	2005	Property Under Finance Lease [7]	$ 762,126			$ 762,126	-$ 506,269	- 65,325		-$ 571,594	$ 190,531
		Sub-Total	**$ 278,994,841**	**$ 17,408,965**	**-$ 1,617,831**	**$ 294,785,975**	**-$ 120,975,301**	**-$ 7,433,878**	**$ 1,461,228**	**-$ 126,947,951**	**$ 167,838,024**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*				$ -				$ -	$ -
		Less Asset Retirement Obligation included in Assets	-$ 762,126			-$ 762,126	$ 506,269	65,325		$ 571,594	-$ 190,531
		Total PP&E for Rate Base Purposes	**$ 278,232,715**	**$ 17,408,965**	**-$ 1,617,831**	**$ 294,023,850**	**-$ 120,469,032**	**-$ 7,368,553**	**$ 1,461,228**	**-$ 126,376,357**	**$ 167,647,493**
		Construction Work In Progress	$ 22,429,542	-$ 4,629,542		$ 17,800,000				$ -	$ 17,800,000
		Total PP&E	**$ 300,662,257**	**$ 12,779,423**	**-$ 1,617,831**	**$ 311,823,850**	**-$ 120,469,032**	**-$ 7,368,553**	**$ 1,461,228**	**-$ 126,376,357**	**$ 185,447,493**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable [6]									
		Add Asset Retirement Obligation Depreciation Expense						- 65,325			
		Total						**-$ 7,433,878**			

Gross Fixed Assets (average) for Rate Base	$ 286,128,283	**Accumulated Depreciation (average)** -$ 123,422,694
		Net Fixed Assets (average) $ 162,705,588
		Less: *Fully Allocated Depreciation*

10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	$ 1,498,681
			Net Depreciation	**-$ 8,932,560**

Table 2-10: Fixed Assets Continuity Schedule 2026 Test Year (Appendix 2-BA)

Accounting Standard: MIFRS
Year: 2026

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	$ 4,183,043			$ 4,183,043	-$ 1,094,157	-$ 167,322		-$ 1,261,480	$ 2,921,563
12	1611	Computer Software (Formally known as Account 1925)	$ 6,272,470	$ 802,500		$ 7,074,970	-$ 4,181,440	-$ 971,015		-$ 5,152,454	$ 1,922,516
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 293,875			$ 293,875	$ -			$ -	$ 293,875
47	1808	Buildings	$ 5,578,968			$ 5,578,968	-$ 1,230,442	-$ 103,232		-$ 1,333,674	$ 4,245,294
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 33,057,078	$ 2,187,391		$ 35,244,469	-$ 13,156,344	-$ 640,742		-$ 13,797,087	$ 21,447,382
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 75,243,200	$ 3,166,448	-$ 223,686	$ 78,185,963	-$ 21,292,322	-$ 1,635,185	$ 188,931	-$ 22,738,576	$ 55,447,387
47	1835	Overhead Conductors & Devices	$ 35,925,954	$ 3,275,207	-$ 348,454	$ 38,852,707	-$ 10,396,669	-$ 712,095	$ 297,035	-$ 10,811,730	$ 28,040,977
47	1840	Underground Conduit	$ -			$ -	$ -			$ -	$ -
47	1845	Underground Conductors & Devices	$ 80,617,329	$ 4,371,428		$ 84,988,757	-$ 29,913,955	-$ 1,942,348		-$ 31,856,303	$ 53,132,454
47	1850	Line Transformers	$ 75,759,020	$ 3,496,021	-$ 908,510	$ 78,346,531	-$ 35,718,548	-$ 1,493,249	$ 854,967	-$ 36,356,830	$ 41,989,701
47	1855	Services (Overhead & Underground)	$ -			$ -	$ -			$ -	$ -
47	1860	Meters	$ -			$ -	$ -			$ -	$ -
47	1860	Meters (Smart Meters)	$ 17,666,116	$ 1,603,194	-$ 137,181	$ 19,132,129	-$ 10,968,045	-$ 583,161	$ 120,295	-$ 11,430,911	$ 7,701,218
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ 2,090,482	$ 100,000		$ 2,190,482	-$ 1,980,738	-$ 69,644		-$ 2,050,382	$ 140,100
8	1915	Office Furniture & Equipment (10 years)	$ 809,563			$ 809,563	-$ 798,232	-$ 11,264		-$ 809,496	$ 67
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 5,450,837	$ 312,400		$ 5,763,237	-$ 4,447,645	-$ 374,163		-$ 4,821,807	$ 941,430
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 6,021,306	$ 500,000		$ 6,521,306	-$ 4,115,809	-$ 267,464		-$ 4,383,273	$ 2,138,033
8	1935	Stores Equipment	$ 30,767			$ 30,767	-$ 29,427			-$ 29,427	$ 1,340
8	1940	Tools, Shop & Garage Equipment	$ 3,338,061	$ 130,745		$ 3,468,806	-$ 3,091,381	-$ 100,197		-$ 3,191,578	$ 277,227
8	1945	Measurement & Testing Equipment	$ 1,973,232	$ 130,485		$ 2,103,717	-$ 1,452,413	-$ 109,797		-$ 1,562,211	$ 541,506
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 514,799			$ 514,799	-$ 497,526	-$ 5,937		-$ 503,463	$ 11,336
8	1955	Communication Equipment (Smart Meters)	$ 96,488			$ 96,488	-$ 96,488			-$ 96,488	$ -
8	1960	Miscellaneous Equipment	$ 382,290	$ 171,094		$ 553,384	-$ 113,595	-$ 33,499		-$ 147,094	$ 406,290
47	1970	Load Management Controls Customer Premises	$ 107,035			$ 107,035	-$ 107,035			-$ 107,035	$ -
47	1975	Load Management Controls Utility Premises	$ 3,130,819			$ 3,130,819	-$ 2,027,165	-$ 181,708		-$ 2,208,873	$ 921,946
47	1980	System Supervisor Equipment	$ 293,582			$ 293,582	-$ 293,583			-$ 293,583	-$ 1
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue [5]	-$ 64,812,464	-$ 3,228,166		-$ 68,040,630	$ 20,626,602	$ 1,566,840		$ 22,193,442	-$ 45,847,188
	2005	Property Under Finance Lease [7]	$ 762,126			$ 762,126	-$ 571,594	- 65,325		-$ 636,919	$ 125,206
		Sub-Total	**$ 294,785,975.23**	**$ 17,018,747**	**-$ 1,617,831**	**$ 310,186,891.57**	**-$ 126,947,951**	**-$ 7,900,509**	**$ 1,461,228**	**-$ 133,387,231.60**	**$ 176,799,660**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*				$ -				$ -	$ -
		Less Asset Retirement Obligation included in Assets	-$ 762,126			-$ 762,126	$ 571,594	65,325		$ 636,919	-$ 125,206
		Total PP&E for Rate Base Purposes	**$ 294,023,850**	**$ 17,018,747**	**-$ 1,617,831**	**$ 309,424,766**	**-$ 126,376,357**	**-$ 7,835,184**	**$ 1,461,228**	**-$ 132,750,312**	**$ 176,674,454**
		Construction Work In Progress	$ 17,800,000	$ 356,000		$ 18,156,000				$ -	$ 18,156,000
		Total PP&E	**$ 311,823,850**	**$ 17,374,747**	**-$ 1,617,831**	**$ 327,580,766**	**-$ 126,376,357**	**-$ 7,835,184**	**$ 1,461,228**	**-$ 132,750,312**	**$ 194,830,454**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable [6]									
		Add Asset Retirement Obligation Depreciation Expense						- 65,325			
		Total						**-$ 7,900,509**			

	Test Year Gross Fixed Assets (avg)	$ 301,724,308	**Test Year Accumulated Depreciation (avg)** -$ 129,563,335
			Net Fixed Assets (avg) $ 172,160,973
			Less: *Fully Allocated Depreciation*

10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	$ 1,566,840
			Net Depreciation	**-$ 9,467,348**

2.2.2 Gross Assets – By Function

Oshawa Power's gross assets are divided into four principal categories as illustrated in Table 2-11 below.

- Distribution Plant assets are the wires, poles, meters and transformers used to distribute electricity through Oshawa Power's service territory. These assets are recorded to OEB's Uniform System of Accounts (USoA) 1805–1860.
- General Plant investments are assets used by staff to plan, maintain and build the distribution system. These assets are recorded in USoA 1920–1980, and include trucks and computer hardware and equipment.
- Intangible Plant, recorded in USoA 1606–1612, relates to assets such as software and contributions paid by Oshawa Power.
- Contributions and Grants consist of the contributed capital or deferred revenue that Oshawa Power has received from developers and others as per the Distribution System Code, recorded in USoA accounts 2440.

2.2.3 Gross Assets – Detailed Breakdown

Oshawa Power provides a detailed breakdown by major plant account for each functionalized plant item. Oshawa Power has included a breakdown of each major plant account according to the OEB's USoA in Table 2-11 below, which includes 2021 OEB Approved, 2021 through 2024 Actuals, the 2025 Bridge Year, and the 2026 Test Year.

Table 2-11: Gross Assets Detailed Breakdown 2021 OEB Approved and 2021-2026

Description	USoA	2021 OEB Approved	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Bridge Year	2026 Test Year
Distribution Plant								
Land	1805	$ 293,875	$ 293,875	$ 293,875	$ 293,875	$ 293,875	$ 293,875	$ 293,875
Buildings	1808	$ 6,136,005	$ 5,809,820	$ 5,847,295	$ 5,578,968	$ 5,578,968	$ 5,578,968	$ 5,578,968
Distribution Station Equipment	1820	$ 27,516,097	$ 28,224,786	$ 28,312,049	$ 28,301,964	$ 30,539,895	$ 33,057,078	$ 35,244,469
Poles, Towers & Fixtures	1830	$ 55,500,579	$ 63,707,962	$ 64,254,466	$ 68,426,020	$ 72,149,200	$ 75,243,200	$ 78,185,963
Overhead Conductors & Devices	1835	$ 28,492,999	$ 27,657,568	$ 29,896,906	$ 35,018,193	$ 33,789,875	$ 35,925,954	$ 38,852,707
Underground Conductors & Devices	1845	$ 64,895,608	$ 63,322,461	$ 68,445,955	$ 72,534,538	$ 77,097,138	$ 80,617,329	$ 84,988,757
Line Transformers	1850	$ 70,649,511	$ 66,064,463	$ 66,994,356	$ 70,886,896	$ 72,807,952	$ 75,759,020	$ 78,346,531
Meters	1860	$ 14,929,550	$ 15,178,601	$ 15,799,457	$ 16,523,350	$ 17,243,733	$ 17,666,116	$ 19,132,129
Gross Distribution Plant		**$ 268,414,225**	**$ 270,259,536**	**$ 279,844,360**	**$ 297,563,805**	**$ 309,500,637**	**$ 324,141,539**	**$ 340,623,399**
General Plant								
Leasehold Improvements	1910	$ 1,477,705	$ 1,556,942	$ 1,712,321	$ 2,040,482	$ 2,040,482	$ 2,090,482	$ 2,190,482
Office Furniture & Equipment	1915	$ 800,129	$ 800,799	$ 805,909	$ 809,563	$ 809,563	$ 809,563	$ 809,563
Computer Equipment - Hardware	1920	$ 5,467,726	$ 3,993,047	$ 4,542,235	$ 4,879,576	$ 4,919,837	$ 5,450,837	$ 5,763,237
Transportation Equipment	1930	$ 5,881,219	$ 5,528,895	$ 5,967,179	$ 6,178,806	$ 5,871,306	$ 6,021,306	$ 6,521,306
Stores Equipment	1935	$ 90,767	$ 30,767	$ 30,767	$ 30,767	$ 30,767	$ 30,767	$ 30,767
Tools, Shop & Garage Equipment	1940	$ 2,793,042	$ 2,999,957	$ 3,107,896	$ 3,212,731	$ 3,237,605	$ 3,338,061	$ 3,468,806
Measurement & Testing Equipment	1945	$ 1,313,545	$ 1,348,984	$ 1,539,415	$ 1,708,629	$ 1,852,282	$ 1,973,232	$ 2,103,717
Communications Equipment	1955	$ 1,011,287	$ 611,287	$ 611,287	$ 611,287	$ 611,287	$ 611,287	$ 611,287
Miscellaneous Equipment	1960	$ 242,998	$ 283,856	$ 283,856	$ 252,290	$ 252,290	$ 382,290	$ 553,384
Load Management Controls Customer Premise	1970	$ 107,035	$ 107,035	$ 107,035	$ 107,035	$ 107,035	$ 107,035	$ 107,035
Load Management Controls Utility Premises	1975	$ 2,366,234	$ 2,404,095	$ 2,582,767	$ 2,859,737	$ 2,890,819	$ 3,130,819	$ 3,130,819
System Supervisor Equipment	1980	$ 293,582	$ 293,582	$ 293,582	$ 293,582	$ 293,582	$ 293,582	$ 293,582
Gross General Plant		**$ 21,845,268**	**$ 19,959,246**	**$ 21,584,249**	**$ 22,984,485**	**$ 22,916,855**	**$ 24,239,261**	**$ 25,583,984**
Intangible Plant								
Capital Contributions Paid	1609	$ 4,136,705	$ 4,136,705	$ 4,175,700	$ 4,183,043	$ 4,183,043	$ 4,183,043	$ 4,183,043
Computer Software (Formally 1925)	1611	$ 2,848,223	$ 2,563,975	$ 2,590,632	$ 3,588,169	$ 4,101,270	$ 6,272,471	$ 7,074,970
Gross Intangible Plant		**$ 6,984,928**	**$ 6,700,680**	**$ 6,766,332**	**$ 7,771,212**	**$ 8,284,313**	**$ 10,455,514**	**$ 11,258,013**
Contributions and Grants								
Contributions & Grants	1995	$ (49,648,616)	$ -	$ -	$ -	$ -	$ -	$ -
Deferred Revenue	2440	$ (4,001,113)	$ (53,831,920)	$ (55,033,142)	$ (57,613,005)	$ (62,469,090)	$ (64,812,464)	$ (68,040,630)
Gross Contributions and Grants		**$ (53,649,729)**	**$ (53,831,920)**	**$ (55,033,142)**	**$ (57,613,005)**	**$ (62,469,090)**	**$ (64,812,464)**	**$ (68,040,630)**
Property Under Finance Lease	2005			$ 717,591	$ 708,325	$ 762,126	$ 762,126	$ 762,126
Gross Fixed Assets Closing Balance		**$ 243,594,693**	**$ 243,087,543**	**$ 253,879,390**	**$ 271,414,822**	**$ 278,994,841**	**$ 294,785,976**	**$ 310,186,892**
Less Retirement Obligations included in Assets		$ -	$ -	$ (717,591)	$ (708,325)	$ (762,126)	$ (762,126)	$ (762,126)
Gross Fixed Assets for Rate Base Purposes		**$ 243,594,693**	**$ 243,087,543**	**$ 253,161,799**	**$ 270,706,497**	**$ 278,232,715**	**$ 294,023,850**	**$ 309,424,766**

2.2.4 Variance Analysis on Gross Assets

Oshawa Power provides this variance analysis based on its materiality threshold of $195,000, as calculated in Exhibit 1 Section 1.9.11 of this Application. The analysis for gross asset additions are categorized as Distribution Plant, General Plant and Intangible Plant and Contributions and Grants. Oshawa Power reports and analyzes gross assets on a project basis and has prepared its variance explanations on the same basis.

2021 OEB Approved vs. 2021 Actual

Gross assets in 2021 were lower by $0.5M than the OEB Approved, primarily due to underspending in General Plant. See Table 2-12 below.

1 **Table 2-12: Variance Analysis on Gross Assets – 2021 Approved vs. 2021 Actual**

Description	USoA	2021 OEB Approved	2021 Actual	Variance
Distribution Plant				
Land	1805	$ 293,875	$ 293,875	$ (0)
Buildings	1808	$ 6,136,005	$ 5,809,820	$ (326,185)
Distribution Station Equipment	1820	$ 27,516,097	$ 28,224,786	$ 708,690
Poles, Towers & Fixtures	1830	$ 55,500,579	$ 63,707,962	$ 8,207,383
Overhead Conductors & Devices	1835	$ 28,492,999	$ 27,657,568	$ (835,431)
Underground Conductors & Devices	1845	$ 64,895,608	$ 63,322,461	$ (1,573,147)
Line Transformers	1850	$ 70,649,511	$ 66,064,463	$ (4,585,048)
Meters	1860	$ 14,929,550	$ 15,178,601	$ 249,050
Gross Distribution Plant		**$ 268,414,225**	**$ 270,259,536**	**$ 1,845,311**
General Plant				
Leasehold Improvements	1910	$ 1,477,705	$ 1,556,942	$ 79,237
Office Furniture & Equipment	1915	$ 800,129	$ 800,799	$ 670
Computer Equipment - Hardware	1920	$ 5,467,726	$ 3,993,047	$ (1,474,679)
Transportation Equipment	1930	$ 5,881,219	$ 5,528,895	$ (352,324)
Stores Equipment	1935	$ 90,767	$ 30,767	$ (60,000)
Tools, Shop & Garage Equipment	1940	$ 2,793,042	$ 2,999,957	$ 206,915
Measurement & Testing Equipment	1945	$ 1,313,545	$ 1,348,984	$ 35,439
Communications Equipment	1955	$ 1,011,287	$ 611,287	$ (400,000)
Miscellaneous Equipment	1960	$ 242,998	$ 283,856	$ 40,858
Load Management Controls Customer Premises	1970	$ 107,035	$ 107,035	$ 0
Load Management Controls Utility Premises	1975	$ 2,366,234	$ 2,404,095	$ 37,861
System Supervisor Equipment	1980	$ 293,582	$ 293,582	$ (0)
Gross General Plant		**$ 21,845,268**	**$ 19,959,246**	**$ (1,886,022)**
Intangible Plant				
Capital Contributions Paid	1609	$ 4,136,705	$ 4,136,705	$ 0
Computer Software (Formally 1925)	1611	$ 2,848,223	$ 2,563,975	$ (284,248)
Gross Intangible Plant		**$ 6,984,928**	**$ 6,700,680**	**$ (284,248)**
Contributions and Grants				
Contributions & Grants	1995	$ (49,648,616)	$ -	$ 49,648,616
Deferred Revenue	2440	$ (4,001,113)	$ (53,831,920)	$ (49,830,807)
Gross Contributions and Grants		**$ (53,649,729)**	**$ (53,831,920)**	**$ (182,191)**
Property Under Finance Lease	2005	$ -	$ -	$ -
Gross Fixed Assets Closing Balance		**$ 243,594,693**	**$ 243,087,543**	**$ (507,150)**
Less Retirement Obligations included in Assets		$ -	$ -	$ -
Gross Fixed Assets for Rate Base Purposes		**$ 243,594,693**	**$ 243,087,543**	**$ (507,150)**

Distribution Plant

The following Distribution Plant related USoA accounts contributed significantly to gross assets in 2021:

- USoA 1830 – Poles, Towers & Fixtures (+$8.2M variance, including disposals of $0.3M)
- USoA 1850 – Line Transformers (-$4.6M variance, including disposals of $1.1M)
- USoA 1845 – Underground Conductors & Devices (-$1.6M variance)
- USoA 1835 – Overhead Conductors and Devices (-$835K variance, including disposals of $272K)
- USoA 1820 – Distribution Station Equipment <50 kV (+$709K variance)
- USoA 1808 – Buildings (-$326K variance)
- USoA 1860 – Meters (Smart Meters) (+$249K variance, including disposals of $388K)

The main drivers for higher distribution plant additions were higher system access costs in areas such as third party relocation, revenue metering, and Advanced Metering Infrastructure (AMI) system upgrades. In addition, there were higher system renewal costs were incurred from replacing failing assets based on annual inspections, and higher system service costs in areas such as voltage monitoring & substation transformer monitoring and telemetry, and system reconfigurations to target reliability improvements.

General Plant

The combined impact of the following General Plant-related investments resulted in gross additions being lower than OEB Approved values.

- USoA 1920 – Computer Equipment - Hardware (-$1.5M variance)
- USoA 1955 – Communications Equipment (-$400K variance)
- USoA 1930 – Transportation Equipment (-$352K variance, including disposals of $30.5K)
- USoA 1940 – Tools, Shop & Garage Equipment (+$207K variance)

The Customer Information system (CIS) Enhancement was deferred to 2025 as a result of opening it up to a competitive bid rather than moving the existing software from hosted to on-premise as originally planned. This change, combined with lower general annual IT and fleet expenditures, resulted in lower gross additions than planned.

Intangible Plant

No material Intangible Plant-related variances are observed between 2021 OEB Approved vs. 2021 Actuals.

Contributions & Grants

These investments were partially offset by higher contributions and grants of $182K than for 2021 OEB Approved.

2022 Actual vs. 2021 Actual

Total gross assets in 2022 increased by $10.1M over 2021, due to investments in Distribution Plant based on asset renewal projects and system access investments made in the year. See Table 2-13 below.

1 **Table 2-13: Variance Analysis on Gross Assets - 2022 Actual vs. 2021 Actual**

Description	USoA	2021 Actual	2022 Actual	Variance
Distribution Plant				
Land	1805	$ 293,875	$ 293,875	$ -
Buildings	1808	$ 5,809,820	$ 5,847,295	$ 37,475
Distribution Station Equipment	1820	$ 28,224,786	$ 28,312,049	$ 87,263
Poles, Towers & Fixtures	1830	$ 63,707,962	$ 64,254,466	$ 546,504
Overhead Conductors & Devices	1835	$ 27,657,568	$ 29,896,906	$ 2,239,338
Underground Conductors & Devices	1845	$ 63,322,461	$ 68,445,955	$ 5,123,494
Line Transformers	1850	$ 66,064,463	$ 66,994,356	$ 929,893
Meters	1860	$ 15,178,601	$ 15,799,457	$ 620,856
Gross Distribution Plant		**$ 270,259,536**	**$ 279,844,360**	**$ 9,584,824**
General Plant				
Leasehold Improvements	1910	$ 1,556,942	$ 1,712,321	$ 155,379
Office Furniture & Equipment	1915	$ 800,799	$ 805,909	$ 5,110
Computer Equipment - Hardware	1920	$ 3,993,047	$ 4,542,235	$ 549,188
Transportation Equipment	1930	$ 5,528,895	$ 5,967,179	$ 438,284
Stores Equipment	1935	$ 30,767	$ 30,767	$ -
Tools, Shop & Garage Equipment	1940	$ 2,999,957	$ 3,107,896	$ 107,939
Measurement & Testing Equipment	1945	$ 1,348,984	$ 1,539,415	$ 190,431
Communications Equipment	1955	$ 611,287	$ 611,287	$ -
Miscellaneous Equipment	1960	$ 283,856	$ 283,856	$ -
Load Management Controls Customer Premises	1970	$ 107,035	$ 107,035	$ -
Load Management Controls Utility Premises	1975	$ 2,404,095	$ 2,582,767	$ 178,672
System Supervisor Equipment	1980	$ 293,582	$ 293,582	$ -
Gross General Plant		**$ 19,959,246**	**$ 21,584,249**	**$ 1,625,003**
Intangible Plant				
Capital Contributions Paid	1609	$ 4,136,705	$ 4,175,700	$ 38,995
Computer Software (Formally 1925)	1611	$ 2,563,975	$ 2,590,632	$ 26,657
Gross Intangible Plant		**$ 6,700,680**	**$ 6,766,332**	**$ 65,652**
Contributions and Grants				
Contributions & Grants	1995	$ -	$ -	$ -
Deferred Revenue	2440	$ (53,831,920)	$ (55,033,142)	$ (1,201,222)
Gross Contributions and Grants		**$ (53,831,920)**	**$ (55,033,142)**	**$ (1,201,222)**
Property Under Finance Lease	2005		$ 717,591	$ 717,591
Gross Fixed Assets Closing Balance		**$ 243,087,543**	**$ 253,879,390**	**$ 10,791,848**
Less Retirement Obligations included in Assets		$ -	$ (717,591)	$ (717,591)
Gross Fixed Assets for Rate Base Purposes		**$ 243,087,543**	**$ 253,161,799**	**$ 10,074,257**

Distribution Plant

The following Distribution Plant-related USoA accounts contributed significantly to gross assets in 2022:

- USoA 1845 – Underground Conductors & Devices (+$5.1M variance)
- USoA 1835 – Overhead Conductors & Devices (+$2.2M variance, including disposals of $0.3M)
- USoA 1850 – Line Transformers (+$930K variance, including disposals of $785K)
- USoA 1860 – Meters (Smart Meters) (+$621K variance, including disposals of $12.9K)
- USoA 1830 – Poles, Towers & Fixtures (+$547K variance, including disposals of $184K)

System renewal ($6.5M) and system access ($3.8M) were the highest investment categories.

Some noteworthy system renewal projects were proactive overhead ($1.7M) and underground ($1.4M) system rebuilds, and reactive work ($2.2M). Reactive work resulted from emergency repairs, equipment failures, and run-to-failure asset replacements identified during the three-year inspection and maintenance cycle. Additionally, isolated distribution asset replacements such as the pole replacement program ($375K) and porcelain switch and insulator replacement program ($553K) were executed to mitigate risk by targeting assets of poor health.

System access investments such as connections ($1.8M) and Third Party Relocations ($1.4M) played a big role in additions to gross assets. Connection investments such as facilitating several service upgrades and new customer connections whereas Third Party Relocations investment included facilitating municipal infrastructure improvement initiatives during the year. An AMI system upgrade ($434K) to replace failed meters also contributed to additions.

System service investments ($1.3M) in furthering distribution automation to support reliability and enhance operational efficiency also contributed to additions. Key areas of

investment were overhead self healing switches ($338K) and smart grid, including SCADA-operated 44kV overhead Switches, SCADA integration and deployment of automation controllers and network-connected devices ($430K).

General Plant

The following General Plant related USoA accounts contributed to gross assets in 2022:

- USoA 1920 – Computer Equipment - Hardware (+$549K variance):
- USoA 1930 – Transportation Equipment (+$438K variance):

The primary drivers of gross additions in general plant were a server hardware refresh and end user hardware replacements to replace aging or out-of-support systems. Fleet expenditure increases were related to procurement of material handler and a 55’ single bucket truck.

Intangible Plant

There was no material impact on gross assets resulting from Intangible Plant in 2022.

Contributions & Grants

These investments were partially offset by contributions and grants of $1.2M in 2022.

2023 Actual vs. 2022 Actual

Total gross assets in 2023 increased by $17.5M over 2022, principally due to old assets nearing or at end of life replaced through asset renewal projects. See Table 2-14 below.

1 **Table 2-14: Variance Analysis on Gross Assets - 2023 Actual vs. 2022 Actual**

Description	USoA	2022 Actual	2023 Actual	Variance
Distribution Plant				
Land	1805	$ 293,875	$ 293,875	$ -
Buildings	1808	$ 5,847,295	$ 5,578,968	$ (268,327)
Distribution Station Equipment	1820	$ 28,312,049	$ 28,301,964	$ (10,085)
Poles, Towers & Fixtures	1830	$ 64,254,466	$ 68,426,020	$ 4,171,554
Overhead Conductors & Devices	1835	$ 29,896,906	$ 35,018,193	$ 5,121,287
Underground Conductors & Devices	1845	$ 68,445,955	$ 72,534,538	$ 4,088,583
Line Transformers	1850	$ 66,994,356	$ 70,886,896	$ 3,892,540
Meters	1860	$ 15,799,457	$ 16,523,350	$ 723,893
Gross Distribution Plant		**$ 279,844,360**	**$ 297,563,805**	**$ 17,719,445**
General Plant				
Leasehold Improvements	1910	$ 1,712,321	$ 2,040,482	$ 328,161
Office Furniture & Equipment	1915	$ 805,909	$ 809,563	$ 3,654
Computer Equipment - Hardware	1920	$ 4,542,235	$ 4,879,576	$ 337,341
Transportation Equipment	1930	$ 5,967,179	$ 6,178,806	$ 211,627
Stores Equipment	1935	$ 30,767	$ 30,767	$ -
Tools, Shop & Garage Equipment	1940	$ 3,107,896	$ 3,212,731	$ 104,835
Measurement & Testing Equipment	1945	$ 1,539,415	$ 1,708,629	$ 169,214
Communications Equipment	1955	$ 611,287	$ 611,287	$ -
Miscellaneous Equipment	1960	$ 283,856	$ 252,290	$ (31,566)
Load Management Controls Customer Premises	1970	$ 107,035	$ 107,035	$ -
Load Management Controls Utility Premises	1975	$ 2,582,767	$ 2,859,737	$ 276,970
System Supervisor Equipment	1980	$ 293,582	$ 293,582	$ -
Gross General Plant		**$ 21,584,249**	**$ 22,984,485**	**$ 1,400,236**
Intangible Plant				
Capital Contributions Paid	1609	$ 4,175,700	$ 4,183,043	$ 7,343
Computer Software (Formally 1925)	1611	$ 2,590,632	$ 3,588,169	$ 997,537
Gross Intangible Plant		**$ 6,766,332**	**$ 7,771,212**	**$ 1,004,880**
Contributions and Grants				
Contributions & Grants	1995	$ -	$ -	$ -
Deferred Revenue	2440	$ (55,033,142)	$ (57,613,005)	$ (2,579,863)
Gross Contributions and Grants		**$ (55,033,142)**	**$ (57,613,005)**	**$ (2,579,863)**
Property Under Finance Lease	2005	$ 717,591	$ 708,325	$ (9,267)
Gross Fixed Assets Closing Balance		**$ 253,879,390**	**$ 271,414,822**	**$ 17,535,431**
Less Retirement Obligations included in Assets		$ (717,591)	$ (708,325)	$ 9,267
Gross Fixed Assets for Rate Base Purposes		**$ 253,161,799**	**$ 270,706,497**	**$ 17,544,698**

Distribution Plant

The following Distribution Plant-related USoA accounts contributed significantly to gross assets in 2023:

- USoA 1835 – Overhead Conductors & Devices (+$5.1M variance, including disposals of $0.4M)
- USoA 1830 – Poles, Towers & Fixtures (+$4.2M variance, including disposals of $0.2M)
- USoA 1845 – Underground Conductors & Devices (+$4.1M variance)
- USoA 1850 – Line Transformers (+$3.9M variance, including disposals of $0.8M)
- USoA 1860 – Meters (Smart Meters) (+$724K variance, including disposals of $10.9K)

System renewal ($12.1M) and system access ($7.1M) were the highest investment categories.

Some noteworthy system renewal projects were proactive overhead ($3.6M) and underground ($1.6M) system rebuilds, and reactive work ($2.7M) resulting from emergency repairs, equipment failures, and run-to-failure asset replacements identified during the three-year inspection and maintenance cycle. Replacement of MS2 municipal switchgear ($3.1M) was also completed and energized in 2023. The project also involved replacement of riser poles, egress cable, and associated duct work and road crossings to best utilize the new assets. Similar to 2022, isolated distribution asset replacements such as the pole replacement program ($412K) and porcelain switch and insulator replacement program ($547K) targeting assets of poor health, also contributed to additions.

Increased system access expenditures for expansions ($3.4M) were the result of increased focus on housing developments that had been previously deferred. Investments in connections ($1.7M) for service upgrades and new customers, and third party relocations ($1.2M) for municipal infrastructure improvement initiatives also contributed additions to gross assets. The Wilson M18 feeder relocation project driven by Hydro One was one the major projects, but was offset by contributions. The

remaining projects involved relocation of assets to accommodate municipal infrastructure betterment initiatives such as the Region of Durham's Victoria-Bloor Road widening project.

Efforts in furthering distribution automation also continued in 2023 through several system service expenditures ($1.3M). Though some investments in software contributed to additions in Intangible Plant, others such as deployment of overhead self healing switches ($181K), SCADA operated 44kV overhead switches, SCADA integration and deployment of automation controllers and network connected devices ($231K) contributed to Distribution Plant. These investments supplemented the Fault Location, Isolation, and Service Restoration (FLISR) system, improving reliability and reducing response times.

General Plant

The following General Plant-related USoA accounts contributed significantly to gross assets in 2023.

- USoA 1920 – Computer Equipment - Hardware (+$337K variance)
- USoA 1910 – Leasehold Improvements (+$328K variance)
- USoA 1975 – Load Management Controls Utility Premises (+$277K variance)
- USoA 1930 – Transportation Equipment (+$212K variance, including disposals of $556K)

Investments in fleet included purchase of a 55' single bucket truck, a digger truck and four hybrid pickup trucks to retire overdue vehicles. There was also investment in general IT ($225K) as well office IT and equipment upgrades ($137K), including replacement of aged end user hardware and office IT, that were significant drivers of gross additions in General Plant. Additionally, a $182K investment in facilities was required to reduce interdepartmental distractions and create designated divisions, including an isolated area for the control room.

Intangible Plant

The following Intangible Plant related USoA accounts contributed significantly to gross assets in 2023.

- USoA 1611 – Computer Software (+$998K variance)

Included in Software investments were a new customer portal that included green button functionality, the implementation of new payroll service application to enable accurate timesheet entry and cost allocation, and a major upgrade to the outage management system to enhance operational efficiency, reduce software costs and better integrate with geographic information systems (GIS).

Contributions & Grants

These investments were partially offset by contributions and grants of $2.6M in 2023.

2024 Actual vs. 2023 Actual

Total gross assets in 2024 increased by $7.5M over 2023, principally due to investments in Distribution Plant based on asset renewal projects, partially offset by an increase in Contributions & Grants. See Table 2-15 below.

Table 2-15: Variance Analysis on Gross Assets - 2024 Actual vs. 2023 Actual

Description	USoA	2023 Actual	2024 Actual	Variance
Distribution Plant				
Land	1805	$ 293,875	$ 293,875	$ -
Buildings	1808	$ 5,578,968	$ 5,578,968	$ -
Distribution Station Equipment	1820	$ 28,301,964	$ 30,539,895	$ 2,237,931
Poles, Towers & Fixtures	1830	$ 68,426,020	$ 72,149,200	$ 3,723,180
Overhead Conductors & Devices	1835	$ 35,018,193	$ 33,789,875	$ (1,228,318)
Underground Conductors & Devices	1845	$ 72,534,538	$ 77,097,138	$ 4,562,600
Line Transformers	1850	$ 70,886,896	$ 72,807,952	$ 1,921,056
Meters	1860	$ 16,523,350	$ 17,243,733	$ 720,383
Gross Distribution Plant		**$ 297,563,805**	**$ 309,500,637**	**$ 11,936,832**
General Plant				
Leasehold Improvements	1910	$ 2,040,482	$ 2,040,482	$ -
Office Furniture & Equipment	1915	$ 809,563	$ 809,563	$ -
Computer Equipment - Hardware	1920	$ 4,879,576	$ 4,919,837	$ 40,261
Transportation Equipment	1930	$ 6,178,806	$ 5,871,306	$ (307,500)
Stores Equipment	1935	$ 30,767	$ 30,767	$ -
Tools, Shop & Garage Equipment	1940	$ 3,212,731	$ 3,237,605	$ 24,874
Measurement & Testing Equipment	1945	$ 1,708,629	$ 1,852,282	$ 143,653
Communications Equipment	1955	$ 611,287	$ 611,287	$ -
Miscellaneous Equipment	1960	$ 252,290	$ 252,290	$ -
Load Management Controls Customer Premises	1970	$ 107,035	$ 107,035	$ -
Load Management Controls Utility Premises	1975	$ 2,859,737	$ 2,890,819	$ 31,082
System Supervisor Equipment	1980	$ 293,582	$ 293,582	$ -
Gross General Plant		**$ 22,984,485**	**$ 22,916,855**	**$ (67,630)**
Intangible Plant				
Capital Contributions Paid	1609	$ 4,183,043	$ 4,183,043	$ -
Computer Software (Formally 1925)	1611	$ 3,588,169	$ 4,101,270	$ 513,101
Gross Intangible Plant		**$ 7,771,212**	**$ 8,284,313**	**$ 513,101**
Contributions and Grants				
Contributions & Grants	1995	$ -	$ -	$ -
Deferred Revenue	2440	$ (57,613,005)	$ (62,469,090)	$ (4,856,085)
Gross Contributions and Grants		**$ (57,613,005)**	**$ (62,469,090)**	**$ (4,856,085)**
Property Under Finance Lease	2005	$ 708,325	$ 762,126	$ 53,801
Gross Fixed Assets Closing Balance		**$ 271,414,822**	**$ 278,994,841**	**$ 7,580,019**
Less Retirement Obligations included in Assets		$ (708,325)	$ (762,126)	$ (53,801)
Gross Fixed Assets for Rate Base Purposes		**$ 270,706,497**	**$ 278,232,715**	**$ 7,526,218**

Distribution Plant

The following Distribution Plant related USoA accounts contributed significantly to gross assets in 2024:

- USoA 1845 – Underground Conductors & Devices (+$4.6M variance)
- USoA 1830 – Poles, Towers & Fixtures (+$3.7M variance, including disposals of $0.1M)
- USoA 1820 – Distribution Station Equipment <50 kV (+$2.2M variance)
- USoA 1850 – Line Transformers (+$1.9M variance, including disposals of $0.6M)
- USoA 1835 – Overhead Conductors & Devices (-$1.2M variance, including disposals of $86.8K)
- USoA 1860 – Meters (Smart Meters) (+$720K variance, including disposals of $81.9K)

System renewal ($4.6M) and system access ($6.7M) were the highest investment categories, with these variances also accounting for job closing accruals and corrections.

System renewal programs such as proactive overhead ($1.3M) and underground ($818K) system rebuilds, reactive work ($2M) resulting from emergency repairs, equipment failures, and run-to-failure asset replacements identified during the three-year inspection and maintenance cycle, contributed significantly to additions. Additionally, isolated distribution asset replacements via annual programs such as the pole replacement program ($311K) and porcelain switch and insulator replacement program ($180K) targeting assets of poor health and high risk, also contributed to additions.

Under system access, third party driven relocations ($4M) contributed significantly to additions. Hydro One's Wilson TS feeder relocation project to move multiple 44kV feeders to a new yard was a substantial undertaking that concluded in 2024. A majority of the costs were covered by Hydro One's contributed capital towards the project. Other municipal initiatives such as the Thornton Rd N road widening project also required asset relocations, adding to gross assets. Expansions ($154K) had a lower impact on additions. While multiple subdivision projects were worked on throughout the year, none were energized by the end of the fiscal year. These projects are expected to be put into service

in early 2025. Additional investments included connections ($1.8M) for service upgrades and new customers, and an AMI system upgrade ($321K) to replace failed meters.

Distribution automation efforts continued via annual system service programs such as overhead self healing switches ($202K) and smart grid including SCADA operated 44kV overhead switches, SCADA integration and deployment of automation controllers and network connected devices ($106K). However, the main system service item contributing to Distribution Plant in 2024 is the 44kV line extension project ($1.4M). This project extended the 165M7 44kV feeder (fed from Enfield TS) west along Conlin Rd W to its intersection with Thornton Rd N, enabling the connection of multiple large industrial and commercial loads in the Northwood Business Park area.

General Plant

No material impact on gross assets resulting from General Plant related USoA accounts in 2024 with the exception of transportation equipment. The decrease of $308K is related to the retirement of one bucket truck and one pickup truck.

Some noteworthy additions are cybersecurity-related hardware expenditures associated with framework controls, and investments in major tools and equipment to support with daily distribution activities.

Intangible Plant

The following Intangible Plant related USoA accounts saw an increase in 2024:

- USoA 1611 – Computer Software (+$513K variance)

Software investments including enhancements to the financial system to enable purchasing approval automation, enhancements to the GIS such as online customer reporting tools, and switch upgrades were the primary additions in 2024.

Contributions & Grants

These investments were partially offset by contributions and grants of $4.9M in 2024. A significant portion of this contribution is from Hydro One towards the Wilson TS feeder relocation project ($2.6M) and the remaining towards programs such as expansions,

connections, and third party relocations under system access and reactive replacement program under system renewal.

2025 Bridge Year vs. 2024 Actual

Total gross assets in 2025 are forecast to increase by $15.8M over 2024, principally due to investments in Distribution Plant. See Table 2-16 below.

Table 2-16: Variance Analysis on Gross Assets - 2025 Bridge Year vs. 2024 Actual

Description	USoA	2024 Actual	2025 Bridge	Variance
Distribution Plant				
Land	1805	$ 293,875	$ 293,875	$ -
Buildings	1808	$ 5,578,968	$ 5,578,968	$ -
Distribution Station Equipment	1820	$ 30,539,895	$ 33,057,078	$ 2,517,183
Poles, Towers & Fixtures	1830	$ 72,149,200	$ 75,243,200	$ 3,094,000
Overhead Conductors & Devices	1835	$ 33,789,875	$ 35,925,954	$ 2,136,079
Underground Conductors & Devices	1845	$ 77,097,138	$ 80,617,329	$ 3,520,190
Line Transformers	1850	$ 72,807,952	$ 75,759,020	$ 2,951,067
Meters	1860	$ 17,243,733	$ 17,666,116	$ 422,382
Gross Distribution Plant		**$ 309,500,637**	**$ 324,141,539**	**$ 14,640,902**
General Plant				
Leasehold Improvements	1910	$ 2,040,482	$ 2,090,482	$ 50,000
Office Furniture & Equipment	1915	$ 809,563	$ 809,563	$ -
Computer Equipment - Hardware	1920	$ 4,919,837	$ 5,450,837	$ 531,000
Transportation Equipment	1930	$ 5,871,306	$ 6,021,306	$ 150,000
Stores Equipment	1935	$ 30,767	$ 30,767	$ -
Tools, Shop & Garage Equipment	1940	$ 3,237,605	$ 3,338,061	$ 100,456
Measurement & Testing Equipment	1945	$ 1,852,282	$ 1,973,232	$ 120,950
Communications Equipment	1955	$ 611,287	$ 611,287	$ -
Miscellaneous Equipment	1960	$ 252,290	$ 382,290	$ 130,000
Load Management Controls Customer Premises	1970	$ 107,035	$ 107,035	$ -
Load Management Controls Utility Premises	1975	$ 2,890,819	$ 3,130,819	$ 240,000
System Supervisor Equipment	1980	$ 293,582	$ 293,582	$ -
Gross General Plant		**$ 22,916,855**	**$ 24,239,261**	**$ 1,322,406**
Intangible Plant				
Capital Contributions Paid	1609	$ 4,183,043	$ 4,183,043	$ -
Computer Software (Formally 1925)	1611	$ 4,101,270	$ 6,272,471	$ 2,171,201
Gross Intangible Plant		**$ 8,284,313**	**$ 10,455,514**	**$ 2,171,201**
Contributions and Grants				
Contributions & Grants	1995	$ -	$ -	$ -
Deferred Revenue	2440	$ (62,469,090)	$ (64,812,464)	$ (2,343,374)
Gross Contributions and Grants		**$ (62,469,090)**	**$ (64,812,464)**	**$ (2,343,374)**
Property Under Finance Lease	2005	$ 762,126	$ 762,126	$ -
Gross Fixed Assets Closing Balance		**$ 278,994,841**	**$ 294,785,976**	**$ 15,791,135**
Less Retirement Obligations included in Assets		$ (762,126)	$ (762,126)	$ -
Gross Fixed Assets for Rate Base Purposes		**$ 278,232,715**	**$ 294,023,850**	**$ 15,791,135**

Distribution Plant

The following Distribution Plant-related USoA accounts expected to see a major increase in 2025:

- USoA 1845 – Underground Conductors & Devices (+$3.5M variance)
- USoA 1830 – Poles, Towers & Fixtures (+$3.1M variance, including disposals of $0.2M)
- USoA 1850 – Line Transformers (+$3.0M variance, including disposals of $0.9M)
- USoA 1820 – Distribution Station Equipment <50 kV (+$2.5M variance)
- USoA 1835 – Overhead Conductors & Devices (+$2.1M variance, including disposals of $0.3M)
- USoA 1860 – Meters (Smart Meters) (+$422K variance, including disposals of $137K)

System renewal ($7.9M) and system access ($8.0M) are expected to remain the highest investment categories contributing to gross additions.

MS7 municipal switchgear ($3.5M) is planned for replacement and in service in 2025. Other annual system renewal efforts in proactive overhead ($1.8M) and underground ($364K) system rebuilds, pole replacement program ($500K) and the porcelain switch and insulator replacement program ($175K) targeting assets of poor health and high risk is expected to continue. Reactive work, including end-of-life asset replacements, motor vehicle accidents, dig-ins, and primary/secondary cable faults, are expected to incur $1.5M in costs.

Additional investment in expansions ($4.0M) including finalizing 2024 projects and new projects in 2025, are expected to contribute significantly to distribution plant additions. Third party driven relocations ($1.75M) resulting from infrastructure relocation work associated with the initiatives like the City of Oshawa's widening of Conlin Road E (from Harmony Rd N to Grandview St N), and regional road improvements on Wentworth St E (from Cedar St to Farewell St), along with connections ($1.7M) for service upgrades and new customers, are expected to be the main drivers of gross additions.

AMI system upgrades ($321K) to replace failed meters and revenue metering ($304K) for new customers also contributed to additions.

Annual system service expenditures in furthering automation via overhead self healing switches ($200K) and smart grid including SCADA operated 44kV overhead switches, SCADA integration and deployment of automation controllers and network connected devices ($240K) are expected to continue in 2025.

General Plant

The following General Plant related USoA accounts are expected to see an increase in 2025:

- USoA 1920 – Computer Equipment - Hardware (+$531K variance)
- USoA 1975 – Load Management Controls Utility Premises (+$240K variance)

Replacements such as network switches and firewall, end user hardware, and control room hardware are the main anticipated drivers of gross additions in General Plant.

Intangible Plant

The following Intangible Plant related USoA accounts are expected to see an increase in 2025:

- USoA 1611 – Computer Software (+$2.2M variance)

CIS software and enhancements ($1.4M) to advance business transformation efforts by facilitating a greater degree of automation, improved business processes, and integration with other systems, are the main drivers of this increase. Other initiatives such as mobile workforce management, customer relationship management (CRM), and financial system enhancement software are also planned for 2025.

Contributions & Grants

Contributions and grants of $2.3M are expected in 2025, in line with historical trends. This is lower than in 2024 when Hydro One made contributions towards the Wilson TS feeder relocation project, as discussed above.

2026 Test Year vs. 2025 Bridge Year

Total gross assets in 2026 Test Year are forecast to increase by $15.4M over 2025 Bridge Year, principally due to investments in Distribution Plant. See Table 2-17 below.

Table 2-17: Variance Analysis on Gross Assets - 2026 Test vs. 2025 Bridge

Description	USoA	2025 Actual	2026 Test	Variance
Distribution Plant				
Land	1805	$ 293,875	$ 293,875	$ -
Buildings	1808	$ 5,578,968	$ 5,578,968	$ -
Distribution Station Equipment	1820	$ 33,057,078	$ 35,244,469	$ 2,187,391
Poles, Towers & Fixtures	1830	$ 75,243,200	$ 78,185,963	$ 2,942,763
Overhead Conductors & Devices	1835	$ 35,925,954	$ 38,852,707	$ 2,926,753
Underground Conductors & Devices	1845	$ 80,617,329	$ 84,988,757	$ 4,371,428
Line Transformers	1850	$ 75,759,020	$ 78,346,531	$ 2,587,511
Meters	1860	$ 17,666,116	$ 19,132,129	$ 1,466,013
Gross Distribution Plant		**$ 324,141,539**	**$ 340,623,399**	**$ 16,481,859**
General Plant				
Leasehold Improvements	1910	$ 2,090,482	$ 2,190,482	$ 100,000
Office Furniture & Equipment	1915	$ 809,563	$ 809,563	$ -
Computer Equipment - Hardware	1920	$ 5,450,837	$ 5,763,237	$ 312,400
Transportation Equipment	1930	$ 6,021,306	$ 6,521,306	$ 500,000
Stores Equipment	1935	$ 30,767	$ 30,767	$ -
Tools, Shop & Garage Equipment	1940	$ 3,338,061	$ 3,468,806	$ 130,745
Measurement & Testing Equipment	1945	$ 1,973,232	$ 2,103,717	$ 130,485
Communications Equipment	1955	$ 611,287	$ 611,287	$ -
Miscellaneous Equipment	1960	$ 382,290	$ 553,384	$ 171,094
Load Management Controls Customer Premises	1970	$ 107,035	$ 107,035	$ -
Load Management Controls Utility Premises	1975	$ 3,130,819	$ 3,130,819	$ -
System Supervisor Equipment	1980	$ 293,582	$ 293,582	$ -
Gross General Plant		**$ 24,239,261**	**$ 25,583,984**	**$ 1,344,723**
Intangible Plant				
Capital Contributions Paid	1609	$ 4,183,043	$ 4,183,043	$ -
Computer Software (Formally 1925)	1611	$ 6,272,471	$ 7,074,970	$ 802,499
Gross Intangible Plant		**$ 10,455,514**	**$ 11,258,013**	**$ 802,499**
Contributions and Grants				
Contributions & Grants	1995	$ -	$ -	$ -
Deferred Revenue	2440	$ (64,812,464)	$ (68,040,630)	$ (3,228,166)
Gross Contributions and Grants		**$ (64,812,464)**	**$ (68,040,630)**	**$ (3,228,166)**
Property Under Finance Lease	2005	$ 762,126	$ 762,126	$ -
Gross Fixed Assets Closing Balance		**$ 294,785,976**	**$ 310,186,892**	**$ 15,400,915**
Less Retirement Obligations included in Assets		$ (762,126)	$ (762,126)	$ -
Gross Fixed Assets for Rate Base Purposes		**$ 294,023,850**	**$ 309,424,766**	**$ 15,400,915**

Distribution Plant

The following Distribution Plant related USoA accounts planned for 2026:

- USoA 1845 – Underground Conductors & Devices (+$4.4M variance)
- USoA 1835 – Overhead Conductors & Devices (+$2.9M variance, including disposals $0.3M)
- USoA 1830 – Poles, Towers & Fixtures (+$2.9M variance, including disposals of $0.2M)
- USoA 1850 – Line Transformers (+$2.6M variance, including disposals of $0.9M)
- USoA 1820 – Distribution Station Equipment <50 kV (+2.2M variance)
- USoA 1860 – Meters (Smart Meters) (+$1.5M variance, including disposals of $0.1M)

System renewal ($8.0M) and system access ($9.2M) are expected to remain the highest investment categories contributing to gross additions.

Targeted asset replacements planned for the 2026 Test Year, as recommended by the asset condition assessment and filtered through the risk prioritization methodology, include MS5 municipal switchgear replacement ($3.5M), overhead ($1.1M) and underground ($393K) system rebuilds, and pole replacement program ($300K). Based on historical trends of expenditures on reactive work, including end-of-life asset replacements, motor vehicle accidents, dig-ins, and primary/secondary cable faults, reactive expenditures of $2.1M are anticipated.

Meter replacement driven by Measurement Canada regulatory requirements has been strategically paced over the planning period. Replacement work worth $1.1M is expected to be completed in 2026.

Investment in expansions ($4.3M) are guided by Oshawa's historical new connection trends and specific developments such as Kedron and Columbus in North Oshawa, and are the highest system access expenditure contributing to gross additions.

Third party driven relocations ($1.75M) dictated by municipal and regional infrastructure initiatives, primarily road-widening projects, and affirmed via coordination efforts with municipal partners to refine scope and timelines are also a main driver of additions.

Some other investment areas are connections ($1.5M) involving installation of necessary infrastructure such as poles, ducts, transformers and cables to facilitate new or upgraded services, and revenue metering ($304K) to accurately measure usage for new customers.

Under system service, a planned egress cable construction project at MS9 to alleviate overburdened assets in North Oshawa and meet growing load demand, increases gross additions by $1M. The project ensures that existing capacity is optimized while supporting future development.

General Plant

The following General Plant related USoA accounts are expected see an increase in 2026:

- USoA 1930 – Transportation Equipment (+$500K variance)
- USoA 1920 – Computer Equipment - Hardware (+$312K variance)

IT investments ($312K) in end user, server, and SCADA hardware to enhance operational efficiencies have been included, in addition to fleet investments ($500K). Procurement of one crew leader truck and two specialized utility vehicles are the main anticipated drivers of gross additions in General Plant.

Intangible Plant

The following Intangible Plant related USoA accounts are expected to see an increase in 2026:

- USoA 1611 – Computer Software (+$803K variance)

Additions are expected from planned system improvements such as records management, GIS upgrades, automation platform, system automation, end user software upgrades, and intranet upgrades intended to enhance data accuracy, streamline processes, and improve operational efficiency.

Investments to improve the customer interface are also an area of focus in 2026, including CRM software, website redesign, and customer communication redesign to improve accessibility, engagement and service quality to Oshawa Power's customers.

Contributions & Grants

Contributions and grants of $3.2M are anticipated in 2026. Contributions are forecast to increase due to the increase in system access spending planned in 2026 in the 2026-2030 Distribution System Plan (DSP), discussed below in section 2.5.

2.3 DEPRECIATION, AMORTIZATION AND DEPLETION

2.3.1 Overview of Depreciation, Amortization, and Depletion

Oshawa Power adheres to Modified International Financial Reporting Standards (MIFRS) capitalization accounting treatments for rate making and regulatory reporting purposes. Oshawa Power's 2012 rebasing application (EB-2011-0073) included the transition to MIFRS effective January 1, 2012. Depreciation is computed on a straight-line basis over the estimated useful life of the item of Property, Plant and Equipment (PP&E). For rate setting purposes, in the first year of service, depreciation is calculated using the half year rule in accordance with the Filing Requirements. The depreciable amount of an asset is determined after deducting its estimated residual value, if material. Oshawa Power has no items of PP&E with material residual values. In accordance with MIFRS standards, the components of each item of PP&E are depreciated separately.

2.3.2 Useful Life and Componentization

In its 2012 application (EB-2011-0073), Oshawa Power adopted, for asset depreciation purposes, the typical useful lives recommended by Kinectrics in its Asset Depreciation Study prepared for the OEB. Oshawa Power retained an independent third party, Metsco, with the objective of establishing the typical useful life (TUL) of major fixed assets employed on Oshawa Power's distribution system. The resulting report, completed in

January 2014, found the typical useful life of the majority of the assets employed on Oshawa Power's distribution system were accurately reflected in the Kinectrics report, with the exception of six asset classes. The Table 2-18 below summarizes the asset classes where Metsco recommends a TUL different to Kinectrics. Oshawa Power confirms that there are no further changes in this Application.

Table 2-18: Oshawa Power Asset Classes Outside of Kinectrics Report

Asset Class	Typical Useful Life (Kinectrics Conclusion)	Typical Useful Life (Metsco Conclusion)
Power Transformers employed at Distribution Station	45 years	40 years
Station Independent Circuit breakers	45 years	40 years
Overhead Conductors	60 years	45 years
Overhead Line Switches	45 years	40 years
SCADA System	20 years	8 years
Direct Buried Secondary Cables	35 years	42.5 years

There were six areas where Oshawa Power's TUL was outside the Kinectrics ranges in Appendix 2-BB. The reason for each were described in Oshawa Power's 2015 Cost of Service Application (EB-2014-0101) and are described below:

- **Power Transformers employed at Distribution**: Metsco analysed the actual useful service life for a batch of power transformers that have been retired from service at Oshawa Power during the past five years. The results of this analysis indicate the mean useful life of power transformers at Oshawa Power to be 39 years rather than 45 years as recommended by Kinectrics.
- **Station Independent Circuit Breakers**: In Metsco's opinion, because this asset class is composed of a broad category of different types of circuit breakers, some installed indoors and some installed outdoors, the surveys performed by Kinectrics did not correctly reveal the typical useful life of outdoor circuit breakers. For this asset, the recommended typical useful life of 40 years was based on the overall

industry experience and more accurately represents the typical useful life of circuit breakers employed on Oshawa Power's system, rather than 45 years as recommended by Kinectrics.

- **Overhead Conductors**: Metsco concludes the typical useful life of overhead line conductors to be 45 years, rather than 60 years as recommended by Kinectrics. While conductors may outlive the poles they are attached to, they are typically replaced whenever a line is rebuilt with new poles because it is economically prudent to change all the components at the same time rather than reconstructing the line in stages.
- **Overhead Line Switches**: Metsco recommended a typical useful life of 40 years instead of 50 years as recommended by Kinectrics based on survey data provided in the Kinectrics report demonstrating an average useful life of 41 years, in addition to Oshawa Power's own operating experience.
- **SCADA System**: Metsco recommended a typical useful life of 8 years instead of 20 years as recommended in the Kinectrics report. This was based on Oshawa Power's own control room hardware and software components, and the fact that many LDCs are implementing major upgrades into their SCADA systems requiring more frequent software and hardware upgrades.
- **Direct Buried Secondary Cables**: Metsco recommended a typical useful life of 42.5 years instead of 35 years recommended by Kinectrics, based on the survey data provided in the Kinectrics report reflecting an average useful life of 42.5 years.

Oshawa Power maintains the proposed levels of depreciation/amortization expense are appropriately reflective of the useful lives of the assets and the OEB's accounting policies. There are no changes to Oshawa Power's depreciation/amortization policy since the last cost of service application.

Tables 2-19 and 2-20 from Appendix 2-BB detail the asset class service lives as recommended by Kinectrics, and compares with the current and proposed service lives adopted by Oshawa Power.

Table 2-19: Service Life Comparison Table F-1 Kinectrics Report (Appendix 2-BB)

		Asset Details			Useful Life			USoA Account Number	USoA Account Description	Current		Proposed		Outside Range of Min, Max TUL?	
Parent*	#	Category| Component | Type			MIN UL	TUL	MAX UL			Years	Rate	Years	Rate	Below Min TUL	Above Max TUL
OH	1	Fully Dressed Wood Poles	Overall		35	45	75	1830	Poles, Towers and Fixtures	45	2%	45	2%	No	No
			Cross Arm	Wood	20	40	55	1830	Poles, Towers and Fixtures	40	3%	40	3%	No	No
				Steel	30	70	95								
	2	Fully Dressed Concrete Poles	Overall		50	60	80	1830	Poles, Towers and Fixtures	60	2%	60	2%	No	No
			Cross Arm	Wood	20	40	55	1830	Poles, Towers and Fixtures	40	3%	40	3%	No	No
				Steel	30	70	95								
	3	Fully Dressed Steel Poles	Overall		60	60	80								
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	4	OH Line Switch			30	45	55	1835	Overhead Conductors and Devices	40	3%	40	3%	No	No
	5	OH Line Switch Motor			15	25	25								
	6	OH Line Switch RTU			15	20	20								
	7	OH Integral Switches			35	45	60	1835	Overhead Conductors and Devices	45	2%	45	2%	No	No
	8	OH Conductors			50	60	75	1835	Overhead Conductors and Devices	45	2%	45	2%	Yes	No
	9	OH Transformers & Voltage Regulators			30	40	60	1850	Line Transformers	40	3%	40	3%	No	No
	10	OH Shunt Capacitor Banks			25	30	40								
	11	Reclosers			25	40	55								
TS & MS	12	Power Transformers	Overall		30	45	60	1820	Distribution Station Equipment	45	2%	45	2%	No	No
			Bushing		10	20	30								
			Tap Changer		20	30	60								
	13	Station Service Transformer			30	45	55	1820	Distribution Station Equipment	40	3%	40	3%	No	No
	14	Station Grounding Transformer			30	40	40								
	15	Station DC System	Overall		10	20	30								
			Battery Bank		10	15	15								
			Charger		20	20	30								
	16	Station Metal Clad Switchgear	Overall		30	40	60	1820	Distribution Station Equipment	40	3%	40	3%	No	No
			Removable Breaker		25	40	60								
	17	Station Independent Breakers			35	45	65	1820	Distribution Station Equipment	40	3%	40	3%	No	No
	18	Station Switch			30	50	60	1820	Distribution Station Equipment	50	2%	50	2%	No	No
	19	Electromechanical Relays			25	35	50	1820	Distribution Station Equipment	35	3%	35	3%	No	No
	20	Solid State Relays			10	30	45								
	21	Digital & Numeric Relays			15	20	20								
	22	Rigid Busbars			30	55	60								
	23	Steel Structure			35	50	90								
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables			60	65	75								
	25	Primary Ethylene-Propylene Rubber (EPR) Cables			20	25	25								
	26	Primary Non-Tree Retardant (Non-TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried			20	25	30								
	27	Primary Non-TR XLPE Cables in Duct			20	25	30								
	28	Primary TR XLPE Cables Direct Buried			25	30	35								
	29	Primary TR XLPE Cables in Duct			35	40	55								
	30	Secondary PILC Cables			70	75	80								
	31	Secondary Cables Direct Buried			25	35	40	1845	Underground Conductors and Devices	42.5	2%	42.5	2%	No	Yes
	32	Secondary Cables in Duct			35	40	60	1845	Underground Conductors and Devices	40	3%	40	3%	No	No
	33	Network Tranformers	Overall		20	35	50								
			Protector		20	35	40								
	34	Pad-Mounted Transformers			25	40	45	1850	Line Transformers	40	3%	40	3%	No	No
	35	Submersible/Vault Transformers			25	35	45	1850	Line Transformers	35	3%	35	3%	No	No
	36	UG Foundation			35	55	70	1845&1850	Underground Conductors and Devices	55	2%	55	2%	No	No
	37	UG Vaults	Overall		40	60	80	1850	Line Transformers	60	2%	60	2%	No	No
			Roof		20	30	45								
	38	UG Vault Switches			20	35	50	1845	Underground Conductors and Devices	35	3%	35	3%	No	No
	39	Pad-Mounted Switchgear			20	30	45	1845	Underground Conductors and Devices	30	3%	30	3%	No	No
	40	Ducts			30	50	85	1845	Underground Conductors and Devices	50	2%	50	2%	No	No
	41	Concrete Encased Duct Banks			35	55	80	1845	Underground Conductors and Devices	55	2%	55	2%	No	No
	42	Cable Chambers			50	60	80								
S	43	Remote SCADA			15	20	30	1975	Load Management Controls - Utility Prem	8	13%	8	13%	Yes	No

Table 2-20: Table F-2 From Kinectrics Report (Appendix 2-BB)

	Asset Details		Useful Life Range		USoA Account Number	USoA Account Description	Current		Proposed		Outside Range of Min, Max TUL?	
#	Category| Component | Type						Years	Rate	Years	Rate	Below Min Range	Above Max Range
1	Office Equipment		5	15	1955&1960	Communication & Misc. Equipment	10	10%	10	10%	No	No
2	Vehicles	Trucks & Buckets	5	15	1930	Transportation Equipment	10	10%	10	10%	No	No
		Trailers	5	20	1930	Transportation Equipment	12	8%	12	8%	No	No
		Vans	5	10	1930	Transportation Equipment	8	13%	8	13%	No	No
3	Administrative Buildings		50	75		Administrative Buildings						
4	Leasehold Improvements		Lease dependent									
5	Station Buildings	Station Buildings	50	75	1808	Buildings and Fixtures	62	2%	62	2%	No	No
		Parking	25	30	1808	Buildings and Fixtures	27.5	4%	27.5	4%	No	No
		Fence	25	60	1808	Buildings and Fixtures	42	2%	42	2%	No	No
		Roof	20	30	1808	Buildings and Fixtures	25	4%	25	4%	No	No
6	Computer Equipment	Hardware	3	5	1920	Computer Equipment - Hardware	4	25%	4	25%	No	No
		Software	2	5	1611	Computer Software	3	33%	3	33%	No	No
7	Equipment	Power Operated	5	10								
		Stores	5	10								
		Tools, Shop, Garage Equipment	5	10	1940	Tools, Shop and Garage Equipment	7	14%	7	14%	No	No
		Measurement & Testing Equipment	5	10	1945	Measurement and Testing Equipment	7	14%	7	14%	No	No
8	Communication	Towers	60	70								
		Wireless	2	10								
9	Residential Energy Meters		25	35	1860	Meters	30	3%	30	3%	No	No
10	Industrial/Commercial Energy Meters		25	35	1860	Meters	30	3%	30	3%	No	No
11	Wholesale Energy Meters		15	30								
12	Current & Potential Transformer (CT & PT)		35	50	1860	Meters	42	2%	42	2%	No	No
13	Smart Meters		5	15	1860	Meters	10	10%	10	10%	No	No
14	Repeaters - Smart Metering		10	15								
15	Data Collectors - Smart Metering		15	20								

2.3.3 Asset Retirement Obligations

Oshawa Power has an Asset Retirement Obligation (ARO) included in this Application. In 2022, Oshawa Power has recognized the obligation to decommission buildings located at 100 Simcoe Street South no later than November 30, 2028. The recording of this ARO started in 2022 and valued as of the date April 2017 when the obligation began. Oshawa Power is amortizing this asset annually until November 2028 in accordance with its lease agreement. Further accretion expense is recorded to recognize the future value of the obligation and has been excluded as part of fixed assets. Table 2-21 provides details of the ARO.

Table 2-21: Asset Retirement Obligation

Asset Retirement Obligation Included Assets for 2026 Test Year			
	Years	**Yearly Amortization**	**Total**
Asset Retirement Obligation as of April 2017			762,125.33
Amortization:			
	2017	48,993.77	
	2018	65,325.03	
	2019	65,325.03	
	2020	65,325.03	
	2021	65,325.03	
	2022	65,325.03	
	2023	65,325.03	
	2024	65,325.03	
	2025	65,325.03	
	2026	65,325.03	-$636,919
Net Book Value of ARO			**125,206.29**

2.3.4 Details for Depreciation, Amortization, Depletion by Asset Group

Oshawa Power has provided details for Depreciation, Amortization and Depletion by asset group for the historical, Bridge Year and Test Year, including asset amount and depreciation rate in Appendix 2-C using MIFRS, see Tables 2-22 and 2-23 below. These

amounts agree to the balances in Appendix 2-BA as shown in the Fixed Asset Continuity Schedules provided in above. The amortization on Oshawa Power's ARO has been excluded in the Appendix 2-C below.

Table 2-22: 2021 Depreciation Expense (Appendix 2-C)

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, Column K	Variance [4]	Variance %
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h	k = j/i
1609	Capital Contributions Paid	$ 4,136,705	$ -	$ -	$ -	$ 4,136,705	25.00	4.00%	$ 165,468	$ 165,468	-$ 0	0%
1611	Computer Software (Formally known as Account 1925)	$ 2,563,975	$ 2,304,206	$ -	$ -	$ 259,769	3.00	33.33%	$ 86,590	$ 154,949	$ 68,359	44%
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1805	Land	$ 293,875	$ -	$ -	$ -	$ 293,875		0.00%	$ -	$ -	$ -	0%
1808	Buildings	$ 5,750,756	$ 127,161	$ 59,064	$ -	$ 5,653,127	62.00	1.61%	$ 91,179	$ 70,956	-$ 20,223	-29%
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1820	Distribution Station Equipment <50 kV	$ 26,988,018	$ 1,723,078	$ 1,236,768	$ -	$ 25,883,324	41.67	2.40%	$ 621,195	$ 609,451	-$ 11,744	-2%
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1830	Poles, Towers & Fixtures	$ 56,362,068	$ 2,046,755	$ 7,615,166	-$ 269,272	$ 58,392,168	46.25	2.16%	$ 1,262,533	$ 1,285,805	$ 23,272	2%
1835	Overhead Conductors & Devices	$ 28,402,759	$ 1,090,640	-$ 473,564	-$ 271,627	$ 27,346,965	52.00	1.92%	$ 525,903	$ 368,055	-$ 157,848	-43%
1840	Underground Conduit	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1845	Underground Conductors & Devices	$ 61,507,401	$ 2,784,307	$ 1,815,060	$ -	$ 59,630,625	42.50	2.35%	$ 1,403,074	$ 1,374,949	-$ 28,125	-2%
1850	Line Transformers	$ 65,349,882	$ 11,632,394	$ 1,805,108	-$ 1,090,527	$ 55,710,568	47.50	2.11%	$ 1,172,854	$ 1,262,854	$ 90,000	7%
1855	Services (Overhead & Underground)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1860	Meters	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1860	Meters (Smart Meters)	$ 14,152,321	$ 7,065,099	$ 1,414,064	-$ 387,785	$ 8,182,038	20.00	5.00%	$ 409,102	$ 557,248	$ 148,146	27%
1905	Land	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1910	Leasehold Improvements	$ 1,097,704	$ 1,038,987	$ 459,238	$ -	$ 288,336	3.00	33.33%	$ 96,112	$ 98,900	$ 2,788	3%
1915	Office Furniture & Equipment (10 years)	$ 800,129	$ 689,429	$ 670	$ -	$ 111,035	10.00	10.00%	$ 11,103	$ 14,148	$ 3,045	22%
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1920	Computer Equipment - Hardware	$ 3,246,867	$ 2,935,574	$ 746,180	$ -	$ 684,383	4.00	25.00%	$ 171,096	$ 241,954	$ 70,858	29%
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1930	Transportation Equipment	$ 5,559,353	$ 2,234,031	$ -	-$ 30,458	$ 3,355,780	10.00	10.00%	$ 335,578	$ 315,538	-$ 20,040	-6%
1935	Stores Equipment	$ 30,767	$ 24,516	$ -	$ -	$ 6,251	7.00	14.29%	$ 893	$ 893	$ -	0%
1940	Tools, Shop & Garage Equipment	$ 2,876,986	$ 2,374,618	$ 122,971	$ -	$ 563,854	7.00	14.29%	$ 80,551	$ 99,264	$ 18,713	19%
1945	Measurement & Testing Equipment	$ 1,586,319	$ 347,825	-$ 237,335	$ -	$ 1,119,827	7.00	14.29%	$ 159,975	$ 108,274	-$ 51,701	-48%
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1955	Communications Equipment	$ 514,799	$ 321,644	$ -	$ -	$ 193,155	10.00	10.00%	$ 19,315	$ 34,570	$ 15,255	44%
1955	Communication Equipment (Smart Meters)	$ 96,488	$ 96,488	$ -	$ -	-$ 0	10.00	10.00%	-$ 0	$ -	$ 0	0%
1960	Miscellaneous Equipment	$ 287,043	$ 157,645	-$ 3,187	$ -	$ 127,804	10.00	10.00%	$ 12,780	$ 13,100	$ 320	2%
1970	Load Management Controls Customer Premises	$ 107,035	$ 107,035	$ -	$ -	$ 0	8.00	12.50%	$ 0	$ -	-$ 0	0%
1975	Load Management Controls Utility Premises	$ 2,363,588	$ 597,214	$ 40,507	$ -	$ 1,786,627	20.00	5.00%	$ 89,331	$ 99,969	$ 10,638	11%
1980	System Supervisor Equipment	$ 293,582	$ 293,582	$ -	$ -	-$ 0	8.00	12.50%	-$ 0	$ -	$ 0	0%
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1995	Contributions & Grants	$ -				$ -		0.00%	$ -	$ -	$ -	0%
2440	Deferred Revenue	-$ 51,783,045	-$ 776,558	-$ 2,048,875	$ -	-$ 52,030,924	45.00	2.22%	-$ 1,156,243	-$ 1,196,433	-$ 40,190	3%
2005	Property Under Finance Lease					$ -		0.00%	$ -	$ -	$ -	0%
	Total	$ 232,585,376	$ 39,215,670	$ 12,551,835	-$ 2,049,668	$ 201,695,292	$ 499		$ 5,558,391	$ 5,679,912	$ 121,521	2%

Table 2-23: 2022 Depreciation Expense (Appendix 2-C)

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, Column K	Variance [4]	Variance %
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h	k = j/i
1609	Capital Contributions Paid	$ 4,136,705	$ -	$ 38,995	$ -	$ 4,156,203	25.00	4.00%	$ 166,248	$ 186,101	$ 19,853	11%
1611	Computer Software (Formally known as Account 1925)	$ 2,563,975	$ 2,155,095	$ 26,657	$ -	$ 422,209	3.00	33.33%	$ 140,736	$ 172,331	$ 31,595	18%
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1805	Land	$ 293,875	$ -	$ -	$ -	$ 293,875		0.00%	$ -	$ -	$ -	0%
1808	Buildings	$ 5,809,820	$ 127,161	$ 37,475	$ -	$ 5,701,396	62.00	1.61%	$ 91,958	$ 108,423	$ 16,465	15%
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1820	Distribution Station Equipment <50 kV	$ 28,224,786	$ 2,078,737	$ 87,263	$ -	$ 26,189,681	41.67	2.40%	$ 628,547	$ 623,524	-$ 5,023	-1%
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1830	Poles, Towers & Fixtures	$ 63,707,962	$ 2,046,755	$ 730,119	-$ 183,615	$ 62,209,881	46.25	2.16%	$ 1,345,079	$ 1,227,885	-$ 117,194	-10%
1835	Overhead Conductors & Devices	$ 27,657,568	$ 1,090,638	$ 2,583,235	-$ 343,897	$ 28,202,444	52.00	1.92%	$ 542,355	$ 474,591	-$ 67,764	-14%
1840	Underground Conduit	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1845	Underground Conductors & Devices	$ 63,322,461	$ 3,126,329	$ 5,123,494	$ -	$ 62,757,879	42.50	2.35%	$ 1,476,656	$ 1,696,134	$ 219,478	13%
1850	Line Transformers	$ 66,064,463	$ 12,368,364	$ 1,715,380	-$ 785,487	$ 55,339,277	47.50	2.11%	$ 1,165,037	$ 1,179,570	$ 14,533	1%
1855	Services (Overhead & Underground)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1860	Meters	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1860	Meters (Smart Meters)	$ 15,178,601	$ 7,448,787	$ 633,762	-$ 12,906	$ 8,059,600	20.00	5.00%	$ 402,980	$ 485,537	$ 82,557	17%
1905	Land	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1910	Leasehold Improvements	$ 1,556,942	$ 1,214,512	$ 155,379	$ -	$ 420,120	3.00	33.33%	$ 140,040	$ 189,716	$ 49,676	26%
1915	Office Furniture & Equipment (10 years)	$ 800,799	$ 720,560	$ 5,110	$ -	$ 82,794	10.00	10.00%	$ 8,279	$ 15,736	$ 7,457	47%
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1920	Computer Equipment - Hardware	$ 3,993,047	$ 2,822,174	$ 549,188	$ -	$ 1,445,467	4.00	25.00%	$ 361,367	$ 275,445	-$ 85,922	-31%
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1930	Transportation Equipment	$ 5,528,895	$ 2,435,671	$ 438,284	$ -	$ 3,312,366	10.00	10.00%	$ 331,237	$ 268,402	-$ 62,835	-23%
1935	Stores Equipment	$ 30,767	$ 24,516	$ -	$ -	$ 6,251	7.00	14.29%	$ 893	$ 893	$ -	0%
1940	Tools, Shop & Garage Equipment	$ 2,999,957	$ 2,375,999	$ 107,939	$ -	$ 677,927	7.00	14.29%	$ 96,847	$ 107,983	$ 11,136	10%
1945	Measurement & Testing Equipment	$ 1,348,984	$ 359,305	$ 190,431	$ -	$ 1,084,894	7.00	14.29%	$ 154,985	$ 150,435	-$ 4,550	-3%
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1955	Communications Equipment	$ 514,799	$ 321,644	$ -	$ -	$ 193,155	10.00	10.00%	$ 19,315	$ 27,107	$ 7,792	29%
1955	Communication Equipment (Smart Meters)	$ 96,488	$ 96,488	$ -	$ -	-$ 0	10.00	10.00%	-$ 0	$ -	$ 0	0%
1960	Miscellaneous Equipment	$ 283,856	$ 157,645	$ -	$ -	$ 126,211	10.00	10.00%	$ 12,621	$ 9,988	-$ 2,633	-26%
1970	Load Management Controls Customer Premises	$ 107,035	$ 107,035	$ -	$ -	$ 0	8.00	12.50%	$ 0	$ -	-$ 0	0%
1975	Load Management Controls Utility Premises	$ 2,404,095	$ 597,214	$ 178,672	$ -	$ 1,896,217	20.00	5.00%	$ 94,811	$ 110,170	$ 15,359	14%
1980	System Supervisor Equipment	$ 293,582	$ 293,582	$ -	$ -	-$ 0	8.00	12.50%	-$ 0	$ -	$ 0	0%
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1995	Contributions & Grants	$ -		$ -		$ -		0.00%	$ -	$ -	$ -	0%
2440	Deferred Revenue	-$ 53,831,920	-$ 798,574	-$ 1,201,222	$ -	-$ 53,633,957	45.00	2.22%	-$ 1,191,866	-$ 1,288,832	-$ 96,966	8%
2005	Property Under Finance Lease					$ -		0.00%	$ -		$ -	0%
	Total	**$ 243,087,543**	**$ 41,169,637**	**$ 11,400,161**	**-$ 1,325,904**	**$ 208,943,890**	**$ 499**		**$ 5,988,125**	**$ 6,021,139**	**$ 33,014**	**1%**

There is a variance of $219,478 for USoA 1845 Underground Conductors & Devices. This account has multiple useful lives based on the various components of assets and the split can vary each year. For the purposes of this Application, Oshawa Power has used an average useful life of assets.

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Table 2-24: 2023 Depreciation Expense (Appendix 2-C)

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, Column K	Variance [4]	Variance %
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h	k = j/i
1609	Capital Contributions Paid	$ 4,175,700	$ -	$ 7,343	$ -	$ 4,179,372	25.00	4.00%	$ 167,175	$ 159,742	-$ 7,433	-5%
1611	Computer Software (Formally known as Account 1925)	$ 2,590,632	$ 2,155,095	$ 997,537	$ -	$ 934,306	3.00	33.33%	$ 311,435	$ 240,036	-$ 71,399	-30%
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1805	Land	$ 293,875	$ -	$ -	$ -	$ 293,875		0.00%	$ -	$ -	$ -	0%
1808	Buildings	$ 5,847,295	$ 127,161	-$ 268,327	$ -	$ 5,585,970	62.00	1.61%	$ 90,096	$ 85,555	-$ 4,541	-5%
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1820	Distribution Station Equipment <50 kV	$ 28,312,049	$ 2,078,737	-$ 10,085	$ -	$ 26,228,270	41.67	2.40%	$ 629,473	$ 621,988	-$ 7,485	-1%
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1830	Poles, Towers & Fixtures	$ 64,254,466	$ 2,046,755	$ 4,389,724	-$ 218,170	$ 64,620,744	46.25	2.16%	$ 1,397,205	$ 1,370,202	-$ 27,003	-2%
1835	Overhead Conductors & Devices	$ 29,896,906	$ 1,090,638	$ 5,551,126	-$ 429,839	$ 32,011,670	52.00	1.92%	$ 615,609	$ 521,316	-$ 94,293	-18%
1840	Underground Conduit	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1845	Underground Conductors & Devices	$ 68,445,955	$ 3,126,329	$ 4,088,583	$ -	$ 67,363,918	42.50	2.35%	$ 1,585,033	$ 1,469,838	-$ 115,195	-8%
1850	Line Transformers	$ 66,994,356	$ 12,263,684	$ 4,742,056	-$ 849,516	$ 57,951,216	47.50	2.11%	$ 1,220,026	$ 1,319,764	$ 99,738	8%
1855	Services (Overhead & Underground)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1860	Meters	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1860	Meters (Smart Meters)	$ 15,799,457	$ 7,448,787	$ 734,746	-$ 10,853	$ 8,728,896	20.00	5.00%	$ 436,445	$ 537,010	$ 100,565	19%
1905	Land	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1910	Leasehold Improvements	$ 1,712,321	$ 1,214,512	$ 328,161	$ -	$ 661,890	3.00	33.33%	$ 220,630	$ 410,073	$ 189,443	46%
1915	Office Furniture & Equipment (10 years)	$ 805,909	$ 720,560	$ 3,654	$ -	$ 87,176	10.00	10.00%	$ 8,718	$ 14,423	$ 5,705	40%
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1920	Computer Equipment - Hardware	$ 4,542,235	$ 2,822,174	$ 337,341	$ -	$ 1,888,732	4.00	25.00%	$ 472,183	$ 343,869	-$ 128,314	-37%
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1930	Transportation Equipment	$ 5,967,179	$ 2,435,671	$ 767,520	-$ 555,893	$ 4,471,161	10.00	10.00%	$ 447,116	$ 271,179	-$ 175,937	-65%
1935	Stores Equipment	$ 30,767	$ 24,516	$ -	$ -	$ 6,251	7.00	14.29%	$ 893	$ 893	$ -	0%
1940	Tools, Shop & Garage Equipment	$ 3,107,896	$ 2,375,999	$ 104,835	$ -	$ 784,314	7.00	14.29%	$ 112,045	$ 122,994	$ 10,949	9%
1945	Measurement & Testing Equipment	$ 1,539,415	$ 359,305	$ 169,214	$ -	$ 1,264,716	7.00	14.29%	$ 180,674	$ 170,414	-$ 10,260	-6%
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1955	Communications Equipment	$ 514,799	$ 321,644	$ -	$ -	$ 193,155	10.00	10.00%	$ 19,315	$ 19,316	$ 1	0%
1955	Communication Equipment (Smart Meters)	$ 96,488	$ 96,488	$ -	$ -	-$ 0	10.00	10.00%	-$ 0	$ -	$ 0	0%
1960	Miscellaneous Equipment	$ 283,856	$ 157,645	-$ 31,566	$ -	$ 110,428	10.00	10.00%	$ 11,043	$ 3,663	-$ 7,380	-201%
1970	Load Management Controls Customer Premises	$ 107,035	$ 107,035	$ -	$ -	$ 0	8.00	12.50%	$ 0	$ -	-$ 0	0%
1975	Load Management Controls Utility Premises	$ 2,582,767	$ 597,214	$ 276,970	$ -	$ 2,124,038	20.00	5.00%	$ 106,202	$ 173,758	$ 67,556	39%
1980	System Supervisor Equipment	$ 293,582	$ 293,582	$ -	$ -	-$ 0	8.00	12.50%	-$ 0	$ -	$ 0	0%
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1995	Contributions & Grants	$ -				$ -		0.00%	$ -	$ -	$ -	0%
2440	Deferred Revenue	-$ 55,033,142	-$ 798,574	-$ 2,579,863	$ -	-$ 55,524,499	45.00	2.22%	-$ 1,233,878	-$ 1,286,519	-$ 52,641	4%
2005	Property Under Finance Lease					$ -		0.00%	$ -	$ -	$ -	0%
	Total	**$ 253,161,799**	**$ 41,064,958**	**$ 19,608,969**	**-$ 2,064,271**	**$ 223,965,597**	**$ 499**		**$ 6,797,439**	**$ 6,569,514**	**-$ 227,925**	-3%

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Table 2-25: 2024 Depreciation Expense (Appendix 2-C)

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, Column K	Variance [4]	Variance %
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h	k = j/i
1609	Capital Contributions Paid	$ 4,183,043	$ -	$ -	$ -	$ 4,183,043	25.00	4.00%	$ 167,322	$ 167,322	$ 0	0%
1611	Computer Software (Formally known as Account 1925)	$ 3,588,169	$ 2,698,033	$ 513,101	$ -	$ 1,146,687	3.00	33.33%	$ 382,229	$ 471,170	$ 88,941	19%
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1805	Land	$ 293,875	$ -	$ -	$ -	$ 293,875		0.00%	$ -	$ -	$ -	0%
1808	Buildings	$ 5,578,968	$ 127,161	$ -	$ -	$ 5,451,807	62.00	1.61%	$ 87,932	$ 101,190	$ 13,258	13%
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1820	Distribution Station Equipment <50 kV	$ 28,301,964	$ 2,357,269	$ 2,237,931	$ -	$ 27,063,660	41.67	2.40%	$ 649,523	$ 688,217	$ 38,694	6%
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1830	Poles, Towers & Fixtures	$ 68,426,020	$ 2,054,166	$ 3,836,408	-$ 113,228	$ 68,403,286	46.25	2.16%	$ 1,478,990	$ 1,440,153	-$ 38,837	-3%
1835	Overhead Conductors & Devices	$ 35,018,193	$ 1,091,785	-$ 1,141,559	-$ 86,759	$ 33,442,387	52.00	1.92%	$ 643,123	$ 604,211	-$ 38,912	-6%
1840	Underground Conduit	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1845	Underground Conductors & Devices	$ 72,534,538	$ 3,547,622	$ 4,562,600	$ -	$ 71,268,216	42.50	2.35%	$ 1,676,899	$ 1,492,389	-$ 184,510	-12%
1850	Line Transformers	$ 70,886,896	$ 13,227,874	$ 2,548,296	-$ 627,240	$ 59,560,410	47.50	2.11%	$ 1,253,903	$ 1,354,067	$ 100,164	7%
1855	Services (Overhead & Underground)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1860	Meters	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1860	Meters (Smart Meters)	$ 16,523,350	$ 7,515,159	$ 802,296	-$ 81,913	$ 9,491,252	20.00	5.00%	$ 474,563	$ 563,339	$ 88,776	16%
1905	Land	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1910	Leasehold Improvements	$ 2,040,482	$ 1,673,749	$ -	$ -	$ 366,733	3.00	33.33%	$ 122,244	$ 166,503	$ 44,259	27%
1915	Office Furniture & Equipment (10 years)	$ 809,563	$ 720,560	$ -	$ -	$ 89,003	10.00	10.00%	$ 8,900	$ 13,049	$ 4,149	32%
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1920	Computer Equipment - Hardware	$ 4,879,576	$ 3,252,613	$ 40,261	$ -	$ 1,647,094	4.00	25.00%	$ 411,773	$ 336,631	-$ 75,142	-22%
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1930	Transportation Equipment	$ 6,178,806	$ 2,462,177	$ 60,978	-$ 368,478	$ 4,115,596	10.00	10.00%	$ 411,560	$ 295,289	-$ 116,271	-39%
1935	Stores Equipment	$ 30,767	$ 24,516	$ -	$ -	$ 6,251	7.00	14.29%	$ 893	$ 893	$ -	0%
1940	Tools, Shop & Garage Equipment	$ 3,212,731	$ 2,651,471	$ 24,874	$ -	$ 573,698	7.00	14.29%	$ 81,957	$ 112,085	$ 30,128	27%
1945	Measurement & Testing Equipment	$ 1,708,629	$ 828,752	$ 143,653	$ -	$ 951,704	7.00	14.29%	$ 135,958	$ 135,783	-$ 175	0%
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1955	Communications Equipment	$ 514,799	$ 321,644	$ -	$ -	$ 193,155	10.00	10.00%	$ 19,315	$ 19,316	$ 1	0%
1955	Communication Equipment (Smart Meters)	$ 96,488	$ 96,488	$ -	$ -	-$ 0	10.00	10.00%	-$ 0	$ -	$ 0	0%
1960	Miscellaneous Equipment	$ 252,290	$ 162,391	$ -	$ -	$ 89,899	10.00	10.00%	$ 8,990	$ 6,647	-$ 2,343	-35%
1970	Load Management Controls Customer Premises	$ 107,035	$ 107,035	$ -	$ -	$ 0	8.00	12.50%	$ 0	$ -	-$ 0	0%
1975	Load Management Controls Utility Premises	$ 2,859,737	$ 645,146	$ 31,082	$ -	$ 2,230,132	20.00	5.00%	$ 111,507	$ 155,739	$ 44,232	28%
1980	System Supervisor Equipment	$ 293,582	$ 293,582	$ -	$ -	-$ 0	8.00	12.50%	-$ 0	$ -	$ 0	0%
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1995	Contributions & Grants	$ -			$ -	$ -		0.00%	$ -	$ -	$ -	0%
2440	Deferred Revenue	-$ 57,613,005	-$ 816,750	-$ 4,856,085	$ -	-$ 59,224,298	45.00	2.22%	-$ 1,316,096	-$ 1,399,017	-$ 82,921	6%
2005	Property Under Finance Lease					$ -		0.00%	$ -		$ -	0%
	Total	**$ 270,706,497**	**$ 45,042,445**	**$ 8,803,836**	**-$ 1,277,618**	**$ 231,343,588**	**$ 499**		**$ 6,811,485**	**$ 6,724,976**	**-$ 86,509**	-1%

1

Table 2-26: 2025 Depreciation Expense (Appendix 2-C)

Year: 2025

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, Column K	Variance [4]	Variance %
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h	k = j/i
1609	Capital Contributions Paid	$ 4,183,043	$ -	$ -	$ -	$ 4,183,043	25.00	4.00%	$ 167,322	$ 167,322	$ 1	0%
1611	Computer Software (Formally known as Account 1925)	$ 4,101,270	$ 2,731,902	$ 2,171,200	$ -	$ 2,454,968	3.00	33.33%	$ 818,323	$ 870,143	$ 51,820	6%
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1805	Land	$ 293,875	$ -	$ -	$ -	$ 293,875		0.00%	$ -	$ -	$ -	0%
1808	Buildings	$ 5,578,968	$ 127,161	$ -	$ -	$ 5,451,807	62.00	1.61%	$ 87,932	$ 103,232	$ 15,300	15%
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1820	Distribution Station Equipment <50 kV	$ 30,539,895	$ 2,913,308	$ 2,517,183	$ -	$ 28,885,178	41.67	2.40%	$ 693,239	$ 618,216	-$ 75,022	-12%
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1830	Poles, Towers & Fixtures	$ 72,149,200	$ 2,068,141	$ 3,317,685	-$ 223,686	$ 71,739,902	46.25	2.16%	$ 1,551,133	$ 1,548,713	-$ 2,420	0%
1835	Overhead Conductors & Devices	$ 33,789,875	$ 1,093,887	$ 2,484,533	-$ 348,454	$ 33,938,255	52.00	1.92%	$ 652,659	$ 636,916	-$ 15,743	-2%
1840	Underground Conduit	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1845	Underground Conductors & Devices	$ 77,097,138	$ 3,712,447	$ 3,520,190	$ -	$ 75,144,787	42.50	2.35%	$ 1,768,113	$ 1,839,433	$ 71,321	4%
1850	Line Transformers	$ 72,807,952	$ 13,293,773	$ 3,859,577	-$ 908,510	$ 61,443,968	47.50	2.11%	$ 1,293,557	$ 1,397,527	$ 103,970	7%
1855	Services (Overhead & Underground)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1860	Meters	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1860	Meters (Smart Meters)	$ 17,243,733	$ 7,988,393	$ 559,563	-$ 137,181	$ 9,535,122	20.00	5.00%	$ 476,756	$ 516,405	$ 39,649	8%
1905	Land	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1910	Leasehold Improvements	$ 2,040,482	$ 1,803,712	$ 50,000	$ -	$ 261,770	3.00	33.33%	$ 87,257	$ 103,996	$ 16,739	16%
1915	Office Furniture & Equipment (10 years)	$ 809,563	$ 732,004	$ -	$ -	$ 77,559	10.00	10.00%	$ 7,756	$ 11,752	$ 3,996	34%
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1920	Computer Equipment - Hardware	$ 4,919,837	$ 3,630,175	$ 531,000	$ -	$ 1,555,162	4.00	25.00%	$ 388,791	$ 392,035	$ 3,244	1%
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1930	Transportation Equipment	$ 5,871,306	$ 2,940,362	$ 150,000	$ -	$ 3,005,944	10.00	10.00%	$ 300,594	$ 244,040	-$ 56,554	-23%
1935	Stores Equipment	$ 30,767	$ 24,516	$ -	$ -	$ 6,251	7.00	14.29%	$ 893	$ -	-$ 893	0%
1940	Tools, Shop & Garage Equipment	$ 3,237,605	$ 2,739,096	$ 100,456	$ -	$ 548,737	7.00	14.29%	$ 78,391	$ 99,654	$ 21,263	21%
1945	Measurement & Testing Equipment	$ 1,852,282	$ 910,161	$ 120,950	$ -	$ 1,002,596	7.00	14.29%	$ 143,228	$ 108,950	-$ 34,278	-31%
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1955	Communications Equipment	$ 514,799	$ 321,644	$ -	$ -	$ 193,155	10.00	10.00%	$ 19,315	$ 19,315	-$ 1	0%
1955	Communication Equipment (Smart Meters)	$ 96,488	$ 96,488	$ -	$ -	$ 0	10.00	10.00%	-$ 0	$ -	$ 0	0%
1960	Miscellaneous Equipment	$ 252,290	$ 187,684	$ 130,000	$ -	$ 129,606	10.00	10.00%	$ 12,961	$ 22,878	$ 9,917	43%
1970	Load Management Controls Customer Premises	$ 107,035	$ 107,035	$ -	$ -	$ 0	8.00	12.50%	$ 0	$ -	-$ 0	0%
1975	Load Management Controls Utility Premises	$ 2,890,819	$ 645,146	$ 240,000	$ -	$ 2,365,673	20.00	5.00%	$ 118,284	$ 166,708	$ 48,424	29%
1980	System Supervisor Equipment	$ 293,582	$ 293,582	$ -	$ -	-$ 0	8.00	12.50%	-$ 0	$ -	$ 0	0%
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	0%
1995	Contributions & Grants	$ -			$ -	$ -		0.00%	$ -	$ -	$ -	0%
2440	Deferred Revenue	-$ 62,469,090	-$ 832,686	-$ 2,343,374	$ -	-$ 62,808,091	45.00	2.22%	-$ 1,395,735	-$ 1,498,681	-$ 102,946	7%
2005	Property Under Finance Lease					$ -		0.00%	$ -		$ -	0%
	Total	**$ 278,232,715**	**$ 47,527,933**	**$ 17,408,965**	**-$ 1,617,831**	**$ 239,409,265**	**$ 499**		**$ 7,270,767**	**$ 7,368,553**	**$ 97,786**	**1%**

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Table 2-27: 2026 Depreciation Expense (Appendix 2-C)

Year: 2026

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, Column K	Variance [4]	Variance %
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h	k = j/i
1609	Capital Contributions Paid	$ 4,183,043	$ -			$ 4,183,043	25.00	4.00%	$ 167,322	$ 167,322	$ 1	0%
1611	Computer Software (Formally known as Account 1925)	$ 6,272,470	$ 3,776,399	$ 802,500		$ 2,897,321	3.00	33.33%	$ 965,774	$ 971,015	$ 5,241	1%
1612	Land Rights (Formally known as Account 1906)	$ -	$ -			$ -		0.00%	$ -	$ -	$ -	0%
1805	Land	$ 293,875	$ -			$ 293,875		0.00%	$ -	$ -	$ -	0%
1808	Buildings	$ 5,578,968	$ 227,109			$ 5,351,859	62.00	1.61%	$ 86,320	$ 103,232	$ 16,911	16%
1810	Leasehold Improvements	$ -	$ -			$ -		0.00%	$ -	$ -	$ -	0%
1815	Transformer Station Equipment >50 kV	$ -	$ -			$ -		0.00%	$ -	$ -	$ -	0%
1820	Distribution Station Equipment <50 kV	$ 33,057,078	$ 3,509,534	$ 2,187,391		$ 30,641,240	41.67	2.40%	$ 735,384	$ 640,742	-$ 94,641	-15%
1825	Storage Battery Equipment	$ -	$ -			$ -		0.00%	$ -	$ -	$ -	0%
1830	Poles, Towers & Fixtures	$ 75,243,200	$ 2,085,078	$ 3,166,448	-$ 223,686	$ 74,741,346	46.25	2.16%	$ 1,616,029	$ 1,635,185	$ 19,156	1%
1835	Overhead Conductors & Devices	$ 35,925,954	$ 1,271,939	$ 3,275,207	-$ 348,454	$ 36,291,619	52.00	1.92%	$ 697,916	$ 712,095	$ 14,179	2%
1840	Underground Conduit	$ -	$ -			$ -		0.00%	$ -	$ -	$ -	0%
1845	Underground Conductors & Devices	$ 80,617,329	$ 4,309,434	$ 4,371,428		$ 78,493,609	42.50	2.35%	$ 1,846,908	$ 1,942,348	$ 95,440	5%
1850	Line Transformers	$ 75,759,020	$ 14,441,824	$ 3,496,021	-$ 908,510	$ 63,065,206	47.50	2.11%	$ 1,327,689	$ 1,493,249	$ 165,561	11%
1855	Services (Overhead & Underground)	$ -	$ -			$ -		0.00%	$ -	$ -	$ -	0%
1860	Meters	$ -				$ -		0.00%	$ -	$ -	$ -	0%
1860	Meters (Smart Meters)	$ 17,666,116	$ 8,077,187	$ 1,603,194	-$ 137,181	$ 10,390,525	20.00	5.00%	$ 519,526	$ 583,161	$ 63,635	11%
1905	Land	$ -	$ -			$ -		0.00%	$ -	$ -	$ -	0%
1908	Buildings & Fixtures	$ -	$ -			$ -		0.00%	$ -	$ -	$ -	0%
1910	Leasehold Improvements	$ 2,090,482	$ 1,981,765	$ 100,000		$ 158,717	3.00	33.33%	$ 52,906	$ 69,644	$ 16,739	24%
1915	Office Furniture & Equipment (10 years)	$ 809,563	$ 738,390			$ 71,173	10.00	10.00%	$ 7,117	$ 11,264	$ 4,146	37%
1915	Office Furniture & Equipment (5 years)	$ -	$ -			$ -		0.00%	$ -	$ -	$ -	0%
1920	Computer Equipment - Hardware	$ 5,450,837	$ 4,149,918	$ 312,400		$ 1,457,119	4.00	25.00%	$ 364,280	$ 374,163	$ 9,883	3%
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -				$ -		0.00%	$ -	$ -	$ -	0%
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -				$ -		0.00%	$ -	$ -	$ -	0%
1930	Transportation Equipment	$ 6,021,306	$ 2,971,174	$ 500,000		$ 3,300,132	10.00	10.00%	$ 330,013	$ 267,464	-$ 62,549	-23%
1935	Stores Equipment	$ 30,767	$ 30,767			$ 0	7.00	14.29%	$ 0	$ -	-$ 0	0%
1940	Tools, Shop & Garage Equipment	$ 3,338,061	$ 2,850,894	$ 130,745		$ 552,539	7.00	14.29%	$ 78,934	$ 100,197	$ 21,263	21%
1945	Measurement & Testing Equipment	$ 1,973,232	$ 1,031,102	$ 130,485		$ 1,007,373	7.00	14.29%	$ 143,910	$ 109,797	-$ 34,113	-31%
1950	Power Operated Equipment	$ -	$ -			$ -		0.00%	$ -	$ -	$ -	0%
1955	Communications Equipment	$ 514,799	$ 455,431			$ 59,368	10.00	10.00%	$ 5,937	$ 5,937	$ 0	0%
1955	Communication Equipment (Smart Meters)	$ 96,488	$ 96,488			-$ 0	10.00	10.00%	-$ 0	$ -	$ 0	0%
1960	Miscellaneous Equipment	$ 382,290	$ 211,431	$ 171,094		$ 256,406	10.00	10.00%	$ 25,641	$ 33,499	$ 7,859	23%
1970	Load Management Controls Customer Premises	$ 107,035	$ 107,035			$ 0	8.00	12.50%	$ 0	$ -	-$ 0	0%
1975	Load Management Controls Utility Premises	$ 3,130,819	$ 645,146			$ 2,485,673	20.00	5.00%	$ 124,284	$ 181,708	$ 57,425	32%
1980	System Supervisor Equipment	$ 293,582	$ 293,582			-$ 0	8.00	12.50%	-$ 0	$ -	$ 0	0%
1985	Miscellaneous Fixed Assets	$ -	$ -			$ -		0.00%	$ -	$ -	$ -	0%
1990	Other Tangible Property	$ -	$ -			$ -		0.00%	$ -	$ -	$ -	0%
1995	Contributions & Grants	$ -				$ -		0.00%	$ -	$ -	$ -	0%
2440	Deferred Revenue	-$ 64,812,464	-$ 879,829	-$ 3,228,166		-$ 65,546,718	45.00	2.22%	-$ 1,456,594	-$ 1,566,840	-$ 110,246	7%
2005	Property Under Finance Lease					$ -		0.00%	$ -		$ -	0%
	Total	**$ 294,023,850**	**$ 52,381,800**	**$ 17,018,747**	**-$ 1,617,831**	**$ 250,151,423**	**$ 499**		**$ 7,639,295**	**$ 7,835,184**	**$ 195,888**	**3%**

2.3.5 Changes to Depreciation Policy

Oshawa Power has not made any changes to its depreciation policy since its last rebasing application (EB-2020-0048).

Depreciation is calculated on a straight-line basis over the remaining useful life of an asset. Construction in progress assets are not depreciated until the asset is in service. Depreciation on assets begins in the year when it is available for use and capable of operating in the manner intended. Depreciation of an asset ceases when the asset is fully depreciated, retired or sold. Assets with distinct components that have different useful lives are depreciated separately based on their major identifiable components.

2.4 ALLOWANCE FOR WORKING CAPITAL

The Filing Requirements permit applicants to take one of two approaches for calculation of the Allowance for Working Capital:

a) The 7.5% Allowance Approach as indicated by the OEB; or

b) The filing of a lead/lag study.

Oshawa Power has opted to use the rate of 7.5% for calculating the Working Capital Allowance as per the letter issued by the OEB on June 3, 2015, “Allowance for Working Capital for Electricity Distribution Rate Applications”. The Working Capital Allowance is the sum of Cost of Power and controllable expenses (i.e. Operations, Maintenance, Billing and Collecting, Community Relations, Administration and General, Property Taxes and LEAP contributions) multiplied by the default value of 7.5%. Oshawa Power is proposing a working capital allowance of $11,797,711 as shown in Table 2-28 below.

Table 2-28: Allowance for Working Capital

Working Capital Allowance	2021 OEB Approved	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Bridge	2026 Test
Operations	2,891,000	2,427,693	2,613,290	3,143,980	2,833,190	2,565,658	4,003,063
Maintenance	1,349,949	996,991	1,103,692	1,175,488	1,442,317	1,295,390	1,349,796
Billing and Collecting	3,500,467	2,862,727	3,254,066	3,949,857	4,899,646	4,767,079	5,247,373
Community Relations	239,216	230,409	297,797	422,398	270,588	335,661	394,033
Administration & General	5,885,460	6,782,354	7,110,887	7,072,385	9,354,202	10,261,426	11,277,725
Property Taxes	152,097	135,660	168,321	137,339	155,853	160,548	164,562
Total Controllable Expenses	**14,018,189**	**13,435,833**	**14,548,053**	**15,901,447**	**18,955,796**	**19,385,762**	**22,436,551**
Cost of Power	121,786,272	85,668,801	103,475,150	106,808,077	111,788,067	118,000,000	134,866,266
Working Capital Base	**135,804,461**	**99,104,634**	**118,023,203**	**122,709,524**	**130,743,863**	**137,385,762**	**157,302,818**
Working Capital Rate %	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%
Working Capital Allowance	**10,185,335**	**7,432,848**	**8,851,740**	**9,203,214**	**9,805,790**	**10,303,932**	**11,797,711**

Oshawa Power has not previously been directed by the OEB to undertake a lead/lag study.

2.4.1 Cost of Power

Oshawa Power has calculated COP for the 2026 Test Year based on its load forecast, discussed in detail in Exhibit 3 of this Application.

Table 2-29: 2026 Test Year COP

2026 Test Year COP	
4705 - Power Purchased	$ 93,082,565
4707 - Global Adjustment	$ 22,094,905
4708 - Charges - WMS	$ 7,031,910
4714 - Charges - NW	$ 14,748,205
4716 - Charges - CN	$ 11,121,977
4751 - IESO SME	$ 322,754
Misc A/R or A/P	$ (13,536,050)
Total	**$ 134,866,266**

Commodity Prices

In accordance with the Filing Requirements, the commodity price estimate used to calculate COP is based on the appropriate split between the Regulated Price Plan (RPP) and non-RPP customers using 2024 Actual data and the most current RPP price.

The RPP and non-RPP price was obtained from the Regulated Price Plan Price Report for the period of November 1, 2024 to October 31, 2025 published by the OEB on October 18, 2024. Oshawa Power has calculated the 2026 Test Year using an estimate of $0.09937 per kWh for RPP customers and $0.1023 per kWh for non-RPP customers.

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

Regulatory Charges

The Wholesale Market Service Charges (WMS) for the 2026 Test Year were calculated using rates as per the OEB Decision and Rate Order EB-2024-0282 dated December 10, 2024 for regulatory charges effective January 1, 2025. Oshawa Power has used a WMS rate of $0.0041 per kWh, a Capacity Based Recovery (CBR) rate of $0.0004 per kWh for Class B customers and a Rural or Remote Electricity Rate Protection (RRRP) rate of $0.0015 per kWh.

Network and Connection Charges

The wholesale Transmission Network and Connection costs for the 2026 Test Year were calculated using rates as per the OEB Decision and Rate Order (EB-2024-0244) dated January 21, 2025 for 2025 Uniform Transmission Rates (UTRs) and the resulting Retail Transmission Service Rates (RTSRs) and 2026 forecast billing determinants.

Smart Meter Entity Charges

The Smart Meter Entity (SME) costs for the 2026 Test Year were calculated as per the OEB Decision and Rate Order EB-2022-0137 dated September 8, 2022 approving a SME

charge of $0.42 per month for Residential and General Service < 50 kW customers effective from January 1, 2023 to December 31, 2027.

Table 2-30 below shows Oshawa Power's COP calculation for the 2026 Test Year (Appendix 2-ZB).

Table 2-30: Commodity Expense Calculation (Appendix 2-ZB)

		2026 Test Year	RPP		2026 Test Year	non-RPP		Total
Electricity Commodity	Units	Volume	Rate	$	Volume	Rate	$	$
Class per Load Forecast								
Residential	kWh	569,083,457		56,549,823	5,528,687		197,153	
GS < 50 KW	kWh	115,523,828		11,479,603	18,127,036		646,410	
GS 50 to 999 KW	kWh	119,240,628		11,848,941	220,481,697		7,862,377	
GS 1000 to 4999 KW	kWh	0		0	77,793,015		2,774,099	
Large User	kWh	0		0	35,088,490		1,251,256	
Unmetered	kWh	2,986,918		296,810	0		0	
Sentinel	kWh	27,837		2,766	0		0	
Street Lighting	kWh	0		0	4,860,547		173,327	
SUB-TOTAL				80,177,943			12,904,622	$93,082,565

Global Adjustment non-RPP	Units							
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential - Class B	kWh			0			368,432	
GS < 50 KW - Class B	kWh			0			1,207,986	
GS 50 to 999 KW - Class B	kWh			0			13,513,878	
GS 1000 to 4999 KW - Class B	kWh			0			1,550,277	
Large User - Class B	kWh			0			0	
Unmetered - Class B	kWh			0			0	
Sentinel - Class B	kWh			0			0	
Street Lighting - Class B	kWh			0			323,907	
				0			0	
				0			0	
				0			0	
GS 50 to 999 KW - Class A	kWh			0			1,031,895	
GS 1000 to 4999 KW - Class A	kWh			0			2,684,526	
Large User - Class A	kWh			0			1,414,006	
SUB-TOTAL				0			22,094,905	$22,094,905

Transmission - Network								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	569,083,457	0.0129	7,341,177	5,528,687	0.0129	71,320	
GS < 50 KW	kWh	115,523,828	0.012	1,386,286	18,127,036	0.012	217,524	
GS 50 to 999 KW	kW	142,722	4.3683	623,450	262,862	4.3683	1,148,259	
GS 50 to 999 KW - Interval Metered	kW	148,081	5.5992	829,137	284,450	5.5992	1,592,694	
GS 1000 to 4999 KW	kW	0	5.5992	0	178,388	5.5992	998,830	
Large User	kW	0	5.9661	0	77,832	5.9661	464,353	
Unmetered	kWh	2,986,918	0.012	35,843	0	0.012	0	
Sentinel	kW	79	3.0132	238.0428	0	3.0132	0	
Street Lighting	kW	0	2.962	0	13,198	2.962	39,092	
SUB-TOTAL				10,216,131			4,532,074	$14,748,205

Transmission - Connection								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	569,083,457	0.0099	5,633,926	5,528,687	0.0099	54,734	
GS < 50 KW	kWh	115,523,828	0.0091	1,051,267	18,127,036	0.0091	164,956	
GS 50 to 999 KW	kW	142,722	3.2111	458,293	262,862	3.2111	844,076	
GS 50 to 999 KW - Interval Metered	kW	148,081	4.079	604,024	284,450	4.079	1,160,273	
GS 1000 to 4999 KW	kW	0	4.079	0	178,388	4.079	727,645	
Large User	kW	0	4.4506	0	77,832	4.4506	346,399	
Unmetered	kWh	2,986,918	0.0091	27,181	0	0.0091	0	
Sentinel	kW	79	3.7695	297.7905	0	3.7695	0	
Street Lighting	kW	0	3.7056	0	13,198	3.7056	48,907	
SUB-TOTAL				7,774,989			3,346,989	$11,121,977

Wholesale Market Service								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	569,083,457	0.0041	2,333,242	5,528,687	0.0041	22,668	
GS < 50 KW	kWh	115,523,828	0.0041	473,648	18,127,036	0.0041	74,321	
GS 50 to 999 KW	kWh	119,240,628	0.0041	488,887	220,481,697	0.0041	903,975	
GS 1000 to 4999 KW	kWh	0	0.0041	0	77,793,015	0.0041	318,951	
Large User	kWh	0	0.0041	0	35,088,490	0.0041	143,863	
Unmetered	kWh	2,986,918	0.0041	12,246	0	0.0041	0	
Sentinel	kWh	27,837	0.0041	114.1317	0	0.0041	0	
Street Lighting	kWh	0	0.0041	0	4,860,547	0.0041	19,928	
SUB-TOTAL				3,308,137			1,483,706	$4,791,843

Class A CBR								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential				-			-	
GS < 50 KW				-			-	
GS 50 to 999 KW				-	17,692,417	0.0006	10,322	
GS 1000 to 4999 KW				-	54,529,558	0.0007	36,872	
Large User				-	35,088,490	0.0004	15,187	
Unmetered				-			-	
Sentinel				-			-	
Street Lighting				-			-	
SUB-TOTAL				-			62,381	$62,381

Class B CBR								Total
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	
Residential	kWh	569,083,457	0.0004	227,633	5,528,687	0.0004	2,211	
GS < 50 KW	kWh	115,523,828	0.0004	46,210	18,127,036	0.0004	7,251	
GS 50 to 999 KW	kWh	119,240,628	0.0004	47,696	202,789,280	0.0004	81,116	
GS 1000 to 4999 KW	kWh	-	0.0004	-	23,263,457	0.0004	9,305	
Large User	kWh	-	0.0004	-	-	0.0004	-	
Unmetered	kWh	2,986,918	0.0004	1,195	-	0.0004	-	
Sentinel	kWh	27,837	0.0004	11	-	0.0004	-	
Street Lighting	kWh	-	0.0004	-	4,860,547	0.0004	1,944	
SUB-TOTAL				322,745			101,828	$424,573

RRRP								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	569,083,457	0.0015	853,625	5,528,687	0.0015	8,293	
GS < 50 KW	kWh	115,523,828	0.0015	173,286	18,127,036	0.0015	27,191	
GS 50 to 999 KW	kWh	119,240,628	0.0015	178,861	220,481,697	0.0015	330,723	
GS 1000 to 4999 KW	kWh	-	0.0015	-	77,793,015	0.0015	116,690	
Large User	kWh	-	0.0015	-	35,088,490	0.0015	52,633	
Unmetered	kWh	2,986,918	0.0015	4,480	-	0.0015	-	
Sentinel	kWh	27,837	0.0015	42	-	0.0015	-	
Street Lighting	kWh	-	0.0015	-	4,860,547	0.0015	7,291	
SUB-TOTAL				1,210,294			542,819	$1,753,113

Smart Meter Entity Charge								
Class per Load Forecast		Customers/Connections	Rate	$	ustomers/Connection	Rate	$	Total
Residential		58,956	0.42	297,137	559	0.42	2,820	
GS < 50		4,217	0.42	21,254	306	0.42	1,543	
SUB-TOTAL				318,391			4,363	$322,754
SUB- TOTAL				103,328,630			45,073,687	148,402,317
OER CREDIT	13.10%			-13,536,050			0	-13,536,050
TOTAL				**89,792,579**			**45,073,687**	**134,866,266**

2.5 DISTRIBUTION SYSTEM PLAN

2.5.1 Overview

Oshawa Power has prepared a DSP in accordance with the OEB's Chapter 5 Consolidated Distribution System Plan Filing Requirements in support of this Application. Oshawa Power's DSP is attached as Attachment 2-1 to this Exhibit. The DSP incorporates specific improvements directed by the OEB in its 2021 Decision and Order on Oshawa Power's Cost of Service application related to:

- Enhanced asset condition assessment, based on a comprehensive, multi-faceted Health Index formulation
- Improved stakeholder engagement with third-parties including customers, municipal and regional governments, broadband service providers, and others.
- Data-driven investment decision-making through a quantified risk prioritization tool guided by the Strategic Assessment Management Plan

Two business cases for large, exceptional investments are included in Appendix A to the DSP:

- Enterprise Resource Plan (ERP) Upgrade
- Non-Wires Solutions

Material justification sheets have been prepared for 22 capital projects above Oshawa Power's materiality threshold, included in Appendix B to the DSP.

2.6 POLICY OPTIONS FOR THE FUNDING OF CAPITAL

Oshawa Power is not proposing any qualifying ACM capital projects in this Application.

Oshawa Power is building a new administrative and operational facility for occupation in 2027 to replace its current operational and administrative facilities. The current facilities, located at 100 Simcoe Street South, are leased from its shareholder, the Corporation of

the City of Oshawa. Oshawa Power has been directed by the City to vacate the premises by May 31, 2028 to allow for downtown redevelopment.

Oshawa Power purchased land in 2024 for a new building but is not requesting cost recovery at this time, with the land purchase cost included in WIP in Appendix 2-AB. The total cost for the new building, including the estimated cost of construction, is not being provided in this Application as the design of the facility is ongoing and the construction work has not been tendered, and therefore final costs remain uncertain. Rather than filing an ACM as part of this Application, Oshawa Power intends to file an ICM application for its new operational and administrative facility once costs and in-service timelines are more certain. Justification of total expenditures, impact on distribution costs and rates to customers, and benchmarking against comparable facilities will be provided in that application.

2.7 ADDITION OF PREVIOUSLY APPROVED ACM AND ICM TO RATE BASE

Oshawa Power has not applied for nor received approval of any ICM assets and therefore has no such assets added to its rate base.

2.8 CAPITALIZATION

2.8.1 Capitalization Policy

Oshawa Power's capitalization policy has not changed since its last rebasing application (EB-2020-0048), and is summarized below.

Oshawa Power's rebasing in 2012 (EB-2011-0073) was completed based on MIFRS and included appropriate changes to its capitalization policy to exclude from capital any costs which are not directly attributable to an item of PP&E, as part of the transition to MIFRS. This capitalization policy under MIFRS is consistent with IFRS, which Oshawa Power

formally adopted for financial reporting purposes on January 1, 2015. This Application does not include any further changes to capitalization policies.

Under IFRS, the cost of an item of PP&E includes only costs that are directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management. The term “directly attributable” is not defined under IFRS. However, there must be a direct relationship that is established by fact between a cost element and a construction or acquisition activity in order for such cost to be “directly attributable” to such activities and, on this basis capitalized as PP&E. The capital treatment for each of the main cost elements is outlined below.

Material Costs

Material costs include stocked items held in warehouses and issued out to each capital project, as well as materials purchased and delivered to capital project sites directly. These costs represent the purchase price, and initial delivery and handling costs of the materials. Oshawa Power capitalizes material costs as they are directly attributable costs of bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management.

Labour Costs

Labour costs that are directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management are capitalized. Labour costs are allocated to individual capital projects through timesheets.

Third Party Contract Costs

Oshawa Power engages third party subcontractors to perform capital construction services. Third party costs are capitalized as they are directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management.

Fleet Costs

Fleet costs are allocated to individual capital projects through the Oshawa Power timesheet system, similar to the process used for labour costs. Vehicle hourly charge rates are calculated by totaling fuel, repairs and maintenance, and other directly attributable costs, then dividing by the estimated number of available for use hours.

2.8.2 Capitalization of Overhead

Where it can be factually established that a direct relationship exists between overhead costs and the construction or acquisition of an item of PP&E, such costs are capitalized as part of the item of PP&E.

Oshawa Power has completed Appendix 2-D, as shown in Tables 2-31 and 2-32 below, which provides a summary of the overhead costs before capitalization, and the actual OM&A amounts capitalized.

Table 2-31: OM&A Before Capitalization (Appendix 2-D)

OM&A Before Capitalization	2021 Historical Year	2022 Historical Year	2023 Historical Year	2024 Historical Year	2025 Bridge Year	2026 Test Year
Customer Service	$ 2,597	$ 2,889	$ 3,520	$ 4,148	$ 4,077	$ 4,389
Operations and Metering	$ 7,062	$ 6,635	$ 7,389	$ 7,375	$ 8,161	$ 9,967
General and Admin	$ 7,946	$ 8,740	$ 9,525	$ 11,871	$ 12,309	$ 13,570
Total OM&A Before Capitalization (B)	$ 17,605	$ 18,264	$ 20,434	$ 23,394	$ 24,547	$ 27,926

Table 2-32: Capitalized OM&A (Appendix 2-D)

Capitalized OM&A	2021 Historical Year	2022 Historical Year	2023 Historical Year	2024 Historical Year	2025 Bridge Year	2026 Test Year	Directly Attributable? (Yes/No)	Explanation for Any Change in Treatment of Capitalized Overhead
Labour and Benefits	$ 3,077	$ 2,789	$ 3,485	$ 3,605	$ 4,246	$ 4,540	Yes	No change
Material Handling	$ 201	$ 211	$ 271	$ 193	$ 298	$ 305	Yes	No change
Vehicle and Related Costs	$ 1,027	$ 884	$ 914	$ 796	$ 778	$ 809	Yes	No change
Total Capitalized OM&A (A)	$ 4,305	$ 3,884	$ 4,670	$ 4,594	$ 5,322	$ 5,654		
% of Capitalized OM&A (=A/B)	24%	21%	23%	20%	22%	20%		

2.8.3 Burden Rates

Oshawa Power considers employee benefit costs for staff working on specific capital projects as directly attributable costs and accordingly capitalizes such costs. This is done by way of an uplift percentage added to each hour of labour charged to capital projects.

The labour burden rate is recalculated each year in order to incorporate any changes to benefit and other directly attributable costs. The payroll burden rate used in Oshawa Power's last rebasing in 2021 was 60%. Consistent with the last rebasing application, the burden rate of 60% has been used throughout this Application.

2.9 COSTS OF ELIGIBLE INVESTMENTS FOR CONNECTION ON QUALIFYING GENERATION FACILITIES

Oshawa Power has not incurred any costs for the connection of qualifying generation facilities.

Attachment 2 – 1

2026-2030 Oshawa Power Distribution System Plan

OSHAWA POWER

2026 - 2030

Distribution System Plan



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5.2 Distribution System Plan

The Oshawa Power Distribution System Plan (DSP) has been prepared in accordance with the Ontario Energy Board's (OEB's) Chapter 5 – Distribution System Plan Filing Requirements for Electricity Distribution Rate Applications, dated December 9 2024 (the "Filing Requirements") as part of Oshawa Power's 2026 Cost of Service Application (the Application).

The DSP is a stand-alone document that is filed in support of Oshawa Power's Application. The DSP covers the historical period of 2021 to 2025, with 2025 being the bridge year, and a forecast period of 2026 to 2030, with 2026 being the Test Year.

The Oshawa Power DSP is organized into three major sections:

Section 5.2 provides a high-level overview of Oshawa Power's DSP, including coordinated planning with third parties and performance measurement for continuous improvement

Section 5.3 provides an overview of Oshawa Power's asset management practices, including an overview of the assets managed and asset management practices/processes and procedures.

Section 5.4 provides a summary of Oshawa Power's 2026-2030 capital expenditure plan, including a variance analysis of historical expenditures, an analysis of forecast expenditures, and justification of material projects above the materiality threshold.

Oshawa Power's DSP has been prepared in support of the four key OEB established Renewed Regulatory Framework For Electricity (RRFE) performance outcomes – Customer Focus, Operational Effectiveness, Public Policy Responsiveness and Financial Performance. These outcomes also align with Oshawa Power's 2026 to 2030 Strategic and Business Plans.

The materiality threshold for Oshawa Power is $195,000 and detailed descriptions of specific projects/programs exceeding the materiality threshold are provided in Section 5.4.2.1

5.2.1 Distribution System Plan Overview

5.2.1.1 Description of the Utility Company

Oshawa Power Group of Companies (the Group), a wholly owned subsidiary of the City of Oshawa, is an enabler of critical energy and infrastructure for the City of Oshawa and in communities across Ontario. The Group represents energy generation, energy services, a broadband communications business, as well as Oshawa PUC Networks (Oshawa Power).

Service Territory

The City is located in the Regional Municipality of Durham and lies on the shoreline of Lake Ontario. Oshawa Power is responsible for the distribution and delivery of electricity to the residences and businesses in the City of Oshawa. The 2021 Canadian Census recorded the City of Oshawa's population as 175,383; the 2024 estimated population of Oshawa is 186,256[1].

Power Grid

Oshawa Power's service territory shares borders with Elexicon Energy Inc. (Elexicon) and Hydro One Networks Inc. (Hydro One). Oshawa Power receives power from three Hydro One owned transformer stations. Oshawa Power owns, operates and maintains nine municipal stations and 6,516 transformers, which feed 488 km of underground cables and 542 km overhead wires, which are supported by 11,252 poles.

Leadership

In 2023, Oshawa Power underwent a change in leadership, bringing in a revitalized vision and new strategic direction. Oshawa Power is guided by:

Vision – Be a trusted partner and leader in the energy sector today and tomorrow

Mission – Empowering customers to thrive through the evolving energy transition

Values –

> ***Safety***: We remain dedicated to always keeping both our community and employees safe. We are proud to offer continuous safety communications and training to both our customers and workforce.
>
> ***Innovation***: We remain outwardly focused to ensure we maintain an innovative approach to our regulated business that benefits our customers.
>
> ***Courage to Act***: We gain strength from challenges and tough decisions. We are not afraid of failure. We thrive on learning and development to support change and continuous improvements that benefit our customers.

[1] CNCL-24-54 https://pub-oshawa.escribemeetings.com/filestream.ashx?DocumentId=15709

Stewardship: We are dedicated to supporting the community we work in, driving energy resilience through advocacy, openness, and storytelling.

Care for People: We always treat our employees, customers, community and partners with respect and look to grow together with trust and integrity. We encourage open dialogue and collaboration.

Customer Focus: Empowering and educating our customers while providing better service and transparency is key to our operations. With the customer in mind, we drive our decisions to safeguard mutual value.

Customers count on Oshawa Power to deliver reliable power at reasonable rates. As the regulator, the OEB's RRFE requires an outcome-based approach focused on long-term value for money. At every step, Oshawa Power as a company, guided by its vision, mission, values and business objectives, looks to serve and deliver on every expectation.

Business Objectives

Specifically identified within the RRFE, the OEB is looking for the following outcomes from its distributors: Public Policy Responsiveness, Financial Performance, Operational Effectiveness and Customer Focus. Oshawa Power has identified the following business goals that will guide the business and operations to achieve these outcomes.

Customer Focus

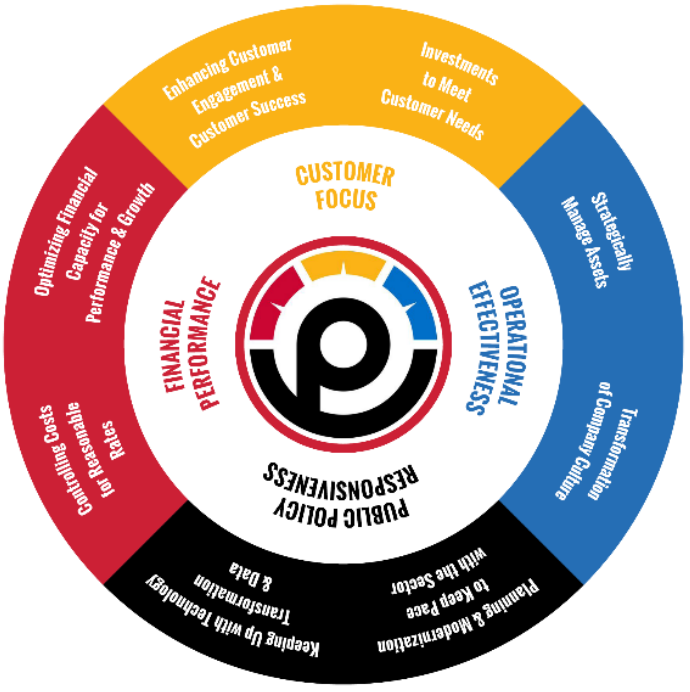
- Enhancing Customer Engagement & Customer Success
- Investments To Meet Customer Needs

Operational Effectiveness

- Strategically Manage Assets
- Transformation of Company Culture

Public Policy Responsiveness

- Planning & Modernization to Keep Pace with The Sector
- Keeping Up with Technology Transformation & Data



Financial Performance

- Controlling Costs for Reasonable Rates
- Optimizing Financial Capacity for Performance & Growth

To hold itself accountable, Oshawa Power identified Desired Outcomes & Measures of Success that will propel the organization to be future ready, resilient, digitally modernized and customer-centric. The Desired Outcomes & Measures of Success as identified in Oshawa Power's Strategic Plan (Attachment 1-2 in Exhibit 1) are as follows:

a. High-Performing Team
b. Growth
c. Operational Efficiency
d. Community & Partner Engagement
e. Digital Maturity
f. Advocacy

5.2.1.2 Capital Investment Overview

Oshawa Power's capital investments over the planning period have been aligned to the four categories of system access, system renewal, system service, and general plant outlined in the Filing Requirements.

System Access investments are driven by customer connection needs, third-party infrastructure needs requiring mandatory utility relocation, and mandated revenue metering and service obligations.

System Renewal investments are required to replace or refurbish assets that have reached the end of useful life, are defective, or are in deteriorating condition leading to high asset failure risk. Oshawa Power uses the outputs of its Asset Condition Assessment (ACA) as a key input in its planning process for asset replacement needs. Additionally, insights from field experts, inspections, and operational observations are also considered to ensure a thorough and informed decision-making process.

System Service investments are focused on enhancements to the system to meet operational objectives. They support system expansions and connections by managing station and feeder operational loading needs, as well as the implementation of distribution automation to maintain and improve system reliability while reducing outage impacts for customers.

General Plant investments are required to meet the facilities, fleet, office systems and IT needs.

The table below presents Oshawa Power's historical actuals and forecast expenditures for both capital and O&M categories. Note that 2025 figures are forecast spending.

Table 1 - Historical and Forecast Capital Expenditures and System O&M ($,000)

Category	HISTORICAL ($ '000)					FORECAST ($ '000)				
	2021	2022	2023	2024	2025 - Bridge Year	2026 - Test Year	2027	2028	2029	2030
System Access (Gross)	4,219	3,839	7,105	6,694	7,995	9,186	9,270	9,356	9,443	9,532
System Renewal (Gross)	6,507	6,538	12,069	4,585	7,948	8,045	8,756	7,056	7,421	8,108
System Service (Gross)	2,828	953	1,294	1,805	1,093	1,336	300	778	962	588
General Plant (Gross)	1,046	1,271	1,721	576	2,716	1,680	1,655	1,730	1,155	802
Total Capital	14,601	12,601	22,189	13,660	19,752	20,247	19,981	18,920	18,980	19,030
Contributed Capital	-2,049	-1,201	-2,580	-4,856	-2,343	-3,228	-3,253	-3,277	-3,303	-3,328
Net Capital	12,552	11,400	19,609	8,804	17,409	17,019	16,728	15,643	15,677	15,702
System O&M	3,425	3,717	4,319	4,276	3,861	$5,353	$5,487	$5,624	$5,765	$5,909

Oshawa Power's historical net capital expenditure from 2021 through 2025 had an average annual expenditure of approximately $13.95M primarily driven by System Access and System Renewal requirements in order to address customer connections and load growth within the service territory, facilitate community infrastructure improvements through asset relocations, and to address the required replacement of equipment at or approaching the end of their useful life.

In 2024, Oshawa Power reported lower in-service amounts in three of the four investment categories—System Access, System Renewal, and General Plant. This was primarily due to strategic reallocation of budget toward the acquisition of land for Oshawa Power's new Operational and Administrative Building. Deferral of subdivision energizations to 2025 due to delays in developer constructed subdivisions was a significant contributor to lower system access expenditures. The land purchase was a necessary and reactive investment following the City of Oshawa's notice to vacate the current leased facility. Oshawa Power acted prudently, securing the property below market average value as confirmed by Cushman & Wakefield. As the investment remains in Work in Progress until 2027 when the building is anticipated to be placed in service, it is not reflected in the in-service amounts presented in the table above.

The COVID-19 pandemic contributed to variances in in-service amounts in 2021 and 2022 compared to 2023. During this period, supply chain disruptions, labor shortages, market uncertainty, and health and safety restrictions led developers to slow or defer housing projects, resulting in a concentration of activity in 2023. Additionally, Oshawa Power was operating below the typical staffing levels expected for a utility of its size and demographic. Internal resource constraints required the deferral of certain system renewal initiatives to 2023 in order to alleviate the burden on existing staff while continuing to meet regulatory obligations and performance targets.

Oshawa Power's net capital expenditure from 2026 through 2030 has an average annual expenditure of approximately $16.15M. Increase in cost over historical values is primarily driven by inflation, customer growth, increasing cost of material and equipment, increased third party driven scope of work, and additional expenditures due to shifted cost responsibilities from customers to the utility (Residential subdivision expansions). Oshawa Power's 2026-2030 DSP, strategically balances increased investments in System Access to support growth, consistent and prudent expenditures in System Renewal and General Plant to maintain reliability and operational effectiveness, and carefully paced System Service spending aligned with forecasted system needs.

5.2.1.2.1 System Access

The emphasis on System Access throughout this DSP is well justified by Oshawa Power's ongoing obligation to provide timely and reliable connections to all customer types—including residential, commercial, industrial, institutional, and DER customers. A particular area of focus is expansion work related to residential subdivisions.

Municipal and regional authorities, such as the City of Oshawa and the Region of Durham, are actively investing in infrastructure enhancement projects, including significant road widening. These projects introduce complexities involving coordination among numerous stakeholders including municipal planning departments, contractors, and utility providers. Oshawa Power plays a critical role in these collaborative efforts, specifically in relocating and upgrading hydro assets to facilitate timely and seamless execution of infrastructure improvements. Such coordinated investments in System Access ensure Oshawa Power effectively meets the evolving demands of the city's rapid expansion.

Major projects in Oshawa Power's 2026-2030 DSP such as Expansions, Third-Party Relocations, Connections and Revenue Metering reflect prudent planning efforts aimed at effectively addressing these identified system needs.

5.2.1.2.2 System Renewal

Oshawa Power's continued focus on System Renewal is justified by its enhanced asset management process as outlined in Oshawa Power's Strategic Asset Management Plan (SAMP), included in Appendix H, and implemented through the utility's Asset Management System (AMS), further described in detail in Section 5.3. The planning process places Safety, Reliability, and Customer Focus at the forefront, aligning directly with the fundamental objectives of System Renewal investments. Given that System Renewal initiatives inherently address critical aspects such as public safety, service reliability, and customer satisfaction, these projects consistently meet the criteria for high-priority investments. Steady, prudent investments in this category are essential to ensuring that asset replacements and refurbishments are executed in a timely manner, minimizing risks associated with aging infrastructure and safeguarding reliable and cost-effective service delivery for customers.

Station switchgear replacements at MS5 and MS11, Overhead and Underground Rebuilds in Measurement Canada requirements are some of the major investments arising from Oshawa Power's structured and priority-driven Asset management process. Section 5.4.1.2 Capital Expenditure Forecast in conjunction with project or program specific material justification sheets in Appendix B provide a comprehensive overview of investment priorities.

5.2.1.2.3 System Service

Oshawa Power continues to modernize its distribution system through targeted investments aimed at maintaining high reliability standards and enhancing operational response times. While expenditures in System Service are lower relative to historical periods, this is reflective of Oshawa Power's improved coordination of significant infrastructure upgrades with System Access investments in third-party relocation projects initiated by municipal and regional authorities. Typically, these coordinated initiatives occur in areas experiencing accelerated growth, presenting optimal opportunities to incorporate system upgrades through prudent planning. This consolidated approach strategically reallocates funding, enabling investments in automation and technological advancement within Oshawa Power's distribution system. Key System Service investments include the deployment of overhead automated self-healing switches and upgrades to SCADA equipment.

In alignment with Ontario Energy Board guidance promoting alternative approaches to traditional infrastructure investments, Oshawa Power has also evaluated Non-Wires Solutions (NWS). The proposed NWS initiatives within the DSP are intended to be strategically deployed as emerging

system needs arise, thereby facilitating deferral of future capital-intensive projects in traditional wires solutions. A comprehensive business case, provided in Appendix A, offers detailed insight into Oshawa Power's methodical approach toward adopting these innovative solutions.

5.2.1.2.4 General Plant

Oshawa Power's General Plant investments support the operational, technological, and customer service functions necessary for Oshawa Power to provide safe, reliable, and efficient service. Investments are aimed at meeting fleet, facilities, office systems and IT needs.

In the 2026–2030 planning period, Oshawa Power will replace fleet vehicles approaching the end of their useful life. A new small bucket truck will also be procured to enhance efficiency and safety in space-constrained areas, where full-sized bucket trucks cannot be effectively deployed.

A new Enterprise Resource Planning (ERP) system implementation to replace the current, but soon to be obsolete, Microsoft Dynamics GP system also falls within this planning period. The new ERP implementation will maintain existing functionality while adding enhanced budgeting, procurement, and warehouse management features. A business case is provided in Appendix A for more details.

Refer to Section 5.4 Capital Expenditure Plan for more details on the overall capital expenditure and each investment category. The figure below shows forecasted investment expenditures, in comparison to historical expenditures, to address needs identified under each investment category.

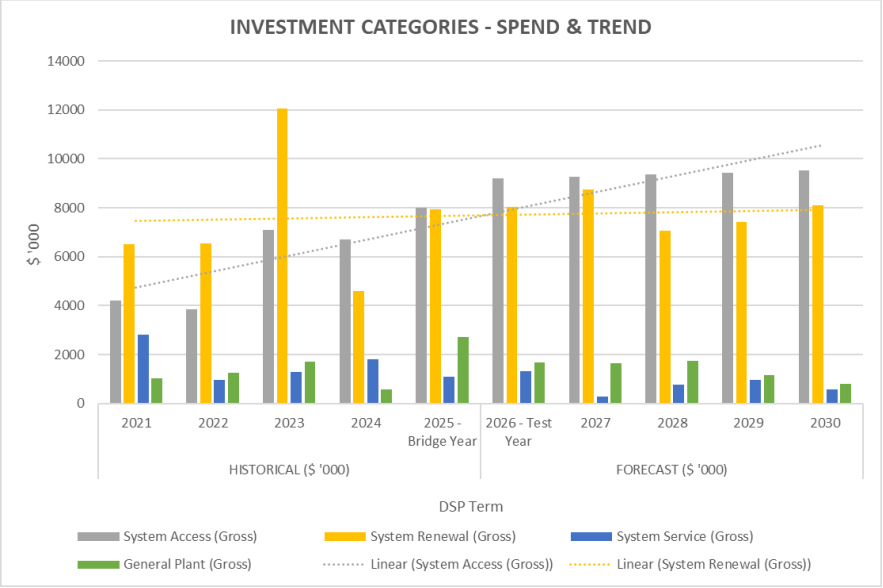


Figure 1 – Historical and Forecast Capital Expenditures & Trend ($,000)

Oshawa Power is anticipating filing an ICM in 2027 for the purpose of receiving cost recovery for the new Operational and Administrative building. The design for the new building is still underway and hence cost estimates are not yet available.

5.2.1.3 Key Changes since Last Filing

Since the last DSP filing, Oshawa Power has undergone a change in leadership and has implemented several operational enhancements to strengthen the organization's ability to deliver on its robust goals of transformation and modernization (additional information is provided in Exhibit 1, Section 1.2 – Executive Summary and Business Plan. Some of the more prominent changes include:

- **Updated Conditions of Service** - Oshawa Power is governed by an updated Conditions of Service. This is a significant milestone, as it is the first update since the original version was filed in 2003. Some of the more substantial changes include updates that were made to reflect Oshawa Power's current practices, which follow that of the evolving industry. More information on the updated Conditions of Service is provided in Exhibit 1, Section 1.4.10.
- **Process Improvements** – Several process improvements have been implemented to achieve internal efficiencies and enhance business value. The Overhead and Underground departments were combined reducing the number of personnel responding to calls. The asset management process was revamped to incorporate a new Strategic Asset Management Plan, Asset Management policy and Risk prioritization Methodology (more on this in Section 5.3); additional improvements were also made to practices and procedures Administratively, a new automated purchase order process and payroll system were implemented.
- **Cybersecurity** – Oshawa Power anticipates reaching target maturity for a medium risk utility with the OEB's Cybersecurity framework by end of year 2025, pending 3rd party verification. With the implementation of the target control set, Oshawa Power is reviewing areas where it can enhance and further strengthen its cybersecurity posture.
- **Communications and Customer Service** – as discussed in Exhibit 1, Section 1.6 – Customer Engagement, communication has improved with the Region and the City through consistent communications and meetings on capital projects and planning, consistent with direction from the OEB in Oshawa Power's last cost of service Decision & Order. Oshawa Power introduced a new customer portal to allow customers to view their electricity consumption, compare usage to past periods, pay bills, receive outage notifications, and much more. The

portal is integrated with Green Button, which provides valuable insight into energy habits and encourages the development of conservation and cost-saving strategies. Watt, an online ChatBot, was introduced to provide 24/7 support for after-hours inquiries and customers' preferences for online connection, account management and finding the information they need without navigating through the entire website.

- **Technology** - FLISR (Fault Location, Isolation, and Service Restoration) software was implemented, along with a custom coding solution to address issues pertaining to filtering of false positives reported from AMI to OMS. A new GIS system (ESRI Utility Network) was implemented that provides better data interoperability with external data, while allowing the expansion of field and office data collection and processing possibilities.
- **Administration** - A new Customer Information System (CIS) system implementation is underway and will be completed by August 2025. The implementation of a new CIS will allow hosting to return to Oshawa Power, which will lead to increased security, improved operational effectiveness, and greater synergies across the organization when combined with the business process optimization and automation efforts across customer service and billing functions, leading to improved productivity and cost effectiveness.
- **Grid Enhancements** – Significant enhancements include the replacement of the switchgear at MS2, and the incorporation of new automation in both the 44kV and 13.8kV distribution systems via the installation of new switching devices such as Alduti-Rupters, Intellirupters, and Viper reclosers, all of which are integrated into our Survalent system (FLISR). Additionally, the extension of two 44kV lines from Enfield TS helps accommodate new commercial and industrial growth in the north end of the city.

5.2.1.4 DSP Objectives

Oshawa Power's DSP is a stand-alone document that has been prepared to support Oshawa Power's Cost of Service (COS) Application. The DSP consolidates Oshawa Power's documentation of its asset management process and its capital expenditure plan.

The DSP provides all stakeholders with the following information:

- An overview of all Oshawa Power's managed assets, its asset condition assessment, asset lifecycle optimization practices, and related objectives and goals;
- An overview of its planning process, that includes consultation, coordination, and engagement with third parties, and consideration of non-wires solutions;
- A review of Oshawa Power's performance over the historical period;

- A view of Oshawa Power's planned expenditures for the 2025 bridge year; and
- A preview of planned expenditures in the 2026-2030 forecast period, that are supported by detailed justifications.

Oshawa Power's approach to developing its capital expenditure plan for the forecast period involved analyzing historical trends, setting realistic forecasts, and integrating customer feedback where appropriate. This allows Oshawa Power to accurately identify customer needs so that it can plan for and respond to changes required to its distribution system in a timely manner. This results in Oshawa Power's distribution system being safe, reliable, and adaptable to evolve with changing industry trends while limiting rate volatility by smoothing expenditures over the forecast period. It meets customer expectations by continuing to be affordable through appropriately paced and prudent spending decisions. Oshawa Power's DSP shows its commitment and focus to ensure that its processes are always aligned with and achieve the four RRFE performance outcomes established by the OEB for electricity distributors:

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

Specific key objectives of the DSP are to:

- To maintain Oshawa Power's high standards of safety for employees and the public and remaining compliant with all regulations and rules.
- To sustainably support growth and meet customer expectations by ensuring adequate system capacity for new and upgraded connections through timely system access investments and proactive consultation, coordination, and engagement with third-party stakeholders.

- To continue maintaining a reliable system by executing system renewal projects identified through the asset condition assessment, strategically prioritized, paced, and guided by the Strategic Asset Management Plan.
- To continue incorporating customer feedback and comments as appropriate into distribution system planning and prioritization of projects.
- To enhance system robustness and resiliency by continued system service initiatives such as deployment of distribution automation devices on the 13.8kV and 44kV networks that modernizes Oshawa Power's distribution system and allows an ongoing improvement in operational responsiveness.
- To evolve with industry trends by embracing digitization, strengthening cybersecurity, and enhancing alignment with public policy initiatives that support electrification.
- To improve operational efficiencies through the deployment of innovative technologies, leveraging data analytics, and streamlining internal processes.
- To continue optimizing workforce effectiveness through disciplined general plant investments in IT, Fleet, and Facilities.

5.2.2 Coordinated Planning with Third Parties

Oshawa Power regularly engages with multiple third-party stakeholders as a matter of good practice and to establish long-term working relationships. This ensures that there is a clear awareness and understanding of how long-term planning projects anticipated by these external stakeholders may potentially impact Oshawa Power's distribution system.

To determine with whom to consult, Oshawa Power seeks to identify organizations with current, or upcoming material needs with respect to electricity supply and infrastructure that are more significant than typical upgrade or connection requests. This is done through a combination of community engagement, government relations and key account-type activities, such as attending events, monitoring policy updates across three levels of government and by reaching out to organizations that are involved with important community developments.

Opportunities to gain any operational efficiencies through early coordination with these stakeholders are identified such that any adjustments in Oshawa Power's project planning and scheduling can be made smoothly, with the least disruption possible, and thereby cost effectively. It also allows Oshawa Power to appropriately plan ahead to ensure that there is adequate system capacity available within its distribution system when new or additional loads are included in

stakeholder plans. Additional, targeted engagement regarding the proposed capital plan has been undertaken and will continue as deemed necessary. This process ensures that the investments are focused on servicing customer priorities and their future needs. Stakeholders include:

- Customers (Residential and Businesses/Key Accounts)
- Municipal and Regional government
- Development Communities
- Telecommunication Entities
- Transportation Authorities
- Independent Electricity System Operator (IESO), Hydro One, & other distributors

5.2.2.1 Customers

Residential

Regular and consistent engagement with residential customers keeps Oshawa Power informed of their needs and expectations. Some communications are single-channel, such as the website's Customer Projects and Blog Page or On-Bill messages. Others are two-way interactions, including the Bi-Annual Customer Satisfaction Survey, Transactional Customer Service Surveys, and the Public Safety Awareness Survey. Additionally, we connect with customers and the public through informal, open conversations at community events.

These engagements have driven improvements such as adding educational resources and a real-time outage map to Oshawa Power's website, introducing welcome packages for new customers, launching the MyAccount portal, and enhancing accessibility to address inquiries or highlight career opportunities.

As described in Exhibit 1 Section 1.6.5, Oshawa Power initiated engagement with Residential and Small Businesses for this Cost of Service (COS) and its Distribution System Plan (DSP) with a two-phase program that included information on the Oshawa Power website, on-bill messaging and two surveys (January 2024 and October 2024). Approximately 1,600 customers completed the Phase One: *Have Your Say* survey and 2,300 customers completed the Phase Two: *Help Shape Oshawa's Electricity Plan* survey.

Phase One: *Have Your Say* was used to identify and confirm customer priorities that would be used to inform the development of the capital expenditure projects within the 2026-2030 DSP.

Phase Two: *Help Shape Oshawa's Electricity Plan* was an in-depth survey to:

- Gauge understanding of Oshawa Power's role in the electricity sector and within the community,
- Communicate the Oshawa Power's plans and the implications of the DSP's proposed capital expenditures to the customers' bills, and
- Gather customer feedback.

Phase One Feedback: Customers indicated their priorities for fair rates and communication regarding outages. Oshawa Power also learned that customers are accessing online services, that they find them easy to navigate, and that EV customers are charging during (overnight) Time of Use (TOU) rates.

Phase One Actions: As a result of the Phase One discussions, Oshawa Power created a project page to share information on its projects, and to address questions.

Phase Two Feedback: Three themes were identified: more communication is desired, customers are cost sensitive, and better customer service is needed. A customer engagement report was prepared and shared internally. Constructive feedback derived from the open comments were directed to various departments within Oshawa Power for consideration as to how the feedback may be addressed. On average 90% of customers understand the importance of the proposed capital investment. The feedback supported the plan in the following ways:

- Confirmed understanding of system investments and importance thereof.
- Confirmed investment needs in customer interface related items such as CIS enhancement, CRM software, website redesign, and customer communication redesign to improve accessibility, engagement and service quality to Oshawa Power's customers.
- Confirmed maintaining reliability is a priority thus aligning with Oshawa Power's focus on maintaining its reliability performance through prudent system renewal efforts.
- Customers expressed cost sensitivity, which aligns with Oshawa Power's approach to include essential but modest increases.
- Customers expressed understanding for the need to gradually modernize and find efficiencies hence supporting Oshawa Power's system service investments in deploying distribution automation devices.
- Customers see Oshawa Power as a responsible business and expressed confidence in Oshawa Power's future planning.

Results of both phases of the survey can be found in Attachments 1-10 and 1-11 of Exhibit 1.

Business/Key Account Entities

There are approximately 4,997 non-residential customers in the City of Oshawa. These accounts are supported throughout the year through:

- Oshawa Power maintaining a membership and involvement in the Oshawa Chamber of Commerce.
- Oshawa Power participating as advisors and subject matter experts for the City of Oshawa's Business Retention and Expansion Plan.
- The Key Account strategy targets fourteen (14) accounts that qualify for the Industrial Conservation Initiative. This strategy, which is executed by the Manager of Sustainability and Business Advocacy (recently re-titled in 2025 to be the Manager of Sustainability and Strategic Partnerships), includes a minimum of four touch points per year, per customer, with additional and/or ad-hoc outreach where value can be added; demonstrating Oshawa Power's commitment to responsible and beneficial relationships with its larger-volume customers.

To further target businesses with COS and DSP-specific content, Oshawa Power initiated communication leveraging the Oshawa Chamber of Commerce's outreach channels to garner feedback from its membership. A two-part program was delivered.

The first part consisted of a digital communication campaign featured a link to the *Help Shape Oshawa's Electricity Plan* on-line survey (previously described). This campaign ran over a 4-week period via the Oshawa Chamber of Commerce's newsletter, to which there are over 3,200 subscribers. During the digital outreach campaign, Oshawa Power executed the second part of the outreach, which consisted of an in-person networking chamber event. In keeping with the atmosphere, Oshawa Power staff networked with attendees sharing three key messages:

- Please complete the on-line survey
- Your feedback is vital as to how we (Oshawa Power) support you, and
- That we (Oshawa Power) are best able to drive change when we hear from our customers.

General conversation feedback was positive about Oshawa Power being a reliable service provider. Several businesses committed to responding to the survey and to spread the word about the opportunity to provide feedback.

More than 50 responses were garnered through this outreach. Key findings from survey responses include a high degree of consideration for implementing energy transition technologies within the next five years, including:

- 28% considering adopting an EV
- 9% considering adopting a heat pump
- 18% considering adopting solar panels
- 21% considering adopting battery energy storage

This feedback is aligned with interest in distributed energy resources stated by the Key Account entities, which is detailed in the following section and in the Large Customer Engagement report. As with Key Account feedback, this information contributed to the development of the NWS strategy, which is provided in detail throughout the NWS Business Case (Appendix A).

For Key Account entities, Oshawa Power reached out to customers to meet regarding COS plans. The outreach achieved a 50% success rate, with responses coming from a variety of sectors including healthcare, continuing education, local and provincial government and manufacturing. The meeting goals were to provide a general update, generate an open discussion about the COS goals, projects and pricing impacts, as well as introducing NWS guidelines and applicability to large customers. Oshawa Power secured feedback to a series of questions about their future energy usage plans, satisfaction with Oshawa Power's services, and feedback about the COS and pricing impacts. The feedback received from Class A Customers provided input into the NWS Business Case and identified potential partners and projects. Specifically, feedback from Key Account entities indicated that there may be several opportunities to collaborate on distributed energy resources. These investments have been reflected in the NWS DSP line items that pertain to c- investment into DERs.

This feedback also provides information about anticipated load changes that Oshawa Power will bring forward during the GTA East Regional Planning process, to inform electricity usage trends impacting the 44kV sub-transmission and 13.8kV distribution circuits.

A Large Customer engagement report was prepared which captures the feedback (Attachment 1-11 in Exhibit 1). Follow up meetings will be scheduled to discuss opportunities arising from NWS and demand-reduction activities, ensuring customers are aware of the upcoming electricity demand-side management (eDSM) framework and grant opportunities and providing support for their electrification plans.

The feedback was well received and incorporated into the Non wire Solutions evaluation process as detailed in the NWS Business Case (Appendix A).

5.2.2.2 Municipal and Regional Government: City of Oshawa and Region of Durham

As discussed in Exhibit 1, the OEB provided specific direction in Oshawa Power's last Cost of Service Decision & Order to improve its coordination with municipal and regional governments. Oshawa Power regularly consults with the City of Oshawa and the Region of Durham via planned and ad-hoc meetings between various relevant departments. It is an on-going and open dialogue that is critical to community growth and long-term planning and ensuring that the growth is properly supported with services and that any efficiencies through coordinated efforts can be achieved. A key outcome of such consultation results in engagement and the development of long-term working relationships.

Recognizing the nature of regional planning and construction, the Region and Oshawa Power connect with bi-annual meetings for closer collaboration for more accurate forecasting on regional capital projects.

Oshawa Power also reached out and met with Durham Region to discuss roadworks projects. The Region shared their internal 2024 Capital Roads Program and Nine-Year Forecast. Both projects anticipated for the current DSP years (2024/25) and future DSP years (2026-2030) were discussed. The discussions explored the project status to understand where they were in their design, tendering process, timelines etc. Projects were reviewed to identify if hydro coordination or relocation would be required, and to ensure that Oshawa Power will be made aware of the project schedules, be provided project drawings, and notified of exactly what utilities are impacted, etc. The prospective nature of these projects means that there is a lack of established scope of work available at this time to Oshawa Power for projects within the forecast period, which requires Oshawa Power to forecast based upon assumptions on scope of work and timelines. Specific details on individual projects will be shared as the project execution phase approaches. The DSP project list was informed using information collected from this process, specifically in the areas where we anticipate likely pole relocations resulting from regional projects. Oshawa Power projects were also reviewed to identify potential coordination opportunities with the Region, and timelines were aligned to achieve efficiencies through scope consolidation. Future regular meetings will continue to facilitate the sharing of information and allow adjustment in plans in a cost effective and timely manner.

Oshawa Power interacts with the City of Oshawa for municipal projects and development. These interactions extend beyond the municipality itself to include other stakeholders, such as developers to be able to see a high-level overview of future plans. There are several municipal touchpoints that include the road works program and development planning. Quarterly meetings are held for utilities coordination. Discussions between the City and Oshawa Power also identify issues such as:

- the constraints in the legacy Oshawa downtown core area where the infrastructure is mature and requires additional planning efforts to accommodate any new construction, and
- new growth development is foreseen / projected where long-term planning such as for land acquisition, the construction of a substation, extensions of 13.8kV or 44kV distribution circuits, procurement of long lead time material etc. will be required to meet customer needs.

Oshawa Power contacted and met with the City of Oshawa to discuss various projects the City has planned during the forecasted DSP period. Project status, implementation timelines, potential Oshawa Power impacts, etc. are communicated. Such ongoing engagement between Oshawa Power and the City will ensure collaboration and promote efficiencies in implementation. Information that was provided by the City was used to inform the development of the DSP list; considerations and impacts to the DSP are similar to that described for regional projects with the best information available at this time.

Further, published regional and municipal plans and reports on population growth also provide information that feeds into Oshawa Power's system planning.

5.2.2.3 Development Communities

Oshawa Power makes efforts to engage the developer community with the goal of keeping them informed and to enable a synergistic approach. Currently a large community development known as the Columbus Part II Planning Area (Columbus) is underway in the north portion of the City of Oshawa. Significant time is being invested into coordination and planning to ensure the project, its needs and impacts are fully identified and understood by all parties.

Oshawa Power initiated meetings with community developers and the City of Oshawa to emphasize the need for accurate load growth forecasting to ensure that Oshawa Power can effectively perform its capital planning. Specifically, Oshawa Power wanted to create an awareness and understanding of how government policies and potential new development requirements (EV chargers, heat pumps, electric heating, etc.) could significantly increase load requirements, and how it relates to

the need and planning of appropriate electricity infrastructure. Today's City of Oshawa plan includes 23,000 new homes to be built in Oshawa area by 2031.

The Columbus Landowners Group prepared a memorandum as a result of the engagement that provides an overview of the Columbus community and summarizes the discussions regarding available power, the need for a station, and a high-level load forecast. To ensure the success of the new community, collaborative discussions and information sharing will continue. Based on the high-level forecast, a new station is not anticipated to be needed within the 2026-2030 forecast period. However, optimization of existing capacity by egressing three (3) new 13.8kV feeders from Oshawa Power's existing MS9 station will be required in order support the development of this community. An optimum location for the future station may also be identified to allow early land designation.

5.2.2.4 Telecommunication Entities

Historically, Oshawa Power interacted with the local telecommunication entities through the Oshawa Municipal Services Coordinating Committee (OMSCC) or when a specific initiative required connection requests. In response to regulation O. Reg. 842/21 [Electricity Infrastructure (Part VI.1 of the Act)], Oshawa Power reached out to all the local telecommunication entities to re-engage and reaffirm the collaborative nature of the relationship and willingness to work together. The open approach has and continues to facilitate a good working relationship. Each entity operates in their own manner and has different needs. All entities are satisfied with Oshawa Power's timely responses to requests for joint use and permit applications. Some look forward to regular meetings, while others are satisfied with meeting on an ad-hoc, as needed basis.

Oshawa Power initiated communications via email with the following telecommunication entities: Rogers Communications, Bell, Telus, Durham Broadband, Durham OneNet, Zayo and TelMAX. The contacts for these companies attend the City of Oshawa's OMSCC meetings. The purpose was to gather information from these telecommunication entities on their plans for the next six (6) years (including ongoing projects) within the boundaries for the City of Oshawa.

None of the telecommunication entities communicated specific plans that would impact Oshawa Power's DSP. Oshawa Power will continue to reach out to try to engage these entities.

5.2.2.5 Transportation Authorities

Metrolinx provides transportation service to the community and residents of the City of Oshawa. As a major infrastructure owner within the service territory. Oshawa Power regularly engages with

Metrolinx to support the implementation of their projects. Oshawa Power initiated communications with Metrolinx to specifically understand any current or planned projects for the next six (6) years that may require Oshawa Power's participation.

Metrolinx Bowmanville GO Extension - Oshawa Power is currently working with Metrolinx on this project. As a complex project, the timeline extends from the present into 2028. Continued collaboration efforts are anticipated in relocating Oshawa Power assets to accommodate the extension project. Project scopes vary and specific details will be confirmed and made available closer to project execution. There are no anticipated rate impacts as Oshawa Power's asset relocations driven by Metrolinx are fully recovered.

Metrolinx Oshawa Bus Facility - Oshawa Power is also facilitating their electric bus pilots, which are being hosted in the Metrolinx Oshawa garage. Through its outreach, Oshawa Power learned that Metrolinx has a bus fleet electrification project planned for its Oshawa garage, and are interested in a potential cogeneration system at the same facility. Regarding the fleet electrification, Oshawa Power informed Metrolinx about the Grid Innovation Fund grant as an opportunity that may be to their interest / benefit. These are important projects that will require cooperation and collaboration to ensure they are appropriately connected and serviced by Oshawa Power's grid. Future meetings will be scheduled with Metrolinx as projects advances. At this time, no deliverables have resulted from preliminary discussions.

Durham Region Transit (DRT) has also initiated the transition of its bus fleet to electric propulsion technologies, beginning with upgrades at their existing Oshawa Depot. Oshawa Power is working closely with DRT to ensure the necessary electrical infrastructure is in place to support this transition.

In addition, DRT is in the early stages of planning a new net-zero bus depot in Oshawa as part of its broader decarbonization strategy. Oshawa Power is actively engaging with DRT through regular meetings to understand their evolving power requirements and support the development of this initiative. At this time, no deliverables have resulted from this preliminary discussion.

With respect to both transportation authorities, Oshawa Power is also seeking external investment via applying for grants from agencies that are interested in the intersection of grid infrastructure and expediting carbon reductions, such as Natural Resources Canada with their Smart Renewables Electrification Pathways program. Such external investment could reduce burden on Oshawa Power's rate payers, as well as transit riders and taxpayers who all contribute to transit's funding.

5.2.2.6 Regional Infrastructure Planning – Transmitter, IESO & Other Distributors

Oshawa Power regularly communicates with Hydro One as Hydro One Transformer Stations (TSs) supply the Oshawa Power distribution system. Regular communication enables and supports the health of the system and its assets. Beyond these immediate connection points, Oshawa Power is part of the GTA East planning area, which also includes Elexicon Energy (Elexicon) and Hydro One Distribution. Oshawa Power provided a load forecast for the next 10 years (2024-2033), information regarding Municipal/community Energy plans, load transfer capability or constraints, capability of Oshawa Power stations (as applicable) and known investment plans affecting regional planning over the next 10 years (2024-2033). This information supported a Needs Assessment Report completed for the third cycle of the Regional Infrastructure Planning (RIP), which is underway. The GTA East Needs Assessment Report is located in Appendix D.

Oshawa Power contacted Hydro One with a request for a Regional Planning Status letter. A copy of the Regional Planning Status – Oshawa PUC Networks Inc. Service Area letter is attached as Appendix D. There are no impacts on the DSP resulting from this engagement.

Oshawa Power also consults with the IESO for the GTA East Region Regional Planning process. For the current Needs Assessment, IESO contributed CDM and DG values. At the time of preparing this application, Oshawa Power along with Elexicon, and Hydro one (Distribution and Transmission) are collaborating with the IESO on the Scoping Assessment and Integrated Regional Resource Planning (IRRP) stage of the Regional Infrastructure Planning Process.

5.2.2.7 Renewable Energy Generation

Oshawa Power prepared and submitted a Renewable Energy Generation (REG) Investment Plan (Appendix F) to the IESO on October 2, 2024, and received a comment letter from the IESO (Appendix E) on October 16, 2024. REG investments are prioritized in the same manner as all other capital projects using the processes, risk assessments, and methods as described in Section 5.3. The IESO letter does not highlight significant impacts on the DSP resulting from normal growth in Distributed Energy Resources (DERs), and so no future potential investments related to DER connections are anticipated.

As mentioned in Section 5.2.2.6 above, and at the time of preparing this COS application, Oshawa Power along with Elexicon, and Hydro one (Distribution and Transmission) are collaborating with the IESO on the Scoping Assessment and Integrated Regional Resource Planning (IRRP) stage of

the third Regional Infrastructure Planning cycle. The outcomes of this process are yet to be determined. Oshawa Power is consistent with the Regional Infrastructure Plan issued February 2020 resulting from the second GTA East regional planning cycle in that there are no REG related investments proposed.

5.2.3 Performance Measurement for Continuous Improvement

5.2.3.1 Distribution System Plan

Oshawa Power continuously reviews the performance targets it is required to meet under the rules set out by the OEB. Specifically, Oshawa Power, monitors the performance indicators that it is required to report to the OEB as part of the OEB's Scorecard:

- Service Quality
- Customer Satisfaction
- Safety
- System Reliability
- Asset Management
- Cost Control
- Connection of Renewable Generation
- Financial Ratios

Oshawa Power continually reviews its performance over time for any positive or negative trends that may be revealed, while at the same time comparing its performance with that of other LDCs. This review is part of Oshawa Power's ongoing effort to continuously improve and address any negative trends identified.

A summary of Oshawa Power's Performance Measures over the historical period is presented in the table below, also available in Exhibit 1, section 1.7.

Table 2 - Oshawa Power Performance Measures over the historical period 2019 to 2023

Scorecard - Oshawa PUC Networks Inc. 8/16/2024

Performance Outcomes	Performance Categories	Measures		2019	2020	2021	2022	2023	Trend	Target Industry	Target Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		100.00%	100.00%	100.00%	98.86%	99.77%	↓	90.00%	
		Scheduled Appointments Met On Time		100.00%	100.00%	100.00%	100.00%	100.00%	→	90.00%	
		Telephone Calls Answered On Time		94.13%	92.03%	96.70%	96.47%	95.98%	↑	65.00%	
	Customer Satisfaction	First Contact Resolution		238	68	103	173	175			
		Billing Accuracy		99.91%	99.91%	99.90%	99.93%	99.95%	↑	98.00%	
		Customer Satisfaction Survey Results		95	94.04%	95.5%	92.5%	89.2%			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness		83.00%	83.00%	82.00%	82.00%	82.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C	→		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	0	→		0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000	→		0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		0.98	1.46	0.57	1.46	0.79	↓		1.42
		Average Number of Times that Power to a Customer is Interrupted [2]		1.09	1.50	0.70	1.04	0.80	↓		1.38
	Asset Management	Distribution System Plan Implementation Progress		99%	98.3%	95.6%	96.5%	118.5%			
	Cost Control	Efficiency Assessment		2	2	2	2	2			
		Total Cost per Customer [3]		$598	$578	$591	$638	$724			
		Total Cost per Km of Line [3]		$35,041	$34,172	$35,852	$16,183	$18,514			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Connection of Renewable Generation	New Micro-embedded Generation Facilities Connected On Time								90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.25	1.33	1.56	1.18	1.21			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.15	1.32	1.41	1.33	1.37			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.00%	9.00%	8.34%	8.34%	8.34%			
			Achieved	9.14%	5.33%	7.98%	8.96%	9.50%			

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

Legend: 5-year trend ↑ up ↓ down → flat; Current year: target met, target not met

As reported in the OEB Scorecard, Oshawa Power has met or exceeded target performance for all measures over the historical period and is committed to continuing this trend.

In the 2021-2025 Distribution System Plan, Oshawa Power set out to address key themes for continuous improvement. Even though objectives were not explicitly identified then in Section 5.2.1.a of the previous DSP, those themes have been drawn out as objectives and commented upon below in this DSP with the efforts highlighted in how these objectives were achieved. Oshawa Power has clearly articulated its continuous improvement objectives in Section 5.2.1.4 of this DSP.

Alleviating capacity constraints and the ability to connect new customers

This objective was achieved. Infrastructure expansions included a 44kV feeder extension from Hydro One's Enfield TS, west on Conlin Road and south on Thornton Road North, to support significant commercial and industrial growth in the Northwood business park area.

SCADA operated, motorized 44kV switches, and automated 13.8kV load break devices were deployed at strategic locations to improve the interconnectivity of feeders and stations. These enhancements allow for more flexible load transfers, help alleviate loading constraints, and reduce outage duration times.

Improve system reliability and mitigate customer outage impacts

This objective was achieved. Advanced FLISR technology was implemented, improving fault location and service restoration capabilities, along with a custom coding solution to address AMI-to-OMS false positives, optimizing outage management.

Additionally, to reduce outage risks caused by foreign interference, bollards were installed around pad-mounted transformers in areas prone to motor vehicle accidents (MVAs), and animal barriers were added at stations MS7 and MS15.

Invest prudently in System Renewal and maintenance

This objective was achieved. Invested approximately $29.7 million in system renewal initiatives during the 2021–2024 historical period, including major projects such as the MS2 switchgear replacement in 2023.

Programs for the replacement of aging infrastructure, including poles and porcelain insulators, were also continued to enhance system reliability and longevity by reducing risk while maintaining cost efficiency.

The 2025 forecast includes an additional $7.9 million in system renewal investments, covering projects such as the MS7 switchgear replacement, targeted overhead rebuilds, and end-of-life asset replacements identified through Oshawa Power's structured maintenance and inspection program.

Meet minimum OEB Cyber Security Framework maturity levels

This objective is projected to be achieved, pending 3rd party verification, by end of year 2025. Oshawa Power also continues to bolster its cyber security posture as the cybersecurity landscape evolves, following recommendations of established frameworks such as the OEB Cyber Security Framework and the US Department of Energy's Cybersecurity Capability Maturity Model (C2M2).

Establish new customer communication channels

This objective was achieved. A new customer portal was introduced to provide customers with access to detailed information about their electricity usage, bill payment options, outage notifications, and more. The portal is also integrated with the Green Button initiative, offering greater accessibility.

In addition, the implementation of a new in-house hosted CIS is underway, with completion expected by Q3 2025, aiming to improve overall service and reduce reliance on external vendors.

These initiatives, along with meeting the targets outlined in Oshawa Power's Scorecard, illustrate progress in key focus areas. Oshawa Power remains dedicated to building on these efforts to address evolving system and customer needs.

5.2.3.2 Service Quality and Reliability

The following subsections detail Oshawa Power's service quality and reliability performance over the historical period 2019 to 2023.

5.2.3.2.1 Service Quality

Oshawa Power tracks and reports on Service Quality requirements in accordance with Chapter 7 of the Distribution System Code. Table below summarizes Oshawa Power's service quality performance as it relates to Service Quality Requirements (SQR). Oshawa Power monitors its service quality parameters and reports on them in accordance with Chapter 7 of the OEB's Distribution System Code.

Table 3 - Oshawa Power SQI metrics for the Historical Period 2019 to 2023

Metric	2019	2020	2021	2022	2023	Target
Low Voltage Connections	100%	100%	100%	98.86%	99.77%	>90%
High Voltage Connections	N/A	N/A	100%	N/A	N/A	>90%
Telephone Accessibility	94.13%	92.03%	96.70%	96.47%	95.98%	>65%
Appointments Met	100%	100%	100%	100%	100%	>90%
Written Responses to Enquiries	100%	100%	97.71%	100%	100%	>80%
Emergency Urban Response	98.55%	100%	100%	98.08%	97.83%	>80%
Emergency Rural Response	100%	100%	90.00%	100%	100%	>80%
Telephone Call Abandon Rate	0.23%	0.52%	0.17%	0.82%	0.65%	<10%
Appointments Scheduling	92.51%	88.21%	81.14%	73.88%	90.16%	>90%
Rescheduling Missed Appointments	100%	100%	100%	100%	100%	100%
Reconnection Performance Standard	100%	100%	100%	100%	100%	>85%
Billing Accuracy	99.91%	99.91%	99.90%	99.93%	99.95%	>98%
Micro REG Facilities Connected on Time	N/A	N/A	N/A	N/A	N/A	>90%

Oshawa Power failed to meet the 90% target rate for "Appointments Scheduling" in 2020, 2021, and 2022. The sole reason for missing this target during these years was delays related to being able to schedule locates.

Oshawa Power outsources it's locate services to a third-party provider. However, due to their staffing constraints and a surge in demand, they were unable to meet the required volume of locate requests.

The increase in locate demand was largely driven by federal and provincial initiatives aimed at accelerating telecommunications growth. Key government initiatives contributing to this surge are outlined in the table below.

Table 4 - Key Government Initiatives

Act / Initiative	Federal / Provincial	Date effective
Universal Broadband Fund (UBF)	Federal	2020
Ontario Broadband and Cellular Action Plan	Provincial	2019
Accelerated High Speed Internet Program (AHSIP)	Provincial	2021
Bill 257 – Supporting Broadband and Infrastructure Expansion Act	Provincial	2021

This was not an issue unique to Oshawa Power. The widespread impact of locate delays across Ontario led the provincial government to introduce Bill 93 – *Getting Ontario Connected Act*. The bill aimed to address systemic issues such as lack of accountability, coordination challenges, and rising demand for locates.

By 2023, the implementation of Bill 93 improved metrics, with Oshawa Power exceeding its targets. However, meeting these stricter requirements came at a cost. Third-party providers had to increase staffing to avoid penalties, which led to higher locate expenses. This financial impact prompted many utilities to request a variance account to cover incremental locate costs not accounted for in base rates.

In response, the Ontario Energy Board (OEB) permitted rate-regulated electricity distributors to establish Account *1508 – Other Regulatory Assets, Sub-Account Getting Ontario Connected Act Variance Account*. This account captures the variance between actual locate costs incurred due to Bill 93 and the amounts included in approved base rates.

5.2.3.2.2 Reliability Performance

Oshawa Power's reliability of supply is measured using reliability indices defined in IEEE 1366-2022 and reported by the LDC as part of the OEB's Electricity Reporting & Record-Keeping Requirements. Specific indices used to measure performance are the System Average Interruption Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI). These two indices adequately describe the two primary components of reliability: frequency and duration of interruptions.

System Average Interruption Duration Index (SAIDI) - Designed to provide information about the average time a customer is interrupted, SAIDI represents the length of outage customers experience in the year on average, expressed as hours per customer.

$$\textbf{SAIDI} = \frac{\text{Total hours of Customer Interruptions}}{\text{Total number of Customers Served}}$$

System Average Interruption Frequency Index (SAIFI) - This index is designed to give information about the average frequency of sustained interruptions per customer over a predefined area, SAIFI represents the number of outages customers experience in the year on average.

$$\textbf{SAIFI} = \frac{\text{Total number of Customer Interruptions}}{\text{Total number of Customers Served}}$$

Oshawa Power maintains records for SAIDI and SAIFI, including and excluding Loss of Supply (LOS) and Major Event Days (MED). A LOS occurs when the Oshawa Power distribution system is ready to accept energy from a supplier, yet the supplier of the energy was not able to perform the service at the desired time. The term "Loss of Supply" therefore defines a situation where Oshawa Power's system is without power for a reason beyond the control of Oshawa Power, essentially being as a result of a Hydro One supply issue, as Hydro One is the sole supplier to Oshawa Power.

MEDs are calculated using the methodology in the IEEE standard 1366-2022. In accordance with OEB requirements, MEDs also require an assessment as to whether the major interruption was beyond the control of Oshawa Power and whether the interruption was unforeseeable, unpredictable, unpreventable or unavoidable.

During a MED event, all outages occurring on that calendar day are reported as MED outages, regardless of cause code. This practice reflects the reality that during a major event, all Oshawa Power's available resources are fully deployed in response to the major event, causing delays in corresponding coincidental outages that may be unrelated to the major event.

5.2.3.2.3 Historical Performance

Oshawa Power's reliability indices for the period 2019 to 2023 are provided in Table 5 and Table 6, with Figure 2 and Figure 3 illustrating Oshawa Power's 5-year SAIDI and SAIFI trends.

Table 5 - Historical Performance Oshawa Power – SAIDI

SAIDI	2019	2020	2021	2022	2023
Including Loss of Supply, Major Events	0.98	1.46	0.72	1.46	0.80
Excluding Loss of Supply, Including Major Events	0.98	1.46	0.57	1.45	0.79
Excluding Loss of Supply, Excluding Major Events	0.98	1.46	0.57	1.45	0.79

Table 6 - Historical Performance Oshawa Power – SAIFI

SAIFI	2019	2020	2021	2022	2023
Including Loss of Supply, Major Events	1.09	1.50	0.83	1.04	1.02
Excluding Loss of Supply, Including Major Events	1.09	1.50	0.66*	1.03	0.80
Excluding Loss of Supply, Excluding Major Events	1.09	1.50	0.66*	1.03	0.80

* SAIFI: Of note, the 2021 value on the scorecard was incorrectly reported as 0.70 due to a formula error and should have been 0.66.

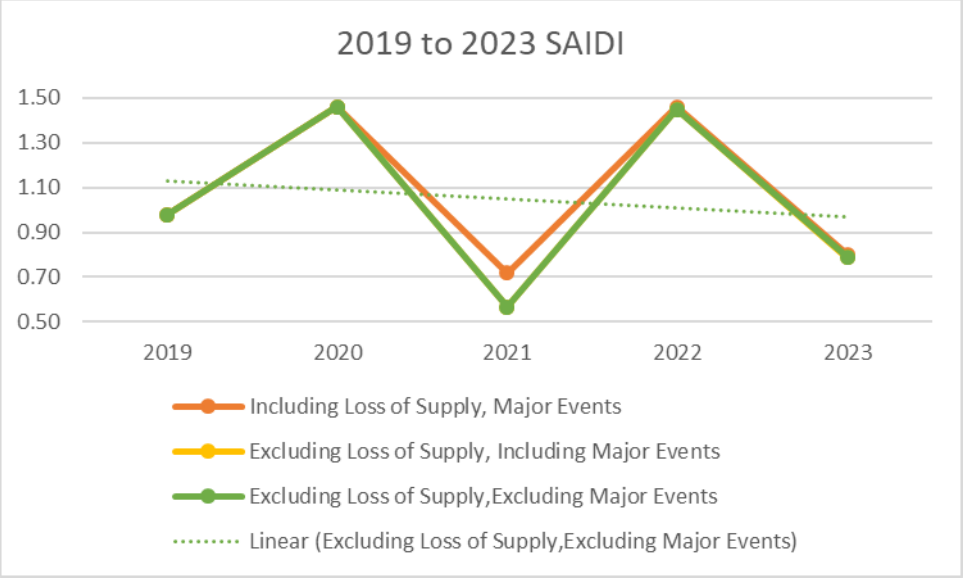


Figure 2 – 2019 to 2023 Oshawa Power SAIDI trends

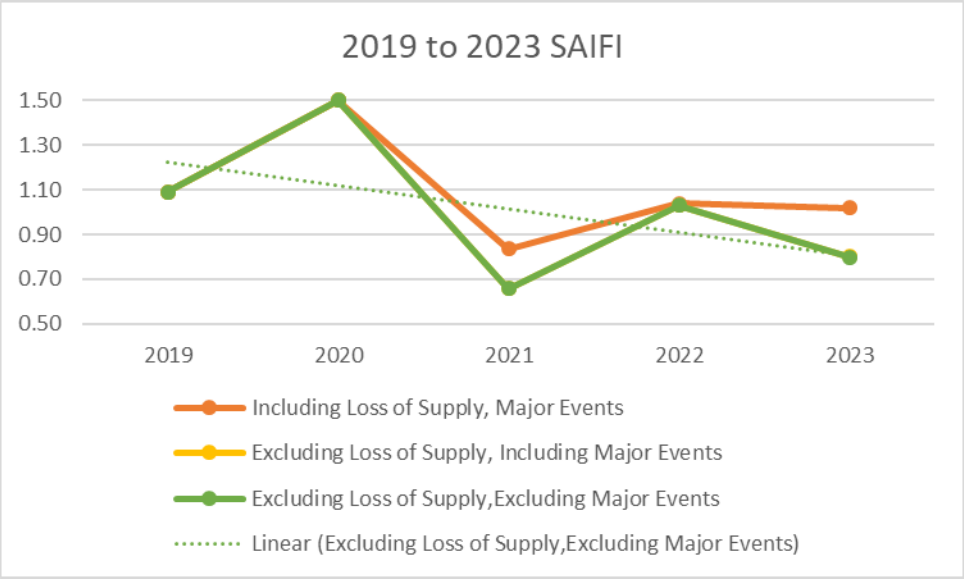


Figure 3 – 2019 to 2023 Oshawa Power SAIFI trends

The tables and figures show that outages within Oshawa Power's control (Adjusted for LOS and MED), outage duration and frequency are trending slightly downward over the most recent 5-year period.

5.2.3.2.4 Major Event Days

Oshawa Power experienced one major event during the 2019 to 2023 period (based on the chart produced by Oshawa Power staff which is presented below). The Loss of Supply event at Thornton Transformer Station occurred in 2021.

Oshawa Power provided the following event description to the OEB as a Major Events submission.

> The Hydro One Thornton Transformer station is supplied by two 230 kV circuits, T24C & T26C respectively. On May 26th, 2021, the T26C 230 kV circuit was out of service for planned insulator replacement work. At 22:09, Hydro One's T24C 230 kV circuit was automatically removed from service, initiated from a customer equipment protection trip. This resulted in a complete loss of supply to the Thornton Transformer Station from the transmission grid and with that, two Oshawa Power stations (MS5 & MS11) completely lost their 44kV supply resulting in 10,554 customers being affected by this outage.
>
> All Hydro One's high voltage 230kV customers were contacted by the Ontario Grid Control Centre and requested to isolate from the grid. Once those customers confirmed they were isolated from the grid, T24C was re-energized (with no load) from the Clarington Transformer Station at 23:16. Load restoration then commenced in stages: Thornton Transformer Station energized at 23:28, Oshawa General Motors station at 23:31, and

Whitby Transformer station at 23:36. Also at 23:36, all the other customer loads were in the process of being restored.

Table 7 - Major Event Days

Code	Cause of Interruption	2019	2020	2021	2022	2023
Number of Interruptions						
2	Loss of Supply			1		
Number of Customer Interruptions						
2	Loss of Supply			10554		
Number of Customer Hour Interruptions						
2	Loss of Supply			9079		

5.2.3.2.5 Customer Interruptions

Customer interruption graphs were created using the historical interruption data and can be found in the table below.

Table 8 - Historical Interruptions

Interruptions	2019	2020	2021	2022	2023	Total of Row	% of Total
Number of Interruptions							
0 - Unknown/Other	17	9	11	7	11	55	1.72%
1 - Scheduled Outage	485	427	731	378	470	2491	78.06%
2 - Loss of Supply	0	0	1	1	1	3	0.09%
3 - Tree Contacts	9	7	11	6	15	48	1.50%
4 - Lightning	1	5	1	2	6	15	0.47%
5 - Defective Equipment	56	71	42	57	58	284	8.90%
6 - Adverse Weather	2	19	5	3	5	34	1.07%
7 - Adverse Environment	6	0	0	0	0	6	0.19%
8 - Human Element	4	9	2	0	2	17	0.53%
9 - Foreign Interference	59	58	47	33	41	238	7.46%
						3191	100%
Number of Customer Interruptions							
0 - Unknown/Other	1316	8492	6523	2044	3066	21441	6.49%
1 - Scheduled Outage	4586	8187	7603	3338	5452	29166	8.83%
2 - Loss of Supply	0	0	10554	5	13514	24073	7.29%
3 - Tree Contacts	3365	670	1146	1895	8439	15515	4.70%

Interruptions	2019	2020	2021	2022	2023	Total of Row	% of Total
4 - Lightning	172	5232	8	2409	12121	19942	6.04%
5 - Defective Equipment	22052	17280	3263	26541	8793	77929	23.58%
6 - Adverse Weather	99	2500	922	17530	671	21722	6.57%
7 - Adverse Environment	2314	0	0	0	0	2314	0.70%
8 - Human Element	14695	14559	6887	0	26	36167	10.95%
9 - Foreign Interference	15906	32597	13213	9425	11028	82169	24.87%
						330438	100%
Number of Customer Hours of Interruptions							
0 - Unknown/Other	568	3317	4982	1562	2354	12784	3.91%
1 - Scheduled Outage	5212	8784	5494	3433	6391	29315	8.97%
2 - Loss of Supply	0	0	9079	0	968	10047	3.08%
3 - Tree Contacts	7174	473	1449	2543	8589	20227	6.19%
4 - Lightning	487	1975	9	1325	11914	15711	4.81%
5 - Defective Equipment	17773	23882	5010	10167	9269	66102	20.24%
6 - Adverse Weather	225	11741	1774	62908	130	76778	23.50%
7 - Adverse Environment	3079	0	0	0	0	3079	0.94%
8 - Human Element	4682	10688	793	0	12	16175	4.95%
9 - Foreign Interference	19046	26001	14564	6835	9987	76433	23.40%
						326649	100%

Figure 4 represents the summation of Interruptions at Oshawa Power over the historical 5-year period. The top three causes of interruptions are Scheduled Outages (78.06%), Defective Equipment (8.90%) and Foreign Interference (7.46%).

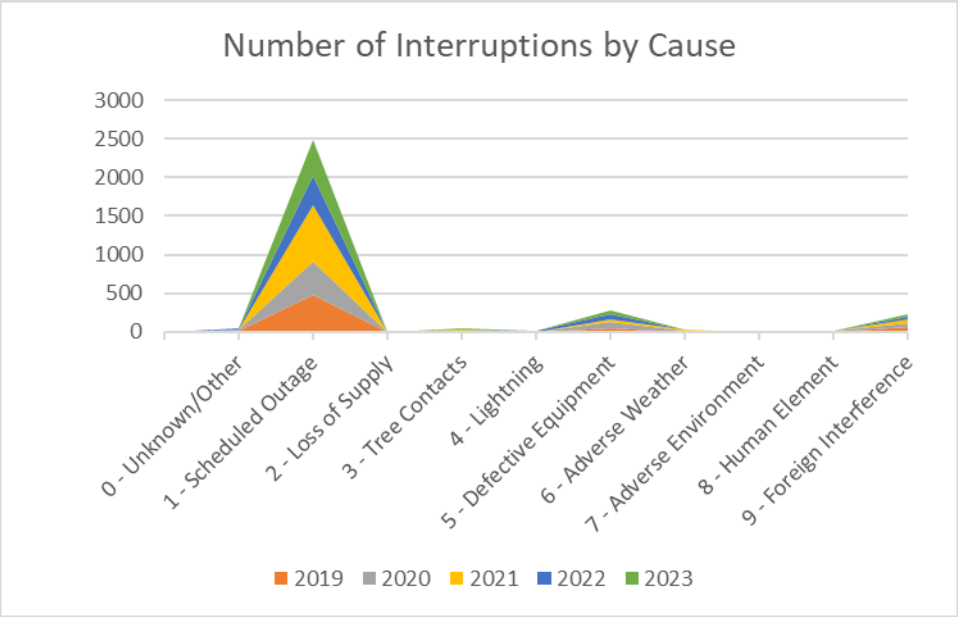


Figure 4 – Cumulative Number of Interruptions by Cause over the 5-year Historical Period 2019 to 2023

Figure 5 represents the summation of Customer Interruptions at Oshawa Power over the historical 5-year period. The top three causes of interruptions are Foreign Interference (24.87%), Defective Equipment (23.58%) and Human Element (10.95%).

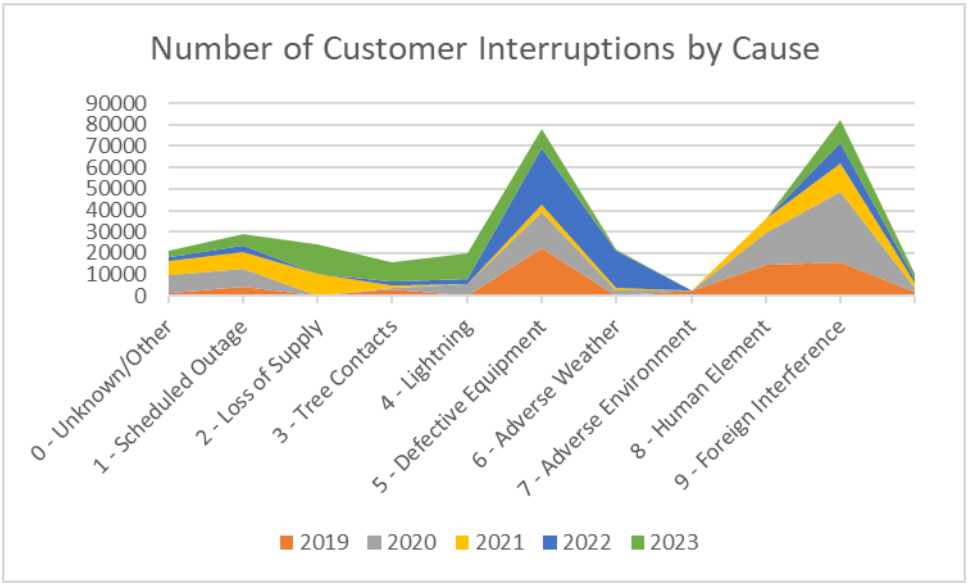


Figure 5 – Cumulative Number of Customer Interruptions by Cause over the 5-year Historic Period 2019 to 2023

Figure 6 represents the summation of Customer-Hours of Interruptions at Oshawa Power over the historical 5-year period. The top three causes of interruptions are Adverse Weather (23.50%), Foreign Interference (23.40%) and Defective Equipment (20.24%).

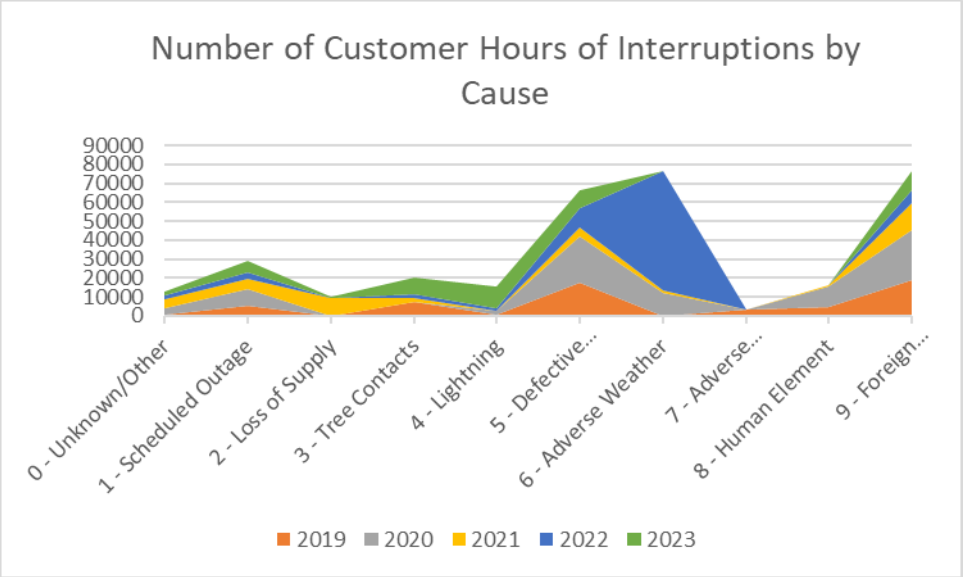


Figure 6 – Cumulative Customer-Hours of Interruptions by Cause over the 5-year Historical Period 2019 to 2023

Scheduled Outages: This is the main source of interruptions that is within Oshawa Power's control. Although it accounts for the largest number of interruptions at 78%, it only accounts for 8.97% of the Customer-Hours of Interruption. Scheduled Outages are the main source of outages for Customers for two reasons:

(i) Because Oshawa Power maintains rigorous safety procedures with respect to worker safety as it relates to the type of work being performed. The Occupational Health and Safety Act requires that an Employer do "Everything reasonable in the circumstances for the safety of the worker". Even though some work may be done on the asset / equipment while it remains energized, it is Oshawa Power's position that the work can be completed both safer and faster with the asset being isolated from sources of power, and

(ii) The Infrastructure Health and Safety Association (IHSA) continues to emphasize the need for Management to create a work environment that targets zero Lost-Time Injuries (LTIs). The safety culture at Oshawa Power is aligned with the IHSA emphasis and as such supervisors and workers perform Hazard Analysis and Job Planning which includes the appropriate use of scheduled outages when possible to minimize safety risk

Defective Equipment: Represents the second largest number of interruptions (8.90%), the second largest number of Customer-Interruptions (23.58%) and the third largest number of Customer-Hours of Interruptions (20.24%). This result should not be totally unexpected as current "Good Utility Practice" utilizes a run to failure approach for many asset classes such as distribution transformers, secondary conductors (both overhead and underground), splices, overhead conductor and insulators. Nonetheless this category has been trending downward over the past 5 years, in all three interruption categories, indicating that the Asset Management strategy adopted by Oshawa Power is having a positive impact on end-of-life assets. It is also common practice to replace near end-of-life assets such as primary and secondary conductors, insulators and distribution transformers during line rebuilds triggered by end-of-life poles from an efficiency aspect. The use of new assets and rebuilding to the latest design standards also minimizes outages to customers once the rebuild has been completed

Adverse Weather: Although the Number of Adverse Weather Interruptions has trended downward over the past 5 years, both the Number of Customer Interruptions and the Number of Customer-Hours of Interruption have trended upward; indicating that infrequent Adverse Weather events are becoming more severe and impacting more customers. Oshawa Power continues to monitor developments in distribution system design hardening and climate change through its membership in the Electrical Distributors Association and other trade organizations and considers adjustments to its practices as it deems appropriate.

Foreign Interference: Represents the third largest number of interruptions (7.46%), the largest number of Customer-Interruptions (24.87%) and the second largest number of Customer-Hours of Interruptions (23.40%). Regardless of these values, Foreign Interference has trended downward over the past 5 years.

The decline in interruptions due to foreign interference, contributing to improved system reliability can be attributed to several targeted measures:

i. Strategic installations of bollards around pad-mounted transformers in areas prone to MVAs have significantly reduced physical damage incidents.
ii. Animal contact prevention at MS7 and MS15 stations, while being historically high contributors to foreign interference, have been effectively mitigated through targeted initiatives. At MS7, the installation of animal fences eliminated the issue, while at MS15, raccoon access was resolved by equipping a wooden pole with a metal sheet to prevent climbing. Additionally, animal fences have been installed at all station locations with outdoor switchgears to provide broader protection against such interference.

The porcelain insulator replacement program has also played a crucial role in improving system reliability. Porcelain insulators have been in service for decades. Over this time, porcelain insulators deteriorate as they age which results in them becoming brittle and breaking or separating unexpectedly (in multiple piece insulator), and becoming contaminated to the point where they begin electrically tracking and eventually causing pole fires during certain weather conditions. Shorter porcelain insulators are replaced with longer polymeric insulators offering greater electrical clearances. They are also a stable structure, and exhibit hydrophobic properties that allow them to self-clean during rainfall. In areas more prone to animal contact, the installation of these longer insulators has provided additional protection. Their stable structure means that they will not come apart unexpectedly for public and worker safety, as well as mitigating pole fires by reducing tracking because of the insulator's hydrophobicity.

Collectively, these measures have significantly enhanced overall system robustness

5.2.3.3 Distributor Specific Reliability Targets

Oshawa Power does not have distributor specific reliability targets and uses the fixed performance target set out in the Scorecard for SAIDI and SAIFI based on its historical average performance, excluding LOS and Major Events.

5.2.3.4 Summary of Effects of Historical Service Quality Indicators and Reliability on the DSP

Service Quality

Oshawa Power has currently met or exceeded all the OEB defined metrics for service quality as reflected in the OEB Scorecard (Table 2); however, Oshawa Power did not meet all targets in the OEB Distribution System Code (DSC) SQI's (Table 3). The explanation as to why Oshawa Power did not meet the DSC SQI target for Scheduling Appointments is found in Section 5.2.3.2.1 - Service Quality. Since the metric for Scheduling Appointments has been resolved and Oshawa Power has met or exceeded all other targets, there are no direct impacts to this DSP.

Customer Satisfaction

Customer engagement data shows that customers understand the importance of reliability and outage prevention and management (see Section, 5.2.2 Coordinated Planning with Third Parties,

and Attachments 1-11 and 1-12 in Exhibit 1). Majority of Oshawa Power's customers agreed with the proposed investments targeted at maintaining ongoing system reliability. 88% agreed with Oshawa Power's distribution automation and remote monitoring and control investments to maintain a reliable system and decrease outage response times. 94% agreed with the targeted system renewal efforts necessary for the safety and reliability of the distribution system.

Oshawa Power was able to establish a downward trend for SAIDI (Figure 2) and SAIFI (Figure 3) during the historical period, while maintaining financial performance. Oshawa Power's 2026-2030 DSP is aligned with customer needs and aimed at continuing to maintain historical reliability trends.

Safety

Oshawa Power has currently met or exceeded all the OEB defined metrics for monitoring the safety of its employees and the public as reflected in the OEB Scorecard (Table 2). Oshawa Power strives to promote safety at work and at home. The DSP continues to consider safety at the forefront of Oshawa Power's planning process guided by its Strategic Asset Management Plan and prioritizes projects and programs posing any safety risks with the intention of achieving comparable results over the 2026-2030 forecast period.

System Reliability

Oshawa Power has been able to establish a downward trend for SAIDI (Figure 2) and SAIFI (Figure 3) during the historical period.

Oshawa Power attributes this outcome to its commitment to continuously monitor reliability and identifying areas for improvement. Oshawa Power's implementation of advanced FLISR technology to improve fault location and service restoration capabilities and targeted efforts in deploying automation devices, replacing porcelain insulators, installing animal protection devices, and replacing assets at end of useful life significantly contribute to the overall reliability of the system. The 2026-2030 DSP continues to emphasize maintaining high reliability standards through guided investments under system renewal and system service.

Asset Management

Oshawa Power uses the following metric to monitor progress in implementation of the OEB approved Distribution System Plan filed in 2020 for rates effective January 1, 2021:

Implementation of DSP = Actual total capital expenditures for a given calendar year / Planned total capital expenditure for a given calendar year

Oshawa Power aims to execute its projects and program with a high degree of control as evident in the scorecard (Table 2), while acknowledging its statutory obligations to provide means to connect new customers or upgrade their service through non-discretionary system access investments. Should System Access expenditure exceed the planned expenditure, Oshawa Power must prioritize it over other the investment categories (System Renewal, System Service and General Plant) in order to meet Financial Performance requirements. This is facilitated by Oshawa Power's Asset Management System inclusive of the Strategic Asset Management Plan. The 2026-2030 DSP is formed with the above factors in consideration.

Cost Control

Oshawa Power is ranked in Cohort 2 as a distributor with actual costs between 10% and 25% lower than predicted costs. Oshawa Power's goal is to sustain current efficiencies, and remain a cost-effective utility. The 2026-2030 DSP is prepared with this goal in mind with stringent maintenance and inspection efforts to avoid premature asset failure, targeted system renewal investments to proactively addressing failing assets, and strategically paced system service investments to improve response times and reduce outage durations.

Public Policy Responsiveness

Oshawa Power will continue to support public policy initiatives put forward by the OEB or the Government of the day. In its planning process, Oshawa Power ensures proper visibility is maintained to proactively identify system constraints to allow DER penetration, EV adoption, and other efforts towards electrification. Oshawa Power will continue supporting policy initiatives, as demonstrated in this DSP through the integration of Non-Wire Solution (NWS) considerations within its system planning process.

Financial Ratios

Oshawa Power has currently met or exceeded all the OEB defined financial performance metrics as reflected in the OEB Scorecard (Table 2). Financial metrics are partially influenced by consistent capital investment execution as per Oshawa Power's 2021-2025 DSP filed with the OEB. Oshawa Power aims to continue monitoring and executing the capital plan as proposed in this 2026-2030 DSP.

5.3 Asset Management Process

This section describes in detail Oshawa Power's Asset Management (AM) process and the direct links between the process and expenditures that comprise the capital investment plan covered by this DSP.

The AM process is guided by Oshawa Power's Strategic Asset Management Plan (SAMP) through the Oshawa Power Asset Management System (AMS).

The SAMP outlines Oshawa Power's approach to managing its assets effectively and efficiently to achieve its Asset Management objectives. The plan provides a framework for decision-making related to asset planning, acquisition, operation, maintenance, renewal and disposal. By following this plan, Oshawa Power aims to optimize the performance, reliability, and sustainability of its assets, while ensuring cost-effectiveness and compliance with regulatory requirements.

Oshawa Power's asset management objectives are aligned with its vision, mission and operational themes.



Figure 7 – Oshawa Power Operational Themes

Oshawa Power's Corporate and AM objectives ensure that the four OEB RRFE performance outcomes continue to be achieved in the forecast period. Oshawa Power's operational themes, asset management objectives, along with measures and targets, are found in the table below.

Table 9 - Asset Management Objectives

RRFE Outcome	Operational Theme	Asset Management Objectives	AM Objective Measures	AM Objective Targets
Operational Effectiveness	Safety	Ensure proper installation, operation, inspection & maintenance activities are established and followed to maintain the highest level of safety	Workplace injuries / incidents; Public safety; Safety Training	No Loss Time (Zero injuries)
				No Serious Electrical Incidents (ESA Public safety)
				Implement safety training programs and improve safety protocols
Operational Effectiveness	Reliability	Strategically plan, design, build, operate & maintain Oshawa power's system to meet and exceed reliability targets	SAIDI, SAIFI	Maintain SAIDI / SAIFI at or below a fixed five-year historical average updated every 5 years
				Target critical assets prone to unplanned downtime
				Inspection / Proactive maintenance
Customer Focus	Customer Focus	Enhance transparency and facilitate customer feedback and engagement to ensure needs and issues are addressed proactively.	Customer Satisfaction; Social Media engagement.	Accuracy in Billing
				Customer surveys
				Educate / Enable transparency - Website, social media (X, Facebook, Instagram, LinkedIn)
				DSP consultations
Financial Performance	Stewardship	Ensure financial, regulatory, and environmental	Regulatory / Environmental	Ensure all regulatory & environmental risks are mitigated.

RRFE Outcome	Operational Theme	Asset Management Objectives	AM Objective Measures	AM Objective Targets
		stewardship is upheld for all stakeholders	restrictions; Revenue Losses	Minimize revenue losses by strategic investments & maintain high level of reliability
Public Policy Responsive-ness	Innovation	Employ creative means, technological and otherwise, to create value through both evolutionary and revolutionary continuous improvement efforts, striving toward operational excellence.	Various continuous improvement measures	Increased Grid Automation
				Increased Process Automation
				Improved Operational efficiency
				Consideration of non-wires solutions

The SAMP applies to all assets owned and operated by Oshawa Power, including distribution lines (overhead and underground), stations, and other infrastructure. The plan ensures that asset management practices are sustainable, cost-effective and socially responsible – guiding principles for making informed decisions to achieve strategic objectives.

The Asset Management System (AMS) is designed to support Oshawa Power's goal of empowering customers through effective and efficient asset management.

The Asset Management System encompasses several key components that guide the company's asset management practices:

- Asset Management Policy
- Asset Management Objectives
- Asset Management Process
- Asset Management Strategies
- Asset Information

5.3.1 Planning Process

The planning process is directed through the Oshawa Power Asset Management Process.

Oshawa Power's Asset Management planning process begins with identifying the needs based on inputs and drivers that can be either internal, external, or driven by strategic investments to meet

the objectives outlined above. Information collected from these investment drivers will determine the initial investments portfolio and are then classified into four categories, as defined in OEB's Chapter 5 filing requirements, namely – System Access, System Renewal, System Service and General Plant.

Available technical alternatives to meet desired outcomes are considered and developed, which can range from "do nothing" to proceeding with a different solution to address identified needs. An example of this consideration could be run to failure versus repairing versus replacement. Where applicable and viable, Oshawa Power also considers Non-Wire Solutions (NWS) to complement or defer traditional infrastructure investments. Considerations are governed by Oshawa Power's Asset Management Strategy, and assets are managed through their entire lifecycle that includes planning, acquisition, operation, maintenance and disposal. Where needs are mandatory, such as in System Access projects, alternatives are not considered, except for the timing of implementation.

The planning process is further described in the following section.

5.3.1.1 Process

The planning process identifies, selects, prioritizes, optimizes and paces investments to ensure asset management needs are met, while ensuring that customer value is maintained.

The planning process is reflected in Figure 8.

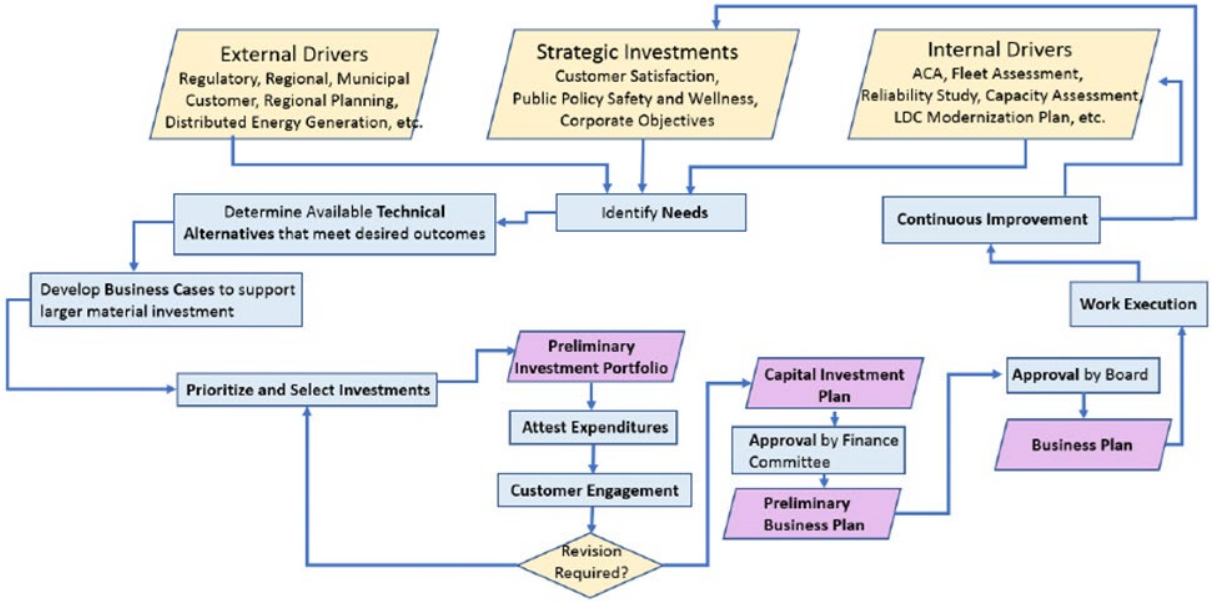


Figure 8 – Asset Management Process

Investment needs are initially identified through several drivers:

- *Internal drivers*
- *External drivers*
- *Strategic investments*

Needs Assessment Phase

Internal drivers

Oshawa Power evaluates the needs of its distribution system through a combination of proactive assessments, operational performance monitoring, and strategic planning activities. These internal drivers are foundational to identifying areas of investment need, which are later shaped into comprehensive projects and programs through a planning process that considers optimization, alignment with customer expectations, risk evaluation, and prioritization.

One of the key mechanisms used to identify asset needs is the continuous monitoring of reliability trends and system performance to pinpoint areas contributing to operational stress. Insights from these reviews are supplemented with prudent maintenance and inspection activities, which generate valuable field data and condition observations. This data is compiled and organized into a comprehensive Asset Condition Assessment (ACA), which, along with other internal evaluations such as system planning studies and operational reviews, informs investment planning for the upcoming 2026-2030 planning period.

Asset Needs **-** As described in Section 5.3.2.3 and detailed further in Appendix C, Oshawa Power developed a robust Asset Condition Assessment (ACA) to evaluate the condition of its in-service assets. This assessment utilized a variety of inputs, including historical loading information, substation and distribution inspection reports, and expert insights from field staff, to assign Health Indices to each asset type. These indices quantify the probability of asset failure based on asset-specific condition criteria.

In parallel, the impact of asset failure was also assessed to quantify overall risk — incorporating both the likelihood and consequence of failure. Assets identified as exceeding Oshawa Power's acceptable risk tolerance were flagged as candidates for renewal within the 2026–2030 planning period. These needs are not automatically advanced as projects but are considered as part of the broader system renewal planning process. The ACA serves as a critical input to Oshawa Power's System Renewal program and supports data-driven prioritization of investments.

Tools, Technology, and IT Requirements - To uphold its high standards of safety, reliability, and stewardship, Oshawa Power recognizes the need to ensure its workforce is equipped with the appropriate tools and technology. Investments in tools include a range of operational assets from personal protective equipment (PPE) and specialized installation tools for distribution hardware, to advanced software and IT platforms that enhance safety, efficiency, and productivity.

This DSP reflects these operational needs through General Plant investment allocations, identifying key areas where updated or new tools and technologies are required. These investment needs are evaluated in accordance with the same prioritization principles applied to other asset categories, ensuring that decisions are aligned with performance objectives and resource constraints.

Fleet and Facility Needs - Oshawa Power also conducts ongoing assessments of its vehicle fleet and operational facilities to ensure they are capable of supporting safe, efficient, and reliable service delivery. Fleet requirements are evaluated based on usage data, asset condition, and operational costs, helping to identify where investments are to be focused. Similarly, facility needs are assessed based on capacity limitations, safety compliance, and operational efficiency, particularly in light of changing work practices. Like other internal drivers, these evaluations serve to highlight gaps and opportunities, ensuring that all asset categories are reviewed systematically and consistently.

External drives

In addition to internal assessments, Oshawa Power's asset management process is significantly informed by a variety of external drivers. These include system loading demands, evolving customer needs, coordination with municipal and regional entities, and compliance with applicable regulatory obligations. These drivers help identify system needs which, once assessed through the broader planning framework, inform the development of strategic investments.

System Loading Demands - As the licensed electricity distributor serving the City of Oshawa, Oshawa Power is committed to meeting its statutory obligations and ensuring safe, reliable, and efficient power delivery across its service territory. To do so, it undertakes load planning at multiple levels:

- Individual Customer Connections - Oshawa Power allocates timely design and system access investments to connect new customers or upgrade existing services. These are managed in accordance with the Distribution System Code (DSC) timelines, ensuring compliance with customer connection standards.

- Localized Areas of Growth: Residential subdivision developments and commercial expansions are supported through capital investments in infrastructure expansions, enabling timely electrification of new communities.
- Strategic Large-Scale Development: Oshawa Power collaborates with customers / developers anticipating future needs such as the Columbus Development Group to coordinate large-scale expansions and phased enhancements that serve multiple future customers.
- System-Wide Growth: Broader demand growth is addressed through proactive engagement with a wide range of stakeholders, including residential and commercial customers, institutional users, transportation authorities, and developers. These engagements are summarized in Section 5.2.2 and inform load forecasting efforts.

Oshawa Power's forecasting methodology aligns with the Ontario Energy Board's Load Forecast Guideline (November 2, 2022). Forecasts incorporate customer input, community energy plans, and relevant electrification policies. The resulting demand profiles are communicated to Hydro One and the IESO and aligned with neighboring Local Distribution Companies (LDCs) through the regional planning process to ensure a coordinated approach to regional system capacity planning.

Customer Needs **-** Beyond forecasting demand, Oshawa Power also engages with customers to better understand their broader service expectations and to be transparent about its upcoming investments. These engagement efforts, outlined in Section 5.2.2 and detailed in Attachments 1-11 and 1-12 of Exhibit 1, provide insight into the evolving needs of various customer classes.

- Residential and Small Commercial Customers - Key themes from engagement include:
  - A desire for improved communication and accessibility,
  - Cost sensitivity, balanced with high expectations for system reliability and outage response, and
  - General alignment of customer priorities with Oshawa Power's business objectives and approach.

In response, the DSP includes targeted investments in customer-facing systems such as CIS enhancements, CRM platforms, website upgrades, and communication improvements. These initiatives support service quality and engagement while maintaining a continued focus on reliability through gradual, well-paced system renewal and service improvements.

- Business and Key Account Customers - Engagement with business and large commercial customers revealed an emerging interest in adopting energy transition technologies over the next five years:
    - 28% are considering electric vehicle adoption
    - 9% are considering heat pump technologies
    - 18% are exploring solar panel installations
    - 21% are evaluating battery energy storage solutions

These insights highlighted opportunities for collaboration on Distributed Energy Resources (DERs) and other Non-Wires Solutions (NWS). Oshawa Power has incorporated this feedback into its NWS evaluation framework, as detailed in the NWS Business Case (Appendix A).

- Municipal and Regional Governments - Municipal coordination plays a critical role in planning system investments. Ongoing collaboration with the City of Oshawa and the Region of Durham has identified hydro infrastructure impacts related to road widening, and other infrastructure initiatives. These findings have informed the prioritization of System Access investments within this DSP to ensure alignment with municipal timelines and improve overall project efficiency.
- Telecommunication Entities – Engagement with telecommunication entities can reveal both broader system planning considerations and localized coordination requirements tied to specific infrastructure projects. Given Oshawa's urban environment and the presence of well-established telecommunications networks, Oshawa Power's coordination efforts did not reveal large-scale, system-wide initiatives planned by these entities and this is reflected in this DSP as such.

Regulatory Drivers - As a regulated utility, Oshawa Power incorporates external requirements arising from federal and provincial regulations into its investment planning. Examples include:

- Metering Obligations: Investments in meter replacement and reverification are guided by Measurement Canada requirements to ensure accuracy in billing and compliance with metering standards.
- Cost Recovery and Customer Impact: The December 23, 2024 amendment to the OEB's Distribution System Code, extending the revenue horizon for residential connections to 40 years, has shifted the cost responsibility for certain projects from the customer to the LDC. This regulatory change has directly influenced project justification and investment planning within the System Access category.

Strategic Investment Needs

Oshawa Power also identifies system needs through strategic initiatives aimed at transforming how it plans, operates, and manages its distribution network. Two notable areas where Oshawa Power has identified such needs are in business transformation through digitization and grid modernization through automation.

Business Transformation – Digitization

Oshawa Power has identified the need to invest in digital systems that enhance operational efficiency by improving data visibility, streamlining workflows, and strengthening coordination across departments.

Some initiatives in this DSP, arising from these needs and guided by Oshawa Power's asset management process are GIS and CIS enhancements, cybersecurity enhancements, ERP replacement, and implementation of new asset management software.

Grid Modernization – Automation

Oshawa Power has also identified system needs related to the modernization of its grid through automation to enhance system flexibility, reduce outage durations, and improve response times.

Some initiatives in this DSP, arising from these needs and guided by Oshawa Power's asset management process are Deployment of overhead self-healing switches and SCADA equipment upgrades.

Capital Investment Planning and Categorization Phase

Identified investment needs are classified into four categories, as defined in OEB's Chapter 5 filing requirements: System Access, System Renewal, System Service and General Plant.

Determine Available Technical Alternatives

This DSP demonstrates evaluation of the risks associated with proceeding or not proceeding with capital expenditures by assessing identified needs against available technical alternatives that may achieve the intended outcomes more efficiently or effectively. In developing alternatives, several considerations are taken into account. These considerations include: Oshawa Power's AM objectives, strategies, costs, bill impacts (rate mitigation), resource availability and financial stability.

Available technical alternatives to meet desired outcomes are considered and developed, which can range from "do nothing" to proceeding with a different solution to address identified needs. An example of this consideration could be run to failure versus repairing versus replacement.

Oshawa Power's Asset Management System governs this process. Inputs such as the Options Analysis Report (Appendix C) play a critical role in evaluating risk and determining optimal intervention timing. The analysis was conducted to assess the operational, capital, and risk-related lifecycle costs of Oshawa Power's critical assets, such as station transformers and switchgear. It supports informed decision-making by identifying the most appropriate timing for asset replacement or refurbishment based on a balanced evaluation of cost and reliability considerations.

Where applicable and viable, Oshawa Power also considers Non-Wire Solutions (NWS) to complement or defer traditional infrastructure investments. Per section 3.1 of the NWS Guidelines, Oshawa Power conducts a pre-analysis of the needs being considered using a binary analysis lens, to determine if they qualify for alternative solutions and therefore require a benefit cost analysis (BCA). Oshawa Power either proceeds with the BCA to evaluate financial feasibility of the alternative solution or documents the rationale for infrastructure investment decisions where NWS were not considered/a Benefit-Cost Analysis (BCA) was not done.

Develop Business Cases

Business Cases are then prepared to support investments that either substantially exceed Oshawa Power's materiality threshold (e.g., ERP System) or where additional contextual detail provides valuable justification for the proposed investment (e.g., NWS).

Prioritize and Select Investments

Investments are selected and prioritized to create a preliminary investment portfolio for the investment period.

The Project Prioritization methodology allows Oshawa Power to compare and rank projects in different business units within the LDC, e.g., overhead, underground, stations, IT etc., as well as, across different investment categories, e.g., system renewal, system service etc. Recognizing the non-discretionary nature of System Access investments, Oshawa Power includes them based on the scheduled need to meet its statutory and regulatory obligations and comply with conditions of licensure.

Weights have been assigned to each Oshawa Power operational theme in accordance with the impact on the overall strategic objectives, and assigned a measure to assess the impact on each value. The operational themes weightings and measures are in the table below:

Table 10 – Impact Matrix

Operational theme	Weighting	Measures
Safety	30%	Impact of Injury to public, including customers and employees
Reliability	20%	Impact to SAIFI/SAIDI
Customer Focus	20%	Impact to number and criticality of customers affected
Stewardship	20%	Environmental (e.g., oil leaks), financial (e.g., cash flow) and regulatory (e.g., OEB scorecard) impacts
Innovation	10%	Positive Impact on other Operational themes

Measuring of risk to each operational theme has two factors associated with it:

1) the likelihood (i.e., probability) of a consequence
2) measure of consequence (i.e., impact) occurring if the project being considered is not done

As such, Oshawa Power uses a 5 x 5 Risk Matrix, that quantifies the likelihood of a consequence and consequences from low to high, as tabulated below. The use of a quantified risk matrix allows Oshawa Power to compare projects based on relative risk scores.

Table 11 - Oshawa Power Risk Matrix

Likelihood / Impact	Low	Medium-Low	Medium	High-Medium	High
Very Likely (>95%)	9	24	67	181	491
Likely (65 to 95%)	7	19	52	141	382
Somewhat Likely (25 to 65%)	5	14	37	100	273
Unlikely (5 to 25%)	2	5	15	40	109
Remote (<5%)	1	3	7	20	55

Note: For all operational themes, except innovation, the combination of Likelihood and Consequence that makes the risk score equal to any number shown in red text above makes the project a critical project.

Based on a combination of the Risk Matrix and the Impact Matrix, which provides guidance on quantifying the operational theme measures, Oshawa Power then calculates the Total Risk Score (TRS) for the investment.

Prioritizing then proceeds through the following steps:

- Calculate TRS for the do-nothing scenario

- Calculate TRS if project under consideration is implemented
- Calculate the difference in the TRS from steps 1 and 2 (TRS)
- Calculate the Cost of Risk Factor (CRRF) for the project

The Cost of Risk Factor is calculated by the following formulation:

CRRF = Project Cost / difference between step 1 and 2 TRS

Once the CRRFs for similarly costing projects are calculated, they can then be prioritized – the project receiving the lowest CRRF score is prioritized the highest, since a low CRRF score indicates that maximum risk is alleviated for the minimum cost.

An example of a project scored for impact and risk is provided in Figure 9.

PROJECT PRIORITIZATION FORM

Investment Category	System Renewal
Grouping	Overhead Asset Renewal
Subcategory	Pole Remediation
Project Number	
Project Name	Pole Replacement Program
Description	
Cost	$2,374,750.00

OT		Before				After			
		Likelihood	Consequence	Risk Value	Risk Score	Likelihood	Consequence	Risk Value	Risk Score
Safety	30%	Very Likely (>95%)	High	491	147.42	Remote (<5%)	High-Medium	20	6.03
Reliability	20%	Very Likely (>95%)	High-Medium	181	36.15	Unlikely (5 to 25%)	Medium	15	2.96
Customer Focus	20%	Very Likely (>95%)	High-Medium	181	36.15	Remote (<5%)	Medium	7	1.48
Stewardship	20%	Very Likely (>95%)	High	491	98.28	Remote (<5%)	High-Medium	20	4.02
Innovation	10%			0	0.00			0	0.00
Total Risk Score (TRS)					318.00				14.48
Δ TRS		303.52							
CRRF ($/ Δ TRS)		7,824							

Figure 9 – Example of Project Scoring

Preliminary Investment Portfolio & Customer Engagement

A preliminary investment portfolio is then prepared. The preliminary investment portfolio is tested against Oshawa Power's total capital and operating funds that determines financial capability and rate impacts.

The preliminary investment portfolio is then reviewed through customer engagement mechanisms (surveys, focus groups, etc.). Feedback is received, which informs on customer preferences for service quality level and rate increase. This feedback helps shape the preliminary investment portfolio by

putting emphasis on projects that address customer needs and enhance their overall satisfaction. The preliminary investment portfolio is revised, if necessary, based on customer feedback.

If revisions are required, each discretionary project proposed undergoes further scoping and risk assessment to determine any synergies and optimization. This may also indicate that to optimize system performance or distribution requirements, the budget may require funding adjustment. A capital investment plan is prepared. The plan is optimally paced to align with priorities, manage rate impacts, and consolidate efforts for greater efficiency.

Capital Investment and Business Plan

The capital investment plan is then sent to the Finance and Audit Committee for review and approval.

Oshawa Power's DSP/COS specific engagement as detailed in Part 5 of the Customer Engagement Report in Attachment 1-10 of Exhibit 1 revealed that customers are aligned with Oshawa Power's plans for the 2026-2030 planning period. Some key stats are highlighted below

- 88% agreed with Oshawa Power's proposed investments in equipment and fleet vehicles for operational needs
- 88% agreed with Oshawa Power's plan to invest in automation and remote monitoring and control for our distribution system in order to improve reliability and decrease response time for outages
- 87% agreed with the Oshawa Power's proposed NWS strategy to modernize our system and ensure we can effectively meet increasing electricity demand

A preliminary business plan is developed as soon as the capital investment plan is approved by the Finance and Audit Committee, and the capital investment plan is presented to the senior leadership team for discussion and review. Final approval of budget and the capital investment plan is determined by Oshawa Power's senior leadership team in consultation with the Board of Directors forming a five-year capital expenditure plan and final Business plan with allocation of funds to each major budget and investment category.

Following final investment plan approval, the Asset Management process would then proceed to the plan execution.

Capital Plan Execution Phase

Work Execution

Oshawa Power views the execution of its capital plan as a dynamic and responsive process, guided by the objectives set out in this DSP and aligned with the principles of the Renewed Regulatory Framework for Electricity (RRFE). Oshawa Power adopts a disciplined project management and oversight approach to ensure that capital investments are delivered on time, within budget, and in a manner that maximizes value for ratepayers.

Acknowledging the non-discretionary nature of some investments such as System Access, Oshawa Power must prioritize it over other the investment categories (System Renewal, System Service and General Plant) in order to meet statutory and regulatory obligations while also meeting Financial Performance requirements. This reprioritization process is conducted by employing Oshawa Power's Asset Management System inclusive of the Strategic Asset Management Plan and quantified risk prioritization methodology. The project prioritization methodology is as described in earlier paragraphs of this Section 5.3.1.1.

Performance & Continuous Improvement

The results of work execution are reflected in annual performance measures. The performance measures included on the scorecard have an established minimum level of performance expected to be achieved. Reviewing work execution and resulting performance leads to continuous improvement in asset management and the capital planning process. As can be seen highlighted in section 5.2.3, Oshawa Power has met or exceeded target performance for all measures over the historical period and is committed to continuing this trend.

5.3.1.2 Process Change

The following changes/updates that impact the planning process have been implemented since Oshawa Power's last COS filing. Oshawa Power deems these as significant iterations to its previous AM process and reflects Oshawa Power's continuous improvement philosophy.

a. Oshawa Power developed an Asset Management Policy. This policy, at a high level, establishes the core asset management principles that drive Oshawa Power's planning framework.
b. Oshawa Power developed a Strategic Asset Management Plan. This plan outlines Oshawa Power's approach to managing its assets effectively and efficiently to achieve its Asset Management objectives. It not only provides a framework for decision-making related to

asset planning, acquisition, operation, maintenance, renewal, and disposal but also aims to optimize the performance, reliability, and sustainability of its assets, which ensures cost-effectiveness and compliance with regulatory requirements.

c. Oshawa Power had an Asset Condition Assessment conducted in 2018 as part of its 2020 DSP rate filing. For the 2025 rate filing, an improved and more comprehensive 2023 Asset Condition Assessment was conducted. The 2023 ACA incorporated more metrics and reduced the weighting on asset service age. For example, Wood Poles in the 2018 ACA report had a weighting of 40% for age in determining overall wood pole asset health. Three (3) other condition metrics accounted for the remaining 60% of wood pole asset health determination. For the 2023 report, age only had a weighting of 22% in determining overall wood pole asset health. There are now 11 other condition metrics that account for the remaining 78% of wood pole asset health determination. This change in weighting on the asset's service age shifts the focus from a time-based replacement to a condition-based replacement decision thereby eliminating pre-mature or early replacement of an asset that still has useful life remaining even though it could be an older asset and past its typical useful service life metric.
d. Oshawa Power started evaluating possibilities for NWS in the overall planning process.
e. Oshawa Power updated its Maintenance Manual. The Maintenance Manual is used to establish maintenance programs that will improve efficiency and prevent unplanned equipment outages. It identifies equipment that requires maintenance, the categories, the methods and the justifications for performing the maintenance, whatever that may be. Maintenance plans established from this Manual ensure that the expenditure on the assets is optimized and that maintenance practices become standard and consistent over time. By being documented as the present day baseline, it allows adjustment of the program and practices should that be warranted as part of Oshawa Power's continuous improvement philosophy.
f. A Substation Power Transformer and Switchgear Lifecycle Risk & Options Analysis report was completed in November 2023 (included in Appendix C). The report recommends refurbishment or replacement for specific station transformers and switchgear over the 2026-2030 forecast period based on asset condition. The analysis drives decision-making on the most cost effective long term solution. It is a determination whether refurbishment (further maximizing the asset's life) or replacement (asset is at its end of life) is the optimum outcome.

5.3.1.3 Data

Oshawa Power's Asset Management process gathers data from various sources to support the analysis and life cycle assessment of its distribution system assets, and to identify and prioritize its capital and operational investments. These sources range from raw statistical data housed within the GIS system, to formal assessments such as the Asset Condition Assessment, to routine data collection from inspection and maintenance records. The following discussion captures some of the key data used to support AM objectives.

Asset Registries

The GIS system is considered to be Oshawa Power's distribution system Asset Registry. It houses considerable data correlated to specific distribution system assets such as the asset type, service age, location, size, type, voltage, etc., as well as asset interconnectivity/dependencies. This data supports multiple analyses including Health Index (HI) formulation/ Impact Index formulation and the Asset Condition Assessment (ACA) (Appendix C).

Oshawa Power's IT department maintains a separate Asset Registry that captures all of its hardware and software technology assets, including lifecycle and vendor support information and cyber risk profile info. It facilitates analysis on End of Life, End of Support and capacity planning.

Maintenance and Inspection Records

Oshawa Power collects and assesses considerable data collected through maintenance, inspection and testing practices. Inspection and test records are maintained on assets such as transformers, switchgear, poles and stations. Infrared (IR) scans and resistograph pole test results also provide critical data inputs as to the condition / health of an asset supporting the AM process. The data serves as inputs into formulating a comprehensive condition assessment for each asset category, as well as scoring for each asset within each asset category, feeding the ACA and Options Analysis Report (Appendix C).

Integral data inputs for the Fleet Management process include maintenance records, inspection reports, condition assessments and Key Performance Indicators (KPIs). The data and trend analysis are used to review the operational value of fleet assets to the organization.

SCADA

Oshawa Power relies on data derived from its SCADA system to support a number of analyses, such as SAIFI and SAIDI statistics, system loading, capacity considerations, load forecasting, and

performance measurement. The net outcomes of these analyses determine system capacity constraints and establish timelines for investments towards projects that will address these capacity constraints or any limitations. The data facilitates the identification of high-risk areas and supports strategic investments in automation. As well, SCADA data supports Oshawa Power's Outage Management System (OMS), and the historical data from the OMS further provides vital insights into the health of the distribution system network.

Oshawa Power's Service Quality reports are a culmination of data including outages, their causes, the assets, location, etc. This data feeds other analyses such as the HI formulation/Impact Index formulation, and into large culminating reports like the ACA and Options Analysis Report.

Financial

Oshawa Power utilizes cost metrics on a per unit basis for certain asset categories based on actual historical replacement costs to estimate future capital costs for projects of similar size and scope. Once a new ERP system is implemented, Oshawa Power will have access to more accurate historical financial data. For additional information, please refer to the ERP business case located in Appendix A.

Customers

Data is collected from Oshawa Power's customers on their preferences through various customer engagement activities. Their preferences, including reliable supply of electricity at fair rates, serve as an input into the SAMP.

External

There are many external factors that provide data inputs into the assessment management process. These include:

- Regulatory requirements – changes in requirements from the OEB, health and safety, labour laws, consumer protection and design standards
- Economics – global economics of inflation and supply chain; local economics of regional growth and employment
- Social and political - broad changes in customers' needs and preferences, and legislative changes drive by policy
- Environmental – climate change, dramatic weather patterns, renewable resources
- Innovation – new technologies are being developed and must always be assessed as to how, or if, they can bring value to the utility, its operations and customers

5.3.2 Overview of Assets Managed

5.3.2.1 Overview of Service Area

Oshawa Power owns and operates a distribution network that currently serves over 62,000 customers (excluding street lighting, sentinel lighting and unmetered scattered load) in the City of Oshawa located in the Regional Municipality of Durham.

Customer by class numbers (as of end 2024) are shown in the table below:

Table 12 - Oshawa Power Customers by Class

Residential	General Service <50 kW	General Service ≥50kW	Large user	Total
58,046	4297	536	1	62,880

The service territory of Oshawa Power covers 145.5 square kilometers consisting of 49.1 square kilometers of rural service area and 96.4 square kilometers of urban service area. Oshawa Power's system has a total of 1,014 circuit km with a split of 53% and 47% between overhead to underground systems respectively.



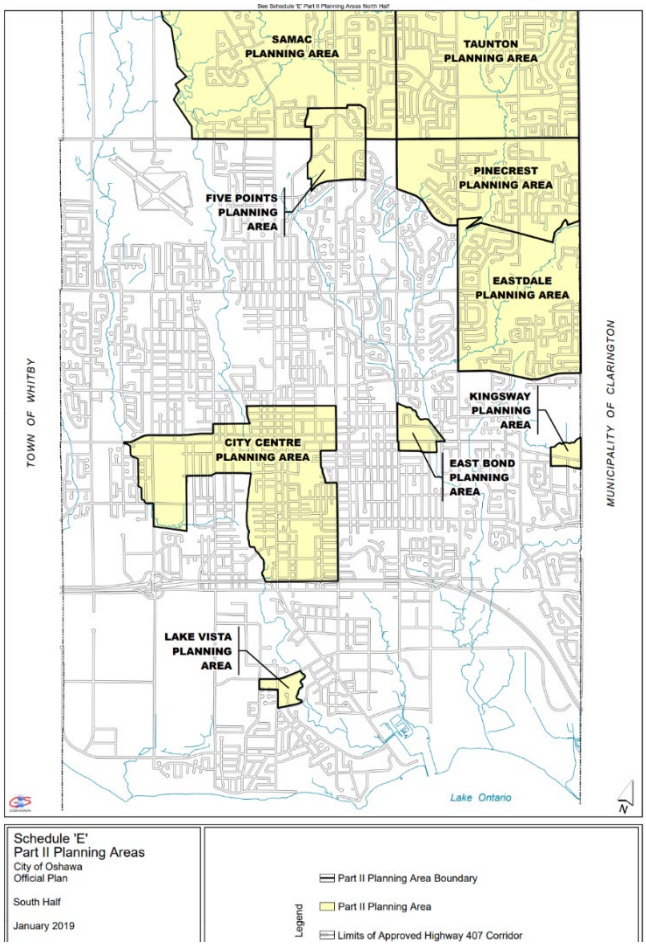
Figure 10 – Oshawa Power Service Territory

This region experiences humid continental climate with moderate seasonal temperate differences. The average weather temperature can vary from -15˚C to +25 ˚C; however, temperature extremes, with wind chill and humidex, can reach to -40˚C during winter and +40˚C in summer. Oshawa Power's peak 2024 summer demand was 231MW. Oshawa Power's peak 2024-2025 winter demand was 196.68MW. At the present time, Oshawa Power remains a summer peaking LDC.

Oshawa is located within the Canadian Standards Association (CSA) heavy loading area as described in CSA 22.3 No. 1-20 Overhead Systems. Accordingly, Oshawa Power's line designs are engineered for the corresponding CSA referenced heavy loading conditions of radial thickness of ice; horizontal wind loading and temperature.

The 2024 population of the City of Oshawa was estimated to be in the order of 186,000. Customer counts are expected to grow based on long-term customer growth trends. The 2024 – 2034 Housing forecast envisions an annual addition of 1,437 units per year consisting of a mix of low (36%), medium (43%) and high (21%) density units.

Oshawa Power accounts for new customer growth and demand in its system access category through investments in connection and expansion programs. New developments will also result in road widening and other community betterment initiatives by municipal bodies, triggering utility relocations. The City of Oshawa's Official Plan identifies planning areas for development. Diagrams of planning areas for upcoming residential subdivision and non-residential development are shown in Figures 11 and 12.



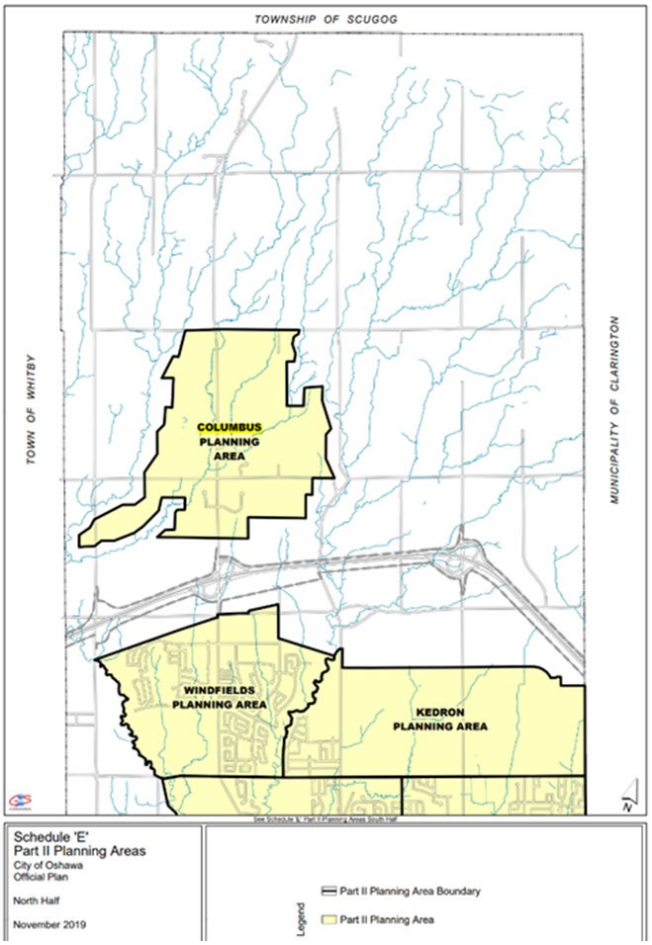


Figure 11 & 12 – Designated Planning Area from City of Oshawa Official Plan

More detailed diagrams of residential subdivision and non-residential development are shown in Figures 13 and 14. Note that the coloured areas of the map represent the City Site Plan Application status that can advance or retreat over time due to various factors outside of Oshawa Power's control.

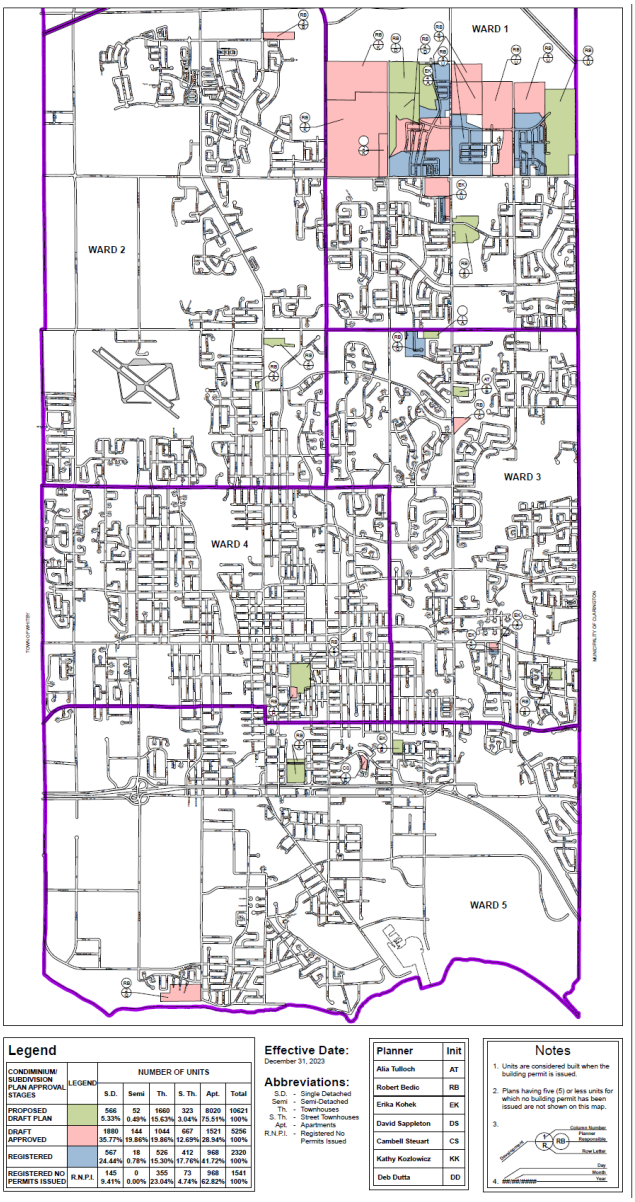


Figure 13 - City of Oshawa Residential Subdivision Activity (December 2023)

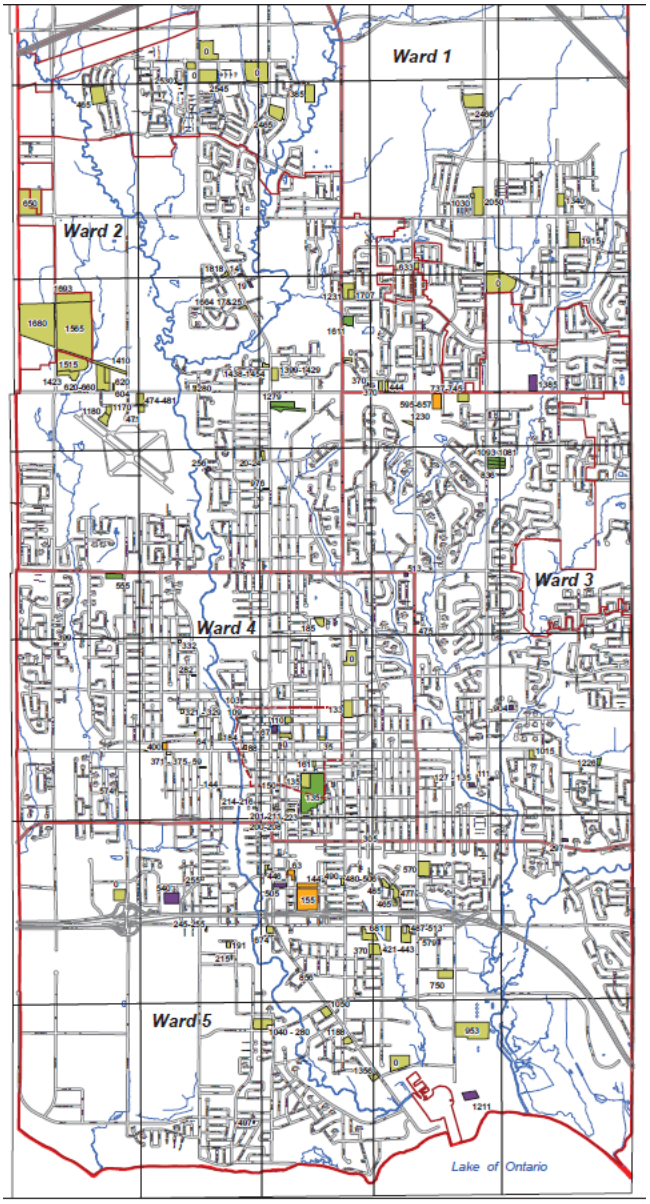


Figure 14 - City of Oshawa Non-Residential Subdivision Activity (January 2024)

5.3.2.2 Summary Description of the System Configuration

Oshawa Power is supplied from three (3) Hydro One-owned Transformer Stations (TSs) at the 44kV subtransmission voltage level which includes Wilson TS, Thornton TS and Enfield TS. The demarcation point between Hydro One and Oshawa Power starts at the 44kV feeders egressing the TSs, where eight (8) 44kV feeders from Wilson TS, four (4) 44kV feeders from Thornton TS and two (2) 44kV feeders from Enfield TS are used to supply nine (9) of Oshawa Power's stations. Figure 15 below provides the approximate geographic locations of Hydro One-owned TSs and Oshawa Power-owned stations within Oshawa Power's service territory.

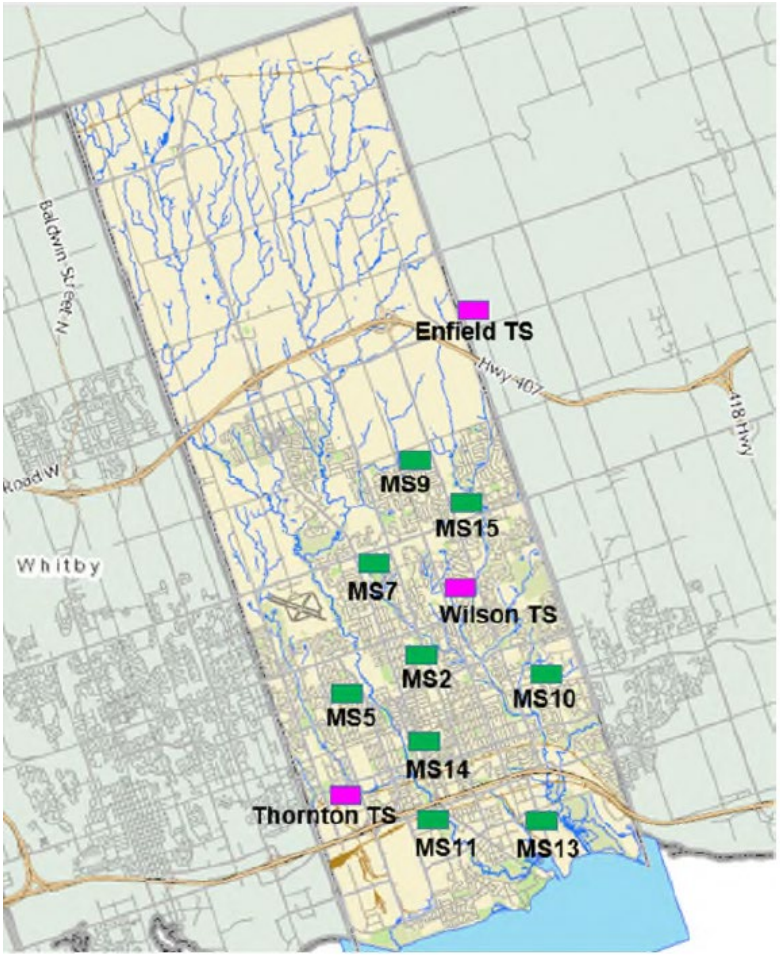


Figure 15 – Hydro One Transformer Station and Oshawa Power Municipal Station Locations

Oshawa Power itself does not have nor own any Transformer Stations. Accordingly, Oshawa Power has never had any transmission or high voltage assets (>50kV) that have been previously deemed by the OEB to be distribution assets. In this DSP, there are no such assets that Oshawa Power seeks the OEB to deem as distribution assets.

Oshawa Power owns and operates its electricity distribution system located within the City of Oshawa located in the Regional Municipality of Durham. Oshawa Power receives power from Hydro One-owned transformer stations at 44kV and as such is not a host nor embedded distributor.

There are no embedded distributors within Oshawa Power's service territory.

The following Figures 16 and 17 respectively show the 44kV and 13.8kV single line diagrams of Oshawa Power's distribution system network.

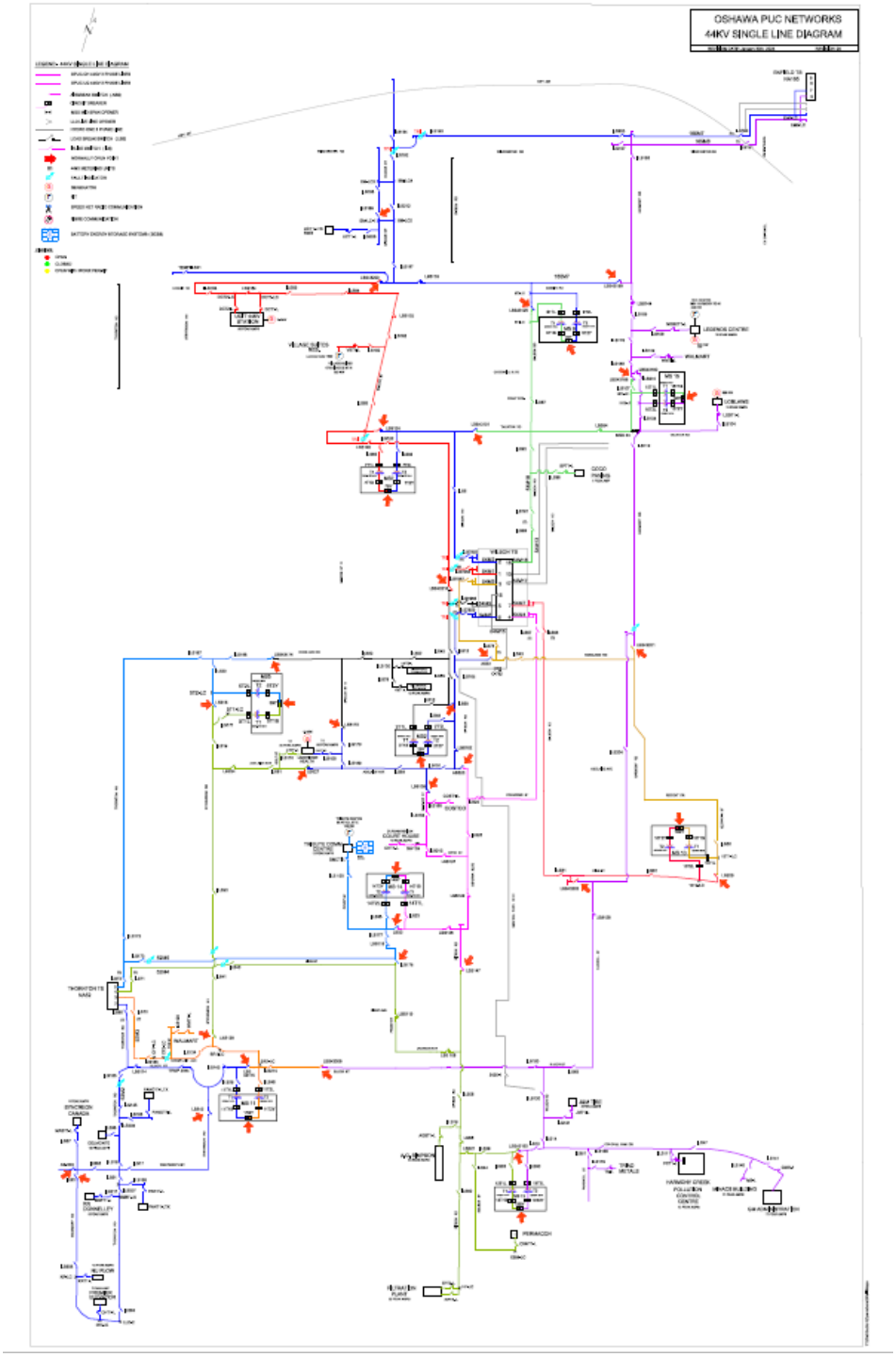


Figure 16 – Oshawa Power 44kV Single Line Diagram

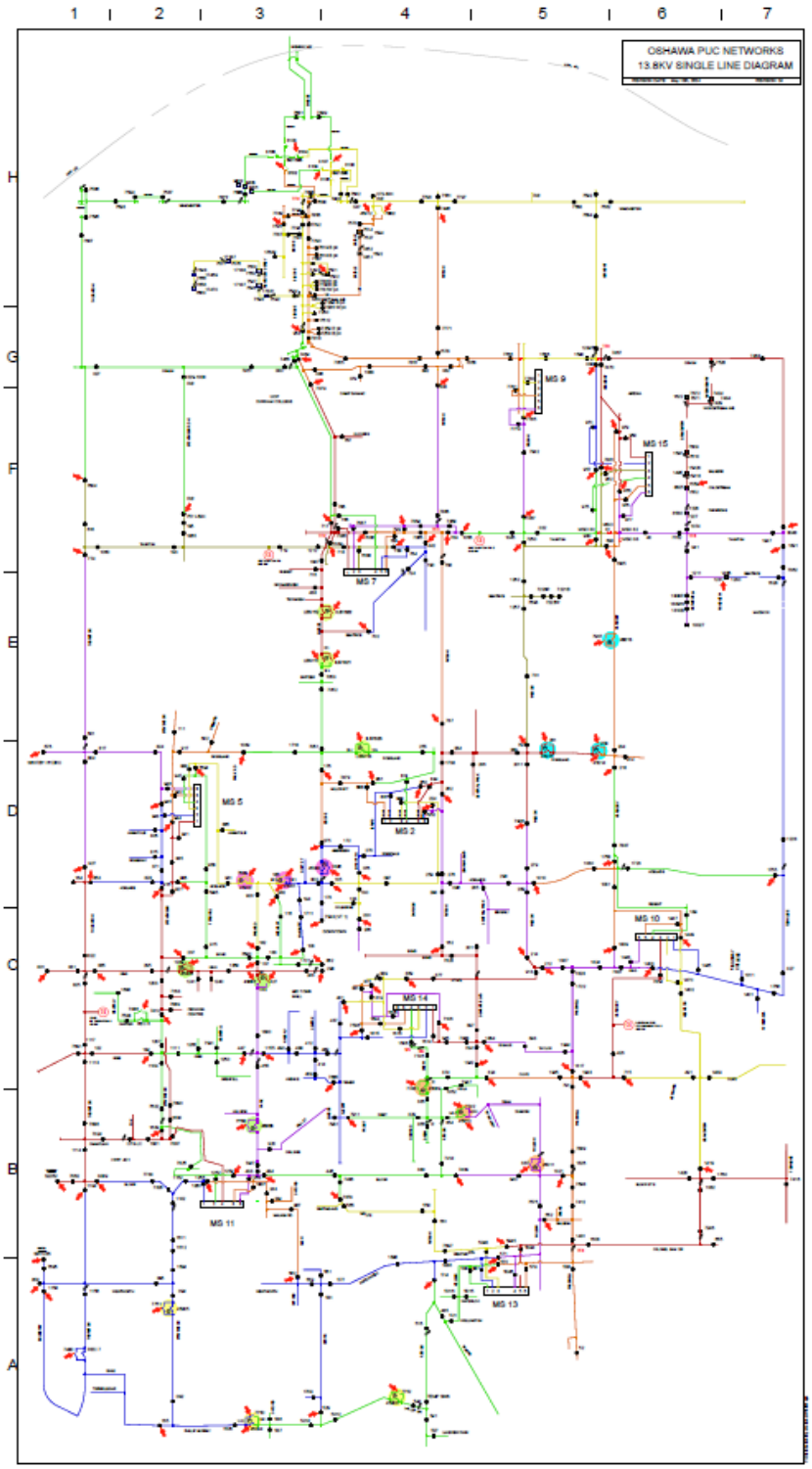


Figure 17 – Oshawa Power 13.8kV Single Line Diagram

All Oshawa Power stations are equipped with two transformers stepping the voltage down from 44kV to 13.8kV, where each are protected by a 44kV circuit breaker. Each station also has a medium

voltage switchgear that contains two transformer breakers and one bus tie breaker between two 13.8kV buses, which are equipped with 13.8kV circuit breakers to protect outgoing 13.8kV feeders. A summary of the station transformer capacity and associated number of feeders for each distribution station is provided in the table below.

Table 13 - Oshawa Power Distribution Station Ratings

Station Name	Transformer Sizes	Number of 13.8kV Feeders
MS2	T1 25/33/41 MVA T2 25/33/41 MVA	6
MS5	T1 25/33/41 MVA T2 20/26/33 MVA	6
MS7	T1 20/26/33 MVA T2 20/26/33 MVA	6
MS9	T1 25/33/41 MVA T2 25/33/41 MVA	6
MS10	T1 25/33/41 MVA T2 25/33/41 MVA	6
MS11	T1 25/33/41 MVA T2 25/33/41 MVA	6
MS13	T1 25/33/41 MVA T2 25/33/41 MVA	6
MS14	T1 20/26/33 MVA T2 20/26/33 MVA	6
MS15	T1 25/33/41 MVA T2 25/33/41 MVA	6

Oshawa Power operates a primary "loop distribution" system, which offers flexibility in switching operations to minimize outage duration and distributes electricity through 14 x 44kV primary feeders and up to 54 x 13.8kV distribution primary feeders. The primary distribution network consists of approximately 542km of overhead primary lines and 488km of underground primary cables, which provides supply to distribution type transformers that step down to the following secondary voltage levels in order to supply customers:

1. 120/240V, 1-ph circuits to serve residential or small commercial customers
2. 120/208V, 3-ph circuits to serve commercial customers

3. 347/600V, 3-ph circuits to serve commercial and industrial customers

The table below provides the number and length of circuits by primary voltage level.

Table 14 - Number and Length of Circuits by Primary Voltage Level

Primary Voltage	Number of Circuits	Overhead System (km)	Underground System (km)
44kV	14	119	4
13.8kV	54	423	484

5.3.2.3 Asset Demographics and Asset Condition Assessment

The most recent ACA was prepared to assess the condition of assets in-service by determining health indices using available condition data (refer to Appendix C for the full ACA report). This ACA provides demographic and asset condition information on fixed assets employed in Oshawa Power's stations, overhead and underground systems.

The ACA report documents the condition of all major assets in units of health indices and provides ranking of assets in designations rated as "very good", "good", "fair", "poor" or "very poor". In determining the health indices of assets, all available information relevant to the assets' health, including age, results of visual inspections and results of diagnostic testing when available, have been utilized. Figures 18 and 19, and Table 15 present the asset demographics and summary results of the ACA.

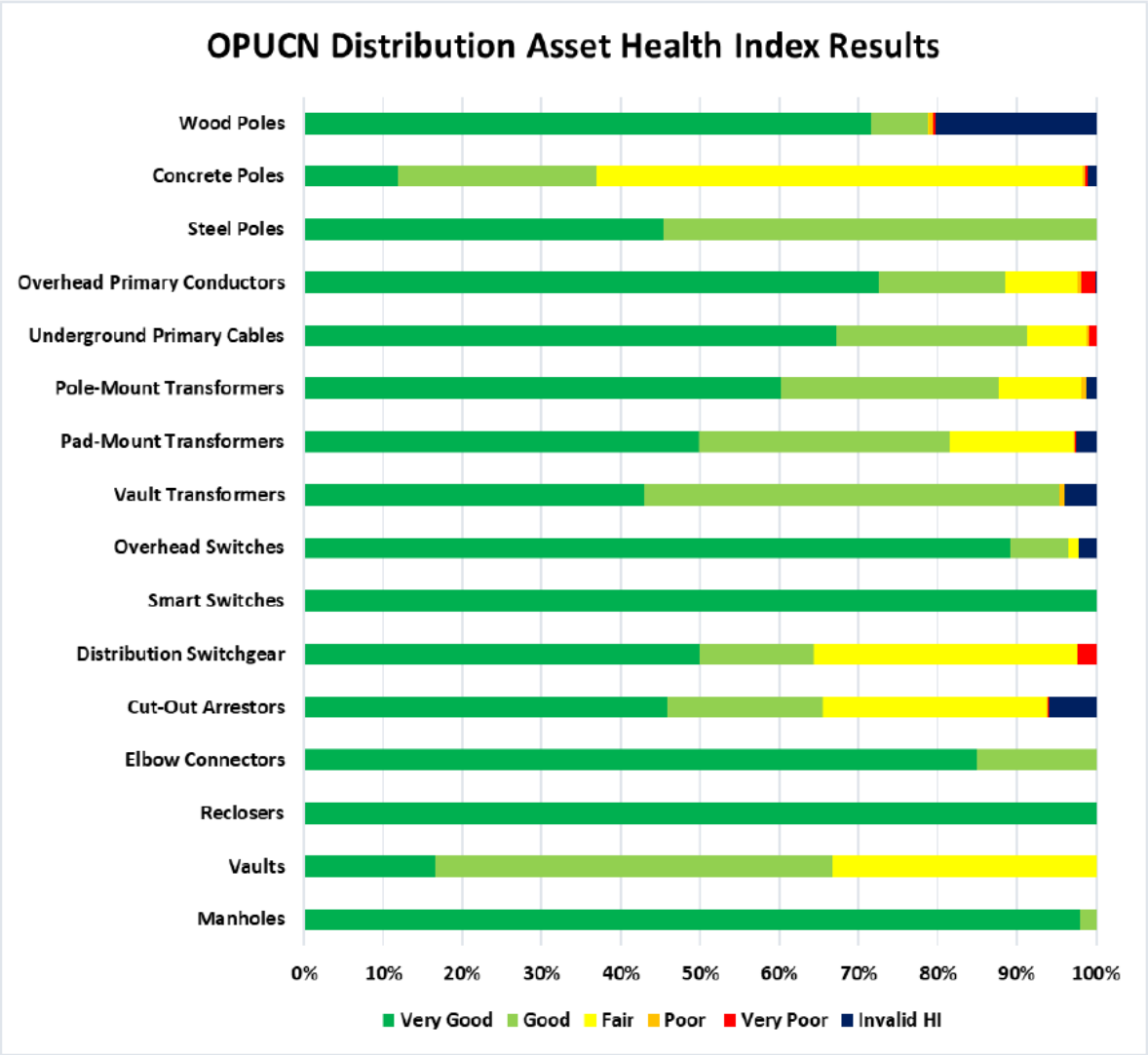


Figure 18 – Distribution ACA Results

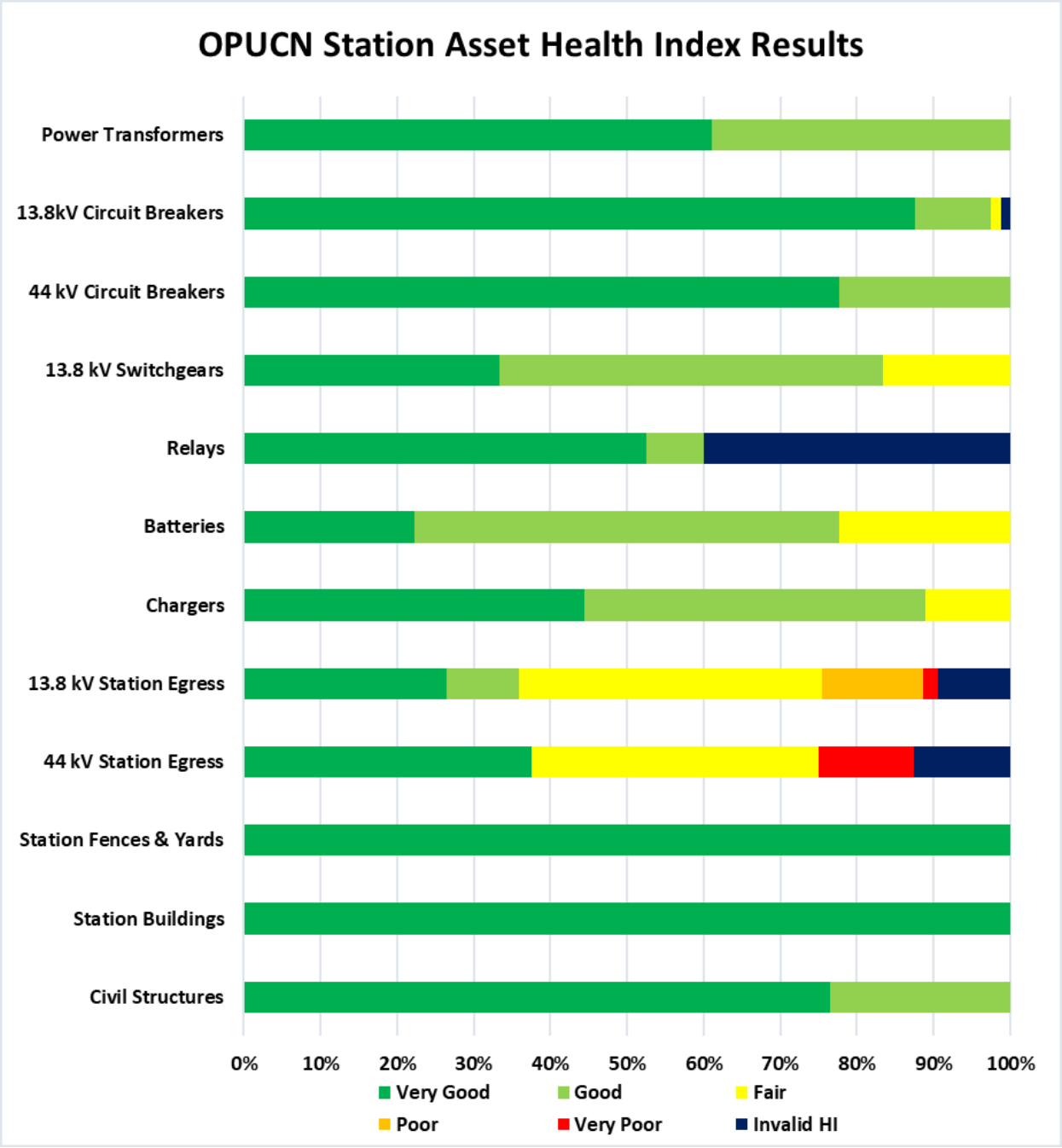


Figure 19 – Station ACA Results

Table 15 - ACA Overall Results

Asset Category	Population – Note 1	HI Distribution						DAI
		Very Good	Good	Fair	Poor	Very Poor	Invalid HI	
Distribution Assets								
Wood Poles	9,435	6,762	663	12	50	39	1,909	83%
Concrete Poles	370	44	93	227	1	1	4	96%
Steel Poles	11	5	6	0	0	0	0	100%
Overhead Primary Conductors (m)	534,458	387,632	85,800	48,164	2,585	10,218	59	100%
Underground Primary Cables (m)	463,792	311,709	111,550	34,893	1,318	4,322	0	100%
Pole-Mount Transformers	2,250	1,356	619	231	15	2	27	100%
Pad-Mount Transformers	3,953	1,973	1,250	618	7	3	102	99%
Vault Transformers	151	65	79	0	1	0	6	97%
Overhead Switches	718	640	53	9	0	0	16	95%
Smart Switches	31	31	0	0	0	0	0	100%
Distribution Switchgear	42	21	6	14	0	1	0	100%
Cut-Out Arrestors	1,761	807	347	498	2	3	104	97%
Elbow Connectors	7,114	6,048	1,066	0	0	0	0	99%
Reclosers	3	3	0	0	0	0	0	100%
Vaults	6	1	3	2	0	0	0	100%
Manholes	49	48	1	0	0	0	0	54%
Station Assets								
Power Transformers	18	11	7	0	0	0	0	99%
13.8kV Circuit Breakers	81	71	8	1	0	0	1	99%
44 kV Circuit Breakers	18	14	4	0	0	0	0	97%
13.8 kV Switchgear Buses	18	6	9	3	0	0	0	100%
Relays	80	42	6	0	0	0	32	70%
Batteries	9	2	5	2	0	0	0	100%
Chargers	9	4	4	1	0	0	0	100%
13.8 kV Station Egress	53	14	5	21	7	1	5	96%
44 kV Station Egress	8	3	0	3	0	1	1	97%

Asset Category	Population – Note 1	HI Distribution						DAI
		Very Good	Good	Fair	Poor	Very Poor	Invalid HI	
Station Fences & Yards	9	9	0	0	0	0	0	100%
Station Buildings	9	9	0	0	0	0	0	100%
Bus Structures	17	13	4	0	0	0	0	94%

The assets have been assessed to be in one of five Health Index conditions: Very Good, Good, Fair, Poor, or Very Poor. For most of the asset classes, the Health Index Formulation (HIF) was previously developed in the 2018 ACA. Where applicable, these HIFs were modified based on the most recent industry best practices and Oshawa Power specific data availability. Most notably the weighting of the service age has decreased for some assets as the industry has moved away from purely age-driven asset management plans. As such, the HI results of these asset classes may have improved since the last ACA as newly available data has shown the assets to be in good condition despite their age being near or past the Typical Useful Life (TUL). If an asset has an invalid HI, then a ratio of age over TUL is used to determine the probability of failure. As part of its commitment to continuous improvement, Oshawa Power will continue collecting asset condition input data during its annual maintenance and inspection cycles. Given that asset evaluations vary by type, please refer to the Asset Condition Assessment (Appendix C) for the criteria used in asset-specific Health Index formulations.

ACA results show that the majority of Oshawa Power's assets are in Very Good or Good condition.

For each asset class, the ACA report also provided a remaining life evaluation based on TUL and a risk evaluation based on asset HI and a variety of impact factors.

The purpose of the risk evaluation is to first assess and quantify (or qualify) the potential risks to both Oshawa Power and its customers in the event of a capacity deficit, and then outline potential mitigation measures that could partially or completely mitigate these risks. To provide clarity, the following definitions are provided:

- Probability is the likelihood of an event occurring;
- Consequence is the outcome or impact of that event; and
- Risk is the product of the probability that an event will materialize multiplied by the consequence of that event.

First the impact is calculated in for each asset using risk factors. Three risk categories are included in the analysis; reliability, safety and environmental. These risk categories have relative weighting that is consistent across all asset classes (Reliability 40%, Safety 40%, and Environment 20%). Within each risk category are individual risk factors which are specific and uniquely graded for each asset class. Risk scores can range from Low to Extreme.

The ACA report provides a recommended replacement plan for assets with Very Poor, Poor or Fair condition, assets classified as high or extreme risk, and assets that are past their economic end of life. The replacement plan is used as a preliminary baseline for Oshawa Power to identify how many assets should be replaced to maintain the overall system health. The recommended assets are further evaluated through Oshawa Power's planning process, as outlined in Section 5.3.1.1, which considers alternative solutions, consolidation of renewal efforts, alignment with other initiatives, and broader system planning needs. Proactive replacement plans have been prepared for the following distribution assets over the 2026 – 2030 forecast period and can be found in the table below.

Table 16 - 2030 Distribution Asset Replacement Plan

Asset Class	Unit	2026	2027	2028	2029	2030
Poles	#	69	55	86	84	79
Overhead Conductors	m	2600	1050	2900	2800	2550
Underground Cables	m	724	1350	2631	1542	4061
Pole-Mount Transformers	#	11	9	40	31	46
Padmount Transformers	#	9	2	25	23	33
Firon Overhead Switches	#	0	99	99	99	99
Porcelain Switches and Insulators	#	0	233	233	233	233
Quick Sleeves	#	0	141	141	141	141
Distribution Switchgear	#	0	2	0	1	2
Meters	#	2800	2800	2800	2800	2800
Locks	#	1555	1555	1555	1555	1555

Proactive replacement of these assets is carried out through targeted system renewal initiatives, including the Pole Replacement Program, Overhead and Underground Renewal Programs, Station Switchgear Replacement Program, and Meter Replacement Program, among others. The station power transformers and switchgear assessment was supplemented by a Lifecycle Risk and Options Analysis report (included in Appendix C) that recommended a replace, refurbish or operate as normal choice for these major station assets. Proactive replacement plans have been prepared for the MS5 station switchgear in 2026 and the MS11 station switchgear in 2027. As part of this program, new riser poles and related underground work will also be carried out at MS5.

Oshawa Power's AM strategy covers the full life cycle of a fixed asset, from the preparation of the asset specification and installation standards to the scope and frequency of preventative maintenance during the asset's service life and finally to the determination of the assets end-of-life and retirement from service. At each stage of an asset's life cycle, decisions are made to achieve the optimum balance between achieving maximum life expectancy, highest operating performance, lowest initial investment (capital costs), and lowest operating costs.

Asset risks (probability of failure x consequence of failure) are considered as part of Oshawa Power's prioritization process and are ultimately used to determine the prioritized list of capital projects and programs over the forecast period.

5.3.2.4 Capacity Assessment of Existing System

Oshawa Power is supplied by three (3) Hydro One- owned Transformers Stations (TSs): Wilson TS, Thornton TS and Enfield TS. Each of these TS's capacity and utilization is reviewed through the Regional Planning Process in conjunction with the IESO, Hydro One and any other LDCs that are supplied from these TSs.

Recent feeder rebuilds and load transfers have optimized the capacity utilization between the three (3) Hydro One TS points of supply.

Oshawa Power stations are planned and configured to be loaded to 100% of their normal or base rating. These stations are designed with a primary loop distribution system to allow for the station to be backed up from one or more adjacent stations. This configuration offers flexibility in switching operations to minimize outage durations, maintain reliability of the distribution system and reduce restoration times during outages. Table 17 provides the capacity utilization at each station. It should be noted that the information in the table below represents the non-coincidental station peak loading. Temporary load transfer can also affect the station load during facilitation of a planned or emergency work.

Table 17 - Municipal Station Capacity Utilization

Oshawa Power Station	Transformer	Normal Capacity (MVA)	2024 Peak Load (MVA)	Capacity Utilization
MS2	T1	25	11.3	45%
	T2	25	14.8	59%
MS5	T1	25	16.9	68%
	T2	20	4.6	23%
MS7	T1	20	21.4	107%
	T2	20	14.3	72%
MS9	T1	25	13	52%
	T2	25	15	60%
MS10	T1	25	17.3	69%
	T2	25	12.4	50%
MS11	T1	25	22.1	88%
	T2	25	13	52%
MS13	T1	25	23.4	94%
	T2	25	19.1	76%
MS14	T1	20	15.6	78%
	T2	20	14.8	74%
MS15	T1	25	17.9	72%
	T2	25	20.8	83%

As per the table above, most of the stations operate well within the normal station rating except for MS7 – T1 where the specific transformer is loaded above its normal rating. This loading condition is a result of the local developments in the area where the station is situated. A plan has already been put in place to transfer load to new feeders from MS9 to alleviate the system capacity constraints and supply future distribution load requirements.

Table 18 provides the feeder capacity information on both the 44kV and 13.8kV distribution network. Currently, the planning capacity limits loading to 400A on 44kV feeders, and 300A on 13.8kV feeders to ensure that adequate feeder transfer capability exists and to withstand load transfers in the event of supply breaker or main feeder failure; however, some feeders are peaking over these values primarily due to temporary load transfer. Exceptions include the 52M4 and 165M8 feeders; the loading on these feeders are normal state loading. Although their planning capacity has been exceeded, their peak loading remains within the feeder design capacity of 600A.

52M4 is equipped with strategically placed switching devices to mitigate potential loading concerns if they arise.

165M8 can be optimized with introduction of new automation and switching devices. Additionally, the two remaining breaker positions at Enfield TS can be utilized as demand increases.

Note that the data represented in this table are coincidental loading at the feeder level and non-coincidental between feeders on the same bus.

Table 18 - Distribution Feeder Capacity Utilization

Feeder	Planning Capacity (Amps)	2024 Peak Load (Amps)	Capacity Utilization
Thornton TS			
52M2	400	279	70%
52M3	400	435	109%
52M4	400	454	114%
52M5	400	343	86%
Wilson TS			
54M1	400	341	85%
54M2	400	157	39%
54M3	400	518	130%
54M4	400	423	106%
54M5	400	238	59%
54M6	400	292	73%
54M7	400	287	72%
54M18	400	313	78%
Enfield TS			
165M7	400	475	119%
165M8	400	477	119%
Station Feeders			
2F1	300	90	30%
2F2	300	200	67%
2F3	300	181	60%
2F4	300	176	59%
2F5	300	258	86%
2F6	300	186	62%
5F1	300	423	141%
5F2	300	142	47%
5F3	300	390	130%
5F4	300	217	72%
5F5	300	-	-
5F6	300	208	69%
7F1	300	422	141%

Feeder	Planning Capacity (Amps)	2024 Peak Load (Amps)	Capacity Utilization
7F2	300	255	85%
7F3	300	323	108%
7F4	300	308	103%
7F5	300	416	139%
7F6	300	180	60%
9F1	300	-	-
9F2	300	446	149%
9F3	300	-	-
9F4	300	319	106%
9F5	300	-	-
9F6	300	185	62%
10F1	300	567	189%
10F2	300	155	52%
10F3	300	125	42%
10F4	300	336	112%
10F5	300	260	87%
10F6	300	207	69%
11F1	300	496	165%
11F2	300	400	133%
11F3	300	-	-
11F4	300	365	122%
11F5	300	243	81%
11F6	300	232	77%
13F1	300	338	113%
13F2	300	216	72%
13F3	300	139	46%
13F4	300	203	68%
13F5	300	232	77%
13F6	300	332	111%
14F1	300	227	76%
14F2	300	280	93%
14F3	300	239	80%
14F4	300	231	77%
14F5	300	298	99%
14F6	300	229	76%
15F1	300	333	111%
15F2	300	179	60%
15F3	300	421	140%
15F4	300	208	69%

Feeder	Planning Capacity (Amps)	2024 Peak Load (Amps)	Capacity Utilization
15F5	300	261	87%
15F6	300	368	123%

Identification of asset capacity is critical to ensure that the distribution system will be able to withstand current and future loading requirements as well as operate the distribution system safely and reliably during both normal and abnormal states.

5.3.3 Asset Lifecycle Optimization Policies and Practices

Since the last DSP, Oshawa Power has developed a documented Asset Management Policy and Strategic Asset Management Plan (SAMP) to guide its asset management activities that impact asset lifecycle optimization.

Oshawa Power's practices for asset lifecycle optimization are designed to achieve optimal system and operating performance while ensuring safety and consideration of balancing customer's needs for reliability and capital expenditure costs and Oshawa Power's expectations in line with the following SAMP asset management objectives:

- Ensure proper installation, operation, inspection & maintenance activities are established and followed to maintain the highest level of safety.
- Strategically plan, design, build, operate & maintain Oshawa Power's system to meet and exceed reliability targets.
- Enhance transparency and facilitate customer feedback and engagement to ensure needs and issues are addressed proactively.
- Ensure financial, regulatory, and environmental stewardship is upheld for all stakeholders
- Employ creative means, innovation, technological and otherwise, to create value through both evolutionary and revolutionary continuous improvement efforts, or simply changing how things are done, in striving toward operational excellence.

In order to achieve these SAMP objectives, Oshawa Power focuses on sustaining (maximizing) the assets so that they can perform reliably and safely, while improving cost effectiveness. The decisions involving investment into fixed assets play a major role in determining the optimal performance of a distribution system. The majority of the investments in fixed assets are triggered by:

- declining performance in the areas of supply system reliability, power quality or safety
- increasing operating and maintenance costs associated with aging assets
- anticipated growth in demand requiring capacity upgrades

In all cases, investments that are either too high or made too far in advance of the actual system need may result in non-optimal operation. On the other hand, investments not made in time when warranted by the system raise the risk of performance targets not being achieved and would result in non-optimal operation. As an example, in this DSP, Oshawa Power has coordinated the 2026 investment of three (3) new feeders from MS9 with a municipal road widening project so that existing plant is replaced in a timely manner that meets both municipal and Oshawa Power's objectives.

Optimal operation of the distribution system is achieved when "right sized" investments into renewal and replacement (capital investments) and into asset repair, rehabilitation and preventative maintenance are planned and implemented based on a "just-in-time" approach. Asset condition, asset performance and inspection results all contribute to the determination of forecast spend. The overall philosophy is to maximize any asset to its fullest and to replace it just prior to it failing.

Oshawa Power also considers the future capacity requirements of an asset to mitigate any premature replacement needs. Examples can include a pole line built to accommodate the expected additional circuitry within its lifecycle (e.g., based on load forecast study) or a distribution transformer sized to accommodate expected increased electrification load (i.e., EV growth study report).

Oshawa Power's asset lifecycle practices cover the full life cycle of a fixed asset, from preparation of the asset specification and installation standards - to the scope and frequency of preventative or reactive maintenance during the asset's service life – and finally to the determination of the assets end-of-life and retirement from service. At each stage of an asset's life cycle, decisions are evaluated and made to achieve the right balance between achieving maximum life expectancy, highest operating performance, lowest initial investment (capital costs) and lowest operating costs.

Oshawa Power considers different parameters when prioritizing System Renewal investments and assesses if the asset should be refurbished, replaced, run-to-failure or require no action. These parameters include, but are not limited to, asset condition, asset depreciation, asset functionality, loading, applicable standards, safety issues and failure risks.

The ACA considers the parameters when assessing an asset and the results provide the number of assets that need to be replaced. Hot spots are identified in a heat map where condition of assets are "fair", "poor" or "very poor", and where applicable, the assets are grouped together to optimize design in forming an overhead or underground rebuild plan. The results of the ACA and heat map are utilized to create a planned capital renewal program and prioritize investments over the next 5 years.

If the assessment of an asset does not require any further action, a do-nothing approach can be implemented until a future inspection indicates otherwise. If additional action is required, Oshawa Power follows the refurbishment standard practices to address the asset and take corrective actions. For example, a pole line in poor condition can be refurbished by replacing certain assets in the pole line that are in "fair", "poor" or "very poor" condition, thus extending the life of the pole line and prudently pacing the rebuild of the whole pole line to an appropriately determined future date.

Oshawa Power adopts lifecycle optimization practices that result in overall lowest lifecycle cost that will determine if an asset needs to be replaced or refurbished. There are two main approaches for these that Oshawa Power employs: either proactive replacement or reactive replacement when the asset is in a "run-to-failure" mode. The approach used for each asset is determined based on a risk management process to ensure that the costs are optimized for a specific asset type while maintaining the reliability, operational efficiency and safety of the distribution system. Investments with highest level of risk mitigation and greatest benefit including major assets, such as station assets, are assessed periodically, and maintenance activities are proactively performed compared to low level risk assets such as conductors and distribution transformers.

Proactive Replacement

Proactive replacement involves assessing the condition of the asset periodically through inspections, testing, functionality and maintenance activities to prevent failures or decline in asset performance with the intent of extending the economic service life of the asset. This approach is adopted for assets with high/extreme-risk of failure and very poor, poor or fair condition or when the O&M cost is higher than savings from deferring replacement, and thus, allows for asset to be proactively replaced.

Major assets that require significant effort to replace and have long lead times for material or asset delivery are replaced based on the results of the ACA. This proactive replacement allows Oshawa Power to modernize the asset and size the asset based on system requirements. This also avoids service failures that may cause major outage impacts or safety risks to customers. The following assets are assessed for proactive replacement:

- Station Transformers
- Station Switchgears
- Station Breakers
- Station Battery and Battery Charger

- Protection & Control Assets
- Load Break Switches
- Switchgears
- Distribution Poles
- Vault Transformers – distribution transformers on a customer vault or supplying high density areas including downtown Oshawa
- Underground Cable – cables with high-risk failures and customer impact
- Vital Distribution Hardware – e.g. automatic splices (quick sleeves), insulators, distribution meters, etc.

Reactive Replacement

Assets that are quick to replace and low risk, that do not require large capital investments and do not cause significant customer outages are "run-to-failure", and are replaced or refurbished on a reactive basis. The maintenance activities for these assets are performed in a reactive mode and the scope of repairs is limited to rectifying deficiencies found during safety inspections. The replacement is typically completed on a like-for-like approach that does not necessarily provide opportunities to upgrade the asset using current technology or planned capacity increase. However, having said that, since these assets are decades old and have been in-service for that same period, present-day replacement in a like-for like approach does in fact introduce new assets that satisfy the fit, form and function of the old assets, but are improved in various areas such as physical and performance properties which overall upgrades the assets simply by replacing it. For example, when transformers with serious deficiencies are identified through inspections, these are immediately replaced. The new transformer is more electrically efficient and would have some features that the old transformer would not. The assets considered under reactive replacement are typically assessed with visual inspection at a minimum.

In both proactive and reactive maintenance, consideration may be given to any future capacity or infrastructure needs. Future capacity or infrastructure needs are easier to accommodate with proactive replacement versus immediate equipment needs required under reactive replacement (e.g., pole hit by car). Examples include replacing an end-of-life transformer with a larger size unit in anticipation of additional capacity needs for charging electric vehicles or replacing a failed pole with a taller and higher class of pole that will complement future planned pole line refurbishment plans.

Maintenance Planning Criteria and Assumptions

Proper maintenance is essential in maintaining system reliability and the functional integrity of the distribution system. It improves distribution system efficiency and prevents unnecessary or unexpected service disruptions, which optimizes expenditures. In order to realize these benefits, Oshawa Power understands that operation and maintenance activities need to be carried out in a cost-effective manner that balances O&M cost vs impacts to reliability and asset replacement cost (e.g., vegetation related outages impacted by Vegetation Management practices). As such, Oshawa Power has established a maintenance program that will keep the asset in its top operational condition as much as reasonably possible to mitigate the risk of unexpected power outages, asset damage, and high cost of repair or replacement in an emergency condition. This program has been divided into two categories: Reactive Maintenance (Unplanned) and Routine System Operations and Maintenance (Planned) and further subdivided into systems, which are either station, overhead system or underground system.

Reactive Maintenance

Maintenance is performed in response to failure of an asset resulting in a power outage, safety hazard and/or environmental problems. It is urgent and requires immediate action. The asset is either repaired or replaced to restore service immediately and, in some cases, permanent repair or replacement is completed in subsequent days.

Routine System Operations and Maintenance

Preventative maintenance is scheduled or performed in response to problems identified in inspection, testing and/or trouble reports. The asset is repaired or replaced prior to a failure. Testing may be performed to predict the asset condition. Oshawa Power complies with or exceeds the minimum inspection requirements set out in the OEB Distribution System Code Appendix C, which specifies inspection and maintenance of distribution system assets. Manufacturer's recommendations and best industry practices are also considered in determining the scope of maintenance. Routine System maintenance is completed on an as required basis while the frequency of Oshawa Power's system inspection and preventative maintenance activities are as follows and included in Oshawa Power's Maintenance Manual in Appendix G.

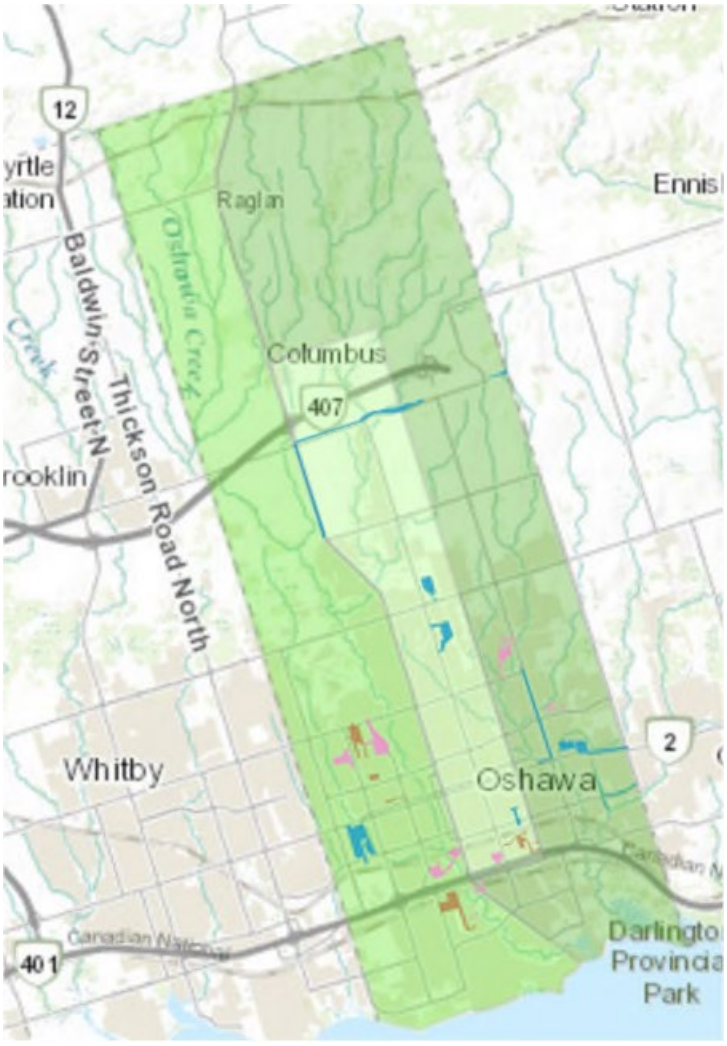


Figure 20 – Oshawa Power Geographic Zones

1. Visual inspections on both OH and UG systems including civil infrastructure and customer owned stations are completed on a 3-year cycle through a distribution system patrol according to geographic zones, completing 1/3 of the distribution system annually as shown in Figure 20. Visual inspections on all distribution automation devices are completed annually to ensure the control and communication devices continue to function in the absence of AC power. This will also include load checks on the batteries and their chargers. Results of the inspection are used in the ACA and allows Oshawa Power to capture and identify any asset deficiencies in the field that requires repair or replacement either through a maintenance or capital program.
2. Infrared (IR) scanning of all critical assets including overhead primary lines, distribution transformers, station asset, terminators, connectors, etc. is carried out annually to identify any anomalies caused by overheating or that may be attributed to poor connections,

overloading or defective equipment, or a combination thereof. IR scanning allows for corrective measures to be taken before the assets fail that can cause power outages. In order to ensure that all anomaly locations are identified, Oshawa Power schedules the inspection during summer when system load is higher and when any anomaly will be even more evident. A third party collects the data and summarizes all defects locations, level of severity and proposed recommended action. Any repairs or replacements required are completed within set timelines depending on the level of severity, with the highest severity completed immediately.

3. Switch maintenance, includes maintenance on all load break switches, air-break switches and in-line (solid blade) switches, is completed on a 3-year cycle. These switches are used on the distribution system to reconfigure overhead circuits on load as required to ensure sufficient supply to the customers during routine and emergency switching. Proper operation of these switches will shorten the outage restoration time resulting in the improvement of system reliability. The maintenance is coordinated through the System Control operator based on system loading considerations and the capability to take a switch out of service, when required. The switch and the manual operating device are cleaned, lubricated, aligned and adjusted. Any defective components are replaced as required. Other deficiencies are reported and documented for follow-up repairs.

4. The pole testing program includes wood, concrete and steel pole inspection and treatment. Oshawa Power conducts on-going visual inspections of its poles and completes non-destructive testing of the in-service wood poles once every five (5) years to determine the physical condition of the pole. Concrete poles are inspected visually for deterioration mostly because of rusting on the re-enforcing steel bars caused by moisture and salt. Steel poles are also inspected visually.

   Oshawa Power typically utilizes a third party in completing the pole testing and conducts the test and inspection for poles that are over 20 years of age. The assessment starts with simple visual inspection of poles accompanied by basic physical tests, such as prodding tests for external condition and hammer tests to detect evidence of internal decay. If there is any indication of decay from these tests, a full assessment such as Resistograph will be applied. Poles that exhibit significant deterioration, but are still structurally sound, are provided with remedial treatment using the wrap method, or boron rod method, to extend the useful service life. Critical poles are replaced immediately.

5. Vegetation management or tree trimming is carried out on a 3-year cycle according to geographic zones, completing 1/3 of the distribution system annually as shown in Figure 20. The objective of this program is to minimize tree contact interruptions and mitigate reliability risks and safety hazards. Oshawa Power contracted utility arbourist forestry crews trim trees within 3.0m of primary conductors and 1.5m of secondary conductors as a minimum to maintain safe distances from power lines and equipment. As required, third parties inspect power lines for tree limbs or vegetation growing too close to the lines or at risk of falling into the lines, outside of planned cycle.

The following table provides a summary of the frequency of system inspection and maintenance for OH and UG systems which is an excerpt from the DSC Appendix C that Oshawa Power currently follows.

Table 19 - Frequency of Overhead and Underground System Inspection and Maintenance

Major or Substantial Distribution Facility*	Patrol	Patrol
Distribution Transformers	**Urban**	**Rural**
Overhead	3	6
Submersible	3	6
Vault	3	6
Pad Mounted	3	6

Stations (see note below)	Outdoor Open	Outdoor Enclosed	Indoor Enclosed	Outdoor Open	Outdoor Enclosed	Indoor Enclosed
Transformer Station	1 month	1	1	6 month	1	1
Distribution Station	1 month	1	1	6 month	1	1
Customer Specific Substation	1	3	3	1	3	3

Lines and Associated Equipment		
Regulators	3	6
Switching and Protective Devices	3	6
Capacitors	3	6
Conductors and Cables		
Overhead	3	6
Underground	3	6
Submarine	3	6
Vegetation (see note below)	3	6
Poles	3	6
Civil Infrastructure	3	6

Note: Where units are not indicated in the table above, values are expressed in years.

Oshawa Power performs a comprehensive system inspection and maintenance for station assets that also includes visual inspection and infrared scanning, as well as, station components maintenance. Some critical assets installed at stations are monitored through the SCADA system and all data collected during inspection are used for condition assessment. This allows Oshawa Power to capture and identify any asset deficiencies in order to develop a corrective action plan. The following maintenance activity and frequency are being performed in the station.

1. Visually inspect all station components including circuit breakers, station transformers and cooling fans, cable terminators, switchgear, station service transformers, batteries, battery chargers, lighting, heating, ventilation, drains, doors, locks, fences, safety equipment, fire extinguishers, eye-wash stations, and all associated devices used to provide protection, control, metering and monitoring of the station.
2. Maintain DC systems by checking and testing voltage of each cell and the total battery voltage and perform load testing on the batteries once a year.
3. Test and maintain the mechanical and electrical features of the protection control system.
4. Collect oil samples from transformers and tap changer compartments and send samples for oil testing and Dissolved Gas in Oil Analysis (DGA). Review test results to determine if further action/testing is required.
5. Perform detailed testing every three (3) years on the transformer including, but not limited to: turns ratio, doble, winding resistance, core ground, power dissipation factor, dielectric absorption, excitation current, cooling system, bushings, alarms and trip mechanism.
6. Complete on-load tap changer maintenance.
7. Check, clean and lubricate switchgear mechanisms, ventilation and fan.
8. Conduct infrared scanning on all high voltage station components.

Table 20 - Frequency of Station Inspection and Maintenance

Maintenance Activity	Frequency			
	Monthly	Quarterly	Annually	Other
Visual Inspection	X			
DC System Maintenance		X		
Infrared Scanning			X	
Insulating Oil Sample Testing			X	
Tap Changer Maintenance				3-year
Switchgear Maintenance				3-year
Protection Control System				3-year
Full Off-line Station Maintenance				3-year

Oshawa Power has improved station maintenance by transitioning to the maintenance activities as prescribed in the ANSI/NETA MTS-2023. The maintenance activities and frequency of those activities meet the minimum requirements as set out by Appendix C of the DSC by the OEB. These activities prolong station asset life and ensure all equipment is operating as designed and as expected.

In parallel with the fixed asset physical condition monitoring and testing described above, performance indicators, particularly those related to asset failures and root causes of power interruptions, are analyzed. Common causes are identified, and system enhancement or replacement projects are proposed where failures have significant implications for service reliability. Analysis is then completed to determine if the cost to continue making repairs (given the frequency of failure and likelihood of future failures), is more or less than the cost of replacement or upgrade. This applies to power transformers and station switchgear.

Data from the foregoing testing program and performance indicator analysis is comprehensively analyzed and the condition of each of Oshawa Power's significant assets is ranked based on the HI calculated in the most recent ACA. This HI is used to indicate if an asset can be maintained or replaced.

Oshawa Power's asset lifecycle practices are to minimize risks while maintaining an optimal system and ensuring the safety and system reliability of the critical distribution system infrastructure. This is achieved by utilizing the best asset management strategies in managing risks that include detailed inspection and testing, standard maintenance of assets and applying proper corrective actions for each asset based on risk and analysis. In doing so, the risk associated with each asset can be mitigated and the prioritization of investments can be optimized over a period of time.

As described in Section 5.3.1.1, Oshawa Power performs assessments to identify and assess risks and related impacts associated with its critical assets, such as transformers, station breakers, main underground and overhead feeders, etc. The risk assessment considers safety risks, reliability risks, and environmental risks. Impact assessment considers potential consequences of not proceeding with the investment. These assessments help to prioritize investments and develop mitigation strategies to address identified risks. Investments assessed for risk and impact are further considered in the planning process where additional factors such as budget spend and rate impact balance the need for investments to maintain/improve reliability with expenditures that impact the ratepayer.

5.3.4 System Capability Assessment for REG and DER

At the time of preparing this document, there is 10,155.45kW connected to Oshawa Power's distribution system. This includes renewable energy, Combined Heat and Power, microgrids and battery energy storage. Oshawa Power is in receipt of two (2) proposals to connect small generation applications for a total of 547.38kW.

Additionally, Oshawa Power submitted a request to Hydro One to increase the capacity threshold allocation on its respective 44KV buses at Hydro One TSs, so that Oshawa Power can accommodate supplementary DER connections on its network.

Currently, Hydro One's TSs do not have any short circuit capacity or thermal capacity constraints that would limit the amount of DERs to be added onto any particular TS or feeder. The information in the table was provided by Hydro One in the published "Hydro One List of Station Capacity" (see Appendix D) and indicates approximate amount of generation that can be added at each Hydro One TS.

The assessment presents that there are no constraints and that there is sufficient capacity on the distribution system to connect future DERs subject to specific Connection Impact Assessments (CIA); as such, Oshawa Power does not anticipate any need for immediate investments (expansion or reinforcement) in the forecast period to facilitate DER connections.

Oshawa Power filed a Renewable Energy Generation Investment Plan October 2024. A copy of the plan is located in Appendix F.

5.3.5 Non-Wires Solutions to Address System Needs

The OEB's Non-Wires Solutions Guidelines (NWS Guidelines) provides guidance on the role of non-wires solutions (NWSs) for rate-regulated electricity distributors, taking into account current and previous provincial conservation and demand management (CDM) frameworks and addressing the treatment of NWSs in distribution rate applications.

After reviewing the system needs to be addressed in Oshawa Power's 2026-2030 DSP, Oshawa Power does not currently have any system needs in this 2026-2030 DSP that would be feasible for a NWS. Instead, in Appendix A, Oshawa Power has provided a business case for capital expenditures aligning with the NWS Guidelines. The business case includes research, system needs analysis, cost benefit analyses and a proposed approach to implementing NWS projects in order to prepare for and mitigate future system needs, especially if demand should materialize at pace with the anticipated energy transition and the growth policy targets attributed to Oshawa Power's service territory. This approach will be essential to keeping costs reasonable for customers during the energy transition, as it represents a new tool in the toolbox when it comes to pacing major investments. This approach also enables Oshawa Power to effectively continue to secure valuable external investments; a strategy which has brought-in grants worth approximately $1M/year over the last decade. Finally, this approach allows Oshawa Power to co-invest in projects being developed by its Key Accounts customers in a timely and cost-effective manner. Without the ability to co-invest, Oshawa Power's customers would miss out on the benefits of the NWS policy.

NWS Consideration within the Planning Process

Oshawa Power took a methodical approach to the consideration of NWS in its planning efforts throughout 2024 after the release of the NWS guidelines in March, in preparation for this DSP. At a high level, Oshawa Power held regular planning events with internal and external stakeholders throughout the year. Planning content covered needs and opportunities within the transmission, distribution and customer "sides" of the system, and also included the submission of three (3) external funding proposals for NWS--focused projects that were identified through the planning process.

As a starting-point, the team reviewed the NWS guidelines and known areas of fit or opportunity within Oshawa Power's distribution system. The team then developed a list of potential NWS investments, and a working group determined a strategy for collaborating on evaluating NWS options for the DSP projects.

In June 2024, Oshawa Power submitted a funding proposal to Natural Resources Canada Energy Innovation Program aimed at developing Distribution System Operator (DSO) competence, while demonstrating the use of a DSO as an NWS to support equity deserving customers. The proposal was accepted and the project will kick-off in April 2025.

While drafting the 2026-2030 Capital Plan, NWS considerations for offsetting the needs were explored and it was determined that NWSs would likely not be eligible for offsetting elements in the capital plan. A deeper dive and brainstorming session led to the development of improved concepts for NWS projects and improved understanding of cost-offsets that would need to be achieved.

In July 20204, Oshawa Power submitted an NWS-focused proposal to the Grid Innovation Fund, which was ultimately not funded. The proposal aimed to combine managed charging with battery energy storage at the street-level transformer for maximized asset life extension during the ramp-up to electric vehicles.

During the fall of 2024, engagement with Key Account entities resulted in significant interest in collaborating on NWS opportunities.

An Expression of Interest was submitted to Natural Resources Canada for $22M to cover embedded smart grid with clean energy solutions as an NWS in support of zero emission transit in the Region of Durham. This expression of interest was not accepted; however, the transit agencies operating in Oshawa are still open to collaboration on grant funding for their projects, and on working toward shared distributed energy resources under the NWS framework.

The planning sessions yielded an NWS strategy that is provided in detail in the NWS Business Case.

Degree of Consideration

Oshawa Power's degree of consideration for NWS throughout the planning for the DSP was commensurate with the following factors:

1. The timing of the release of the new guideline being well within the planning deadlines for the 2026-2030 DSP; i.e., Oshawa Power implemented as much late-stage planning as possible within the available timeframe.
2. The fact that all NWS eligible projects were included in the post 2030 timeline, unless the high load growth associated with the energy transition materializes and requires their early offset with an NWS.
3. The availability of highly valuable external funding sources; i.e., as noted above, Oshawa Power put significant planning resources into three (3) grant applications for NWS projects because time sensitive grants were available.
4. Interest shown from stakeholders; i.e., conversations with Key Account entities, prospective NWS collaborators and solution providers showed a high degree of promise, and interest to move forward with explorations. Further information on this can be found in the NWS Business Case, the Business and Large Customer Report and Section 5.2.2 on Coordination with Third Parties.
5. The size of the requested investment being above Oshawa Power's materiality threshold, but below the $2M requirement threshold for NWS benefit cost analyses. The sections on DSP NWS Budget and Learnings from Others will provide further context on the dollar amount requested per year.

Learnings from Others

While engaging in the NWS planning activities highlighted in this section Oshawa Power gained three significant insights detailed below.

1. Timing Impacts on BCA Outcomes

Oshawa Power submitted a Grid Innovation Fund proposal that was ultimately not accepted. The project sought to build on research done by Toronto Hydro Electric Systems Limited (Toronto Hydro) to implement battery energy storage at transformers to prolong the asset's life via load smoothing. The goal was to pair transformer batteries with a residential managed charging

program that could use algorithms and machine learning to optimize transformer loading. Given the very high comparative costs of batteries as opposed to transformers, the project would have initially had a negative BCA outcome.

One of the key tasks of the project was to forecast the point at which installing batteries at grid edge would have been cost effective, based on the level of saturation of grid upgrades required. Oshawa Power will plan to incorporate forecasting of BCA turning points into future DSP planning, as many NWSs may take several years to accrue benefits.

2. Operations and Maintenance of NWSs

Oshawa Power has assisted with the development of several distributed energy resources in the past, via the organization's innovation programming. Please see Exhibit 1, Section 1.8 on Facilitating Innovation for details on these projects. Several lessons learned have been garnered through our past work, which will be relevant to NWS deployment. Specifically, Oshawa Power notes that a high degree of competence will be required to guarantee up-time and levels of equipment maintenance associated with maintaining utility reliability indices. As the saturation of distributed energy resources grows, distributor involvement in third party asset monitoring may become more important. It is unclear if potential partners will have the skill sets required or be willing to take on contractual obligations associated with owning an energy asset that addresses electricity demand on the grid. Furthermore, early Key Account preferences seem to lean toward procuring energy benefits from NWSs owned by the distributor, rather than the other way around (being customer-owned). Going forward, Oshawa Power will put a focus on cataloguing customer preferences in this matter.

3. Fast Pace of Change and the Need for Ongoing Monitoring

Like most Ontario electricity distributors, Oshawa Power has noted the fast pace of change with regard to forecasted load growth and new incoming customer requests. Based on the scale and speed of change, it is possible that new NWS projects may become viable each year. Distributors will need to treat NWS analysis as an ongoing, "living" aspect to planning, rather than an annual exercise. Furthermore, distributors will need access to the IESO's Save On Energy program designs and future plans in order to develop complementary and non-duplicative projects.

5.4 Capital Expenditure Plan

This section outlines Oshawa Power's capital expenditure plan for the 2026–2030 forecast period. It provides an in-depth analysis of proposed investments, guided by Oshawa Power's asset management system and planning process, as detailed in Section 5.3. Additionally, it highlights key trends, variances, and interdependencies between the forecast period (2026–2030) and the historical period (2021–2025).

The subsections below offer detailed insights into capital expenditure performance, forecasting, and modifications:

Section 5.4.1.1 – Capital Expenditure Performance

Explains variances by investment category, comparing actual expenditures against Ontario Energy Board (OEB) approved/planned amounts. It also examines differences in the volume of work completed versus projections.

Section 5.4.1.2 – Capital Expenditure Forecast

Forecasted capital investments are analyzed at a category level, with an emphasis on key investment drivers and objectives within each category.

Section 5.4.1.3 – Forecast vs. Historical Analysis

Compares capital expenditures for the 2026–2030 forecast period against historical spending (2021–2025), identifying trends, shifts in priorities, and influencing factors.

Section 5.4.1.4 – Modifications to Capital Programs

Any significant changes to Oshawa Power's typical capital programs in the forecast period are outlined here, including adjustments to scope, funding allocations, or strategic priorities.

Section 5.4.1.5 – Impact of Capital Expenditure on System O&M

Discusses how planned capital expenditures affect operations and maintenance (O&M) costs, including potential efficiencies, cost savings, or increased operational requirements.

5.4.1 Capital Expenditure Summary

The capital expenditure plan summary outlines Oshawa Power's planned investments over a 10-year period, encompassing five (5) historical years and five (5) forecasted years. Capital investments for the 2026–2030 DSP planning period are categorized according to the four primary DSP investment categories - System Access, System Renewal, System Service, and General Plant.

A summary of OEB-approved capital expenditures from Oshawa Power's previous filing along with actuals and variances are presented in Table 22, and discussed in detail in section 5.4.1.1 Capital

Expenditure Performance. Figures 21 to 25 depict annual net variances across the four investment categories. Forecasted expenditures by category are detailed in Table 22. Additional information can be found in Chapter 2 Appendices 2-AA and 2-AB.

Table 21 – Appendix 2AB

CATEGORY	AMOUNT CATEGORY	HISTORICAL VARIANCE ANALYSIS																			
		2021				2022				2023				2024				2025			
		Plan	Act.	Var	Var	Plan	Act.	Var	Var	Plan	Act.	Var	Var	Plan	Act.	Var	Var	Plan	Bud.	Var	Var
		$ '000			%	$ '000			%	$ '000			%	$ '000			%	$ '000			%
System Access	Gross Capital	5,911	4,219	-1,692	-28.6%	5,016	3,839	-1,177	-23.5%	4,662	7,105	2,443	52.4%	4,767	6,694	1,927	40.4%	4,772	7,995	3,223	67.5%
	Contributed Capital	-2,043	-1,350	693	-33.9%	-1,813	-866	947	-52.2%	-1,718	-2,446	-728	42.4%	-1,738	-4,433	-2,695	155.0%	-1,733	-2,140	-407	23.5%
	Net Capital	3,868	2,869	-999	-25.8%	3,203	2,973	-230	-7.2%	2,944	4,659	1,715	58.3%	3,029	2,261	-768	-25.3%	3,039	5,855	2,816	92.7%
System Renewal	Gross Capital	6,198	6,507	309	5.0%	9,636	6,538	-3,098	-32.2%	9,122	12,069	2,947	32.3%	9,209	4,585	-4,624	-50.2%	9,143	7,948	-1,195	-13.1%
	Contributed Capital	0	-578	-578	-	0	-324	-324	-	0	-124	-124	-	0	-424	-424	-	0	-204	-204	-
	Net Capital	6,198	5,929	-269	-4.3%	9,636	6,214	-3,422	-35.5%	9,122	11,945	2,823	30.9%	9,209	4,162	-5,047	-54.8%	9,143	7,745	-1,398	-15.3%
System Service	Gross Capital	1,109	2,828	1,719	155.0%	799	953	154	19.3%	1,383	1,294	-89	-6.4%	886	1,805	919	103.7%	995	1,093	98	9.8%
	Contributed Capital	0	-120	-120	-	0	-11	-11	-	0	-10	-10	-	0	0	0	-	0	0	0	-
	Net Capital	1,109	2,708	1,599	144.2%	799	942	143	17.9%	1,383	1,284	-99	-7.1%	886	1,805	919	103.7%	995	1,093	98	9.8%
General Plant	Gross Capital	1,775	1,046	-729	-41.1%	851	1,271	420	49.4%	994	1,721	727	73.1%	875	576	-299	-34.1%	713	2,716	2,003	281.0%
	Contributed Capital	0	0	0	-	0	0	0	-	0	0	0	-	0	0	0	-	0	0	0	-
	Net Capital	1,775	1,046	-729	-41.1%	851	1,271	420	49.4%	994	1,721	727	73.1%	875	576	-299	-34.1%	713	2,716	2,003	281.0%
TOTALS	**Gross Capital**	**14,993**	**14,601**	**-392**	**-2.6%**	**16,302**	**12,601**	**-3,701**	**-22.7%**	**16,161**	**22,189**	**6,028**	**37.3%**	**15,737**	**13,660**	**-2,077**	**-13.2%**	**15,623**	**19,752**	**4,129**	**26.4%**
	Contributed Capital	**-2,043**	**-2,049**	**-5**	**0.3%**	**-1,813**	**-1,201**	**612**	**-33.7%**	**-1,718**	**-2,580**	**-862**	**50.2%**	**-1,738**	**-4,856**	**-3,118**	**179.4%**	**-1,733**	**-2,343**	**-610**	**35.2%**
	Net Capital	**12,949**	**12,552**	**-397**	**-3.1%**	**14,489**	**11,400**	**-3,089**	**-21.3%**	**14,443**	**19,608**	**5,165**	**35.8%**	**13,999**	**8,804**	**-5,195**	**-37.1%**	**13,890**	**17,409**	**3,519**	**25.3%**
O&M	**O&M**	**4,331**	**3,425**	**-906**	**-20.9%**	**4,161**	**3,717**	**-444**	**-10.7%**	**5,489**	**4,319**	**-1,170**	**-21.3%**	**4,488**	**4,276**	**-212**	**-4.7%**	**3,861**	**3,861**	**0**	**0.0%**

Table 22 - Forecasted Expenditures

FORECAST CAPITAL EXPENDITURE ($' 000)							
Category	**Amount Type**	**2026**	**2027**	**2028**	**2029**	**2030**	**TOTAL**
System Access	Gross Capital	9,186	9,270	9,356	9,443	9,532	**46,787**
	Contributed Capital	-2,916	-2,941	-2,965	-2,991	-3,016	**-14,829**
	Net Capital	6,270	6,330	6,391	6,452	6,515	**31,958**
System Renewal	Gross Capital	8,045	8,756	7,056	7,421	8,108	**39,385**
	Contributed Capital	-312	-312	-312	-312	-312	**-1,560**
	Net Capital	7,733	8,444	6,744	7,109	7,796	**37,825**
System Service	Gross Capital	1,336	300	778	962	588	**3,964**
	Contributed Capital	0	0	0	0	0	**0**
	Net Capital	1,336	300	778	962	588	**3,964**
General Plant	Gross Capital	1,680	1,655	1,730	1,155	802	**7,022**
	Contributed Capital	0	0	0	0	0	**0**
	Net Capital	1,680	1,655	1,730	1,155	802	**7,022**
TOTALS	**Gross Capital**	**20,247**	**19,981**	**18,920**	**18,980**	**19,030**	**97,158**
	Contributed Capital	**-3,228**	**-3,253**	**-3,277**	**-3,303**	**-3,328**	**-16,389**
	Net Capital	**17,019**	**16,729**	**15,642**	**15,678**	**15,701**	**80,769**
System O&M	**O&M**	**$5,353**	**$5,487**	**$5,624**	**$5,765**	**$5,909**	**28,137**

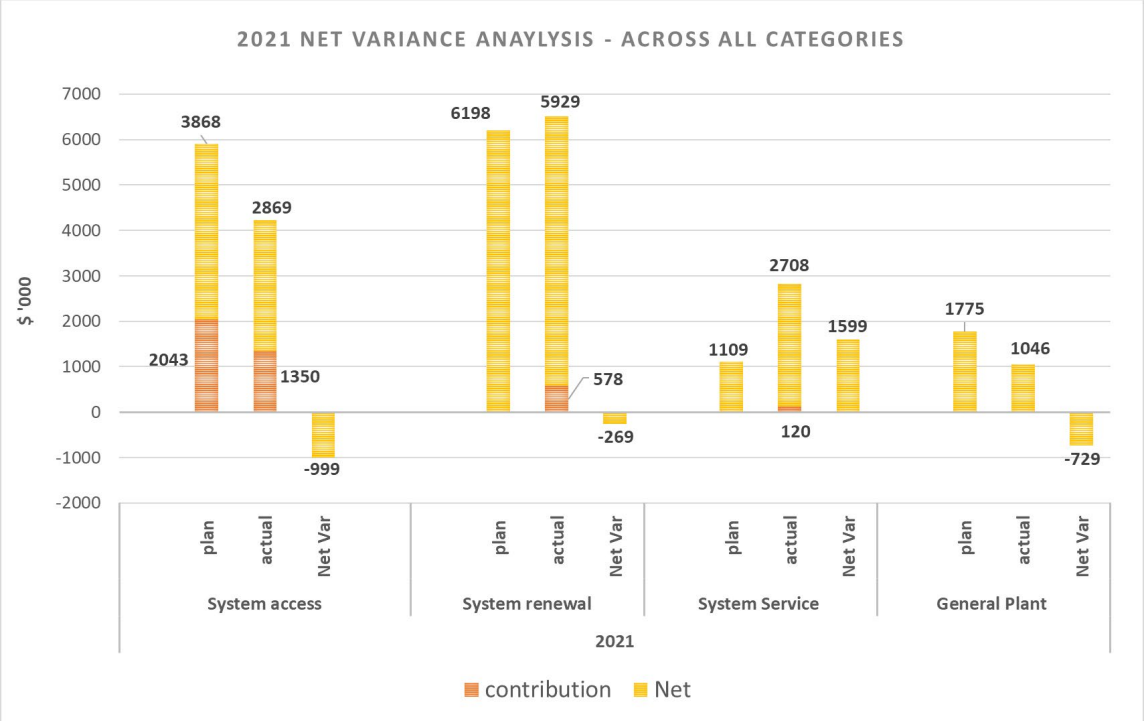


Figure 21 – Net Variance Analysis 2021

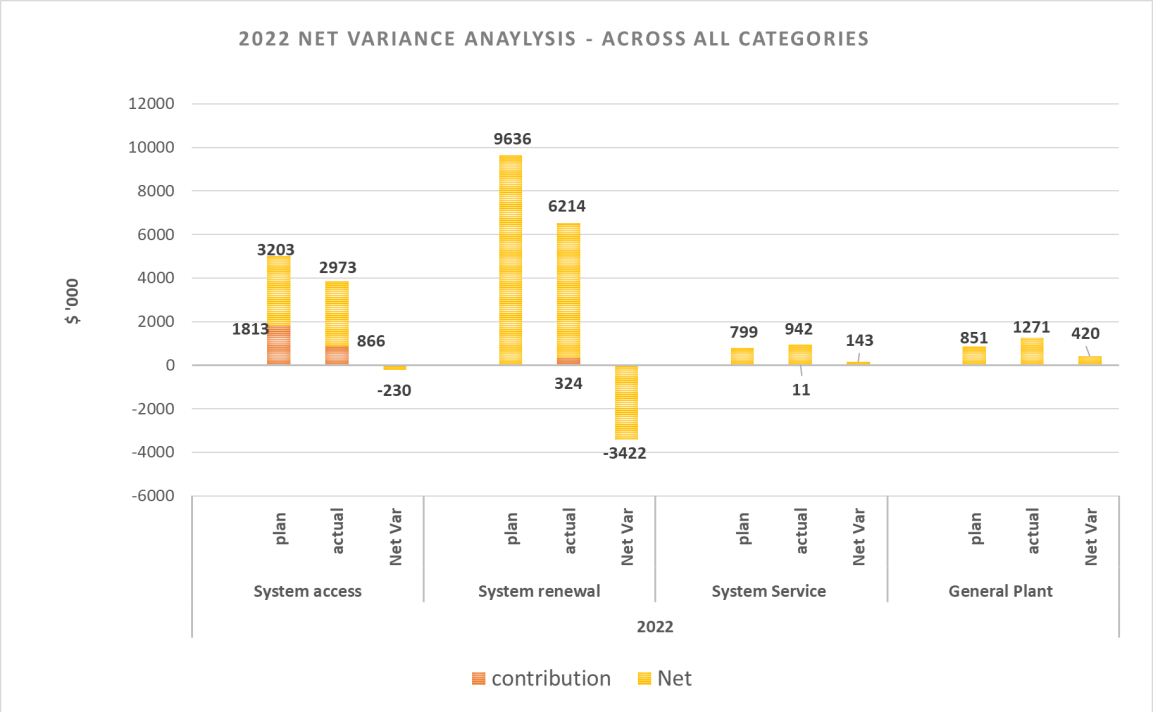


Figure 22 – Net Variance Analysis 2022

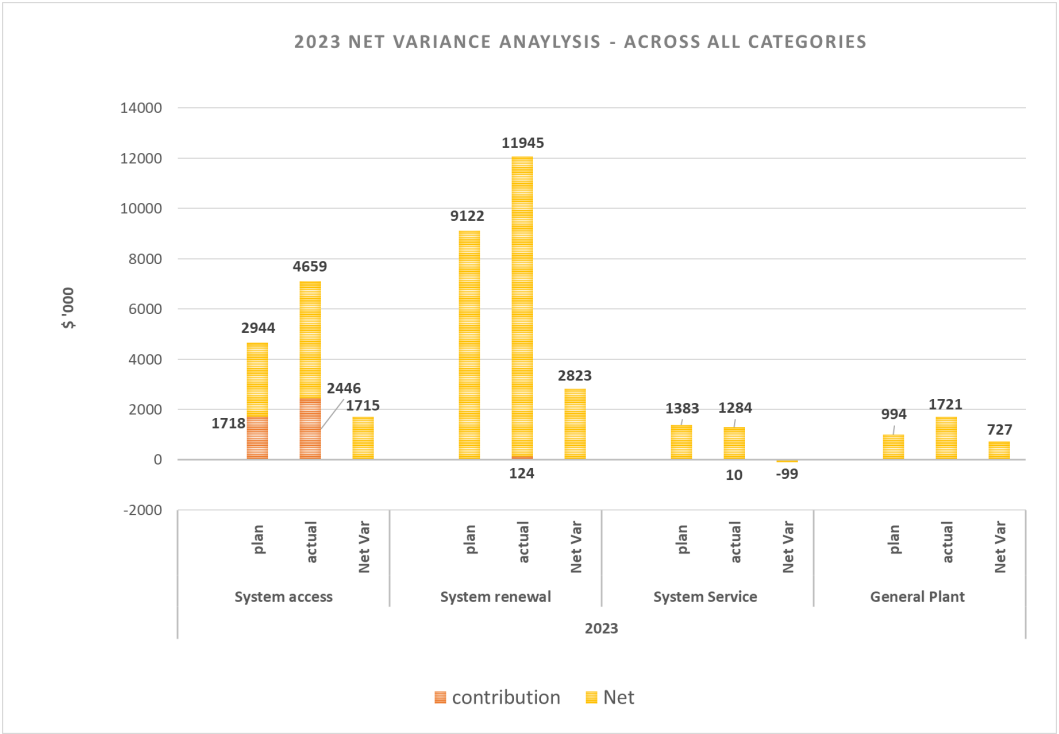


Figure 23 – Net Variance Analysis 2023

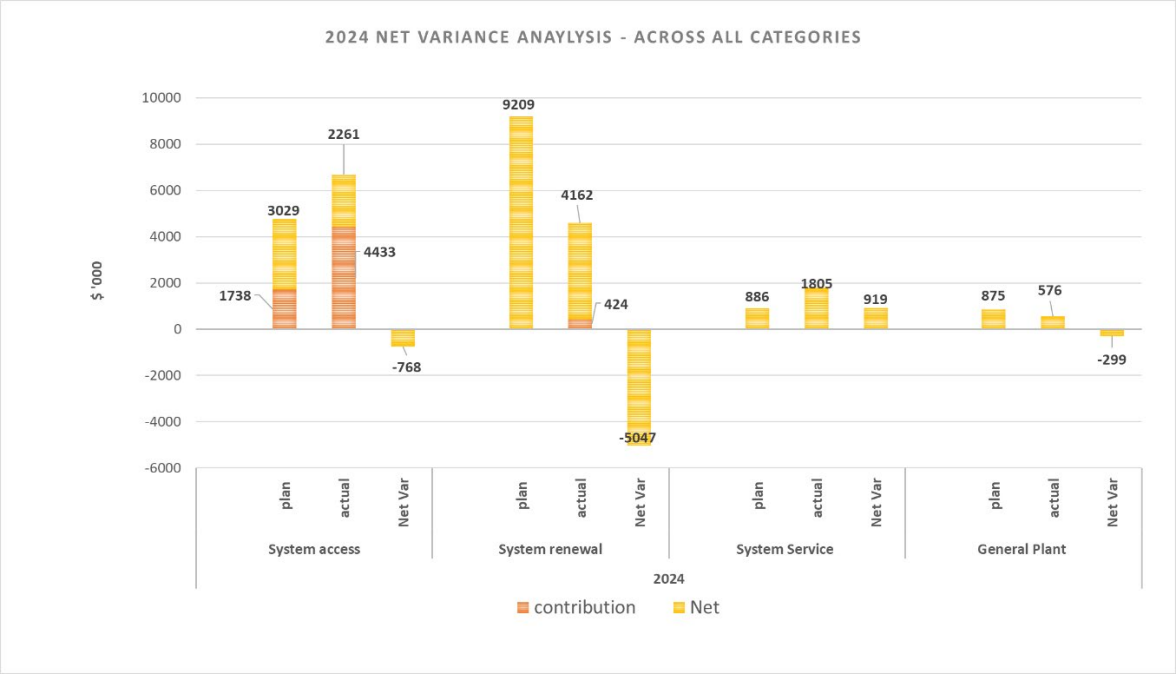


Figure 24 – Net Variance Analysis 2024

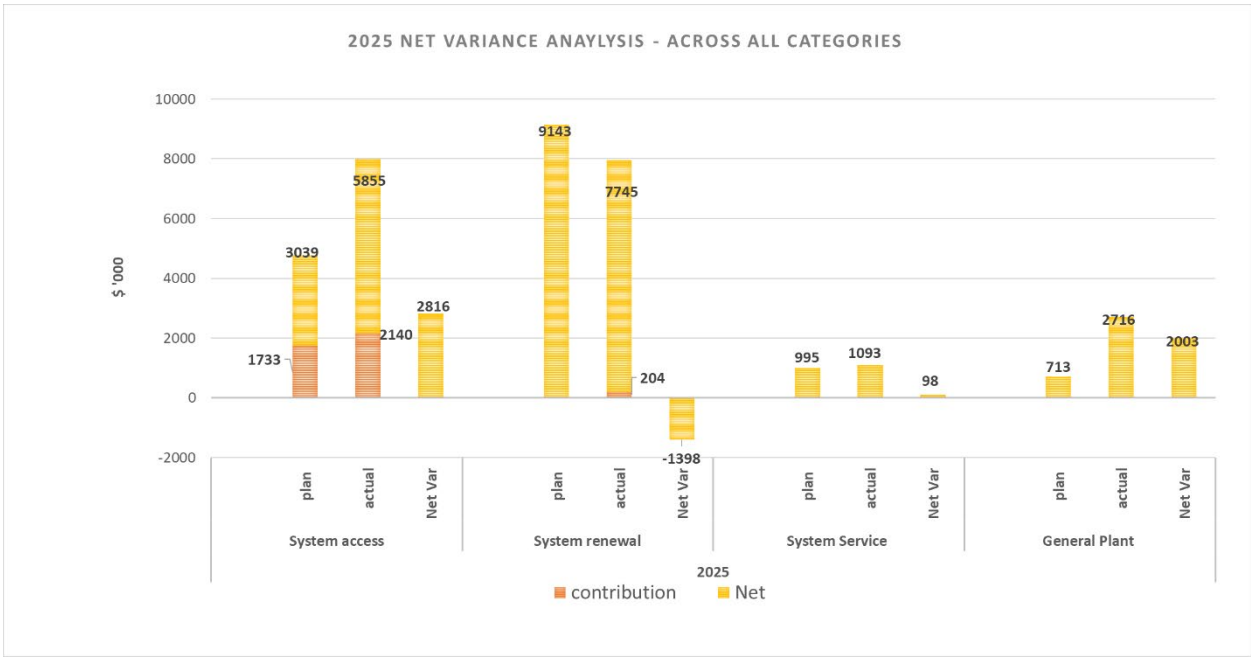


Figure 25 – Net Variance Analysis 2025

5.4.1.1 Capital Expenditure Performance

The final variance percentages and amounts represent net values, comparing actuals against OEB approved amounts. However, variance discussions are presented in terms of gross values, as they

provide a clearer picture of project timelines, and the volume of work completed. For example, a low variance between anticipated gross expenditures and planned expenditures would indicate that the work was completed as expected. However, if contributed capital was higher than anticipated, it could create the impression that less work was performed than was actually completed. Discussing work performed that make up gross values, provides a more accurate reflection of actual project activity and controllable costs.

SYSTEM ACCESS

System Access jobs are customer driven and are expected to have large variability due to the reactive nature of jobs that fall under this category.

Figure 26 shows the net expenditures under System Access for the 2021-2025 historical period.

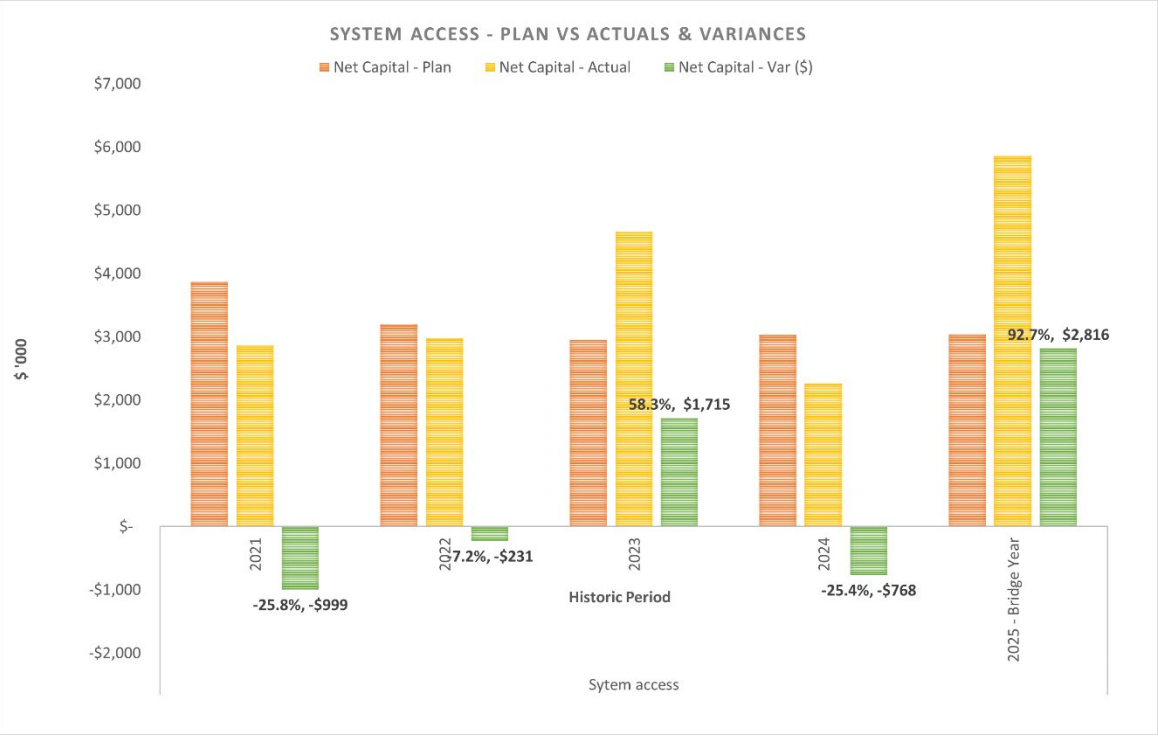


Figure 26 – System Access Plan vs Actuals & Variance

2021 – 25.8% ($999K) Under Budget

Underspend Areas

The most significant underspending was in Expansions, which had a forecast of $2.38M but only incurred $407K, resulting in a $1.97M (83%) variance. This shortfall was primarily due to the impact of COVID-19 on housing developments, as supply chain disruptions, labor shortages, market uncertainty, and health & safety restrictions led developers to slow or defer projects.

Overspend Areas

The largest overspending occurred in Third-Party Relocations, where actual costs reached $2.17M, exceeding the $1.82M budget by $347K (19%), due to a higher volume of relocation work than initially planned.

Overall Impact

The total System Access Gross Expenditures were $4.2M, which was 1.7M (29%) lower than the approved $5.9M, primarily due to lower subdivision expansion spending. Connections and Revenue Metering also had a combined underspending impact. However, lower capital contributions to gross expenditures ratio, reduced the net variance. The effect of lower expenditures in expansions partially offset by higher third-party relocation costs and reduced contributions resulted in an overall Net 25.8% variance, or $999K under budget.

2022 – 7% ($230K) Under Budget

Underspend Areas

The most significant underspending, as in 2022, was in Expansions, where actual costs totaled $404K, compared to the $2.38M forecast, resulting in a $1.98M (83%) variance. This shortfall was due to the lingering effects of COVID-19 on housing developments, including supply chain disruptions and labor shortages during the transition back to in-person operations. While efforts resumed, the subdivisions were still not ready to be put into service by the end of 2022.

Overspend Areas

Third-Party Relocations exceeded the forecast by $555K (62%), with actual costs reaching $1.45M compared to the $900K budget. This overage was driven by a higher-than-anticipated volume of relocation projects. The Region driven Simcoe-Winchester Road widening project was significant, requiring multiple hydro asset relocations.

Additionally, Connections exceeded the budget by $229K (20.8%), with actual costs at $1.33M compared to the planned $1.1M. This was due to a higher number of customer connection and upgrade requests, as well as increased costs in material and labor.

Overall Impact

The Total System Access Gross Expenditures amounted to $3.84M, which was $1.2M (23.5%) below the approved budget of $5.02M, primarily driven by reduced spending on expansions.

However, actual contributions to gross expenditure ratio was less than anticipated due to developers and other third-party stakeholders contributing lower amounts.

The combined effect of lower expansions expenditures offset by overspending on connections and third-party relocations and lower contributions resulted in a 7% variance, or $230K under budget.

2023 – 58% ($1.72M) Over Budget

In 2023, System Access activities experienced a significant surge as the lingering effects of COVID-19 subsided. Accelerated development, increased customer demand and a rise in third-party infrastructure projects drove higher-than-anticipated expenditures. With supply chain disruptions easing and economic activity picking up, many previously deferred projects moved forward, resulting in cost overruns across most major investment categories. While increased capital contributions from developers helped offset some of these costs, the overall variance remained substantial due to the scale of the overspending.

Underspend Areas

The AMI system upgrade was the only category with underspending, coming in $83K (19%) below budget. This was due to a lower-than-expected number of failed meters requiring replacement with the next generation of smart meters.

Overspend Areas

Expansions were the largest driver of the overspend, exceeding the budget by $1.1M (43%). This was primarily due to accelerated investment in housing developments that had been previously deferred. Connection expenditures also significantly exceeded budget by $611K (56%), largely due to a higher than expected volume of new service connections and upgrades, combined with inflationary pressures on material and labor costs.

Third-party relocations saw one of the largest percentage variances, coming in $697K (134%) over budget. Major projects contributing to this overspend included the Region Victoria Street-Bloor Street road widening and Hydro One's Wilson M18 Feeder relocation.

Overall Impact

Total System Access gross expenditure reached $7.1M, surpassing the planned $4.66M by $2.4M (52%) due to increased expansion and third-party relocation efforts. Lower capital contribution to gross expenditure ratio also contributed to the net variance of $1.72M (58%) over budget.

2024 – 25% ($768K) Under Budget

Underspend Areas

Expansions were the largest contributor to underspending, coming in $2.23M (94%) below budget. While multiple subdivision projects were worked on throughout the year, none were energized by the end of the fiscal year. These projects are expected to be put into service in early 2025.

Overspend Areas

Third-Party Relocations exceeded planned gross amounts by $3.4M (572%), making it the largest overspend category. The variance was driven by asset relocation projects required for municipal and provincial infrastructure work such as the Thornton Road North road widening project of $1.1M, as well as the Hydro One driven Wilson TS Feeder Relocate Project of $2.6M. However, Hydro One's feeder relocate project was fully offset by contributions thus leaving no impact on the net variance.

Connections came in $669K (61%) over budget, due to a higher than expected number of new upgrade and connection requests. Ongoing rising material and labor costs, combined with increased customer demand, contributed to this overage.

Overall Impact

Total System Access gross expenditures reached $6.7M, exceeding the planned gross amount of $4.77M by $1.9M (40%).

However, a significantly higher capital contribution ($4.4M) to gross expenditure ratio and large underspend in Expansions resulted in a net underspend of $768K (25%) below budget. The combined underspend effect of $51K from Revenue Metering and AMI system upgrades also played a minor role in ending the year under budget.

2025 – Forecasted to be 93% ($2.82M) Over Budget

Underspend Areas

AMI System Upgrades are forecasted to be $240K (49%) under budget due to a strategic reallocation of funds to higher-priority areas, with the recognition that a proactive meter replacement program is set to begin in 2026.

Overspend Areas

Expansions are forecasted to be $1.59M (67%) over budget, making them the largest contributor to the variance. This is due to the anticipated completion and energization of multiple subdivision

projects that were carried over from 2024, as well as additional expansion work in 2025 required to accommodate new developments.

Third-Party Relocations are projected to exceed the budget by $1.17M (202%), representing the largest percentage variance. This increase is primarily driven by infrastructure relocation work associated with the City's widening of Conlin Road E (from Harmony Road North to Grandview Street North) and regional road improvements on Wentworth Street East (from Cedar Street to Farwell Street), among others. Much of the new Conlin Road East work was not anticipated when the last DSP was filed, however the City shifted its focus to this phase of the common road widening initiative.

Connections are projected to be $621K (56%) over budget, due to higher than anticipated customer demand for new service connections and upgrades, as supported by historical trends in this area.

Overall Impact

Total System Access gross expenditures are forecasted to reach $7.99M, exceeding the DSP approved $4.77M by $3.22M (68%). Lower capital contributions to gross expenditure ratio are expected to further increase net variance. Lower contributions are expected due to focus on third party relocations - which typically receive lower contributed capital.

Though strategic reallocations within the category offer some relief, net expenditures are forecasted to be $2.82M (93%) over budget.

SYSTEM RENEWAL

System Renewal has both proactive and reactive components. Based on higher priority needs arising budget reprioritizations cause variances under this category.

Figure 27 shows the net expenditures under system renewal for the 2021-2025 historical period.

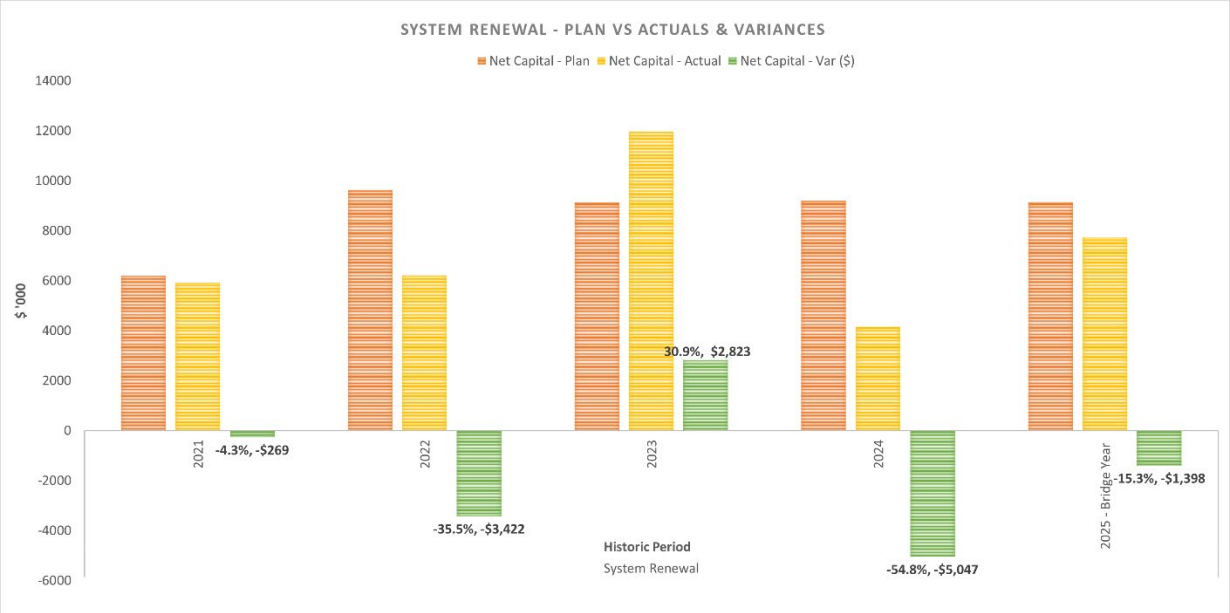


Figure 27 – System Renewal Plan vs Actuals & Variance

2021 – 4% ($269K) Under Budget

In 2021, system renewal expenditures were largely in line with expectations, with some notable variances in key programs. While certain projects, such as reactive maintenance, significantly exceeded budget due to unanticipated failures and emergency work, other programs, including the overhead and underground system rebuilds, came in under budget.

Underspend Areas

The Overhead System Rebuild Program came in $739K (37%) under budget due to some projects being put in service in later years.

The Underground System Rebuild Program was $526K (39%) under budget. This was due to municipal cable replacement being deferred and incorporated into the Municipal Substation Switchgear Replacement Program in 2023.

The Municipal Substation Switchgear Replacement Program of $500K being consolidated into the 2023 budget, also contributed to the underspend.

Overspend Areas

Reactive Maintenance was the primary driver of overspending, exceeding the budget by $2.15M (194%). This was largely due to the replacement of run-to-failure assets, including overhead and underground transformers, switches, and insulators, as well as a higher-than-expected volume of emergency repairs and unplanned asset failures—such as primary and secondary cable faults and

damage from adverse weather and motor vehicle accidents—that required immediate corrective action. The increased expenditures were non-discretionary to maintain system reliability and ensure compliance with safety standards.

Overall Impact

Total system renewal gross expenditures reached $6.51M, exceeding the approved $6.20M by $309K (5%). However, with the inclusion of capital contributions totaling $578K, the net system renewal expenditures were $5.93M, resulting in being $269K (4%) under budget.

2022 – 35% ($3.42M) Under Budget

In 2022, system renewal expenditures were significantly lower than planned, primarily due to the deferral of capital projects. While reactive maintenance saw a sharp increase due to unplanned asset failures, major planned investments, including the Municipal Substation Switchgear Replacement Program, were postponed, contributing to the overall underspend. Oshawa Power was operating below the typical staffing levels expected for a utility of its size and demographic. Internal resource constraints required the deferral of certain system renewal initiatives to 2023 in order to alleviate the burden on existing staff while continuing to meet regulatory obligations and performance targets.

Underspend Areas

The Municipal Substation Switchgear Replacement Program was deferred, resulting in a full budget variance of $2.13M (100%). The delay was due to project rescheduling and coordination with broader station renewal initiatives, pushing expenditures to future years.

The Overhead System Rebuild Program came in $1.02M (37%) under budget, due to some project in service deferrals to later years.

The Underground System Rebuild Program was $990K (41%) under budget. Deferral of some projects including municipal cable replacement work were major drivers.

Overspend Areas

Reactive Maintenance exceeded budget by $1.07M (94%) due to a higher-than-expected number of emergency repairs and equipment failures, as well as focus on run to failure asset replacements identified during Oshawa power's robust three year inspection and maintenance cycle. The need for unplanned asset replacements and corrective actions to maintain safety and system reliability drove costs beyond initial forecasts.

Overall Impact

Total system renewal gross expenditures reached $6.54M, lower than the planned $9.64M by $3.10M (32%). Capital contributions of $324K further reduced the net expenditure, leading to a total variance of $3.42M (35%) under budget. While reactive maintenance increased significantly, the overall shortfall was primarily driven by the deferral of the Municipal Substation Switchgear Replacement Program and other Overhead and Underground rebuild projects.

2023 – 31% ($2.82M) Over Budget

In 2023, system renewal expenditures exceeded budget by $2.95M (32%), primarily driven by higher-than-anticipated costs across several major programs. While planned overhead and underground rebuild projects were executed, previously deferred projects and higher material and labor costs contributed to substantial variances. Additionally, the Municipal Substation Switchgear Replacement Program incurred significantly higher costs due to a broader project scope, while reactive maintenance also saw an increase due to unexpected asset failures.

Underspend Areas

The Municipal Substation Transformer Replacements and Oil Containment Installation program was deferred, resulting in a $1.5M (100%) underspend. Following industry best practices on condition-based assessment, the need to replace these transformers was re-evaluated, and it was determined that deferring their replacement could be defended as being more prudent.

The Vault Transformer Replacement Program was $84K (52%) under budget as the company re-evaluated the necessity of certain replacements. Following industry best practices and focusing on condition-based replacement needs, as opposed to service life (age) heavy replacement recommendations, led to fewer replacements than initially planned.

Overspend Areas

The Municipal Substation Switchgear Replacement Program exceeded budget by $986K (46%) due to an expanded scope that included riser pole replacements, extensive duct work, concrete encasement, road crossings, and increased cable material costs. These additional requirements were necessary to ensure long-term reliability and compliance with evolving infrastructure standards.

The Overhead System Rebuild Program was $1.59M (79%) over budget. This was due to projects from prior years being placed in service in 2023. Escalating material and labor costs were also experienced.

The Underground System Rebuild Program also exceeded budget by $412K (34%), due to projects from prior years being placed in service in 2023. Inflation and supply chain challenges also impacted key underground infrastructure components resulting in overspend.

Reactive maintenance saw a $1.53M (132%) increase over budget due to run-to-failure asset replacements identified during the inspection and maintenance cycle, and higher-than-expected number of emergency repairs and asset failures, necessitating unplanned replacements.

Overall Impact

Total system renewal gross expenditures reached $12.07M, exceeding the planned $9.12M by $2.95M (32%). While $124K in capital contributions helped offset some of the increased costs, the net impact was a $2.82M (31%) over-budget variance. The primary drivers of this overspend were the expanded scope of the Municipal Substation Switchgear Replacement Program, previously deferred projects being placed in service, rising costs in overhead and underground rebuilds, and an increase in reactive maintenance expenditures.

2024 – 55% ($5.05M) Under Budget

In 2024, System Renewal expenditures came in significantly below budget, with a total variance of $5.05M (55%) under budget. This underspending was mainly driven by delayed or deferred projects, particularly in municipal switchgear replacements, station transformer replacements and overhead system rebuilds. However, the Reactive program experienced notable overspending that partially bridging the variance from budget. The deferrals were necessary in order to facilitate acquisition of land for Oshawa Power's new Consolidated Operational and Administrative Building. It is not reflected in in-service amounts, as the building is anticipated to be placed in service in 2027. The investment will remain in Work in Progress until then.

Underspend Areas

The Municipal Substation Switchgear Replacement Program of $2.13M (100%) was deferred, leading to no expenditures in 2024.

Municipal Transformer Replacements and Oil Containment Installation of $1.5M (100%) was also deferred. The decision was further substantiated by an options analysis report indicating that the transformers are in good condition and would not require replacements in the current and upcoming DSP cycle. Enhanced inspection, maintenance practices and improved record-keeping helped confirm that replacements are not necessary at this time, as reflected in the latest ACA.

The Overhead System Rebuild Program was $840K (39%) below budget, primarily due to the deferral of a project that was planned for Dearborn Avenue, Kendal Aveune, Mary Street North, Agnes Street, Elgin Street East, William Street East, Ontario Street, and Division Street. The deferral was necessary to reallocate funds to other priorities. This project is now scheduled for completion within the 2026-2030 forecast period, based on the findings of the latest ACA.

Overspend Area

Reactive Program exceeded its budget by $802K (68%). This overspend was driven by unanticipated system repairs, replacements brought to light by maintenance and inspections of typical "run-to-failure" assets such as overhead and underground transformers, reactive replacements arising from primary and secondary cable faults, motor vehicle accidents, dig-ins, and trouble calls.

Overall Impact

Total System Renewal gross expenditures amounted to $4.59M, which was $4.62M (50%) below the planned $9.21M. Capital contributions totaling $424K, further added to the net variance.

The net variance for System Renewal was $5.05M (55%) under budget, primarily due to deferrals, scope reductions, and a reallocation of budget to other projects.

2025 – Forecasted to be 15% ($1.40M) Under Budget

Based on current projections, System Renewal expenditures for 2025 are forecasted to be $1.40M (15%) under the DSP approved budget. The underspending is due to the deferral of Municipal Transformer Replacements and the Underground System Rebuild Program, which offsets increased spending in switchgear replacements, reactive work, and pole replacements. A small amount of capital contributions is also expected to further reduce net expenditures.

Underspend Areas

Municipal Transformer Replacements and Oil Containment Installation amounting to $1.50M is being deferred. The decision is supported by an options analysis confirming replacements are not required in this DSP cycle.

Underground System Rebuild Program is forecasted to be $1.11M (75%) below budget, as funding was reallocated to higher-priority projects, such as those in System Access. The revised ACA, incorporating a multifaceted health index and impact assessment, has ensured that investment is focused on the most critical areas in the upcoming 2026-2030 forecast period.

Porcelain Switch and Insulator Replacement Program is expected to be $375K (68%) under budget, reflecting a shift in priorities within System Renewal.

Overspend Areas

Municipal Substation Switchgear Replacement Program is forecasted to exceed the budget by $1.38M (65%) due to expanded project scope. Additional work includes riser pole replacements, duct installation, concrete encasement, road crossings and egress cable replacement, ensuring optimal use of the new switchgear. The projected costs align with those incurred in the most recent switchgear replacement project completed in 2023.

Reactive Program is projected to be $272K (23%) over budget, reflecting historical trends of higher expenditures on run-to-failure asset replacements and unplanned reactive work, including motor vehicle accidents, dig-ins, and primary/secondary cable faults.

Pole Replacement Program is expected to exceed the budget by $100K (25%), as reduced spending in 2024 shifted work into 2025 to maintain infrastructure reliability.

Overall Impact

Total System Renewal gross expenditures are forecasted to reach $7.95M, which is $1.19M (13%) below the planned $9.14M. Capital contributions of $204K are also anticipated, further reducing the net expenditure.

As a result, the net variance for System Renewal is forecasted to be $1.40M (15%) under budget, primarily due to the deferral of station transformer replacement and underground system rebuild projects, offsetting increased spending in switchgear replacements, reactive work, and pole replacements.

SYSTEM SERVICE

System Service projects focus on upgrading and modernizing the distribution network to enhance capacity, reliability, and efficiency. Variability in spending can arise from budget reallocations for mandatory or reactive jobs.

Figure 28 shows the net expenditures under system service for the 2021-2025 historical period.

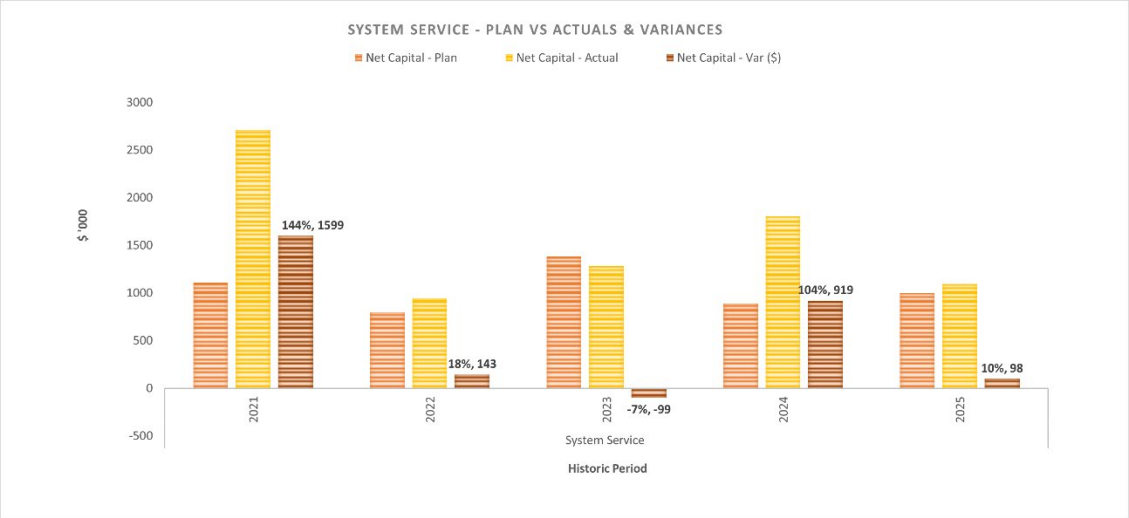


Figure 28 – System Service Plan vs Actuals & Variance

2021 – 144% ($1.6M) Over Budget

In 2021, System Service expenditures significantly exceeded the approved budget due to higher-than-anticipated costs across multiple projects. The overspending was primarily driven by system reconfigurations aimed at improving reliability, as well as increased investment in automation and self-healing switch installations.

Underspend Areas

The Operational Technology (GIS, OMS, ODS, SCADA) program came in $248K (93%) under budget due to deferral of efforts to 2023.

Overspend Areas

A reliability improvement project, which was not originally planned, accounted for an additional $955K in expenditures. This project, targeting reconfiguration in the Simcoe-Winchester area, involved the installation of new pad-mounted switchgears to address multiple reliability concerns, including reducing the number of customers on Feeder 7F4, creating an express feeder to serve rural Oshawa, and transferring load to MS9 to alleviate constraints on MS7.

The Voltage Monitoring Project, aiming to be in service in 2020, was ultimately energized in 2021 at a total cost of $632K. Efforts in securing grants helped reduce net expenditures to $532K. While the full amount contributed to the 2021 overspend, the actual budget overage was $82K based on the allocated $450K from prior budgets.

The OH Automated Self-Healing Switches program exceeded its budget by $102K (51%) due to the installation of two additional motorized 44kV switches, in addition to the originally planned number of 13.8kV switches.

Overall Impact

Total System Service gross expenditure reached $2.83M, exceeding the planned $1.11M by $1.72M (155%). However, contributions of $120K partially offset this overspend, resulting in a net variance of $1.6M (144%). The primary drivers of this variance were the Simcoe-Winchester Reconfiguration project, deferred in service of the voltage monitoring project, and increased deployment of self-healing automation switches to enhance system reliability and operational flexibility.

2022 – 17.9% ($143K) Over Budget

System service expenditures in 2022 exceeded the planned budget, primarily due to increased costs in automation and smart grid initiatives. While some projects were completed under budget, the overall variance was driven by higher-than-expected spending on system automation and reliability improvements.

Underspend Areas

Operational Technology (GIS, OMS, ODS, SCADA) was $185.4K (88.3%) under budget, due to deferral of work to 2023.

Overspend Areas

Overhead Automated Self-Healing Switches and Smart Grid (SCADA-Integrated 44kV OH Switches, Automation Controllers, and Network-Connected Devices) combined, exceeded the budget by $368.7K due to higher installation costs for 44kV motorized switches aimed at enhancing system automation and reliability. Additionally, the replacement of associated pole hardware expanded the project scope, leading to increased labor and vehicle time.

Overall Impact

Total system service net expenditures reached $942K, exceeding the planned $799K by $143.4K (17.9%). The overspending was primarily driven by investments in self-healing automation and smart grid infrastructure to enhance system resilience and operational efficiency.

2023 – 7.1% ($98.5K) Under Budget

In 2023, system service expenditures were slightly lower than planned, with a total variance of $98.4K (7%) under budget. While significant investments were made in operational technology and system improvements, budget reallocations contributed to the overall underspend.

Underspend Areas

The 44kV Line Extension (Ritson Road – Winchester Road East and Conlin Road East) project was deferred to align with a regional road widening project that affects the poles within the same project scope area. As of 2025, this work is in the design phase and will be completed as part of the third-party relocation project. This approach ensures operational efficiencies and avoids duplicate efforts, resulting in a budget variance of $375K (100%).

Municipal Substation Network Upgrades were not executed in 2023 due to project reprioritization to offset increase system access expenditure, leading to a $150K (100%) variance.

Municipal Substation Transformer Monitoring and Telemetry expenditures were $69K (46%) below budget due to a refined implementation approach that reduced costs.

Overspend Areas

Operational Technology (GIS, OMS, ODS, SCADA) exceeded budget by $446.1K (168%). However, this increase reflects the deferral of spending from previous years. In 2021, this category was underspent by $247.5K (93%), and in 2022, it was underspent by $185.4K (88.3%). With these prior-year budgets rolling into 2023, the cumulative variance is $13.2K over the combined planned amounts, indicating that efforts were concentrated into 2023 rather than being true overspending.

Repair, improvements and upgrades of OT and Smart Grid Infrastructure exceeded budget by $47.3K (110%). This increase was similarly driven by deferred spending from prior years. In 2021, this category was underspent by $19.8K (48%), and in 2022, it was underspent by $25.2K (64.7%). When factoring in the total deferred spending from previous years, the net variance is $2.3K over the cumulative planned amounts, reflecting a concentrated effort in 2023 rather than an overage.

Overall Impact

Total system service net expenditures reached $1.28M, falling below the planned $1.38M by $98.5K (7.1%). While investments in operational technology and system improvements increased, the deferral of major infrastructure projects, particularly the 44kV line extension, offset these costs. Most of the overages in OT and repair projects were due to the carryover of deferred budgets from previous years, leading to a more balanced overall spending profile across the period.

2024 – $918K (104%) Over Budget

Underspend Areas

Municipal Substation Transformer Monitoring and Telemetry of $150K (100%) had no in-service expenditures reported. Though costs were incurred in 2024, some pending work requires the assets to be put in service early 2025 and were captured under Work-In-Progress.

Operational Technology (GIS, OMS, ODS, SCADA) expenditures were $151K (97%) below budget, as the project's energization is scheduled for 2025. While most work was completed and costs were incurred in 2024, the project will be placed in service in 2025 due to outstanding items that still need to be finalized.

Overspend Areas

The 44kV Line Extension was the primary driver of the variance, totaling $1.39M. This project extended the 165M7 44kV feeder (fed from Enfield TS) west along Conlin Road West to its intersection with Thornton Rodd North, enabling the connection of multiple large industrial and commercial loads in the Northwood Business Park area.

Overall Impact

Total System Service expenditures reached $1.80M, surpassing the planned $886K by $919K (104%), primarily due to the unplanned 44kV Line Extension project. Delays in projects being put in service, partially offset the overall variance.

2025 – Forecasted to be $98K (10%) Over Budget

Underspend Areas

Municipal Substation Network Upgrades of $150K (100%) under budget have been reprioritized to address more immediate system needs. This strategic adjustment ensures that investments align with evolving infrastructure requirements.

Overspend Areas

Municipal Substation Transformer Monitoring and Telemetry is expected to be $87K (58%) over budget due to costs incurred in 2024 that required finalization before the project could be placed in service. These outstanding items, along with 2025-related work, will be completed in 2025. Similarly, Operational Technology (GIS, OMS, ODS, SCADA) spending is projected to be $71K (23%) over budget, as pending components from the 2024 scope are expected to be completed and commissioned in 2025.

Smart Grid (SCADA operated 44kv OH Switches, SCADA Integration and Deploy of Automation Controllers and Network Connected Devices) is forecasted to be $90K (60%) over budget due to

delays in material lead times, which resulted in the deferral of 2024 expenditures and associated work to 2025.

Overall Impact

Total System Service expenditures for 2025 are forecasted at $1.09M, exceeding the DSP approved $995K by $98K (10%). The primary drivers of this variance are the completion of deferred 2024 projects and investments in Smart Grid automation and Operational Technology. While some initiatives have been reprioritized, overall expenditures align with the long-term strategy of modernizing the distribution system.

GENERAL PLANT

General Plant investments support the operational and technological functions necessary for Oshawa Power to provide safe, reliable and efficient service. Some areas of focus are facilities, fleet, office systems and IT infrastructure. Variability in this area typically arises from material lead times and budget reprioritizations to other key areas.

Figure 29 shows the gross expenditures under system service for the 2021-2025 historical period. There are no capital contributions under this category in the historical period and so gross and net values are the same.

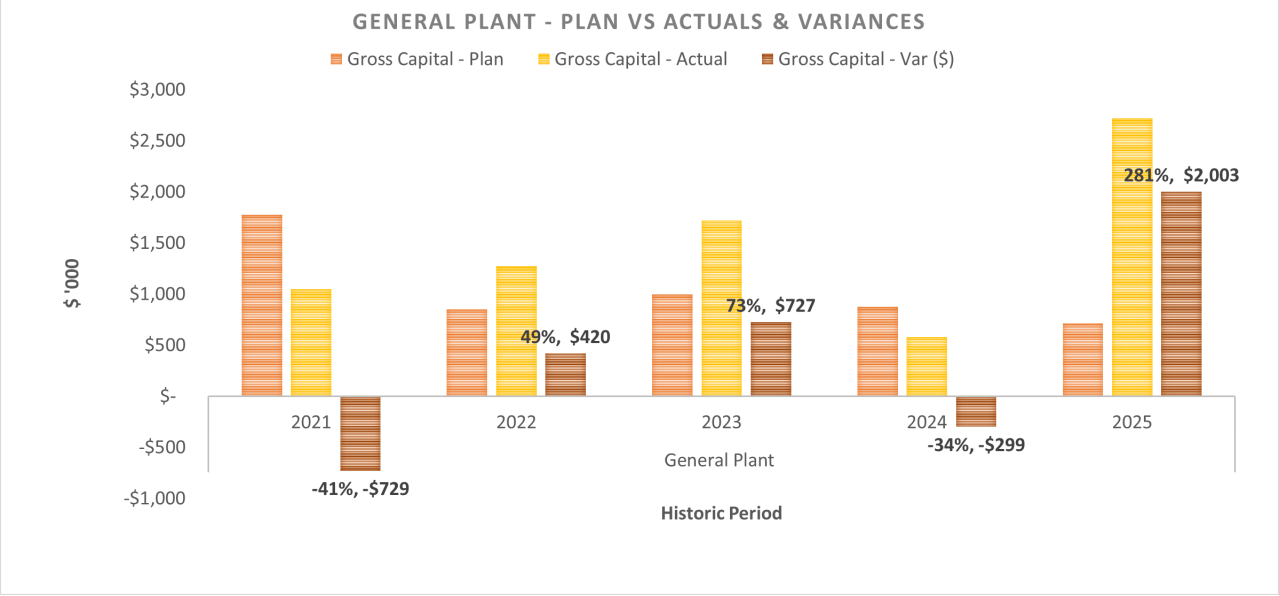


Figure 29 – General Plant Plan vs Actuals & Variance

2021 – 41% ($728.2K) Under Budget

In 2021, general plant expenditures were significantly lower than planned, with a total variance of $728.2K (41%) under budget. While key investments were made in facilities, major tools and office IT upgrades, certain projects were either delayed or not executed, contributing to the overall underspend.

Underspend Areas

Fleet expenditures were $333.9K (101%) below budget. As final payments on the large two large fleet vehicles, expected to arrive in 2021, were delayed and delivered in 2022.

Information Technology General spending was $187.5K (45%) below budget, however some IT spending for end user equipment was coded to Office IT & Equipment Upgrades, which was over budget by 152.9k netting a $35k deviation from plan.

CIS Software and Enhancements had no expenditures in 2021, leading to a $736K (100%) variance. Upon further investigation, Oshawa Power deemed it more prudent to open up the CIS to a competitive bid rather than to just move the existing software from hosted to on-premise as originally planned. Due to the change in scope, this project was deferred to a later year.

Overspend Areas

Facilities exceeded budget by $192.6K (193%) in response to COVID-19 protocols. Workstation barriers were installed, and the air filtration system was replaced with one capable of filtering potential pathogens.

Major Tools & Equipment spending was $183.7K (184%) over budget. Requirement to replace the backup generator resulted in overspend.

Overall Impact

Total general plant net expenditure reached $1.05M, falling $728.2K (41%) short of the planned $1.77M. While investments in facilities, tools, and office IT increased, the deferral of major projects, particularly the fleet and CIS software, contributed to the underspend.

2022 – 49.5% ($420.7K) Over Budget

Underspend Areas

No underspend areas.

Overspend Areas

Facilities expenditures were $60.5K (60.5%) over budget. In 2022, unanticipated renovations to the second floor of the main office building were made, including floor replacement, lighting upgrade and installation of new window blinds. The main facility garage roof was also redone contributing to the overspend.

The largest overage occurred in Information Technology General, which exceeded the budget by $314.5K (224.7%), due to a required server infrastructure upgrade. Server pricing had increased significantly due to supply chain issues and though the infrastructure upgrade was planned for 2023, it was moved to 2022 because Oshawa Power received favourable pricing at the time, reducing the overall cost.

Overall Impact

Total general plant expenditures reached $1.27M, surpassing the planned $850.5K by $420.7K (49.5%). While spending on IT and facilities significantly increased, fleet and office IT spending remained closer to budget. The higher costs were driven by a combination of project acceleration, unplanned expenditures, or cost fluctuations, leading to the overall budget overage.

2023 – 73% ($726.3K) Over Budget

Underspend Areas

IT General was underspent by $177K (44%), mostly due to the server refresh accelerated to 2022.

Overspend Areas

Fleet exceeded the budget by $467.5K (156%) – As the final payments for the two large fleet vehicles were due in 2023. And the organization purchased four new hybrid pick-up trucks to allow for the removal of overdue fleet vehicles, which were kept in service to aid in our reaction to the COVID – 19 pandemic.

Facilities expenditures were $81.7K (82%) over budget due to renovations at the main office, as well as construction for a new control room – to reduce distractions and limited interruptions allowing operators to be more focused on their tasks.

The Customer Self-Serve Online Portal was a new investment in 2023, contributing an unplanned $100.7K. The previous customer portal was being deprecated by the software provider and Oshawa Power was required to find a new solution.

Additionally, Software-HR/Timesheet expenditures totaled $206.3K, adding to the overall IT spending increase. This software was required to reduce operational burden and effectively charge time across the organization.

Overall Impact

Total general plant expenditures reached $1.72M, exceeding the planned $994.3K by $726.3K (73%). While investments in fleet, new software, and facilities increased, underspending in office IT mitigated some of the budgetary impact. The high variance was primarily driven by new technology implementations and infrastructure upgrades.

2024 – $298K (34%) Under Budget

Underspend Areas

Fleet expenditures were $379K (86%) under budget. – As the purchases of two new large fleet vehicles were delayed. Invoicing occurs upon delivery of physical units.

Overspend Areas

Information Technology General was over budget by $117K (127%) mostly due to an increased spend in cybersecurity-related hardware and software associated with the Framework controls, including a Network Access Control (NAC) appliance and upgraded Wireless Access Points.

Overall Impact

Total General Plant expenditures were $576K, which was $299K (34%) below the planned budget. The underspend was primarily due to delays in fleet delivery.

2025 – Forecasted to be $2.00M (281%) Over Budget

Underspend Areas

There are no notable underspend areas for the 2025 forecast year.

Overspend Areas

Information Technology General is forecasted to exceed the budget by $208K (65%). Overspend is a split between additional mandatory SCADA licensing costs and investments in automation technology and labour.

CIS Software and Enhancements accounts for a large portion of the overspend, with $1.4M forecasted in expenditures, $731K of which was deferred from 2021. Upon further investigation, Oshawa Power decided to open the CIS to a competitive bid rather than simply transitioning the existing software from hosted to on-premises, as initially planned. This change in strategy will help Oshawa Power in its Business Transformation efforts by facilitating a greater degree of automation, improved business processes, and integration with other systems.

A project to implement a Mobile Workforce Management software, costing $235K, was not part of the approved DSP budget but was added to the 2025 budget in order to reduce reliance on manual and error-prone paper-based processes.

CRM software and Financial System enhancements amounting to $50K and $70.2K respectively were not part of approved DSP budget either and were also added to the 2025 budget. These projects represent incremental enhancements in their respective areas.

Overall Impact

Total General Plant expenditures are forecasted at $2.72M, which is $2.00M (281%) over the planned budget. The main driver of this variance is the $1.4M expenditure for CIS Software and Enhancements, $736K of which was deferred from 2021, along with increased spending in Information Technology General and Office IT & Equipment Upgrades, mostly related to Cybersecurity and Business Transformation projects.

5.4.1.2 Capital Expenditure Forecast

Oshawa Power's planning process that includes research, stakeholder coordination, detailed analysis, optimization efforts, risk prioritization and a balanced pacing approach has resulted in a Total Net Proposed Capital Expenditures of approximately $80.8M over the 2026-2030 forecast period. Oshawa Power notes that there are no expenditures for non-distribution activities within this proposed capital expenditures envelope.

The distribution between different investment categories is depicted in Figure 30, with each ring represents Gross, Contribution and Net amounts. Total gross expenditure is forecasted to be approximately $97.2M with expected contributions of approximately $16.4M, which results in a total net expenditure of $80.8M.

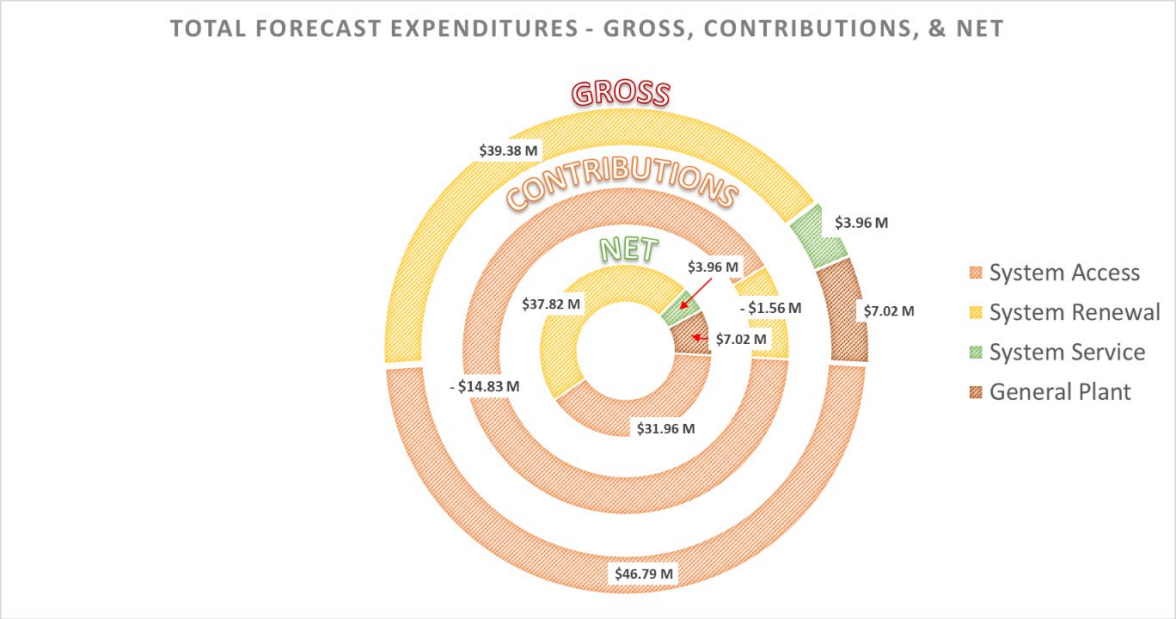


Figure 30 – Total Forecast Expenditures

The total forecast expenditure for the 2026-2030 forecast period across all investment categories is shown in the table below:

Table 23 - Total Forecast Expenditure

FORECAST CAPITAL EXPENDITURE ($' 000)								
Category	**Amount Type**	**2026**	**2027**	**2028**	**2029**	**2030**	**TOTAL**	**% TOTAL**
System Access	Gross Capital	9,186	9,270	9,356	9,443	9,532	**46,787**	**48.2%**
	Contributed Capital	-2,916	-2,941	-2,965	-2,991	-3,016	**-14,829**	**90.5%**
	Net Capital	6,270	6,330	6,391	6,452	6,515	**31,958**	**39.6%**
System Renewal	Gross Capital	8,045	8,756	7,056	7,421	8,108	**39,385**	**40.5%**
	Contributed Capital	-312	-312	-312	-312	-312	**-1560**	**9.5%**
	Net Capital	7,733	8,444	6,744	7,109	7,796	**37,825**	**46.8%**
System Service	Gross Capital	1,336	300	778	962	588	**3,964**	**4.1%**
	Contributed Capital	0	0	0	0	0	**0**	**0.0%**
	Net Capital	1,336	300	778	962	588	**3,964**	**4.9%**
General Plant	Gross Capital	1,680	1,655	1,730	1,155	802	**7,022**	**7.2%**
	Contributed Capital	0	0	0	0	0	**0**	**0.0%**
	Net Capital	1,680	1,655	1,730	1,155	802	**7,022**	**8.7%**
TOTALS	**Gross Capital**	**20,247**	**19,981**	**18,920**	**18,980**	**19,030**	**97,158**	**100.0%**
	Contributed Capital	**-3,228**	**-3,253**	**-3,277**	**-3,303**	**-33,28**	**-16,389**	**100.0%**
	Net Capital	**17,019**	**16,729**	**15,642**	**15,678**	**15,701**	**80,769**	**100.0%**

SYSTEM ACCESS

System Access expenditures are driven entirely by external stakeholders, such as customers and municipal bodies, to facilitate connections and accommodate community betterment initiatives.

They represent a significant portion of total capital investments. Over the 2026-2030 period, gross System Access expenditures total $46.79M, accounting for 48.2% of all planned capital expenditures. However, after factoring in $14.83M in contributions, the net System Access expenditures amount to $31.96M, equating to 39.6% of total net capital expenditures.

Appropriate resource allocation ensures timely and reliable customer connections to the electrical grid as part of the Oshawa power's service obligations, and facilitate municipal-driven projects, such as road widening which require infrastructure adjustments. The programs that comprise the System Access expenditure envelope are detailed in the table below.

Table 24 - System Access Expenditure Envelope

FORECAST SYSTEM ACCESS EXPENDITURE ($' 000)							
Project/ Program	**Amount Type**	**2026**	**2027**	**2028**	**2029**	**2030**	**TOTAL**
Connections	Gross	1,505	1,510	1,516	1,521	1,527	**7,579**
	Contributions	-877	-880	-883	-886	-890	**-4,415**
	Net	628	630	633	635	637	**3,164**
Expansions	Gross	4,284	4,352	4,422	4,493	4,565	**22,116**
	Contributions	-1,330	-1,351	-1,373	-1,395	-1,417	**-6,866**
	Net	2,954	3,001	3,049	3,098	3,148	**15,250**
Third Party Relocations	Gross	2,901	2,901	2,901	2,901	2,901	**14,504**
	Contributions	-710	-710	-710	-710	-710	**-3,548**
	Net	2,191	2,191	2,191	2,191	2,191	**10,956**
Revenue Metering	Gross	496	507	517	528	539	**2,587**
TOTAL	**Gross**	**9,186**	**9,270**	**9,356**	**9,443**	**9,532**	**46,787**
	Contributions	**-2,916**	**-2,941**	**-2,965**	**-2,991**	**-3,016**	**-14,829**
	Net	**6,270**	**6,330**	**6,391**	**6,452**	**6,515**	**31,958**

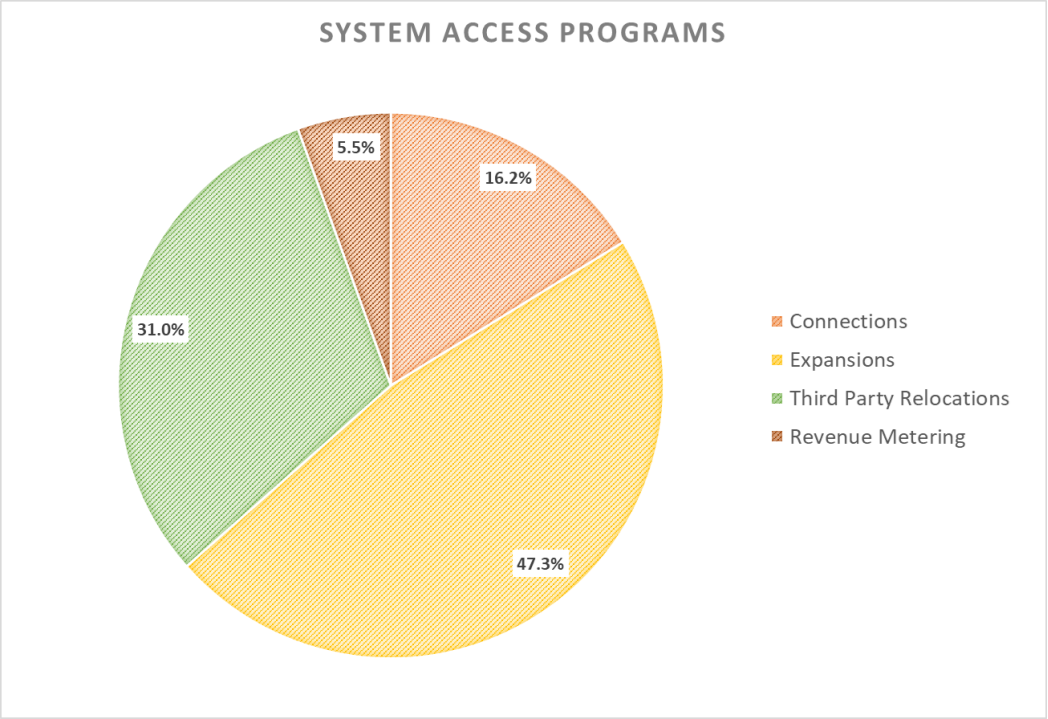


Figure 31 – System Access Programs

Expansions represent the largest component of System Access expenditures, with a gross investment of $22.12M (47.3%). This is driven by ongoing customer growth, guided by Oshawa's historical new connection trends, the City of Oshawa's population growth study, and specific developments such as Kedron Part II Planning area (Kedron) and Columbus Part II Planning area (Columbus) in North Oshawa. Recent regulatory changes have increased net costs for expansions. The Minister of Energy's November 2023 Letter of Direction and the OEB's December 23, 2024 amendment to the Distribution System Code have extended the revenue horizon for residential customers to 40 years, thereby reducing contributions received and shifting more costs onto the LDC.

Third-Party Relocations represent the second-largest driver of System Access expenditures, totaling $14.50M (31.0%) - gross. These projects are dictated by municipal and regional infrastructure initiatives, primarily road-widening projects. Significant efforts have been made to coordinate with municipal partners to refine scope and timelines; however, preliminary plans indicate potential significant variances in scheduling and costs. As a result, the budget for Third-Party Relocations is annualized and does not account for year-over-year fluctuations.

Connections and Revenue Metering represent smaller, yet essential, portions of System Access investments. Connections account for a gross investment of about $7.58M (16.2%) to install the

necessary infrastructure—ducts, poles, transformers and cables—for new or upgraded services driven by historical customer growth trends. Meanwhile, Revenue Metering involves a gross investment of approximately $2.59M (5.5%) to deploy metering equipment as per measurement Canada requirements that ensure accurate measurement and billing.

System Access expenditures are critical in ensuring reliable electrical service and meeting municipal infrastructure needs. While customer growth necessitates ongoing investments in Expansions, regulatory changes have increased net costs borne by the LDC. Additionally, Third-Party Relocations remain a variable cost, dependent on evolving municipal project timelines. These factors underscore the importance of strategic planning to balance investment pacing and cost efficiency while maintaining regulatory compliance and service reliability.

SYSTEM RENEWAL

System Renewal investments are essential for maintaining the safety, reliability, and resilience of Oshawa Power's distribution system. These expenditures focus on replacing aging or deteriorating infrastructure to prevent service disruptions and ensure long-term system performance.

Over the 2026-2030 period, gross System Renewal expenditures total $39.38M, representing 40.5% of total planned capital investments. After accounting for $1.56M in contributions, the net System Renewal expenditure amounts to $37.82M, or 46.8% of total net capital expenditures.

Budget allocations prioritize targeted asset replacements based on Asset Condition Assessments (ACA), historical failure data, and risk-based prioritization. Programs within the System Renewal category are detailed in the table below.

Table 25 - System Renewal Expenditure Envelope

FORECAST SYSTEM RENEWAL EXPENDITURE ($' 000)							
Projects/ Programs	**Amount Type**	**2026**	**2027**	**2028**	**2029**	**2030**	**TOTAL**
Quick Sleeve Replacement Program	Gross	0	250	250	250	250	**1,000**
Municipal Substation Switchgear Replacement Program	Gross	3,042	2,316	0	0	0	**5,358**
Overhead System Rebuild Program (prev. OH Line Renewal)	Gross	1,072	486	1,045	1,631	1,225	**5,459**
Pole Replacement Program	Gross	300	600	492	492	492	**2,375**
Porcelain Switch and Insulator Replacement Program	Gross	0	150	150	150	150	**600**
Reactive	Gross	2,138	2,138	2,138	2,138	2,138	**10,690**
	Contributions	-312	-312	-312	-312	-312	**-1,560**
	Net	1,826	1,826	1,826	1,826	1,826	**9,130**
Underground System Rebuild Program (prev. UG Line renewal)	Gross	393	54	1,185	727	1,663	**4,022**
UG Cable injection Program	Gross	0	479	0	61	0	**540**
Firon Switch Replacement Program	Gross	0	313	313	313	313	**1,250**
Overloaded Transformer Replacement Program	Gross	0	267	267	267	267	**1,069**
Distribution Switchgear Replacement Program	Gross	0	603	0	176	394	**1,173**
Distribution System - Lock Replacement	Gross	0	0	117	117	117	**350**
Metering - Meter Replacement Program	Gross	1,100	1,100	1,100	1,100	1,100	**5,500**
TOTAL	**Gross**	**8,045**	**8,756**	**7,056**	**7,421**	**8,108**	**39,385**
	Contributions	**-312**	**-312**	**-312**	**-312**	**-312**	**-1,560**
	Net	**7,733**	**8,444**	**6,744**	**7,109**	**7,796**	**37,825**

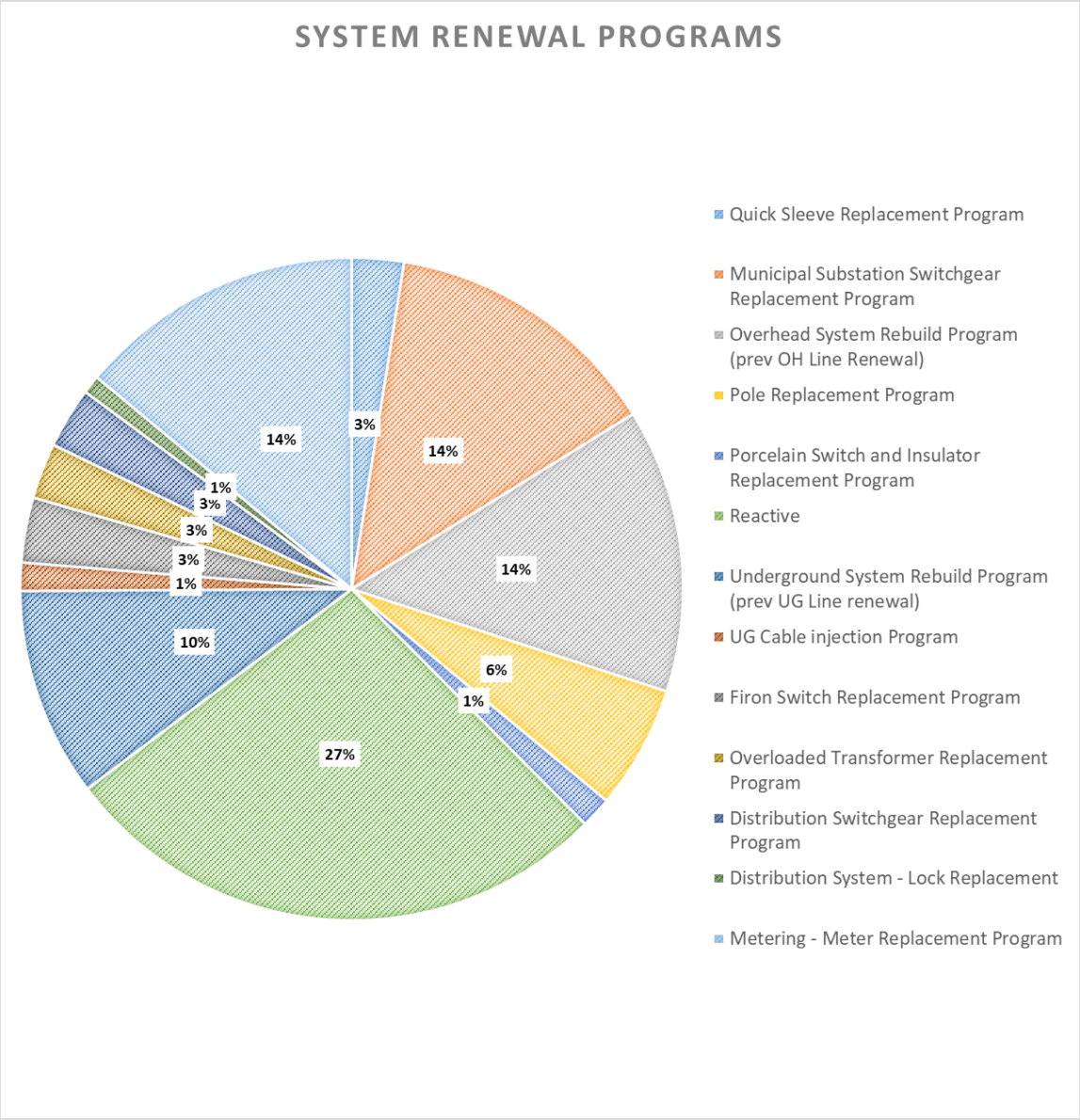


Figure 32 – System Renewal Programs

Representing the largest portion of the System Renewal budget at $10.69M gross (27.2%), the Reactive Replacement Program addresses assets that are run to failure—such as pole mount and pad mount transformers, switches and similar equipment—identified during Oshawa Power's three-year maintenance cycle. It also covers unanticipated events like contractor dig-ins, motor vehicle accidents, adverse weather incidents and trouble calls. Anticipated contributions are recovered from third parties for damages incurred.

The Meter Replacement Program accounts for $5.50M gross (14.0%) and is driven by Measurement Canada regulatory requirements. By pacing meter replacements over the planning period, the program mitigates rate volatility and avoids concentrated cost impacts on customers.

With a gross investment of $5.46M (13.9%), the Overhead System Rebuild Program consolidates the replacement of overhead lines along with associated poles, transformers, dips and supporting infrastructure. This comprehensive upgrade is structured to complete all necessary work in one coordinated effort, enhancing operational efficiency.

At $5.36M gross (13.6%), the Municipal Switchgear Replacement program focuses on replacing switchgear at municipal stations. Using insights from the ACA, combined with an options analysis, the program determines the optimal timing and intervention type, including necessary replacements of associated dip poles, egress cables and related components.

Contributing $4.02M gross (10.2%), the Underground System Rebuild Program focuses on renewing underground assets that are at, or nearing, the end of their useful life due to deteriorating condition and high risk. This program includes the replacement of underground cables, ducts, deteriorating pad-mounted transformers, and associated hardware such as elbows and connectors.

Collectively, the remaining initiatives—including Quick Sleeve Replacement (2.5% gross), Pole Replacement (6.0% gross), Porcelain Switch and Insulator Replacement (1.5% gross), UG Cable Injection (1.4% gross), Firon Switch Replacement (3.2% gross), Overloaded Transformer Replacement (2.7% gross), Distribution Switchgear Replacement (3.0% gross), and Distribution System – Lock Replacement (0.9% gross)—address safety concerns, reduce operational inefficiencies, and optimize asset life and performance. These programs are designed with future planning in mind, ensuring that investments not only replace at-risk assets promptly, but also align with long-term system objectives. Together, they contribute to a balanced approach that integrates risk management, operational efficiency, and strategic asset optimization to sustain high standards of safety and system reliability over the planning horizon.

SYSTEM SERVICE

System Service investments total $3.96M over the 2026-2030 period, representing 4.1% of overall capital expenditures. These investments are focused on modernizing the distribution system and ensuring adequate capacity for Oshawa Power to meet its service obligations in connecting customers to the grid. The modernization efforts are designed to enhance safety, reliability, power

quality, system efficiency and overall performance. System Service expenditures ensure that the distribution network can continue to support growth and technological advancements.

There are no anticipated contributions under system service in the forecast period, therefore all values and discussions are expressed in gross terms.

Projects and programs within the System Service category are detailed in the table below.

Table 26 - System Service Expenditure Envelope

FORECAST SYSTEM SERVICE EXPENDITURE ($' 000)						
Projects / Programs	**2026**	**2027**	**2028**	**2029**	**2030**	**TOTAL**
OH Automated Self-Healing Switches	0	0	565	565	565	**1,695**
Asset Management Software	165	0	0	0	0	**165**
Underground Fault Locators	0	0	13	13	13	**39**
SCADA Equipment Upgrade	0	0	0	350	0	**350**
Non Wires Solutions (NWS)	171	300	200	34	10	**715**
3 New Feeders MS 9	1,000	0	0	0	0	**1,000**
TOTAL	**1,336**	**300**	**778**	**962**	**588**	**3,964**

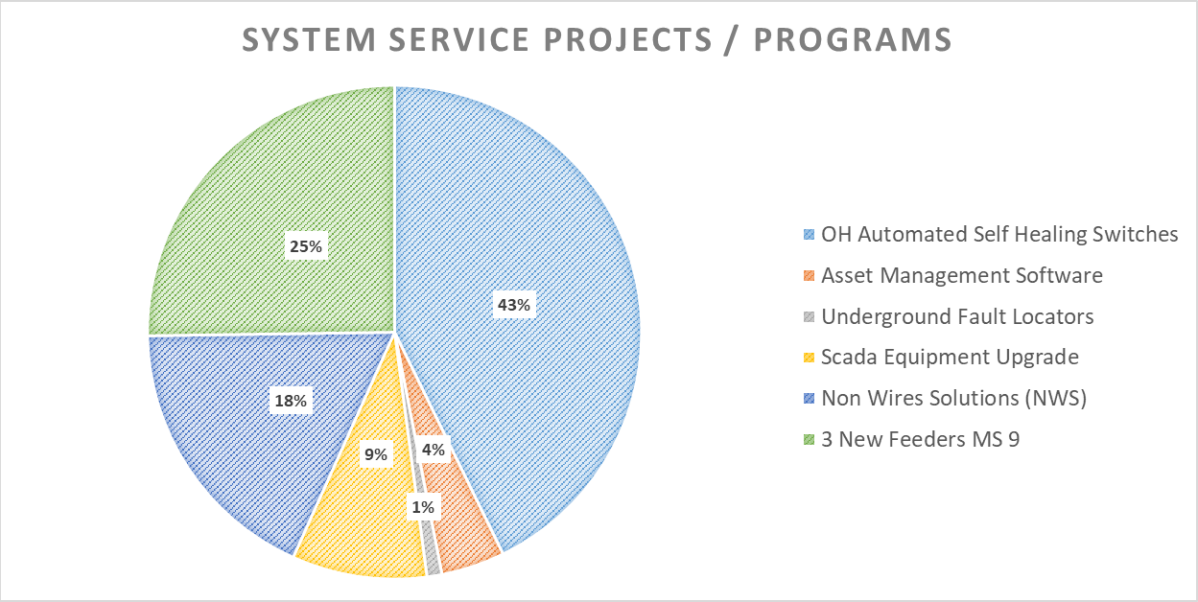


Figure 33 – System Service Programs

The Overhead Automated Self-Healing Switch Program represents the largest portion of System Service expenditures, accounting for $1.70M (42.9%). This initiative improves service reliability and supports grid modernization by introducing remote operated/automated devices enabling remote switching during normal and emergency conditions, reducing outage durations and enhancing operational efficiency.

The three (3) New Feeders at MS9 make up $1.00M (25.3%) and involves constructing new feeders to alleviate overburdened assets in North Oshawa and meet growing load demand. The project ensures that existing capacity is optimized while supporting future development.

Investments in Non-Wires Solutions (NWS) total $715K (18.2%) was allocated in response to the Ontario Energy Board's new Non-Wires Solutions Guidelines. NWS investments in the forecast period have been identified and include distributed energy resources, demand-side management programs and automated control systems. These initiatives target areas of anticipated accelerated load growth and aim to enhance system flexibility and capacity, positioning the grid to potentially defer future capital investments in traditional wires solutions.

The SCADA Equipment Upgrade ($350K, 8.8%), Asset Management Software ($165K, 4.3%) and Underground Fault Locators ($39K, 0.9%) account for $554K (14%) of System Service expenditures. These investments enhance automation, cyber security and asset management practices. The SCADA upgrade strengthens system protection and control, while the asset management software streamlines Oshawa Power's Asset Condition Assessment (ACA) process for improved risk-based

decision-making. Additionally, underground fault locators improve outage response efficiency by enabling faster fault detection and restoration.

GENERAL PLANT

General Plant investments total $7.02M over the 2026-2030 period, representing 7.2% of overall capital expenditures. These investments support the operational, technological and customer service functions necessary for Oshawa Power to provide safe, reliable and efficient service. They address facilities, fleet, office systems and IT infrastructure to ensure the utility has the necessary resources to maintain service quality, improve efficiency and adapt to evolving industry and regulatory requirements. General Plant expenditures enable Oshawa Power to sustain effective operations while supporting long-term system and business needs.

There are no anticipated contributions under general plant in the forecast period, therefore all values and discussions are in gross terms.

Projects and programs within the General Plant category are detailed in the table below.

Table 27 - General Plant Expenditure Envelope

FORECAST GENERAL PLANT EXPENDITURE ($' 000)						
Projects / Programs	**2026**	**2027**	**2028**	**2029**	**2030**	**TOTAL**
Fleet	500	600	500	460	240	**2,300**
ERP Software	0	500	0	0	0	**500**
Enterprise Server Hardware/Software Upgrades	116	66	591	116	66	**955**
Facilities	100	100	100	100	100	**500**
Major Tools & Equipment	130	130	130	130	130	**650**
Customer Information System (CIS) Software and Enhancements	0	0	50	50	50	**150**
Cybersecurity Upgrades	40	40	40	40	40	**200**
End User Hardware/ Software Upgrades	196	146	146	146	146	**782**
SCADA Hardware/ Software Upgrade	0	0	100	40	0	**140**

FORECAST GENERAL PLANT EXPENDITURE ($' 000)						
Projects / Programs	**2026**	**2027**	**2028**	**2029**	**2030**	**TOTAL**
Automation Platform	125	0	0	0	0	**125**
System Automation	30	30	30	30	30	**150**
CRM Software	50	0	0	0	0	**50**
Customer Communication Redesign	100	0	0	0	0	**100**
GIS Upgrade	50	0	0	0	0	**50**
Intranet Upgrade	50	0	0	0	0	**50**
MDM Enhancements	18	18	18	18	0	**70**
OMS Enhancements	25	25	25	25	0	**100**
Records Management	100	0	0	0	0	**100**
Website Redesign	50	0	0	0	0	**50**
TOTAL	**1,680**	**1,655**	**1,730**	**1,155**	**802**	**7,022**

Figure 34 shows the distribution of material programs that comprise the overall general plant expenditures.

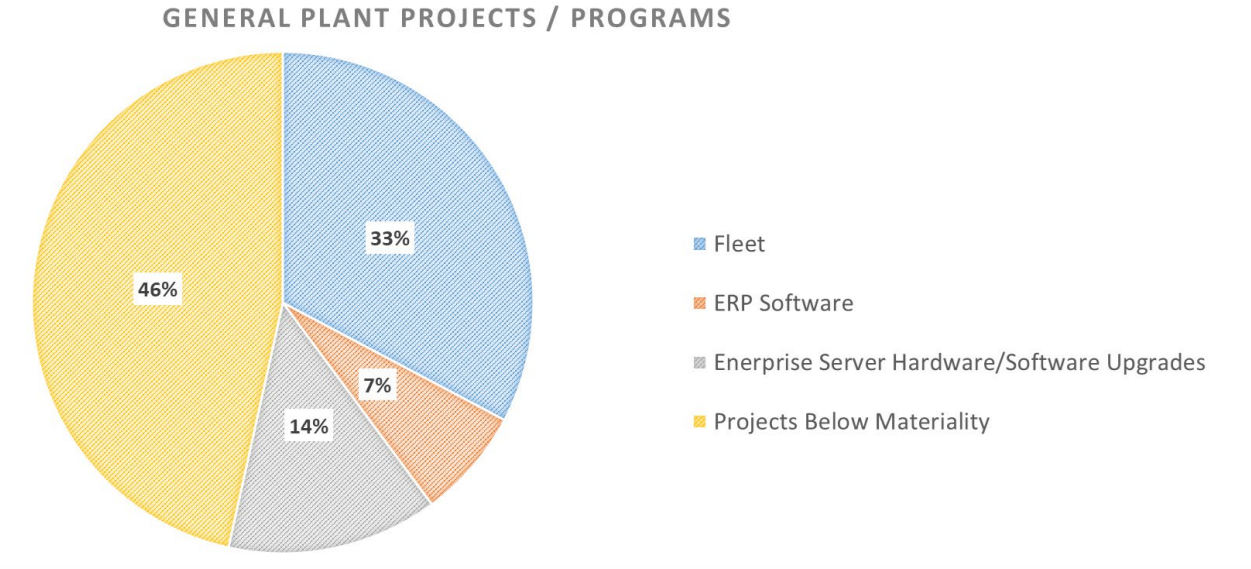


Figure 34 – General Plant Programs

Figure 35 shows the breakdown of projects below materiality under this investment category.

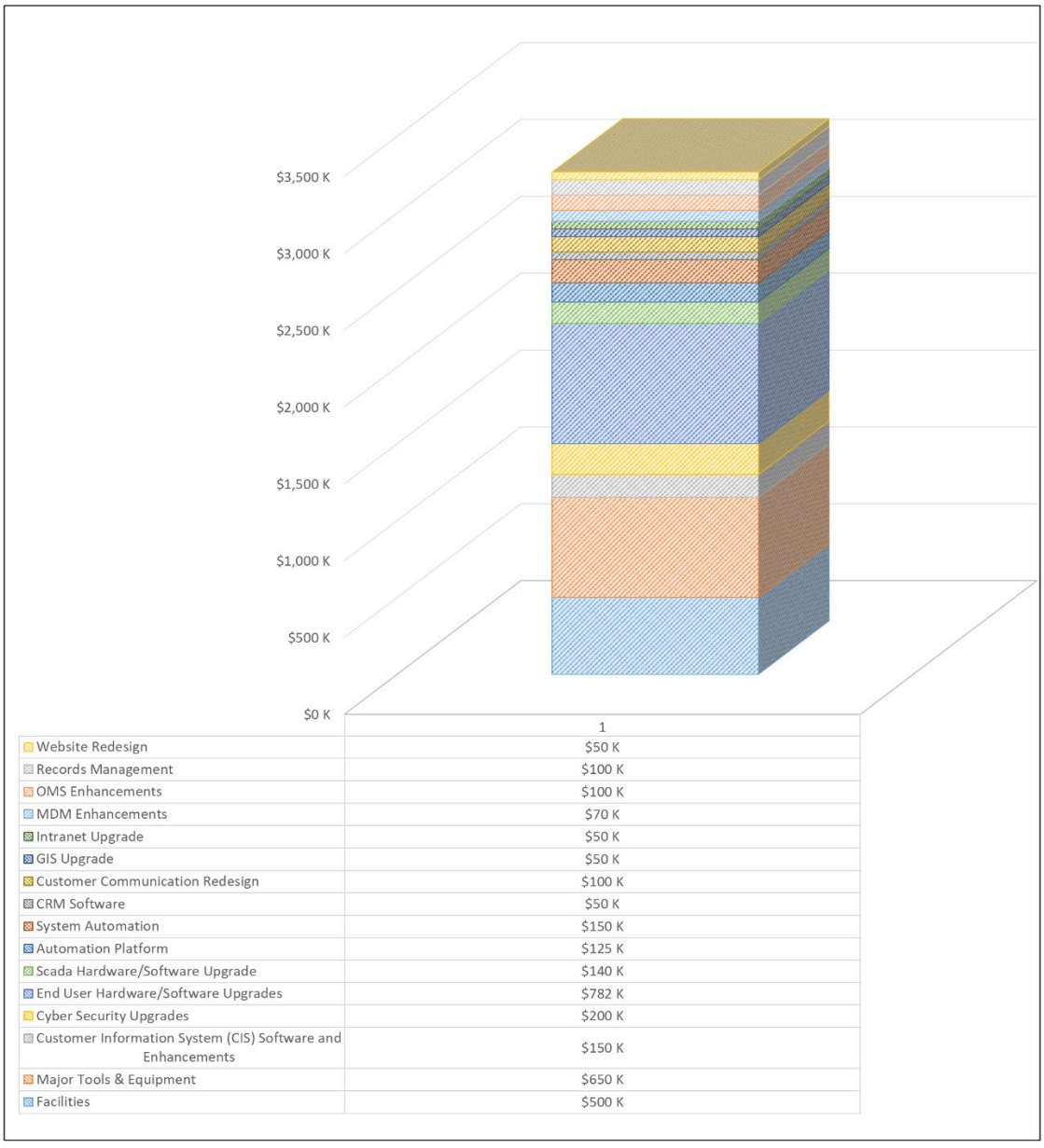


Figure 35 – Projects Below Materiality Threshold

Fleet investments account for $2.30M (32.8%) of the general plant category. The existing vehicles have reached or are nearing end-of-service life based on an assessment of age, condition, and increased maintenance and repair costs. Oshawa Power plans to acquire two (2) aerial devices (bucket trucks), one (1) Radial Boom Derrick (RBD) (digger truck), six (6) light duty vehicles (pick-ups and panel van) and one (1) pole trailer in the 2026-2030 DSP planning period.

ERP system replacement with capital costs of $500K (7.1%) associated with a cloud-based solution, enterprise server hardware and software upgrades for $955K (13.6%) and cybersecurity enhancements for $200K (2.8%) improve operational efficiency, security and compliance with evolving regulatory requirements.

SCADA hardware/software upgrades total $140K (2.0%), OMS enhancements account for $100K (1.4%) and MDM enhancements make up $70K (1.0%). These operational technology upgrades improve outage management, monitoring and response, and data management to better support the distribution system.

Facilities upgrades total $500K (7.1%), ensuring Oshawa Power's physical infrastructure remains functional and properly maintained for Oshawa Power's growing workforce.

Major tools and equipment investments account for $650K (9.3%), providing field crews with necessary resources to perform daily operations safely and effectively.

System improvements such as records management for $100K (1.4%), GIS upgrades for $50K (0.7%), automation platform for $125K (1.9%), system automation for $150K (2.1%), end user hardware/software upgrades for $782K (11.1%) and intranet upgrades for $50K (0.7%) are intended to enhance data accuracy, streamline processes, and improve operational efficiency.

Customer interface related items include CIS enhancements for $150K (21.4%), CRM software for $50K (7.1%), website redesign for $50K (7.1%) and customer communication redesign for $100K (14.3%) to improve accessibility, engagement and service quality to Oshawa Power's customers.

Accounting Treatment – Project Life Cycle > 1 Year

For capital projects spanning multiple years, costs remain in construction Work-In-Progress (WIP) until the project is completed and energized. Once the project is in service, capitalization of assets occurs. Many of Oshawa Power's subdivision expansion projects follow this cycle, where the development may extend over multiple years. In such cases, all costs incurred remain in WIP each year and are capitalized in the year the project is considered energized (put in-service).

5.4.1.3 Forecast vs. Historical Analysis

The subsections that follow, compare category investments in the historical and forecast periods.

SYSTEM ACCESS

The historical and forecast System Access expenditures are shown in Figure 36.

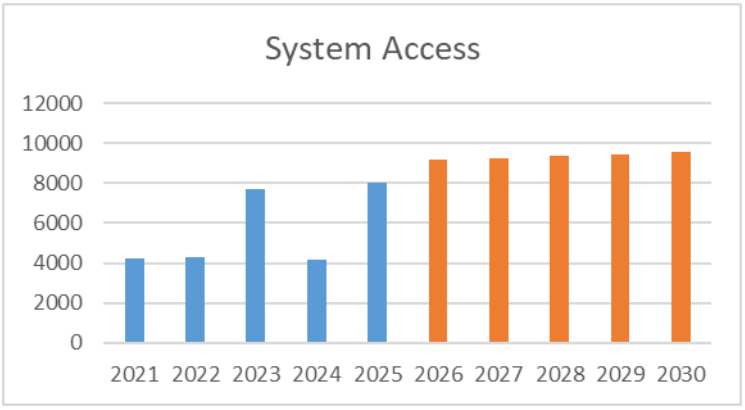


Figure 36 – System Access Expenditure Comparison

Forecast average annual System Access expenditure is approximately 65% higher than historical annual System Access expenditures. System Access investment requirements over the historical period were heavily influenced by the impacts of COVID with limited investments in 2021 and 2022. System Access investment started to recover beginning in 2023 and continue to grow through the forecast period with the exception of 2024 where Expansion needs were considerably reduced. COVID impacts on the supply chain have specifically impacted material costs and delivery timeframes affecting projects both internal and external to Oshawa Power.

The forecasted System Access investments are based on growth projections and committed or known development activity from Oshawa Power participation in municipally driven consultations.

Oshawa Power projects increase in Expansions costs (extension of the revenue horizon to 40 years for all residential customers has shifted more costs from contributed capital to the net cost borne by the LDC) and Third-Party relocations over the forecast period as compared to historical.

SYSTEM RENEWAL

The historical and forecast System Renewal expenditures are shown in Figure 37.

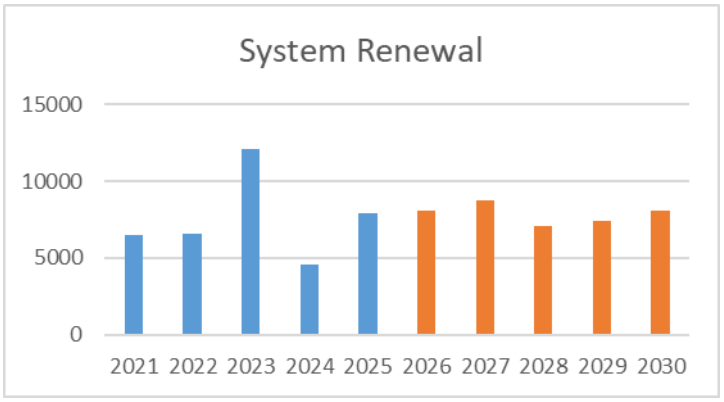


Figure 37 – System Renewal Expenditure Comparison

Forecast average annual System Renewal expenditure is approximately 5% higher than historical annual System Renewal expenditures.

In the historic period, expenditures in 2023 were significantly higher than other years primarily due to two main expenditures in the Municipal Substation Switchgear Replacement Program and Overhead System Rebuild Program that comprised approximately 56% of the annual spend (due to deferred efforts from previous years).

Forecast System Renewal expenditures are primarily driven by the results of the Asset Condition Assessment, specific proactive replacement programs (i.e., Quick sleeve replacement) and reactive replacement. Forecast expenditures have been planned to pace spending, while meeting ACA and other program asset replacement targets (i.e., Forecast Reactive Replacement is 8% less than historical levels reflecting the beneficial impact of increased focus on proactive replacement programs).

SYSTEM SERVICE

The historical and forecast System Service expenditures are shown in Figure 38.

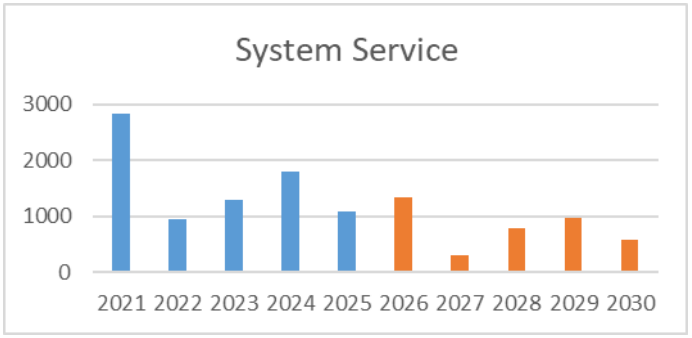


Figure 38 – System Service Expenditure Comparison

Forecasted average annual system Service expenditure is approximately 50% lower than historical levels, as projections are mostly focused on integrating automated devices rather than large-scale infrastructure projects like the 44kV line expansion and the Simcoe-Winchester reconfiguration during the historical period. Additionally, the reduction in System Service expenditures is necessary to offset higher anticipated costs in the System Access category.

In the historical period, expenditures in 2021 were significantly higher than other years primarily due to a Reliability Improvements program targeting reconfiguration in the Simcoe-Winchester area to address multiple reliability concerns, including reducing the number of customers on Feeder 7F4, creating an express feeder to serve rural Oshawa, and transferring load to MS9 to alleviate constraints on MS7.

Forecast expenditures reflect a continuing focus on grid automation (i.e., OH Automated Self-Healing Switches) and the implementation of selected Non-Wires Solutions projects. Significant expenditure in 2026 is the installation of three (3) new feeders from MS9 to continue to relieve overloading of the MS7 station, to provide capacity for new load requirements, and as capacity optimization use of Hydro One's Enfield TS that supplies MS9.

GENERAL PLANT

The historical and forecast General Plant expenditures are shown in Figure 39.

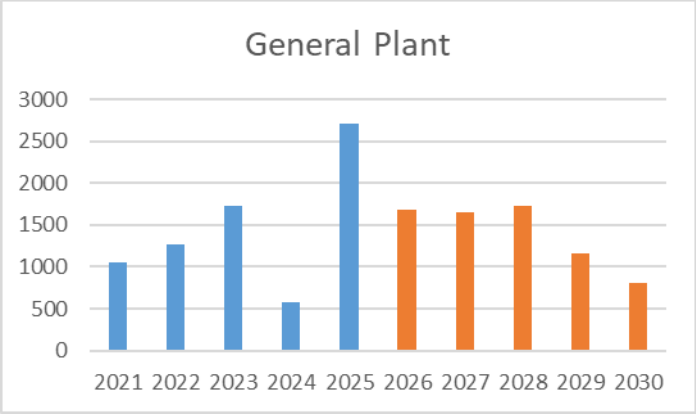


Figure 39 – General Plant Expenditure Comparison

Forecast average annual General Plant expenditure is approximately 4% lower than historical annual General Plant expenditures.

In the historical period, expenditures increased over time reflecting needs and cost of Oshawa Power's IT systems, facilities and fleet in the post-COVID period. Low expenditures in 2024 are due to delays in fleet delivery and high expenditures in 2025 reflect the implementation of CIS

Software and Enhancements entirely in 2025 as opposed to 2021 as initially planned. Forecast expenditures reflect a continuing focus on General Plant expenditures in fleet and IT infrastructure. Investment pace is variable and reflects changing annual needs. Fleet investment is generally evenly paced over the forecast period. Most annual IT investments are non-material except for the ERP Software in 2027 representing approximately 30% of General Plant expenditure and the Enterprise Server Hardware/Software Upgrades in 2028 representing approximately 34% of annual General Plant Expenditures.

5.4.1.4 Modifications to Capital Programs

Oshawa Power has not made significant changes to its Capital Programs; however, it has enhanced its planning process by developing and implementing an improved Asset Management System that includes a Strategic Asset Management Plan (SAMP) and a quantified risk prioritization methodology (Refer to Section 5.3). Where appropriate, Oshawa Power has optimized asset life, coordinated with third parties, and consolidated project scopes to maximize the value of replaced or refurbished assets.

SYSTEM ACCESS

All programs under System Access remain consistent with historical capital initiatives. Notably, although the scope of work remains unchanged, expansion-related costs are forecast to be higher due to a shift toward utility-borne expenses in line with the Ontario Energy Board's revised cost allocation for residential subdivisions. Additionally, the AMI system upgrade—which replaced failing meters with a new generation of meters—has been moved from System Access to the Meter Replacement Program under System Renewal. This change reflects the fact that a significant number of meters are approaching reverification in 2027, prompting a proactive, risk-balanced approach to pace future investments and avoid bulk expenditures that could impact rates.

SYSTEM RENEWAL

Capital programs under System Renewal are proposed based on analyses such as Asset Condition Assessments and options analysis, supported by field expert recommendations and historical data. While the type of assets being targeted may defer based on these findings, the overall goal of replacing/refurbishing assets to maintain safety and system reliability remains unchanged.

Two noteworthy additions are the Meter Replacement Program and the Underground Cable Injection Program. Both are designed to pace investments and prevent large-scale, bulk replacement efforts in the future—cable injection maximizes asset life and defers replacement to

future DSP periods, while annual meter replacement ensures timely updates to maintain metering accuracy and spreading out reverification timelines.

SYSTEM SERVICE

Oshawa Power continues its grid modernization by integrating monitoring and automated devices into its distribution system. In response to the Ontario Energy Board's guidance on alternative approaches to traditional infrastructure investments, consideration of Non-Wires Solutions (NWS) has been introduced. The intent of the proposed NWSs is to deploy them when new system needs materialize to keep deferred capital projects in the timeframe of the next DSP. For further details, please refer to the NWS Business Case in Appendix A.

Additionally, three (3) new feeders are proposed for the 2026–2030 forecast period to accommodate developments such as Kedron Part II Planning Area (Kedron) and Columbus Part II Planning Area (Columbus) in North Oshawa.

GENERAL PLANT

There are no significant changes to programs such as Fleet, Facilities and Major Tools. IT and OT investments are guided by evolving organizational needs and are justified in Section 5.4.2, "Justifying Capital Expenditures," and their respective material justification sheets for projects/programs above materiality.

Furthermore, Oshawa Power is prioritizing a new ERP system to ensure continued operational efficiency as the current Microsoft Dynamics GP system nears obsolescence. For additional details, please refer to the business case in Appendix A.

5.4.1.5 Impact of Capital Expenditure on System O&M

With growth in customer connections and expansion of Oshawa Power's asset pool, there is upward pressure on system O&M increases. Oshawa Power's intention is to manage O&M expenditures within expected incremental increases due to growth and inflation. Oshawa Power forecasts an average annual increase of 2.5% for O&M over the 2026 – 2030 forecast period.

Oshawa Power is investing significantly in System Renewal in the forecast period. Replacement of assets nearing end-of-life with new assets will result in neutral pressure on O&M expenditures, as new assets still require system planned maintenance equivalence to the assets they replace.

General Plant system support expenditures will continue to provide a better overall understanding of Oshawa Power's assets that leads to more efficient and optimized design, maintenance and investment activities.

The table below summarizes Oshawa Power's expectations on forecast capital investment impacts on forecast O&M for major assets.

Table 28 - O&M Impacts for Significant Assets

Item	Growth impact on O&M	Relocate impact on O&M	Replace impact on O&M	Support impact on O&M
Poles	increase	neutral	neutral	neutral
Cables	increase	N/A	decrease (repairs only)	neutral
UG Transformers	increase	N/A	neutral	neutral
UG Switchgear	increase	N/A	neutral	neutral
OH Transformers	Increase	neutral	neutral	neutral

Oshawa Power notes that non-capital expenditures (i.e., implementation of Asset Condition Assessment recommendations) are expected to increase O&M expenditures over the forecast period that should lead to improved asset reliability performance (i.e., reduced reactive replacement impacts).

Overall, capital system investments are not expected to have a significant impact on total O&M costs over the forecast period.

5.4.2 Justifying Capital Expenditures

Oshawa Power's capital planning process is designed to ensure that investments are strategically identified, optimized, prioritized and paced to maximize value for customers while maintaining financial and operational efficiency. This section provides an overview of the structured approach used to develop capital expenditures, integrating insights from internal and external stakeholders, historical data, subject matter expertise and comprehensive analytical processes.

To translate system needs into actionable projects and programs, Oshawa Power compiles and assesses input from various sources, including customer feedback, regulatory requirements, asset condition assessments and load growth projections. These inputs are rigorously analyzed using

industry best practices, quantitative risk assessments and strategic asset management frameworks to ensure investments are aligned with key organizational objectives.

A multi-layered prioritization process is embedded within Oshawa Power's planning framework. At the individual asset level, investments are evaluated through Asset Condition Assessments and Option Analysis to determine the optimal intervention strategy. At the project and program level, the quantified Risk Prioritization methodology, guided by the Strategic Asset Management Plan, is leveraged to ensure the most critical investments are addressed first while balancing long-term system needs, reliability and cost-effectiveness, and maintaining high service quality standards.

Additionally, prudently pacing investments is a key component of Oshawa Power's capital planning strategy. Efforts are made to minimize significant year-over-year variances in expenditures, ensuring a balanced allocation of resources while aligning project timelines with system needs. This disciplined approach prevents cost volatility and supports long-term financial sustainability, ultimately delivering stable and predictable outcomes for customers.

These key principles and processes are further elaborated on, providing a breakdown of the analytical methods used, the decision-making frameworks guiding investment selection, and how Oshawa Power optimizes its capital expenditures to meet both present and future demands.

Capital Planning Approach - Identification, Optimization, Prioritization, and Pacing

As described in Section 5.3.1.1 Process and illustrated in Figure 8 (Asset Management Process), Oshawa Power adopts a structured approach to capital planning that balances the needs of both internal and external stakeholders. This process ensures that capital investments are systematically identified, analyzed, and optimized to align with operational objectives, regulatory requirements, and customer expectations.

Internal Stakeholder Input

Needs are identified through consultations with various departments, including IT, Fleet and Facilities and Operations. These discussions highlight investments required for both the distribution system—ensuring safety and reliability—and organizational infrastructure that supports the efficient delivery of services to the public.

Additionally, historical data is analyzed to identify trends in reactive maintenance needs, enabling proactive planning for future expenditures. Once these needs are compiled, comprehensive analyses are conducted to substantiate investment requirements and ensure alignment with Oshawa Power's strategic priorities.

External Stakeholder Coordination

The data-gathering process also involves coordination with third-party stakeholders, as elaborated in Section 5.2.2 Coordinated Planning with Third Parties. This includes:

- Municipal Engagement: Collaborating with municipalities to align renewal efforts with road improvement projects such as widening initiatives.
- Large Demand Growth Drivers: Engaging with transportation entities, developers, and Large customers (Key account entities) to plan for system expansions that accommodate load growth.
- Telecommunications Entities: Supporting initiatives that expand internet access through joint-use infrastructure planning.
- Customer & Community Engagement: Consulting residential customers and small businesses to ensure investments align with evolving community needs.
- Regulatory Compliance: Monitoring and adapting to evolving regulations from the Electrical Safety Authority (ESA), Ontario Energy Board (OEB), and Measurement Canada to ensure smooth transitions and compliance with industry frameworks.

Data Analysis & Investment Optimization

Identified needs serve as an initial foundation, but further analysis is conducted to prioritize investments and ensure their timely and efficient execution.

Key analytical processes include:

- Asset Condition Assessments (ACA): Evaluating the state of existing assets to determine necessary interventions (Appendix C).
- Historical Impact Assessments: Reviewing past outage data (e.g., failure impacts due to quick sleeves) to identify recurring issues and mitigate risks (Included in relevant material sheets in Appendix B).
- Options Analysis Reports: Assessing alternatives to optimize asset utilization and determine the optimal intervention type and timing (Appendix C).
- Alternative Considerations: Included in material justification sheets (Appendix B), where applicable.
- System Capacity Assessments: Ensuring infrastructure can support anticipated growth and demand (Section 5.3.4).

Using the outputs of these analyses, investments are further refined for efficiency. This includes bundling geographically clustered asset replacements into larger projects (e.g., grouping pole

replacements into an overhead rebuild project) and aligning capital programs with external initiatives to optimize costs and scheduling.

Prioritization & Justification of Investments

Once investments are optimized, they undergo a structured prioritization process using quantified risk prioritization methodologies. This ensures that each project is ranked based on a multifaceted evaluation of risk, system impact, and alignment with Oshawa Power's corporate objectives, Asset Management (AM) strategy and the Renewed Regulatory Framework For Electricity (RRFE) outcomes. (Section 5.3 and subsections & SAMP – Appendix H)

Additionally, investment proposals are substantiated through supporting documents, including:

- Business Cases: Such as the ERP (Appendix A) and Non-Wires Solutions (Appendix A).
- Material Justification Sheets: Demonstrating the need and cost-effectiveness of planned expenditures.
- Strategic Alignment Documents: Ensuring projects align with Oshawa Power's Strategic Plan (Attachment 1-2 in Exhibit 1) and IT Strategy (Attachment 1-4 in Exhibit 1), keeping pace with evolving industry trends and technology.

By maintaining a rigorous and structured planning approach, Oshawa Power ensures that all capital investments are well-justified, strategically aligned and focused on delivering long-term value to customers.

Technological Changes and Cost-effective Innovative Investments

Oshawa Power is focused on keeping up with technological advancements and implementing cost-effective investments to improve system reliability, response times and resilience. A key initiative is the expansion of automated systems, such as Overhead Self-Healing Switches that allow the system to quickly isolate faults and restore power, reducing outage durations and improving safety by minimizing the need for manual intervention.

Investments in underground faulted circuit indicators, SCADA system upgrades and Automation Controllers (RTACs) at stations provide better system visibility and help improve operational efficiency. These technologies enable faster response times and reduce maintenance costs, contributing to overall reliability.

Expanding feeders ensures the system can meet future customer demand while optimizing existing assets and capacity, MS9 with the Columbus development as an example, especially with

new developments leaning towards electrification. This supports both growing electricity needs and environmental goals, contributing to decarbonization efforts.

Internally, Oshawa Power is investing in improved records management and data systems that create operational efficiencies.

Additionally, Oshawa Power is proposing a Non-Wires Solutions (NWS) budget aimed at keeping deferred investments outside of the 2026-2030 planning period, as loads associated with the energy transition materialize. This approach is an innovative take on budgeting for NWSs. Section 5.3.5 and the NWS Business Case (Appendix A) elaborate on the cost efficient, innovative approach to NWS deployment.

Consideration of Traditional Planning Needs

Oshawa Power's capital planning process integrates traditional considerations such as load growth, asset condition and reliability to ensure a robust and resilient future-ready distribution system. By analyzing historical data and engaging with both internal and external stakeholders, Oshawa Power projects future demand driven by population growth and increased load from major customers, ensuring the system can accommodate this expansion.

The Asset Condition Assessment (ACA) plays a key role in identifying aging or defective infrastructure in need of replacement or repair. This, coupled with risk prioritization guided by the Strategic Asset Management Plan (SAMP), enables Oshawa Power to prioritize investments and address reliability concerns proactively, minimizing service disruptions. These traditional factors are embedded within a comprehensive planning framework, ensuring investments meet both current system needs and future demands.

Individual Investment Justifications

Each investment category ensures that Oshawa Power's distribution system remains safe, reliable, cost-effective and aligned with evolving technological demands. The categories as summarized in Section 5.2.1.2 Capital Investment Overview directly support this DSP's objectives highlighted in Section 5.2.1.4 DSP Objectives. The information below demonstrates how various projects and programs align with these objectives, while delivering tangible value to customers. For further details on specific projects, refer to the Material Justification Sheets in Section 5.4.2.1.

SYSTEM ACCESS

DSP Objective Targeted:

- ✓ To sustainably support growth and meet customer expectations by ensuring adequate system capacity for new and upgraded connections through timely system access investments and proactive consultation, coordination, and engagement with third-party stakeholders.
- ✓ To continue incorporating customer feedback and comments as appropriate into distribution system planning and prioritization of projects.

Justification & Investment Need:

System access investments are driven by external stakeholder requirements, ensuring Oshawa Power meets regulatory and community needs efficiently. These projects include:

Third-Party Relocations – Coordinated with municipal and regional infrastructure projects to avoid redundant work and optimize cost-sharing opportunities.

Connections, Expansions, & Revenue Metering – Planned based on forecasted growth trends, including historical demand patterns and municipal population growth studies. These projects ensure resources are allocated and available to accommodate projected growth.

Planning efforts leverage population growth studies from the City of Oshawa and historical demand trends, ensuring a balanced, data-informed approach. Recent OEB revisions to the cost allocation model for residential subdivisions resulting in increased costs borne by the utility are incorporated into capital planning to ensure continued support for new housing developments while maintaining financial sustainability.

Customer Value

- Reliable and timely connections to accommodate Oshawa's rapid growth.
- Cost-efficient planning that aligns with municipal development to avoid unnecessary disruptions and expenditures.
- Support for housing development by adapting to regulatory changes and ensuring adequate resource availability.

SYSTEM RENEWAL

DSP Objective Targeted:

- ✓ To maintain Oshawa Power's high standards of safety for employees and the public and remaining compliant with all regulations and rules.
- ✓ To continue maintaining a reliable system by executing system renewal projects identified through the asset condition assessment, strategically prioritized, paced, and guided by the Strategic Asset Management Plan.

Justification & Investment Need:

System renewal investments focus on replacing assets that have reached or are approaching the end of their useful life, are defective, or no longer meet operational requirements. Additionally, reactive asset replacements due to adverse weather, equipment failures and motor vehicle accidents are addressed under this category.

Key renewal programs include:

Pole Replacement, Overhead & Underground Rebuilds, Switchgear & Transformer Replacements – These programs address aging infrastructure identified through Oshawa Power's comprehensive Asset Condition Assessment (ACA). The ACA employs a multi-faceted Health Index methodology to assess asset condition, risk and impact. Assets exceeding risk tolerance thresholds are prioritized for replacement to prevent failures, maintain service reliability and optimize capital expenditures. (See Appendix C for ACA methodology and results.)

Porcelain Insulator, Firon Switch, and Quick Sleeve Replacement Programs – Developed based on field expertise and industry best practices, these programs are supported by historical data demonstrating increased outage restoration times and preventable failures. Proactive replacement efforts enhance reliability and minimize avoidable service disruptions.

Meter Replacement Program – Driven by Measurement Canada regulatory requirements, this program ensures compliance while employing a strategic investment pacing approach. Spreading meter replacements over time helps mitigate rate volatility and prevents concentrated cost impacts on customers.

Customer Value

- Enhanced service reliability by replacing aging and high-risk infrastructure before failure.
- Reduced outage impacts through proactive, industry-informed asset management.

- Stable, predictable rates by pacing investments efficiently and avoiding cost spikes.

SYSTEM SERVICE

DSP Objective Targeted:

- ✓ To enhance system robustness and resiliency by continued system service initiatives such as deployment of distribution automation devices on the 13.8kV and 44kV networks that modernizes Oshawa Power's distribution system and allows an ongoing improvement in operational responsiveness.
- ✓ To evolve with industry trends by embracing digitization, strengthening cybersecurity, and enhancing alignment with public policy initiatives that support electrification.

Justification & Investment Need:

System service investments modernize and enhance the distribution system, ensuring it remains resilient and capable of meeting future demands. Key programs include:

New Feeder Installations – Supporting anticipated load growth in high-development areas like Columbus and Kedron.

Overhead Self-Healing Switches & SCADA Equipment Upgrades – Enhancing automation and system flexibility, reducing outage durations, and improving response times.

Underground Fault Locator & Asset Management Software – Providing better visibility and analytics to improve outage detection, asset tracking, and overall system efficiency.

Additionally, Non-Wires Solutions (NWS) are being introduced in alignment with the OEB's vision of leveraging innovative, non-traditional approaches to grid planning. It is aimed at enhancing the system's flexibility and capacity, positioning it to potentially defer future capital investments in traditional wires solutions.

Customer Value:

- Flexible and adaptive infrastructure, ensuring cost-effective long-term capacity expansion
- Improved response times and reduces outage duration
- Capacity availability to support development of new communities

GENERAL PLANT

DSP Objectives Targeted

- ✓ To continue optimizing workforce effectiveness through disciplined general plant investments in IT, Fleet, and Facilities.
- ✓ To improve operational efficiencies through the deployment of innovative technologies, leveraging data analytics, and streamlining internal processes.
- ✓ To evolve with industry trends by embracing digitization, strengthening cybersecurity, and enhancing alignment with public policy initiatives that support electrification.

Justification & Investment Need:

General plant investments support the operational, technological, and customer service functions necessary for Oshawa Power to provide safe, reliable, and efficient service. Key initiatives include:

ERP System Replacement – Ensures continued operational efficiency as the current Microsoft Dynamics GP system nears obsolescence.

Cybersecurity Software and Hardware Upgrades – Enhances system security, reliability, and compliance with the OEB's cybersecurity framework.

Fleet Investments – Replaces vehicles at end of useful life to maintain field service capabilities.

SCADA, OMS, and MDM Enhancements – Strengthens operational technology systems, improving outage management, monitoring, and response.

Customer Communication & Service Improvements – Enhancements to CIS, website, CRM, and customer engagement platforms for better accessibility and service experience.

Records Management, GIS, and Automation – Improves data accuracy, record management, and operational efficiency.

Tools & Equipment Upgrades – Ensures field crews have the necessary resources to perform daily operations safely and effectively.

Customer Value:

- Strengthened cybersecurity and IT infrastructure, ensuring compliance and protecting customer data.
- Enhanced customer communication systems improving accessibility and responsiveness
- Equip employees with the tools necessary to provide safe, reliable, and affordable power

Overall Investment Justification

Oshawa Power has optimized, prioritized and prudently paced its forecasted investments to maximize value for customers while maintaining financial and operational efficiency. This helped mitigate lumpy investment years and resulting rate impact, while ensuring quality of service is not compromised. 2026 (Test Year) and 2027 are forecasted to have slightly higher system renewal costs due to targeted replacements of Station Switchgears. System Service investments support new developments by installing three (3) new feeders from the existing MS9 station, and contribute to higher expenditures in the 2026 Test year.

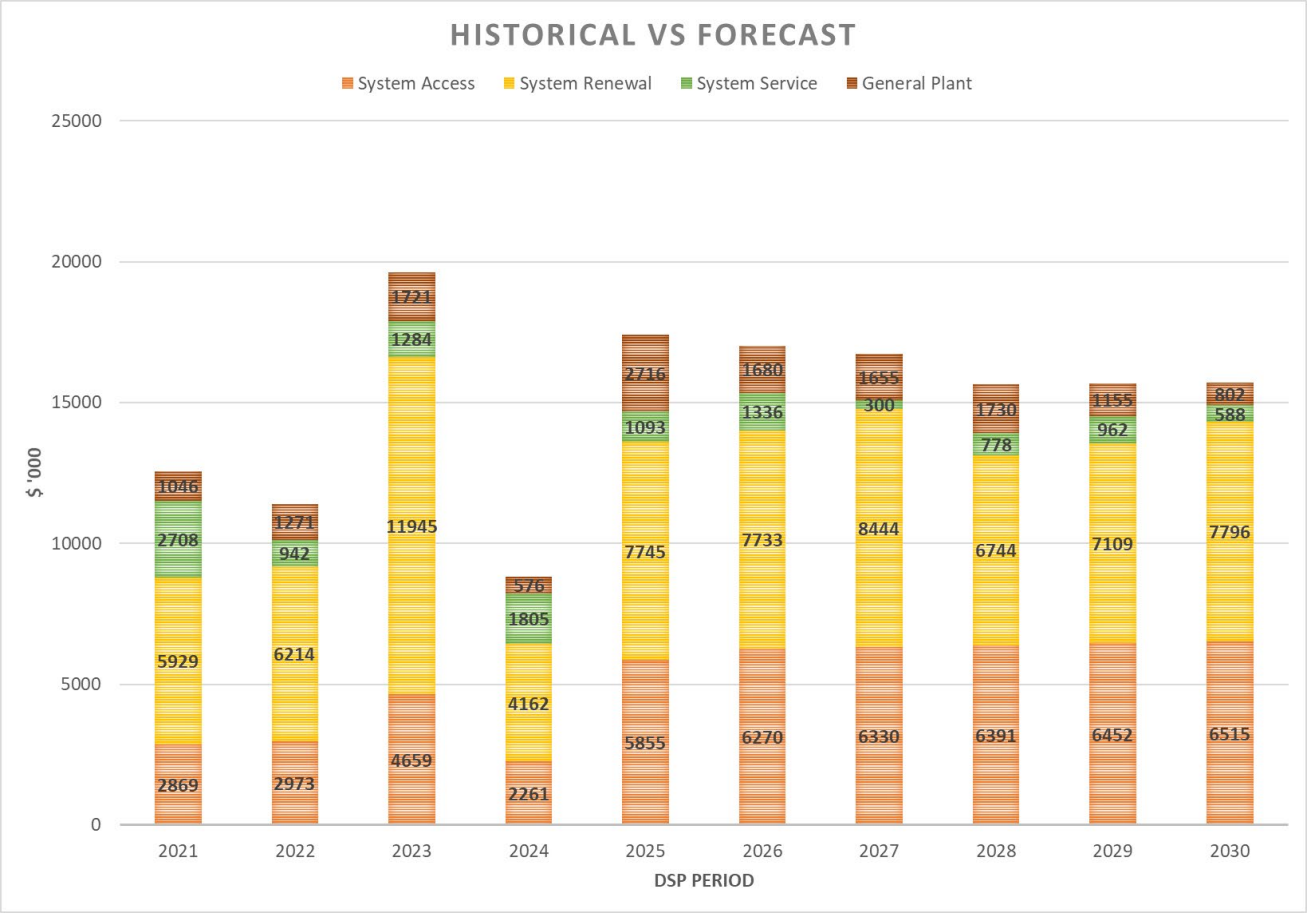


Figure 40 – Historical vs Forecast Expenditures

Oshawa Power's proposed capital investment of $80.8M for the 2026-2030 period represents a 17% increase from the overall 2021-2025 OEB approved envelope of $68.9M. This is a reasonable and necessary adjustment due to various factors such as inflationary pressures on labor, materials and transportation costs, and the ongoing economic impacts from the post-pandemic environment. Additionally, population growth, evolving regulatory requirements, and federal,

provincial, and municipal policies supporting electrification and decarbonization are placing heightened demands on the electrical grid.

Recent regulatory changes, particularly revisions to the cost allocation model for residential subdivisions, have increased utility-borne costs, which also contribute to the need for this higher capital investment.

As shown in the figure above, System Access plays a major role in the increased envelope, supported by the points above.

The total proposed investment aligns with Oshawa Power's strategic objectives to modernize the system, replace aging infrastructure, ensure service reliability, and accommodate the projected growth of the region. These investments are justified as they reflect the long-term needs of the distribution system and the need to address both current and future demands. The proposed expenditures are essential to maintaining safe, reliable, and cost-effective service for customers while staying responsive to regulatory changes and technological advancements. The planned investments are aligned with customers' priorities and preferences as can be seen in the Customer Engagement Report in Attachment 1-10 in Exhibit 1, balancing rate stability with the required system upgrades.

5.4.2.1 Material Investments

The focus of this section is on projects/programs that meet the materiality threshold set out in Chapter 2 of the Filing Requirements for Electricity Distribution Rate Applications. The materiality threshold for Oshawa Power's DSP is $195,000. A list of all projects/programs are presented in the table below. Material justification sheets have been prepared to address the following requirements:

- General information on the project/program
- Evaluation criteria and information requirements for each project/program
- Category-specific requirements for each project/program

All capital expenditures for the forecast years (2026-2030) are summarized in the table below and the material capital expenditures (>$195K in any year) are justified in their respective Material Justification Sheets (Appendix B)

Table 29 - Capital Project/Program Expenditures for the 2026-2030 Forecast Years

Category	Project #	Project/Program Name	Annual Expenditure $'000					Total Net Forecast Expenditure (2025-2030) $'000
			2026	2027	2028	2029	2030	
System Access	SA-01	Third Party Driven Relocations	2,191	2,191	2,191	2,191	2,191	10,955
	SA-02	Connections	628	630	633	635	637	3,164
	SA-03	Expansions	2,954	3,001	3,049	3,098	3,148	15,250
	SA-04	Revenue Metering	496	507	517	528	539	2,587
System Renewal	SR-01	Pole Replacement Program	300	600	492	492	492	2,376
	SR-02	OH System Rebuild Program	1,072	486	1,045	1,631	1,225	5,459
	SR-03	UG system Rebuild Program	393	54	1,185	727	1,663	4,022
	SR-04	UG Cable injection Program	0	479	0	61	0	540
	SR-05	Porcelain Switch and Insulator Replacement Program	0	150	150	150	150	600
	SR-06	Firon Switch replacement Program	0	313	313	313	313	1,252
	SR-07	Quick Sleeve Replacement Program	0	250	250	250	250	1,000
	SR-08	Overloaded Transformer Replacement Program	0	267	267	267	267	1,068
	SR-09	Distribution Switchgear Replacement Program	0	603	0	176	394	1,173
	SR-10	Municipal Switchgear Replacement Program	3,042	2,316	0	0	0	5,358
	SR-11	Distribution system - Lock replacement	0	0	117	117	117	351
	SR-12	Reactive Replacement Program	1,826	1,826	1,826	1,826	1,826	9,130
	SR-13	Meter Replacement Program	1,100	1,100	1,100	1,100	1,100	5,500
System Service	SS-01	3 New Feeders from MS 9	1,000	0	0	0	0	1,000
	SS-02	OH Automated Self Healing Switches	0	0	565	565	565	1,695
	SS-03	Asset Management Software	165	0	0	0	0	165
	SS-04	Underground Fault Locators	0	0	13	13	13	39
	SS-05	SCADA Equipment Upgrade	0	0	0	350	0	350
	SS-06	Non Wires Solutions (NWS)	171	300	200	34	10	715
General Plant	GP-01	Customer Information System (CIS) Software and Enhancements	0	0	50	50	50	150
	GP-02	Cyber Security Upgrades	40	40	40	40	40	200
	GP-03	End User Hardware/Software Upgrades	196	146	146	146	146	780
	GP-04	Enterprise Server Hardware/Software Upgrades	116	66	591	116	66	955
	GP-05	ERP Software	0	500	0	0	0	500
	GP-06	SCADA Hardware/Software Upgrade	0	0	100	40	0	140
	GP-07	Automation Platform	125	0	0	0	0	125
	GP-08	System Automation	30	30	30	30	30	150
	GP-09	CRM Software	50	0	0	0	0	50
	GP-10	Customer Communication Redesign	100	0	0	0	0	100
	GP-11	GIS Upgrade	50	0	0	0	0	50
	GP-12	Intranet Upgrade	50	0	0	0	0	50
	GP-13	MDM Enhancements	18	18	18	18	0	72
	GP-14	OMS Enhancements	25	25	25	25	0	100
	GP-15	Records Management	100	0	0	0	0	100
	GP-16	Website Redesign	50	0	0	0	0	50
	GP-17	Fleet	500	600	500	460	240	2,300
	GP-18	Facilities	100	100	100	100	100	500
	GP-19	Major Tools & Equipment	130	130	130	130	130	650

The table below ranks material capital expenditures according to the risk-based prioritization methodology detailed in Section 5.3.1.1. Recognizing the non-discretionary nature of System Access investments, Oshawa Power includes them based on the scheduled need to meet its statutory and regulatory obligations and comply with conditions of licensure; therefore, these investments are not ranked.

Additionally, the table illustrates the likelihood and level of impact that form the foundation of the project ranking methodology. Appendix A of the Strategic Asset Management Plan (found in Appendix H) provides descriptions of potential asset failure consequences corresponding to each impact level. For example, under "Customer Focus," a High-Medium impact signifies an event affecting major commercial or industrial customers, such as universities, colleges, and manufacturing plants, or an event impacting approximately 4,600 customers.

The Risk Matrix (Table 11) assigns specific values to each combination of likelihood and impact. Similarly, Table 10 defines the weightings associated with each operational theme, which are also reflected in the table below.

The Total Risk Score (TRS) for each investment is determined by combining the Risk Matrix (Table 11) and the Impact Matrix (Table 10). Projects are subsequently ranked based on the maximum risk mitigation achieved by executing the investment, calculated as the difference between the TRS before and after project implementation.

Table 30 – Project Ranking and Prioritization Matrix for Material Capital Expenditures

Project Priority	Investment Category	Project Name		Safety	Reliability	Customer Focus	Stewardship	Innovation	Δ TRS
			Weight	30%	20%	20%	20%	10%	
-	System Access	Expansions		-	-	-	-	-	-
-	System Access	Third Party Relocations		-	-	-	-	-	-
-	System Access	Connections		-	-	-	-	-	-
-	System Access	Revenue Metering		-	-	-	-	-	-
-	System Renewal	Reactive		-	-	-	-	-	-
1	System Renewal	Pole replacement Program	**Likelihood**	Very Likely	Very Likely	Very Likely	Very Likely	-	304
			Impact	High	High-medium	High-medium	High	-	
2	System Renewal	Municipal Switchgear Replacement Program	**Likelihood**	Likely	Very Likely	Likely	Likely	-	128
			Impact	High-medium	High-medium	High-medium	High-medium	-	
3	System renewal	OH System Rebuild Program	**Likelihood**	Likely	Likely	Likely	Remote	-	111
			Impact	High	Low	Low	Low	-	
4	System Renewal	Quick Sleeve Replacement Program	**Likelihood**	Somewhat Likely	Somewhat Likely	Somewhat Likely	Somewhat Likely	-	86
			Impact	High	High-medium	Medium	Low	-	
5	System Renewal	UG System Rebuild Program	**Likelihood**	Very Likely	Very Likely	Very Likely	Remote	-	66
			Impact	Medium	High-medium	Medium	Low	-	
6	System Service	3 New Feeders MS9	**Likelihood**	Somewhat Likely	Somewhat Likely	Somewhat Likely	Somewhat Likely	-	57
			Impact	Medium	High-medium	High-medium	Medium	-	
7	System Service	Overhead Automated Self Healing Switches	**Likelihood**	Somewhat Likely	Likely	Somewhat Likely	Unlikely	Somewhat Likely	54
			Impact	Medium	Medium	Medium	Medium-Low	High	
8	System Renewal	Firon Switch Replacement Program	**Likelihood**	Likely	Likely	Likely	Likely	-	45
			Impact	Medium	Medium	Medium	Medium	-	
9	General Plant	ERP Software	**Likelihood**	Somewhat Likely	Somewhat Likely	Likely	Somewhat Likely	Likely	45
			Impact	Low	Low	Medium-Low	Low	High	
10	System Renewal	Meter Replacement Program	**Likelihood**	Very Likely	Very Likely	Very Likely	Very Likely	-	38
			Impact	Medium-Low	Medium-Low	Medium	Medium	-	
11	System Renewal	Distribution switchgear replacement program	**Likelihood**	Unlikely	Likely	Somewhat Likely	Somewhat Likely	-	35
			Impact	Medium	High-medium	Medium	Medium-Low	-	
12	System Renewal	UG Cable injection Program	**Likelihood**	Somewhat Likely	Somewhat Likely	Somewhat Likely	Somewhat Likely	-	21
			Impact	Medium	Medium	Medium	Low	-	
13	General Plant	Fleet Replacement Program	**Likelihood**	Likely	Somewhat Likely	Remote	Somewhat Likely	Unlikely	18
			Impact	Medium	Medium	Low	Medium-Low	Medium-Low	
14	System Renewal	Overloaded Transformer Replacement Program	**Likelihood**	Somewhat Likely	Very Likely	Unlikely	Unlikely	-	18
			Impact	Medium-Low	Medium	Medium-Low	Medium-Low	-	
15	System Service	Non Wire Solutions	**Likelihood**	Remote	Somewhat Likely	Somewhat Likely	Somewhat Likely	-	18
			Impact	Low	Medium	Medium	Medium	-	
16	System Service	SCADA Equipment Upgrade	**Likelihood**	Unlikely	Likely	Somewhat Likely	Unlikely	Somewhat Likely	16
			Impact	Medium	Medium	Medium	Low	Medium-Low	
17	General Plant	Enterprise / Server Hardware / Software replacement	**Likelihood**	Likely	Likely	Likely	Likely	Likely	13
			Impact	Low	Medium-Low	Low	Low	Medium	

5.4.2.2 Benefit-Cost Analysis Framework

As an outcome of the Framework for Energy Innovation (FEI) consultation and associated FEI Report, the OEB issued the BCA Framework for Addressing Electricity System Needs on May 16, 2024. This framework provided additional guidance for rate-regulated electricity distributors on incorporating Non-Wires Solutions (NWS), aligning with the previously released Non-Wires Solutions Guidelines for Electricity Distributors dated March 28, 2024.

As recognized in the NWS guideline and as was the case for Oshawa Power, distribution system planning for its 2025 rate application was already at a relatively advanced stage.

However, Oshawa Power took immediate action in the best interest of its ratepayers, to adhere to the policy and identify, assess and incorporate NWS opportunities wherever possible. Per section 3.1 of the NWS Guidelines, Oshawa Power took the following steps:

1. Conducted a pre-analysis of the programs being considered for the DSP using a binary analysis lens, to determine if any programs qualified for alternative solutions and therefore required a benefit cost analysis to be run.
2. Provided a rationale for infrastructure investment decisions where NWS were not considered/a Benefit-Cost Analysis (BCA) was not done – this rationale can be found in the Non-Wires Solutions Business Case included in Appendix A of the DSP.

The results of evaluating potential NWS against traditional solutions, revealed that there were no system needs within the 2026-2030 DSP for which non-wires solutions would be suitable.

As an additional step, Oshawa Power reviewed other data sources that suggested the NWS-qualifying opportunities may arise during the 2026-2030 such that the system's flexibility could be enhanced thus positioning Oshawa Power to potentially defer future capital investments in traditional wires solutions. The Business case on Non-Wires Solutions attached in Appendix A, provides Oshawa Power's approach on adoption and implementation of NWS.

Appendix A

Business Cases – ERP Software & NWS

OSHAWA POWER

Business Case:
Non-Wires Solutions



1 EXECUTIVE SUMMARY

On March 28th, 2024, The Ontario Energy Board (OEB) introduced a new mandatory set of guidelines called the Non-Wires Solutions Guidelines for Electricity Distributors (NWS Guidelines). Used in tandem with the OEB's Benefit-Cost Analysis Framework for Addressing Electricity System Needs and the Filing Guidelines for Incentives for Electricity Distributors to Use Third-Party DERs as Non-wires Alternatives, the NWS Guidelines support the development of business cases for implementing NWSs to address identified system needs that will require an investment of $2M or more in the distributors grid.

Oshawa Power's 2026-2030 DSP does not have any system needs that could be addressed using a NWS. The DSP was established based on historical load growth and best available information about Oshawa Power's service territory, and does not reflect the full possible load growth that could occur if the energy transition accelerates.

Given potential accelerated load growth, Oshawa Power has proposed capital expenditures for several NWS projects which are still in early stages of development. Oshawa Power proposes to advance these initiatives proactively in recognition of the potential for demand to exceed current forecasts if the energy transition accelerates, as well as to test the viability of NWS as a strategic tool to offer flexibility, cost-effectiveness, and scalability for the future. Oshawa Power's early investments in NWS projects are intended to build internal capacity and understanding of the effectiveness of NWS and position Oshawa Power to respond more nimbly to emerging needs. This approach also lays the groundwork for broader NWS adoption over time, positioning Oshawa Power to defer future capital investments in traditional wires solutions to ensure cost-effective continued reliability for customers.

In this business case, Oshawa Power has researched and outlined four NWS project opportunities for further exploration. These projects, along with all of the documentation required by the OEB for transparently demonstrating NWS considerations within this Application are captured in this business case, with the exception of benefit cost assessments because system needs are not fully known. Instead, in keeping with the targeted scoping and focused assessment nature of the NWS projects, Oshawa Power has proposed its best estimates of project budget with the understanding that the application of NWS is still nascent and additional understanding and precision with respect to costing will develop over time.

Oshawa Power is committed to early investments in targeted studies and exploration regarding how best to develop NWS projects that have the potential to offer flexibility, cost-effectiveness, and scalability in the future, leveraging external funding where possible. In June 2024, Oshawa Power submitted a funding proposal to NRCan's Energy Innovation Program aimed at developing Distribution System Operator (DSO) competence, while demonstrating the use of a DSO as an NWS to support equity deserving customers, such as long-term care homes and aggregators focusing on assets in lower-income neighborhoods. The proposal was accepted and the project will be launched in April 2025. This project is not captured within capital expenditures, as it is fully externally funded. However, Oshawa Power has noted how the DSO project can be leveraged to support the success of the four NWS projects.

2 BACKGROUND AND ANALYSIS OF NEEDS

Oshawa Power has included capital expenditures for NWS activities within the 2026-2030 DSP. The Organization is providing this business case to satisfy the materiality threshold for DSP investments, and to provide additional details for section 5.3.5 of the Distribution System Plan "Non-Wires Solutions to Address System Needs".

The NWS Guidelines came into effect in 2024 but recognized that distributors filing cost of service applications in 2024 and 2025 were in an advanced state of preparing their distribution system plans and cost-of-service applications may be challenged to fully implement the requirements. Oshawa Power is filing for 2026 distribution rates and had already completed most distribution system planning prior to the issuance of the guidelines. Since the NWS Guidelines strongly recommend making funding requests for NWSs during the rebasing process, as this improves the OEB's ability to review the system needs identified in the context of the distribution system plan, Oshawa Power has proposed several projects aimed at exploring and testing the efficacy and cost-effectiveness of NWS in its service territory.

In preparing these NWS projects in the context of a short planning horizon, Oshawa Power has taken all steps possible to estimate project costs and potential impacts, including grounding estimates in internal expertise as well as analysis of comparable deployments. However, Oshawa Power recognizes that given its relative lack of experience with these types of projects, these costs and impacts may evolve. As such, Oshawa Power has developed a structured approach to project design that reflects its understanding of the technical requirements, potential benefits, and implementation considerations. Oshawa Power has selected NWS initiatives that can proactively test the viability of NWS to meet system needs and provide benefits to customers. On that basis Oshawa Power is seeking funding to proceed with early-stage deployment, guided by a clear rationale and structured approach.

Part of the rationale for selecting the proposed NWS initiatives relates to uncertainty given the potential for increased electricity demand as a result of the energy transition and economic development. At this time, all three levels of government have been predicting increased electricity demand for Oshawa Power for several years; however, load increases have yet to materialize in alignment with the policy predictions. Oshawa Power sees investment in NWSs as an approach to address this uncertainty in demand between prudent DSP investments in traditional infrastructure based on historical load growth and potential materialization of unpredictable loads.

Advancing NWS initiatives now aligns with the OEB's NWS Guidelines and allows Oshawa Power to build readiness, evaluate performance under real-world conditions, and adapt its approach as demand trends evolve. Oshawa Power therefore proposes projects that have the potential to address:

1. **Longer-term needs**: Addressing expected increased demand that may materialize within the next 10 years based on Oshawa Power's knowledge of its service territory, government policy and expectations associated with the clean energy transition.
2. **Unexpected short-term needs:** Should demand increase more quickly than forecast during the 2026-2030 period, creating local constraints even through the addition of one exceptionally large customer, NWS resources can be scaled up quickly and cost-effectively on an as-needed basis.
3. **Affordability:** Which can be achieved through implementing lower-cost NWS solutions, targeting solutions that benefit customers with incentives, and by leveraging external grants for scaling-up or implementing NWS activities sooner.

Oshawa Power's approach, outlined in detail below, is to request cost recovery for identified NWS activities in recognition of the potential for demand to exceed current forecasts if the energy transition accelerates, as well as to test the viability of NWS as a strategic tool to offer flexibility, cost-effectiveness, and scalability for the future.. Further information about the prudence of this strategy is provided throughout the following business case.

2.1 NWS Needs and Eligibility Analysis

The following sections provide an overview of the data sources Oshawa Power has analyzed to develop a list of system needs to be considered in preparing the NWS Guidelines deployment strategy. Going forward, these data points will be rolled into an updated DSP process, with enhanced documentation to record decision-making.

Within each sub-section below, a discussion will be provided regarding the NWS eligibility of each system need identified. This is because Oshawa Power has not yet fully developed a binary screening policy, due to the recent timing of the launch of the NWS Guidelines. Oshawa Power is actively developing a binary screening policy via participation in a Utilities Standards Forum working group and expects to have fully implemented this aspect of the NWS guidelines in 2025.

Area of Need # 1 – Distribution System Plan Investments of $2M or More

This data set includes prioritized projects identified via the traditional DSP process. Readers of this business case should refer to the DSP for details on projects included within each program, within the 2026-2030 period.

NWS Eligibility – System Renewal Projects

The system renewal projects within this DSP focus on assets that are at or approaching the end of their useful life and pose a high level of risk. The included projects typically do not benefit from NWSs or are in a condition where an NWS would not effectively mitigate the associated risks.

NWS Eligibility – System Access Projects

The system access jobs within the DSP are not well-suited for NWSs due to their mandatory and immediate nature. These projects involve critical activities such as revenue metering, system expansions to accommodate new developments, and asset relocations required to align with municipal infrastructure plans like road widening. The inherent urgency and regulatory requirements associated with the proposed system access jobs leave little opportunity for alternative approaches. No NWS solutions were identified as feasible for serving these purposes.

NWS Eligibility – System Service Projects

Oshawa Power's system service projects are focused on addressing system operational objectives such as safety, reliability, performance, and system efficiency. They are specifically targeted at optimizing the existing asset base and enhancing overall system performance to best support the existing customer base and facilitate seamless growth. Their focus on achieving precise performance improvements, such as increasing reliability or enhancing system efficiency, requires tailored solutions that leverage Oshawa Power's asset base such as bringing out three new feeders from an existing substation with three currently vacant breaker positions. They also all fall below the $2M threshold for required evaluation. Consequently, these projects are not conducive to NWS.

Per section 3.1 of the NWS Guidelines, projects marked GP (general plant) are excluded from the NWS evaluation requirement.

Area of Need # 2 – Areas of Known Constraint in the Distribution Grid

This data set includes infrastructure where upgrades may be necessary to address capacity constraints or facilitate greater grid integration thereby limiting customer opportunities.

For the purpose of clearly identifying areas of need, further comments are broken out by system voltage.

44 kV Sub-Transmission Grid

Oshawa Power is part of the GTA East regional planning group, which is currently in its active planning cycle. Oshawa Power has provided load forecast data that demonstrates new capacity requirements needed within the next five years. Therefore, NWS projects that free-up 44KV capacity could be eligible and cost-effective within the planning horizon of this DSP. NWS projects targeting transmission capacity have been included below in the section titled “NWS Projects”.

13.8 kV Distribution Grid

Oshawa Power currently has no constraints in terms of short circuit capacity, as reported in the Renewable Energy Generation Investment Plan; however, there are some areas of infrastructure that are nearing, or are at technical capacity. These areas include:

- The overloaded transformers that form program SR7 in the DSP (as noted above – already considered deteriorated, the risk is not mitigated with an alternate approach);
- MS7; and,
- The following table of feeders with limited technical capacity remaining.

Table 1: Feeders with Limited Capacity with the Oshawa Power Distribution Grid

5F1	2F5	14F5
5F2	7F1	15F6
7F5	10F1	15F1

In addition to the equipment that is fully loaded, grid edge connections (transformers and secondary wires) are expected to be the first point of constraint caused by net zero

retrofits and EV adoption. Therefore, grid-edge infrastructure could be eligible for NWS projects within the timeframe of the DSP.

Area of Need # 3 – Customer Needs Assessment

Key Accounts

Oshawa Power runs a Key Account program that includes proactive and ad hoc communications aimed at supporting larger customers' unique needs and regulatory opportunities. For the purposes of this submission, Oshawa's Key Accounts are defined as customers that have at any time qualified for the Industrial Conservation Initiative because they have historically been Oshawa's single biggest drivers of load changes. These customers are responsible for 26.7 MW peak demand, or roughly 10% of Oshawa's peak load and therefore have an important impact on the grid's trajectory[1].

As demonstrated in the Business / Key Account Report appended to the DSP, Oshawa's Key Accounts have shown a strong interest in NWSs. Feedback indicates that these customers feel there is an important opportunity to explore within the context of their own needs and plans for implementing distributed energy resources (DERs). To the extent that some of the Key Accounts have solid plans for DER implementation, these projects have been included below in a summary of potential NWS projects for Oshawa Power to pursue, in the section titled "NWS Projects".

Beyond the Class A Key Accounts, Oshawa Power reviewed customer needs arising from the Customer Engagement survey. The following two areas of needs were assessed as having a fit with NWS opportunities.

Business Customers (non-key account)

Survey results from business customers indicate a strong interest in energy transition technologies such as heat pumps, solar panels, battery energy storage and electric vehicles. This is consistent with the types of technologies being considered by Key Accounts and points to a potential opportunity for engagement on CDM programming or distributed energy resource inclusion when planning NWSs. The Business / Large Customer Engagement Report has further details regarding survey results.

Affordability

As demonstrated throughout various sections of this Application, Oshawa Power is experiencing a challenge with outstanding customer debt and is simultaneously hearing

[1] Peak loads of all customers over 500kW who qualify for the ICI Program, divided by Oshawa Power's ~250 system peak.

from customers that affordability is a top priority. Oshawa Power's actions to address this key area of need are detailed in Exhibit 1 and Exhibit 4.

Using the lens of NWS policy, Oshawa Power has identified NWS options that support affordability by being more cost-effective than traditional infrastructure, as well immediately and directly benefitting customers through bill savings. Such programs would leverage mechanisms such as incentives or support with managing bills. Options for such programming have been highlighted in the list of potential NWSs below. It should be noted that quantifying the non-energy social benefits of these projects may be challenging within the BCA structure; however, the importance of such consideration cannot be understated as electricity costs begin to climb in lockstep with the potential energy transition.

Area of Need #4 – Potential Electricity Demand Changes

All three levels of government have published documents that could cause Oshawa's electricity demand to increase significantly, if fully realized in the market, including:

- The Canadian Net-Zero Emissions Accountability Act, 2021;
- Canada's Electric Vehicle Availability Standard;
- Ontario's Municipal Housing Targets;
- The Durham Community Energy Plan; and,
- The City of Oshawa Community Greenhouse Gas Reduction Plan.

To-date, Oshawa Power has not seen the full materialization of load growth associated with these policies, which may suggest that growth could be happening at a slower pace, or will happen unevenly over time. To that end, in its Electricity Energy Efficiency Programming Post 2024 Bulletin, the Government of Ontario has stated that "Ontario's electricity consumption has largely remained flat since 2005, partly due to successful electricity energy efficiency programs. However, due to electrification, emission reduction efforts and economic growth, Ontario is expecting an unprecedented increase in electricity demand over the next two decades." Further, in its 2025 Annual Planning Outlook, the IESO has stated that "electricity demand is forecast to increase 75% by 2050, which is higher than the 60% increase previously forecasted". This demonstrates that:

- The energy transition may lead to the potential for short-notice load growth;
- The unprecedented nature of the energy transition is challenging to predict/forecast;
- LDCs would be prudent to build their DSPs based on historically successful forecasting methods, but also implement strategies such as NWS deployments to address the energy transition.

- In alignment with the above, the following chart provides a breakdown of potential drivers of load growth for Oshawa Power, and the corresponding capital projects that would be required to address this increase.

Table 2: Potential Sources of High Demand and Corresponding Capital Projects that may be Required in Oshawa 2026-2030

SOURCE OF GROWTH	DETAILS	POTENTIAL CAPITAL PROGRAM REQUIRED TO ADDRESS NEW LOAD SOURCE
EV Adoption	• Provincial and Regional Transit electrification (~400 buses) • Municipal fleet electrification • Residential EV uptake • Commercial EV uptake	• New high demand services with redundancy for fleet support. • Transformer and secondary wire upgrades in priority neighbourhoods – high-level estimated cost $1M across 5 years
Net Zero Adoption	• Key Account Feedback (see Business and Large Customer Report for details)	• Transmission Station to post 2031 – high level estimated cost $20M • Redundancy loop to feed Thornton trunk line to support several Net Zero buildings proposed for Northwood Business Park – high-level estimated cost: $2M
Ontario Housing Targets	• 23,000 new homes by 2031 according to Ontario's Housing Targets • Oshawa is one of the fastest growing communities in Canada, according to its 2024 Community Profile	• New substation – high-level estimated cost $15M
Ec. Dev. Trends	• Uptick in requests for new large load connections • Oshawa geographically ideal for datacenters	• TBD – based on unique customer requests.

Finally, with respect to load uncertainty, Ontario has recently released new eDSM (formerly CDM) programming that includes a broad range of tools including energy efficiency, demand response, green generation and battery energy storage. Without knowledge of targets, achievable potential or new potential programs, LDCs may have challenges in interpreting load trends going forward, or developing non-duplicative programming/projects.

3 PROPOSED NWS PROJECTS

Using the information identified through the NWS Needs and Eligibility Analysis, Oshawa Power has built the following five-point strategy to meet the NWS Guidelines requirement and generate tangible benefits for customers based on the research in the prior sections.

1. Prevent customer cost impacts by keeping energy transition growth initiatives to post 2030 through grid optimization.
2. Where possible, deploy NWSs that directly and immediately promote customer affordability and/or economic development, as well as creating system benefits that pass cost-effectiveness testing.
3. Leverage collaboration and grant opportunities to achieve positive benefit cost analysis outcomes (through incremental investment as opposed to bearing full costs of programs and infrastructure).
4. Leverage Oshawa Power's existing grants to cover the OM&A and/or shared aspects of NWS projects.
5. Broadly make use of numerous "tools in the toolbox" stated within the guidelines, such as eDSM programming, procurement from third parties and building assets that accrue benefits across various system actors (customers, LDC, transmission) to ensure commensurate and appropriate third-party investment.

The following section provides an overview of NWS project or program opportunities identified to offset areas of future constraint that may arise during the energy transition. Four potential initiatives have been researched and vetted for effectiveness, deployment readiness and cost, but have not been subject to the detailed benefit cost analysis process. This is because the needs they aim to offset have not yet materialized and therefore cannot be quantified or priced for comparison.

Project #1 – Managed Residential EV Charging

Background: Oshawa Power has focused on developing EV readiness through taking the following actions:

- Developing two research, outreach and education programs as part of NRCan's Canada's Zero Emission Vehicle Education and Awareness fund;
- Executing a Grid Innovation Fund project "Feeder Level Forecasting and Data Disaggregation for Distributed Energy Resource Identification" in partnership with Peak Power and Hatch, aimed at identifying EV charging signals in meter data and overlaying a propensity study to predict future EV uptake by neighbourhood;
- Supporting the City of Oshawa and Region of Durham with EV charger installations via NRCan's Zero Emission Vehicle Infrastructure Program;
- Developing relationships with top "managed charging" organizations operating cost-effective infrastructure deferral projects within Canada to attempt to secure additional external funding; and,
- Participating in the Region of Durham's project team for the development of a 2025 strategic EV Charging System Network.

Between 2023 and 2024 Oshawa experienced a 53% year-over-year increase in the number of battery electric and plug in hybrid vehicles, with over 2,100 such vehicles now attributed to Oshawa's postal codes, according to Ontario's Ministry of Transportation Q4 2023 and 2024 data sets. Oshawa Power's Grid Innovation Fund work provides a strong indication of specific neighbourhoods where EV adoption could initially challenge grid-edge equipment within the next five years. Oshawa Power will correlate these data points with at-capacity grid-edge infrastructure to determine where equipment deferrals can be achieved through managed charging.

In 2024 Oshawa Power worked with Optiwatt, a managed charging supplier to create a Grid Innovation Fund project that was ultimately not funded. Many of the costs and assumptions from this budget are inferred from that proposal's content as well as findings from Optiwatt's other studies in other jurisdictions such as Alberta, as funded by Fortis Alberta and the GTHA, as funded by The Atmospheric Fund. These studies are demonstrating the value of the tool in Ontario, as well as its ability to be offered under a cost effectiveness model for asset deferral.

Program Description: Oshawa Power will offer an incentive for EV owners using level 2 charging at home to use a software and telematics based managed EV charging app. The app will be programmed to reduce violations on transformers, loading on secondary lines and it will provide bulk system load curve smoothing. The program could be deployed widely, or targeted at specific neighbourhoods and scaled over time, based on cost-effectiveness and need. For additional context regarding the consideration to deploy

widely, the program becomes more cost-effective with increased participation because of efficiencies gained across scale. The program could be tied into Oshawa Power's DSO project with NRCan, for monitoring and ongoing optimization.

Estimated Impact: Shift up to 95% of participants' EV charging load to off-peak, deliver an average load shift of 0.5 to 1.1kW per EV per DR event, as per studies published by Oshawa Power's potential supplier, Optiwatt.

Budget Breakdown: The budget breakdown for this project is as shown in the table below.

Table 3: Estimated Budget Breakdown

Line Item	2026 (10% Uptake)	2027 (15% Uptake)	2028 (20% Uptake)	2029 (20% Uptake)	2030 (20% Uptake)
Ongoing charging management	$ 4,000	$ 6,000	$ 8,000	$ 8,000	$ 8,000
Advertising	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ -
One Time set-up Fee	$ 100,000	$ -	$ -	$ -	$ -
Incentives	$ 20,000	$ 10,000	$ 10,000	$ 10,000	$ -
Staff Time	$ 42,000	$ 10,000	$ 10,000	$ 10,000	$ 2,000
Total:	$ 171,000	$ 31,000	$ 33,000	$ 33,000	$ 10,000

Anticipated Uptake: Up to 20% of plug-in EV population in Oshawa**,** holding steady based on attrition being offset by new EV ownership.

Benefits: The key benefits to this program are anticipated to be grid-edge equipment deferral, distribution station deferral and improvements to energy affordability for Oshawa's customers via incentives and assistance with managing loads.

Project #2 – Northwood Business Park and Thornton Transit Electrification Embedded Low Carbon Smart Grids

Background: The Northwood Business Park and Thornton areas of Oshawa are anticipated to host new large load customers with an aggregated load up to 50 MW within the next five years. Two of these customers are major transit providers seeking to electrify fleets along the Thornton portion of Oshawa's grid. Oshawa Power is actively engaged in key account discussions with these customers, who are at advanced stages of planning and internal approvals for their new facilities and have public policy obligations requiring them to move forward with their designs. At this time, four customers have stated plans

to install several MW of distributed energy resources in the forms of solar, battery energy storage and potentially natural gas co-generation. Other transit agencies in the Greater Toronto/Hamilton Area Ontario have successfully worked with their distributor to plan NWS projects that focus on peak demand management and enhance reliability. This project would follow similar logic and engage multiple partners for a collaborative, multi-benefit outcome.

Program Description: Oshawa Power will use the cost benefit evaluation process to review options for collaborating on the sizing and functionality of the distributed energy resources being implemented in the grid, in order to procure, at an appropriate price, capacity, redundancy and/or load optimization services. Using Oshawa Power's DSO competencies that will be developed through NRCan funding, and the organization's existing automation expertise, this project will take the form of an embedded smart grid with renewables to address the rapid influx of new high demand and high consumption loads.

Estimated Impact: To be determined based on the scale of the needs and the outcomes of a BCA. Project requirements are still being studied and finalized by project proponents.

Budget Breakdown: One-time investments of 5% and 10% in 1MW Battery Energy Storage and Solar PV installations happening at customer-owned DER sites. Costs for the project have been based-off averages of industry reports regarding procurement of fully installed resources in 2024. These investments could be scaled over time or through NWS budget re-allocation, based on the outcome of the BCA.

Table 4: Estimated Budget Breakdown

Line Item	2026	2027	2028	2029	2030
Battery Energy Storage Capacity	$ -	$ 130,000	$ -	$ -	$ -
Solar Capacity	$ -	$ 125,000	$ -	$ -	$ -
Total:	$ -	$ 255,000	$ -	$ -	$ -

Anticipated Uptake: Multi-year contracts.

Benefits: The key benefits of this program are anticipated to be distribution system asset deferral, transmission station deferral and improved grid reliability.

Project #3 – Incremental Incentives for Save On Energy Solar Energy Management Systems

Background: Oshawa Power has expertise in managing residential solar energy management installations as a virtual power plant via the Solar Energy Management Systems pilot, which ran between 2015 and 2019. Currently, Oshawa Power is collaborating with a major post-secondary educational organization to grow this knowledge base to apply to new load management such as heat pumps and EV charging, with funding from the Ontario Centre of Innovation. Simultaneously, Save On Energy has newly released incentives for residential solar plus battery installations, which could cause an influx of these systems in Oshawa's grid. Under the Save On Energy program design, customers are only able to offset their loads, with no instructions with regard to the use of the energy stored in their battery systems. Allowing LDCs to influence the timing of battery energy storage deployment could create additional value for relatively low incremental value, depending on the saturation of these technologies within the grid.

Program Description: Oshawa Power will monitor uptake of solar energy storage implementation within its service territory and, if appropriate, design/offer incentives for residential customers to reserve capacity for load management activities. Based on Oshawa's past work in this space, it is likely that households will have BESS units of approximately 10 kW and that a large portion of that capacity will be able to be deployed during peak hours. Capacity needs would be managed through Oshawa Power's DSO, being developed with funding from NRCan.

Estimated Impact: 0.19 MW Peak Shaving capacity, based on demonstrated results from Oshawa's SEMS pilot.

Budget Breakdown: $1,000 incentive per household to provide capacity during Oshawa Power's capacity calls, via its DSO project. Funds for reporting and future program design 2029. Costs will be solely for incentives; given the direct line-of-site the utility has to participants in the Save On Energy programs.

Table 5: Estimated Budget Breakdown

Line Item	2026	2027	2028	2029	2030
Battery Energy Storage Capacity Incentive	$ -	$ 14,000	$ 11,000	$ -	$ -
Staff Time	$ -	$ -	$ -	$ 907	$ -
Total:	$ -	$ 14,000	$ 11,000	$ -	$ -

Anticipated Uptake: 25 sites, deployed on a pilot basis for 2027 and 2028.

Benefits: The key benefits to this program are anticipated to be grid-edge equipment deferral, distribution station deferral and improvements to energy affordability for Oshawa's customers via incentives and assistance with managing loads.

Project #4 – Port of Oshawa Battery Energy Storage Solution

Background: The Port of Oshawa area has recently experienced several requests for large loads by new potential industrial clients. Bringing significant, transmission-scale capacity to the Port would require lengthy build-outs across the community, a new transmission station, or a non-wires solution.

Program Description: Oshawa Power will defer or avoid the need for a new transmission station to feed the Port of Oshawa through collaborating on a multi-investor battery energy storage project.

Estimated Impact: To be determined based on the scale of the needs and the outcomes of a BCA. Project requirements are still being studied and finalized by project proponents.

Budget Breakdown: One time 6% investment in a 1.5 MW battery energy storage project hosted by third party stakeholders**.** These investments could be scaled-up over time or through NWS budget re-allocation, based on the outcome of the BCA.

Table 6: Estimated Budget Breakdown

Line Item	2026	2027	2028	2029	2030
Battery Energy Storage Capacity	$ -	$ -	$ 156,000	$ -	$ -
Total:	$ -	$ -	$ 156,000	$ -	$ -

Anticipated Uptake: multi-year contract.

Benefits: The key benefits to this program are anticipated to be transmission station deferral and grid-scale demand reductions.

3.1 TIMELINES

The NWS Guidelines become mandatory in 2026; therefore, Oshawa Power is well positioned to take action on the above business case. In terms of timelines, at a high-level, Oshawa Power will break-down efforts in the following manner:

2025:

- Finalization of guideline implementation activities;
- Ongoing technical and financial analysis of system needs; and,
- Ongoing engagement with the customer base, grant activities and research that provides data regarding system needs and opportunities.

2026-2030:

- Testing third party approaches for streamlining/standardizing the evaluation and costing of non-wires eligible technologies;
- Ongoing monitoring of needs and opportunities;
- Annual reporting on NWS considerations and, if applicable budget deployment;
- Documentation of NWS considerations for next DSP.

4 COST BENEFIT ANALYSIS

In keeping with Oshawa Power's commitment to targeted exploration regarding how best to develop and deploy NWS projects that have the potential to offer flexibility, cost-effectiveness, and scalability in the future, this cost benefit analysis is based on best estimates of the costs of NWS in the early stages of development. Oshawa Power has attempted to keep costs low while also testing NWS projects that have the potential to deliver customer benefits and savings in the future.

Based on the outcomes of planning sessions, partnership explorations and research, Oshawa Power has proposed the following budget for NWS within the DSP.

Table 7: Proposed Breakdown of the DSP Budget

NWS Program Estimated Budget	2026	2027	2028	2029	2030	Total
Managed Residential EV Charging	$ 171,000	$ 31,000	$ 33,000	$ 33,000	$ 10,000	$ 278,000
Northwood Business Park and Thornton Transit Electrification Embedded Low Carbon Smart Grids	$ 0	$ 255,000	$ 0	$ 0	$ 0	$ 255,000
Incremental Incentives for Save On Energy Solar Energy Management Systems	$ 0	$ 14,000	$ 11,000	$ 907	$ 0	$ 25,907
Port of Oshawa Battery Energy Storage Solution	$ 0	$ 0	$ 156,000	$ 0	$ 0	$ 156,000
Total:	$ 171,000	$ 300,000	$ 200,000	$ 33,907	$ 10,000	$ 714,907

Cost Benefit Analysis – Alternative Approach to NWS Project Implementation

Oshawa Power's approach also includes opportunistically seeking external grants and funding for projects that will meet anticipated system needs. Where significant external funding could be gained through co-investing some or all of the NWS capital expenditures for one project, Oshawa Power will scale the project or re-allocate those funds to other NWS projects where cost-effective and to the benefit of the customer.

Proposed Reporting Approach

Oshawa Power recognizes that this business case does not include cost benefit analyses that are required to support the implementation of NWSs. Instead, Oshawa Power Oshawa Power will report on NWS implementation as part of its annual IRM filing. This report would contain the following content:

- An overview of the need or opportunity that materialized;
- All content within the required BCA framework.

Through this process and commitment, the OEB and Oshawa Power's customers can be assured that any use of the requested budget will be prudent, transparently documented and aligned with the NWS Guidelines.

5 NEXT STEPS

Beyond being a mandatory requirement, implementing the NWS Guideline represents a strategic opportunity to enhance Oshawa Power's energy optimization practices, achieve significant cost savings, contribute to environmental sustainability and support customer choice and affordability. By taking a proactive stance to advance NWS initiatives, Oshawa Power can be ready to cost-effectively support the clean energy transition.

OSHAWA POWER

Enterprise Resource Planning:
Upgrade Project



1 EXECUTIVE SUMMARY

As common with most, if not all, medium to large organizations today, Oshawa Power leverages business technology systems to augment its human resources to perform the operational functions required for its sector. An enterprise resource planning (ERP) system is often used as a foundational technology to support a company's core business processes. For Oshawa Power, its ERP system is Microsoft Dynamics GP (a popular mid-market product).

In April 2023, Microsoft announced that it will no longer develop and release new versions of its Dynamics GP ERP solutions and will discontinue technical support by late 2029. To avoid reliability, performance, and security risks that could manifest from owning and operating an unsupported system, Oshawa Power is planning to replace its legacy ERP with a new solution.

After considering a number of factors, including Oshawa Power's resource capacity, strategic objectives, competing priorities, and different options related to the ERP, such as keeping the status quo and pursuing a full suite ERP solution, it was determined that the most prudent option is to replace the existing system with a new like-for-like implementation with some value-added enhancements.

The identified benefits are related to cost and risk avoidance, as well as productivity and efficiency gains. The ERP upgrade project also supports the company's strategic objectives and business transformation goals.

The capital requested for this project assumes that cloud-based software will be the optimal solution for Oshawa Power, although this will not be decided until a vendor is selected in Q3 of 2025. Non-capitalized implementation costs associated with a cloud-based solution, if adopted, will be tracked in a new Cloud Computing Implementation Costs Deferral Variance Account for disposal in Oshawa Power's next rebasing application. See Exhibit 9 for Oshawa Power's requests related to its Deferral and Variance Accounts. Should an on-premise solution be identified as the most prudent option, Oshawa Power will request cost recovery for additional capital invested through an incremental capital module (ICM) application, to be filed once costs and in-service date are finalized.

2 BACKGROUND, CURRENT AND FUTURE STATE

2.1 WHAT IS ERP?

Enterprise Resource Planning (ERP) is the integrated management of main business processes, often in real time and enabled by software and technology. ERP is usually referred to as a category of business management software—typically a suite of integrated applications—that an organization can use to collect, store, manage and interpret data from many business activities. ERP systems can be on-premise or cloud-based. Cloud-based applications have grown in recent years due to the increased efficiencies arising from information being readily available from any location with internet access.

The ERP system integrates varied organizational systems and facilitates error-free transactions, thereby enhancing the organization's efficiency.

CHARACTERISTICS

ERP systems typically include the following characteristics:

- An integrated system
- Operates in (or near) real time
- A common database that supports all the applications
- A consistent look and feel across modules
- Implementation of the system with sometimes complicated application/data integration by the Information Technology (IT) department or a third-party systems integrator
- Deployment options include: on-premises, cloud hosted, or SaaS (Software-as a-Service)

BEST PRACTICES

Most ERP systems incorporate industry best practices. This means the software reflects a vendor's interpretation of the most effective way to perform each business process. Use of best practices eases compliance with requirements such as IFRS, Sarbanes-Oxley, or Basel II. They can also help comply with de facto industry standards, such as electronic funds transfer. This is because the procedure can be readily codified within the ERP software and replicated with confidence across multiple businesses that share that business requirement.

Configuring an ERP system is largely a matter of balancing the way the organization wants the system to work, and the way the system is designed to work out of the box.

ERP systems typically include many configurable settings that in effect modify system operations.

ERP systems are theoretically based on industry best practices, and their makers intend that organizations deploy them "as is". ERP vendors do offer customer configuration options that let organizations incorporate their own business rules, but gaps in features often remain even after configuration is complete.

ERP customers have several options to reconcile feature gaps, each with their own pros and cons. Possible technical solutions include rewriting part of the delivered software, writing a homegrown module to work within the ERP system, or interfacing to an external system. These three options constitute varying degrees of system customization—with the first being the most invasive and costly to maintain. Alternatively, there are non-technical options such as changing business practices or organizational policies to better match the delivered ERP feature set. Key differences between customization and configuration include:

- Customization is always optional, whereas the software must always be configured before use
- The software is designed to handle various configurations and behaves predictably in any allowed configuration.
- Configuration changes survive upgrades to new software versions. Some customizations (e.g., code that uses pre–defined "hooks" that are called before/after displaying data screens) survive upgrades, though they require retesting. Other customizations (e.g., those involving changes to fundamental data structures) are overwritten during upgrades and must be re-implemented.
- Advantages of customization include:
- Improving user acceptance
- Potential to obtain competitive advantage relative to other companies using only standard features.
- Customization's disadvantages include that it may:
- Increase time and resources required to implement and maintain
- Hinder seamless interfacing/integration between suppliers and customers due to the differences between systems
- Limit the company's ability to upgrade the ERP software in the future
- Create overreliance on customization, undermining the principles of ERP as a standardizing software platform

ADVANTAGES

The most fundamental advantage of ERP is that the integration of numerous business processes saves time and expense. The way that ERP solutions are built make for excellent collaboration across different departments. With integrated applications and

data storage all under one solution, various business units get a clear picture into how each is functioning and contributing to the business.

With the ERP system in place, teams across the organization can communicate unhindered as they are not operating on disparate platforms. The integration on the back-end is extremely important and helps employees integrate and work as one. This expanded collaboration can increase decision-making, while being a single source of truth for all data entry.

One of the benefits of ERP is that it offers full access to every business function and process in an organization all in one place. The ERP solution monitors data daily and can provide day-to-day information, helping an organization be as precise as possible when it comes to factors such as inventory levels and business operations.

ERP applications can stand on their own but can also be integrated in the entirety of the ERP system, making for easier scalability and configuration in an organization. By being able to add or take away applications, ERP can help scale a business as it evolves over time.

The ERP system boosts productivity in a range of different ways that all stem from the automation of basic tasks and making processes more straightforward. With the streamlined approach from an ERP system, there is less time dedicated to digging up information, which allows for employees to perform other tasks faster. Manual data entry is also reduced, making tasks such as inventory management much easier and making metrics tracking and reporting much simpler.

The way an ERP solution is structured makes it so data input only occurs one time but can serve multiple purposes across the organization. This can result in saving the business time and money as it streamlines redundant tasks. The upfront costs and cost savings will also depend on which type of ERP solution you choose.

Without a centralized ERP software solution, organizations rely on numerous systems to run the business. The more systems, the higher the potential IT and labour costs. An ERP system could potentially reduce those costs. Separately, it could also reduce training requirements for the end-user since they would only need to learn on one system. This could result in more profitability and less disruptions.

The purpose of implementing an ERP solution is to highlight and build from an organization’s best practices and consistencies. This allows you to streamline operations and standardize workflows, ultimately to reduce manual labour and human error across your business.

ERP software offers many advantages, but standardization is one of the most important. By relying on standardization and configuration, organizations could also see reduced project costs and better cross-team collaboration with less friction.

2.2 CURRENT STATE

Oshawa Power currently uses the Microsoft Dynamics GP (Great Plains) 2016 ERP software primarily as a Financial Information System (FIS) in support of the following business functions:

- General Ledger Management
- Financial Accounting
- Payroll
- Accounts Payable
- Accounts Receivable
- Billing (for non-utility customers, such as developers and attachments)
- Purchasing
- Warehousing/Inventory Management
- Partial implementation of Fixed Asset Module/Register

The legacy MS Dynamics GP system is an on-premise solution with the following modules enabled to varying degrees of functionality and integration with other business systems:

- Job Costing (Partial)
- Financial (Full)
- Sales (Partial)
- Purchasing (Partial)
- Inventory (Partial)
- Payroll (Partial; Integrated with HRIS)

The most recent version upgrade was conducted in 2022 as part of the regular IT asset lifecycle management process to ensure supportability and enable new functionality.

Because the full functionality of most modules was not implemented, the current degree of process automation is suboptimal.

2.3 PROBLEM/OPPORTUNITY STATEMENT

In April 2023, Microsoft announced that version 18.5, released at the end of 2022, was the software's final major update and that support will end on September 30, 2029. Like many other software vendors, Microsoft is focusing on migrating its products to cloud-based solutions and encouraging its customers to transition to its Dynamics 365

Business Central cloud-based ERP solution. The end-of-support announcement means that although the product may still function, it will no longer receive the software vendor's direct support or security patches and updates, making it potentially vulnerable and less reliable over time.

Understanding that Oshawa Power's MS Dynamics GP ERP solution is coming towards end-of-life in 2029, there is a need to start planning for its replacement to ensure business continuity for those areas of the company that relies on this system to conduct its business activities. A negative consequence of the end-of-support announcement by Microsoft is that third-party support for Dynamics GP is becoming increasingly more costly and difficult to find. It is expected that this trend will only worsen over time and as it nears the end-of-support date. Given that Oshawa Power utilizes a third-party managed services firm to provide support services for its Dynamics GP solution, there is a risk of resource shortages and/or increasing costs to maintain continued support of the legacy system in the coming years. This scenario is not uncommon and inevitably occurs whenever a software vendor decides to discontinue a long-existing product in favour of a "new and improved" offering.

The need to transition away from the current ERP solution provides an opportunity for Oshawa Power to pursue greater productivity and efficiency benefits by aligning the future system implementation to the company's Business Transformation initiative to modernize the management of the business. This will be done by deploying greater end-to-end process automation, leveraging technology to enhance internal controls, and reducing manual tasks. There is also an opportunity to expand the utilization of the replacement ERP platform by implementing additional business modules, such as budgeting and warehousing, to provide greater system functionality as well as integration to other business systems, such as the Customer Information System (CIS), and Geo-spatial Information System (GIS) to enable additional business process optimization possibilities.

2.4 STAKEHOLDERS/REQUIREMENTS

The current MS Dynamics GP ERP solution was implemented mainly as a FIS. As such, its primary business users are those in the finance and accounting areas of the organization, as well as those who are responsible for procurement and inventory management. As mentioned, the main business functions enabled by this system include general ledger management, financial accounting, job costing, payroll, accounts payable, accounts receivable, and some financially related activities associated with purchasing, inventory management and warehousing.

Although the current system has been serving its intended purpose to leverage a computerized solution to support the management its financial and supply chain business activities, there are opportunities for improvements. Over time, it became

apparent that some of the tasks are being performed outside of the ERP system (in spreadsheets and paper-based documents) because the required functionality (such as workflow or electronic authorizations) or end-to-end processes were not available or enabled in the system. This has created inefficiencies and potential gaps in process controls. A priority for the new ERP will be to streamline and enable as much of these business processes in the technology solution to capture and realize productivity benefits.

2.5 OPTIONS

OPTION 1

Although Microsoft has announced that it will no longer provide updates, enhancements and support to the current version of Dynamics GP by September 30, 2029, the option to continue to utilize the legacy ERP solution is available to users. However, the business continuity and performance risks associated with lower reliability, greater security vulnerabilities, increasing difficulties and costs to secure third-party support render this option imprudent and unacceptable. The potential negative impacts could affect not only internal staff but also other key stakeholders like customers, vendors, and other business partners. To knowingly accept the status quo and the related risks is contrary to the objectives of good governance and responsible management.

OPTION 2

Oshawa Power's current ERP system is primarily a FIS that supports the basic financial and accounting functions of the organization. Although it integrates with the existing HRIS to enable the payroll function and also provides some services to support the purchasing and inventory management functions, the organization's technology ecosystem is essentially a "best-of-breed" model with standalone business solutions that are not connected. Furthermore, many of the available business functionalities in the various modules of the current ERP system have not been enabled or are not well utilized, or are not supported due to system and resource limitations, and incompatibility with our niche industry.

A new ERP system would remain to serve mainly as a FIS but replacing all of the existing modules and functionality of the current system, while adding new financial modules or submodules, such as Budgeting and Financial Planning, Procurement, Inventory and Warehouse Management, with added functionality to support streamlined end-to-end business processes to eliminate or reduce manual and paper based tasks and improve process controls.

Other potential features include the latest innovations such as artificial intelligence (AI) for predictive analytics, natural language processing, robotic process automation (RPA), machine learning, chatbots and virtual assistants, and image recognition. Furthermore, the new ERP solution will be implemented with newly designed standard reports to eliminate the use of unofficial reports and documents created outside of the ERP system to improve controls over designated formal reports and documents.

It would also re-establish integration with the HRIS (Dayforce) and add new interfaces with the CIS, GIS and the Work Estimating and Planning System.

The future state technology ecosystem will still remain largely a “best-of-breed” model but with greater functionality and integration between the new ERP and other business systems.

OPTION 3

Instead of pursuing a “best-of-breed” model for Oshawa Power’s technology ecosystem, an alternative is to implement a full suite ERP that replaces some of the existing standalone business solutions such as the Dayforce HRIS, the Estimating and Planning System, and the billing system. It would also include the implementation of other business modules not currently being used today such as Asset Management, Work Management, Procurement, Inventory Management, Warehouse Management and Customer Relationship Management. The new full suite ERP would be tightly integrated internally to enable more seamless end-to-end business processes that span across different business units and business systems.

Deploying a full suite ERP would be the most expensive and complex alternative, estimated to cost an order of magnitude more than a like-for-like replacement, based on similar implementations at other similarly-sized utilities, but would also provide the greatest benefits. It also comes with greater project risks and costs associated with the premature decommissioning and write-off of legacy systems still with useful life.

2.6 OPTIONS ANALYSIS

For reasons which are already presented in the previous section, the status quo (or do nothing) option is not only inadvisable, it would be irresponsible. As a regulated electrical utility, the essence of Oshawa Power’s core business is to responsibly manage its assets to ensure desired performance: capacity, reliability, resiliency, and affordability. Managing IT assets is no different: Responsible IT asset lifecycle management requires that the assets be supported, regularly maintained, upgraded, and replaced when nearing end of useful life.

In an ideal world without constraints and competing priorities, the option of pursuing a new full suite ERP to replace the legacy MS Dynamics GP system would likely be the best way forward. Having most of the core business processes enabled by functional modules all internally integrated within a single ERP platform would offer a more holistic view of the various operational areas, simpler overall IT architecture, a consistent look and feel, and ease of maintenance and support. However, the drawbacks are that such an implementation would require a much bigger effort from many more business stakeholders within the company, much higher costs, greater project complexity, and more challenging change management needs. For the size of an organization like Oshawa Power, which is already resource-constrained, the prospect of embarking on a new full suite ERP is daunting.

Given the volume of competing business priorities and resource limitations facing Oshawa Power, the most prudent option to pursue for the replacement ERP is the new like-for-like (with enhancements) option. This would reduce the challenge of acquiring additional resources to backfill those who would be dedicated to the ERP project; securing funds to pay for the project; higher risks associated with a bigger and more complex project; and the financial impacts of having to write-off legacy IT assets that are not yet fully depreciated. Accepting this option would address the issues contained in the problem statement and deliver the benefits described in the opportunity statement.

Therefore, the recommended option is **OPTION 2: New Like-for-Like ERP (with Enhancements)**.

3 PROPOSAL DESCRIPTION

3.1 PROPOSED SOLUTION

The scope of Oshawa Power's proposed ERP project is mainly to replace MS Dynamics GP generally on a like-for-like basis, with some new functionality such as budgeting and expanded utilization of other financial sub-modules including accounts payable and receivable and supply chain modules such as inventory and warehouse management.

In addition, the project scope includes the building of integration between the new ERP and the following existing systems:

- Customer Information System (CIS - Jomar)
- Geo-spatial Information System (GIS - Esri)
- Human Resource Information System (HRIS - Dayforce)

- Estimating and Planning System (Erth Quadra)

The integration with the CIS is to enable better management of customer billing, account adjustments, refunds, interest accrued, etc. Integrating the ERP with the GIS will enable the exchange of data related to fixed asset locations. Similarly, the HRIS interface will enable the sharing of employee, payroll, job costing, and timesheet data between these two systems. Finally, connecting the ERP with the Estimating and Planning System will support job costing, materials scheduling, invoice management, fixed asset valuation and depreciation, and use of compatible units for design and project estimates.

Although the current Dynamics GP ERP is an on-premise solution housed in Oshawa Power's own data centre, the decision to remain with an on-premise approach or migrate to a cloud-based solution for the new ERP will be considered and determined when competitive bids are solicited in a Request for Proposal (RFP) process.

3.2 PROPOSED TIMELINE

Milestone	Timeline
Select vendor to aid in writing RFPs for both software and integration.	Q3/25
Release RFPs to solicit bids for both software and implementation	Q4/25
Select Vendors, complete scoping	Q4/25
Begin ERP project	Q1/26
Go-live with new ERP	Q1/27

4 COST/BENEFIT ANALYSIS

4.1 GENERAL ASSUMPTIONS

Assumptions listed in this section are considered generally accepted facts at the time this business case was created.

Financial benefits include only cash impact on the organization (change in financial statements).

The benefit realization period for each function is assumed to be 5 years after system go-live.

4.2 COST ESTIMATIONS

Given that a decision on whether to select a new on-premise ERP solution or a cloud based one will not be made until reviewing competitive bids through an RFP process in Q3 of 2025, it is not possible to provide a definitive cost estimate at this time as the cost structure and financial accounting treatment for these two options are quite different.

The implementation costs (software, hardware, labour, training, and even the annual maintenance fees during the project) for on-premise solutions are typically higher and paid upfront over the duration of the project and can be capitalized. The associated operating costs occur after project go-live in the form of annual maintenance and support costs.

For cloud-based solutions, nearly all the implementation costs are considered operational expenses and cannot be capitalized. The initial costs are typically lower than for on-premise solutions but higher overall in the long run.

Because of the uncertainty whether the new ERP will be an on-premise solution or in the cloud and the different accounting treatment for project and asset lifecycle costs, the cost estimates provided will be technology agnostic and high-level. They are intended to provide an order of magnitude representation of the actual cost estimates that will be received through a competitive bidding process, and have been redacted to protect the integrity of that process.

The formal project budget will only be determined after deciding on product selection, the type of technology (on-premise vs. cloud), and performing a detailed project design (i.e., “blueprinting”).

The capital costs associated with a cloud-based solution are estimated to be $500,000 which is an estimate of the costs associated with interfacing a cloud solution with on-premise systems, such as CIS and Dayforce, and for any customizations required to meet our niche industry needs, such as fixed asset modules. These amounts have been included with Oshawa Power’s Distribution System Plan.

Non-capitalized implementation costs associated with a cloud-based solution would be recorded a new requested Cloud Computing Implementation Costs Deferral Variance Account for disposal in Oshawa Power’s next rebasing application. At that time, Oshawa Power will demonstrate how the costs recorded in the account meet the applicable criteria for disposition including causation, materiality and prudence of these expenditures.

Should an on-premise solution be identified as the most prudent option, Oshawa Power will request cost recovery through an ICM application for the additional capital invested. That application would provide information to demonstrate the need, materiality and prudence of those capital expenditures.

4.3 BENEFITS EVALUATION

FINANCIAL BENEFITS

- Avoidance of costs in the form of additional staff personnel to perform business tasks and processes manually in the absence of an ERP system
- Avoidance of costs associated with errors and omissions caused by having to perform business tasks and processes manually in the absence of an ERP system
- Avoidance of costs increases due to resource scarcity associated with continued maintenance and support from external third-party service provider for discontinued platform
- Productivity and efficiency improvements stemming from the adoption of standardized and optimized business processes embedded in the new ERP solution
- Productivity gains from additional integration with other business systems
- Cost savings arising from the reduction in the use of paper documents and forms, and printing services

NON-FINANCIAL BENEFITS

- Alignment with Oshawa Power's 2026-2030 Strategy & Business Plan strategic objective of "Keeping up with Technology Transformation & Data"
- Reduction of errors and omissions through process automation and elimination of manual paper-based tasks
- Reduction in risks associated with fraud and negligence through the use of internal controls technology functionalities such as work flows, segregation of duties, and digital authorizations
- Reduction of business continuity, performance and security risks as a result of technological obsolescence
- Better business insights and decision-making from the use of formal standardized reporting providing the "single source of the truth"
- Foundational ERP technology platform for potential future expansion into a full suite solution by implementing additional modules

5 NEXT STEPS

The capital requested for this project has been made assuming that a cloud-based software solution will be the optimal for Oshawa Power, although this will not be decided until a vendor is selected in Q3 of 2025. Non-capitalized implementation costs associated

with a cloud solution, if adopted, will be tracked in a new requested Cloud Computing Implementation Costs Deferral Variance Account for disposal in Oshawa Power's next rebasing application. See Exhibit 9 for Oshawa Power's requests related to its Deferral and Variance Accounts. Should an on-premise solution be identified as the preferred option, Oshawa Power may request cost recovery for additional capital invested through an incremental capital module ICM application to be filed once costs and in-service date are finalized.

Appendix B

Material Justification Sheets

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Material Justification Sheet

A. General Project Information

Project Name	Third Party Driven Relocation	**Project Number**	SA-01
Investment Category	System Access	**Project Year**	2026-2030
Project Description	This program consists of line relocation projects which are required in order to accommodate projects related to road work by the City of Oshawa, the Region of Durham, the Ministry of Transportation or any other third party such as developers or Hydro One. Projects within this program are initiated by third party request to relocate Oshawa Power's facilities. The City of Oshawa's and Region of Durham's plans were referenced along with detailed correspondence to estimate spending required and timing of projects although detailed planning is not available at this time. The size of load and number of customers affected varies by project in this category. The budget will consist of several relocation projects which will not be more detailed in scope until closer to the driver's construction when designs have been established.		
Start Date	2026-2030	**Expected In-Service Date**	2026-2030

Estimated Expenditure Timing

	Q1	Q2	Q3	Q4
2026	$725,000	$725,000	$725,000	$725,000
2027	$725,000	$725,000	$725,000	$725,000
2028	$725,000	$725,000	$725,000	$725,000
2029	$725,000	$725,000	$725,000	$725,000
2030	$725,000	$725,000	$725,000	$725,000

Historical and Forecast Capital Expenditures

Historical and Forecast Program expenditures ($,000) are shown below.

Category	Historical Period				Bridge Year	Test Year	Forecast Period			
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Capital (Gross)	$2,168	$1,455	$1,217	$4,033	$1,750	$2,901	$2,901	$2,901	$2,901	$2,901
Contributions	$630	$136	$618	$2,956	$350	$710	$710	$710	$710	$710
Capital (Net)	$1,537	$1,318	$599	$1,077	$1,400	$2,191	$2,191	$2,191	$2,191	$2,191

Economic Evaluations	Final economic analysis as described in the DSC is not applicable to this program.
Historical Comparative Projects	Third-party relocation costs are estimated based on the best available information gathered through coordination meetings with relevant authorities regarding future plans, supported by historical annual average expenditures.
Investment Priority	Mandatory priority. Prioritization of relocation projects is based on development plans of the third parties. Projects can be delayed, cancelled or replaced as a result of changes in the third party's plans. Third Party Relocation projects are mandatory and therefore, receives a high priority in the overall investment envelope.
Alternatives Analysis	While line relocations are generally executed on a like-for-like basis the opportunity is taken to look at feeder routes, future needs, increasing conductor size, or anything else reasonable to plan for future requirements from an efficiency perspective. This exercise will reduce the need for any system renewal and/or system service work required in the future years as well as contribute to a long-term enhanced system operational efficiency, and cost effectiveness. Each project is analyzed on a case-by-case basis to determine if there are any design changes opportunities that the Third Party could implement, to improve cost effectiveness of the relocation, thereby reducing costs for both parties. In addition, Oshawa Power ensures that all relocation projects are completed in accordance with Oshawa Power's standards which have been developed to minimize overall cost and expenses.
Innovative Nature of the Project	Future operational requirements are considered in projects where appropriate and accommodation is made in the design for same. For example, provision for remotely operated switches and communications circuits are incorporated where applicable.
Leave to Construct	This project is below 50 kV and therefore Leave to Construct is not required, as per O. Reg. 161/99.

Images, Drawings, Maps, & Other Reference Material

The following third party driven relocation projects and currently known and comprise the 2026-2030 capital expenditure program:

SA	1a	Simcoe St/ Russett Ave Intersection	$	26,250.00
SA	1b	Winchester Rd. / Bridle Rd Intersection	$	138,750.00
SA	1c	Ritson Rd./Beatrice St. Intersection	$	105,000.00
SA	1d	Ritson Rd. from north of Taunton Rd to Conlin Rd	$	562,500.00
SA	1e	Rossland Rd from Park Rd to Simcoe St	$	600,000.00
SA	1f	Rossland Rd from Ritson Rd to Harmony Rd	$	675,000.00
SA	1g	Thronton Rd from north of Stellar Dr to King St	$	600,000.00
SA	1h	Phillip Murray Ave/Stevenson Rd Intersection	$	90,000.00
SA	1i	Stevenson Rd/Laval Dr Intersection	$	60,000.00
SA	1j	Stevenosn Rd from CPR Belleville to Bond St	$	450,000.00
SA	1k	Stevenson Rd from Bond St to Rossland Rd	$	1,361,250.00
SA	1l	Townline Rd from Beatrice St to Taunton Rd	$	281,250.00
SA	1m	Gibb St from east of Stevenson Rd to Simcoe St	$	1,000,000.00
SA	1n	Wemworth St/Thornton Rd Intersection	$	120,000.00
SA	1o	73-0453 Conlin-Wilson Roundabout / 73-0454 Conlin Road East	$	531,000.00
SA	1p	73-0455 Conlin Road East	$	184,125.00
SA	1q	73-0456 Northwood Roads	$	632,250.00
SA	1r	73-0457 Columbus Road / 73-0486 Ritson/Columbus Roundabout	$	1,951,500.00
SA	1s	73-0459 Central Oshawa Hub Infrastructure Improvements	$	345,750.00
SA	1t	73-0460 Ritson Road North	$	406,500.00
SA	1u	73-0479 Britannia Ave W / 73-0492 Britannia Ave West Bridge	$	585,000.00
SA	1v	GWP 2601-19-00, 2146-20-00 - Hwy 401/Bloor/Harmony Interchange Reconstruction - OPUC	$	250,000.00

B. Evaluation Criteria and Information Requirements

Efficiency, Customer Value, Reliability and Safety

Efficiency	Oshawa Power's capital plan for system relocation as presented in the DSP is based on consultation with municipal officials to understand future projects requiring relocations of distribution system assets. The locations of municipal road work plans were also compared with Oshawa Power's planned renewal projects already budgeted for approval. This ensures that a renewal project will not be completed prior to a planned third-party relocation project in the short term unless there is a completed design to avoid the relocation of recently rebuilt assets which ultimately increases construction efficiencies.
Customer Value	There are no direct benefits to customers except in areas where the infrastructure is deteriorating and then there will be an increase in reliability, Customers also benefit indirectly from the work performed by municipalities which supports community development and growth.
Reliability	Relocation due to third party driven requests do not specifically address reliability, however, Oshawa Power will build to the latest industry standards and regulations to maintain reliability and install remotely operated switches and communications circuits where applicable. In order to address future challenges Oshawa Power designs the relocated system to avoid future hazards such as tree growth or land development where possible.
Safety	Facilities will be built to maintain and potentially improve the risk of safety concerns through the renewal of aged infrastructure and design of new infrastructure to the latest distribution standards such as CSA 22.3 for overhead and underground systems and in compliance with O. Reg. 22/04.

Investment Need

Primary Driver	The primary driver for this program is a mandatory service obligation to accommodate third party infrastructure development requirements.
Secondary Driver	There are no secondary drivers

Information Used to Justify the Investment	The objective of this program is to meet regulatory obligation to relocate facilities for municipal and regional road work and other third party driven infrastructure upgrades.
Investment Justification	
Demonstrated Utility Practice	While relocating the facilities Oshawa Power can take the opportunity to upgrade/modify the system to create flexibility in operations and accommodate future needs on the system. This will reduce the need for additional System Service work required in the future and contribute to higher system operational efficiency and cost effectiveness in the long term.
Cost-Benefit Analysis	Relocation of distribution system infrastructure to accommodate municipally driven projects has minimal impact to the overall system. Cost recovery is generally based on cost sharing between Oshawa Power and the third party driving the project. This is typically based on cost apportionment agreed upon by both LDC and third party or in accordance with Public Service Works on Highway Act. Where major infrastructure changes are required, or design changes are made at the specific request of the third party then a cost sharing agreement will be created before the start of the construction.
Historical Outcomes	Relocation projects are driven by development plans of municipal government and other third parties. Oshawa Power has very limited control over the scope and timing of these projects, however, past history has been taken into account when predicting the expenditure for these projects. To mitigate risk of scheduling problems, Oshawa Power works very closely with these third parties to exchange scheduling information. This is to ensure that all road work requiring system relocations are planned for and well-coordinated with other Oshawa Power projects.
Conservation and Demand Management	
Not Applicable	

A. General Project Information

Project Name	Connections	**Project Number**	SA-02
Investment Category	System Access	**Project Year**	2026-2030
Project Description	The Connections program will encompass projects that facilitate service upgrades or connection of new customers who lie along Oshawa Power's distribution system. The cost to install ducts, poles, transformers, and cable to supply electricity to new or upgraded services are captured here. The cost per service can vary widely with the nature of the work and the capacity of each new service. This project is driven by customers, developers and varies from year to year. Oshawa Power is obligated to complete this work. The forecast costs are mainly driven by historical trends and considerations of growth and development in Oshawa.		
Start Date	2026-2030	**Expected In-Service Date**	2026-2030

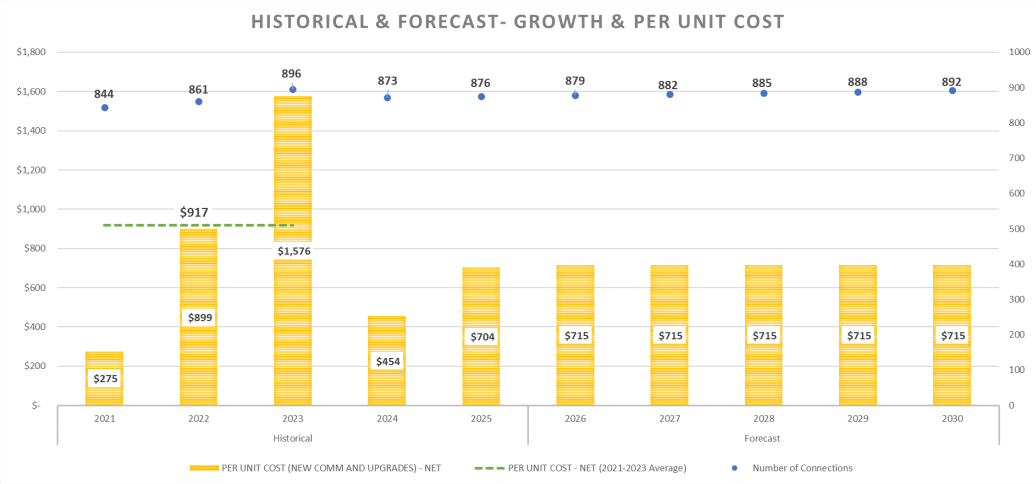
Estimated Expenditure Timing

	Q1	Q2	Q3	Q4
2026	$376,000	$377,000	$376,000	$376,000
2027	$377,000	$378,000	$378,000	$377,000
2028	$379,000	$379,000	$379,000	$379,000
2029	$380,000	$380,000	$381,000	$380,000
2030	$382,000	$382,000	$382,000	$381,000

Historical and Forecast Capital Expenditures

Historical and Forecast Program expenditures ($,000) are shown below.

Category	Historical Period				Bridge Year	Test Year	Forecast Period			
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Capital (Gross)	$992	$1,329	$1,711	$1,769	$1,721	$1,505	$1,510	$1,516	$1,521	$1,527
Contributions	$760	$555	$299	$1,373	$1,105	$877	$880	$883	$886	$890
Capital (Net)	$232	$774	$1,412	$396	$616	$628	$630	$633	$635	$637
Number of connections (incl upgrades)	844	861	896	873	876	879	882	885	888	892

Economic Evaluations	Only applicable if infrastructure has to be extended or enhanced. In this case an economic evaluation will be run on the cost of this extension after five years.
Historical Comparative Projects	Historical costs are provided that show comparative expenditure information. Note that actual costs can vary dramatically from year to year.  **Figure 1 – Historical and Forecast Growth Spend** The per-unit cost from 2021 to 2023 is skewed higher due to unusually low contributions in 2023. Recognizing this irregularity and applying a reasonable inflation adjustment to the 2025 estimate, a conservative per-unit cost of 715 was adopted for the 2026-2030 planning period. During the 2021-2023 historical period, the average number of service upgrades was 751 annually, while the commercial growth rate, represented by gross customer additions, was approximately 2.44%. These factors—the average number of upgrades and gross customer additions—collectively determine the anticipated annual customer connections for the forecast period. All residential additions are categorized under expansion, based on the assumption that most new residential connections are associated with new subdivision developments.
Investment Priority	Mandatory Priority. New connections are made based on customer/developer request. The process is managed by Oshawa Power staff through various systems to ensure proper visibility and timelines. Projects within this program are executed with a high priority as they are mandatory and driven by the connection requirements set out in the DSC. The timing and priority are also determined through Oshawa Power's AM process. In some cases where extensive civil work is required for the customer to gain access to the distribution system, scheduling requirements are adjusted. The availability of an egress to the existing main

	distribution system within proximity of the proposed connection will have the largest impact on timing. All new customers in this program lie along the distribution system, but these connections often require enabling civil work to construct duct banks, install transformers, and/or install poles.
Alternatives Analysis	Project Design Alternatives: Oshawa Power is responsible for system design and connection. For each customer request there are specific requirements, such as service size, transformer size, service egress type (overhead or underground), and any site specific barriers that must be accommodated. Where possible the designers will investigate the different supply options for a customer and make a recommendation as to the most cost-effective solution. Scheduling Alternatives: These projects are customer driven and do not have alternative scheduling options with the exception of minor variation in timing of connecting the service
Innovative Nature of the Project	Future operational requirements are considered in projects where appropriate and accommodation is made in the design for same. For example, provision for remotely operated switches, fault indicators and communications circuits are incorporated where applicable.
.Leave to Construct	This project is below 50 kV and therefore Leave to Construct is not required, as per O. Reg. 161/99
Images, Drawings, Maps, & Other Reference Material	

B. Evaluation Criteria and Information Requirements

Efficiency, Customer Value, Reliability and Safety

Efficiency	New services/upgrades are driven by customer/developer requests and are mandated by the OEB to be completed as stated in Oshawa Power's AM Process.
Customer Value	The benefits to Customers through this project include receiving a connection to the electricity grid and/or the ability to request an upgrade. This project captures the cost to install ducts, poles, transformers, and cable to supply electricity to new or upgraded services.

Reliability	New connections are constructed using best utility practices that consider reliability by design i.e., designing the system in a way that is safe and reliable through distribution system hardening (Oshawa Power's line designs are engineered for the corresponding CSA referenced heavy loading conditions of radial thickness of ice; horizontal wind loading and temperature) and ensuring that it meets Oshawa Power standard design which are typically over and above the CSA minimum requirements.
Safety	New construction meets the latest distribution standards for safety including CSA standards for OH and UG.
Investment Need	
Primary Driver	As a regulatory requirement, Oshawa Power must remain compliant with the obligations set forth for connecting customers in the DSC. This is a mandatory service obligation to connect customers within 5 calendar days.
Secondary Driver	There are no secondary drivers.
Information Used to Justify the Investment	This project is a main contributor to performance metrics tied to the mandatory service obligation outlined in the DSC to connect customers within five calendar days. Success is measured and posted publicly by means of the OEB scorecard which can be found on the OEB's website.
Investment Justification	
Demonstrated Utility Practice	New connections are constructed using best utility practices that consider reliability by design through distribution system hardening (Oshawa Power's line designs are engineered for the corresponding CSA referenced heavy loading conditions of radial thickness of ice; horizontal wind loading and temperature) and ensuring that it meets Oshawa Power standard design which are typically over and above the CSA minimum requirements.
Cost-Benefit Analysis	Costs for these projects are based on standardized processes and materials and are recovered through economic evaluations as prescribed in the DSC.
Historical Outcomes	Projects within this program are initiated by customers and the actual spending can vary between years. This is an OEB-mandated activity under the Distribution System Code (DSC). Oshawa Power has highly trained staff that work with project

	developers to the best of their ability to manage timelines and to best accommodate the customer. Meetings/correspondence with customers take place frequently and at their request to best manage customer expectations.

Conservation and Demand Management

Not Applicable

A. General Project Information

Project Name	Expansions	**Project Number**	SA-03
Investment Category	System Access	**Project Year**	2026-2030
Project Description	The purpose of the expansion program is to facilitate the connection of new residential subdivisions and associated customers to Oshawa Power's distribution system that do not lie along the existing distribution system. This program is driven by developers and varies from year to year. Forecasted costs are estimated using historical expenditures, the forecasted growth rate, and recent updates to economic evaluation methodologies. Based on best available information on historical trends at the time, a 1.6% customer growth rate for the residential class was assumed. This represents a more conservative approach compared to the population growth projections published by the City of Oshawa. For the test year, expenditures were divided equally across each quarter. However, this allocation does not reflect how the expenditures will actually be incurred, as the timeline for this program is strictly driven by developers and will vary accordingly.		
Start Date	2026-2030	**Expected In-Service Date**	2026-2030

Estimated Expenditure Timing

	Q1	Q2	Q3	Q4
2026	$1,071,000	$1,071,000	$1,071,000	$1,071,000
2027	$1,088,000	$1,088,000	$1,089,000	$1,088,000
2028	$1,105,000	$1,106,000	$1,106,000	$1,105,000
2029	$1,123,000	$1,123,000	$1,124,000	$1,123,000
2030	$1,141,000	$1,141,000	$1,142,000	$1,141,000

Historical and Forecast Capital Expenditures

Historical and Forecast Program expenditures ($,000) are shown below.

Category	Historical Period				Bridge Year	Test Year	Forecast Period			
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Capital (Gross)	$407	$404	$3,397	$154	$3,972	$4,284	$4,353	$4,422	$4,493	$4,565

Contributions	$(39)	$229	$1,529	$85	$685	$1,330	$1,351	$1,373	$1,395	$1,417
Capital (Net)	$447	$175	$1,867	$69	$3,287	$2,954	$3,002	$3,049	$3,098	$3,148
Number of new residential customers	501	770	1194	917	932	947	962	977	993	1009

Economic Evaluations

A final economic evaluation is performed after all units are energized as per section 3.2 of the DSC and in Oshawa Power's Conditions of Service.

Historical Comparative Projects

Historical cost data is provided to show comparative expenditure trends; however, actual costs can vary significantly from year to year.

The correlation between the number of new customers and annual gross or net expenditures does not provide a clear picture of the cost per new residential customer. This is because the timing of subdivision energization and customer account setup often does not align, with homes being connected or accounts established in different years than when the subdivision is energized.

To address this, a sample of historical subdivision projects that have been energized and processed through the Economic Evaluation Model (EEM) was analyzed to determine the cost per lot. The resulting net cost per lot is used to estimate the required budget to accommodate customer connections based on the assumed growth rate.

The historical average net cost per lot from the sampled subdivision jobs is approximately $2,526.90 (see Figure 1).

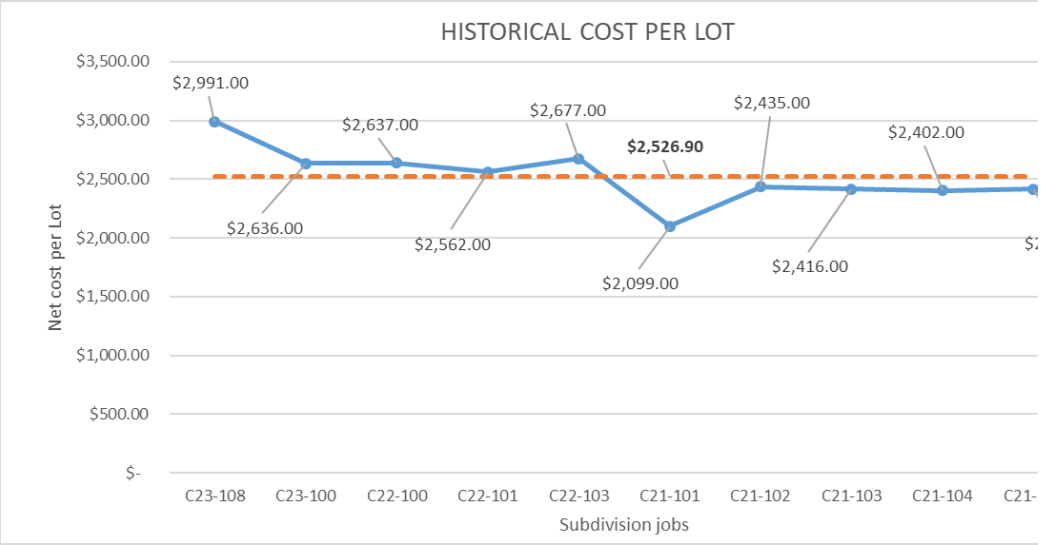


Figure 1 – Historical Cost per lot

However, changes resulting from the Minister of Energy's November 2023 Letter of Direction and the OEB's amendment to the Distribution System Code (released December 23, 2024) have impacted the net cost per lot borne by the LDC. Specifically, the extension of the revenue horizon to 40 years for all residential customers has shifted more costs from contributed capital to the net cost borne by the LDC.

To reflect this change, Oshawa Power re-ran EEM models for the same sample of subdivision jobs, keeping gross costs per lot constant. This adjustment increased the average net cost per lot to $3,120.60, which is used to estimate the annual budget for the 2026-2030 forecast period (see Figure 2).

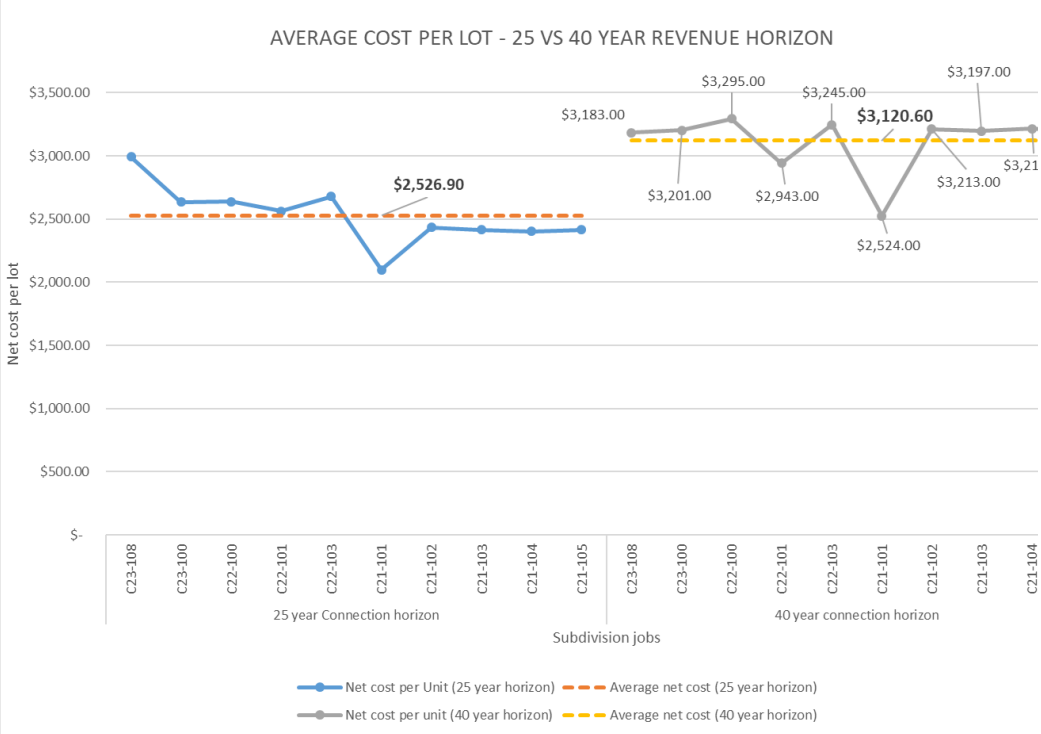


Figure 2 – Average Cost per lot

Investment Priority

Mandatory Priority. New connections are made based on customer/developer request. The process is managed by Oshawa Power staff through various systems to ensure proper visibility and timelines. Projects within this program are executed with a high priority as they are linked directly with the customers that Oshawa Power serves. This program is mandatory, and the timing and priority is also determined through Oshawa Power's AM process. Oshawa Power is obligated to complete expansion projects as per the requirements set out in the DSC. Factors that may affect the timing of these projects include the availability of distribution system, developer's schedules, coordination with third parties, and availability of labour resources.

Alternatives Analysis	Developments are planned and funded in accordance with Oshawa Power's Conditions of Service **Project Design Alternatives:** Oshawa power is responsible for all system design and the ultimate ownership of the electrical distribution plant. The options for design alternatives are limited to the requirements of the City of Oshawa for servicing new subdivisions and Oshawa Power's standards. **Project Scheduling Alternatives:** Project schedule is based on the Developers requirements. **Project Funding Alternatives:** There are two alternatives for project funding that are provided to the developer and outlined in the Conditions of Service. Oshawa Power completes an economic evaluation for every application, and it is at the developer's discretion to determine to proceed with one of the following alternatives: ***1. Distributor Constructed*** Oshawa Power will make an "Offer to Connect" and will include without limitation: the description of the expansion facilities and connection assets, Basic and variable connection fees, an economic evaluation, a capital contribution evaluation and the customer's choice of obtaining alternative bids, settlement of capital contribution, rebates related to expansions, the Oshawa Power Offer to Connect document, and a reference to the Oshawa Power conditions of service. ***2. Developer Constructed (Alternative Bids)*** Where a capital contribution is required and the work does not involve work with the existing Oshawa Power distribution system, the developer may obtain alternative bids for the expansion project from qualified contractors.
Innovative Nature of the Project	Subdivisions are supplied with loop feeds to allow for ease of operation with minimal outages. Loops feeds provide an alternate electrical source during an outage event to minimize outage duration. Each new service is sized appropriately to facilitate customer load growth to mitigate the need for future upgrade requests.
Leave to Construct	This project is below 50 kV and therefore Leave to Construct is not required, as per O. Reg. 161/99

Images, Drawings, Maps, & Other Reference Material

B. Evaluation Criteria and Information Requirements

Efficiency, Customer Value, Reliability and Safety

Efficiency	New services are driven by customer/developer requests and are mandated by the OEB to be completed under the DSC as stated in Oshawa Power's AM Process.
Customer Value	New Customers benefit from a connection to an electrical system that is modern, reliable, efficient, and built to current standards.
Reliability	New subdivisions are constructed using best utility practices that consider reliability by design. The electrical infrastructure in expansion projects is designed and constructed to provide a resilient distribution system by utilizing the loop feed method. This reduces the duration of outages by providing an alternate feed when an outage event occurs.
Safety	New construction meets Oshawa power's standards, Canadian Standards Association (CSA) standards, Utilities Standards Forum (USF) Standards, and meets the safety requirements of Ontario Regulation 22/04.

Investment Need

Primary Driver	The main driver is the developer's requests where they are to make provision for electrical servicing of residential units. Scope and timelines are based on requirements put forth by customers and/or obligations set forth for connecting customers in the DSC.
Secondary Driver	There are no secondary drivers.
Information Used to Justify the Investment	This project is a main contributor to performance metrics tied to the mandatory service obligation outlined in the DSC to connect customers within five calendar days. This project also supports Oshawa power's core values of customer and community value, operational excellence and financial and environmental sustainability.

Investment Justification

Demonstrated Utility Practice	Whenever possible new service connections use standardized designs to maximize cost effectiveness for the affected customer and to minimize rate impact for Oshawa power's customers in

	general. Oshawa power also considers System Operation Efficiency by ensuring new infrastructure enables the customer's load to grow without requesting a service upgrade. This is done by ensuring every new service is rated up to 200A standard.
Cost-Benefit Analysis	If development of a new subdivision is staged, for the duration of the time between connection of the first customer in the stage and last customer in the stage, the construction of the main distribution system may not be fully complete. This may result in system segregation and lesser ability to restore power quickly in the case of faults. This is mitigated by the fact that the plant is fairly new and other than manufacturing defects, no outages are expected. Costs for these projects are predictable based on standardized processes and materials and are partially recovered through economic evaluations as prescribed in the DSC.
Historical Outcomes	Projects within this program are initiated by developers and the actual spending can vary between years. This is an OEB-mandated activity under the DSC. Oshawa power has highly trained staff that work with project developers to the best of their ability to manage timelines and to best accommodate the customer. Meetings/correspondence with customers take place frequently and at their request to best manage customer expectations.

Conservation and Demand Management

Not Applicable

A. General Project Information

Project Name	Revenue Metering – New Connections	**Project Number**	SA-04
Investment Category	System Access	**Project Year**	2026-2030
Project Description	New Meters to be installed on new services including commercial, residential and industrial. O&M for new residential meter installs is negligible. We are continuing to utilize our existing Automated Metering Infrastructure (AMI) head end and use next generation Elster A4 meters for all single phase new residential and small commercial installations. All 3 phase installations will also use Elster A4CI meters compatible with our existing AMI. All meters must be compliant to OEB, CSA and Measurement Canada rules.		
Start Date	2026-2030	**Expected In-Service Date**	2026-2030

Estimated Expenditure Timing

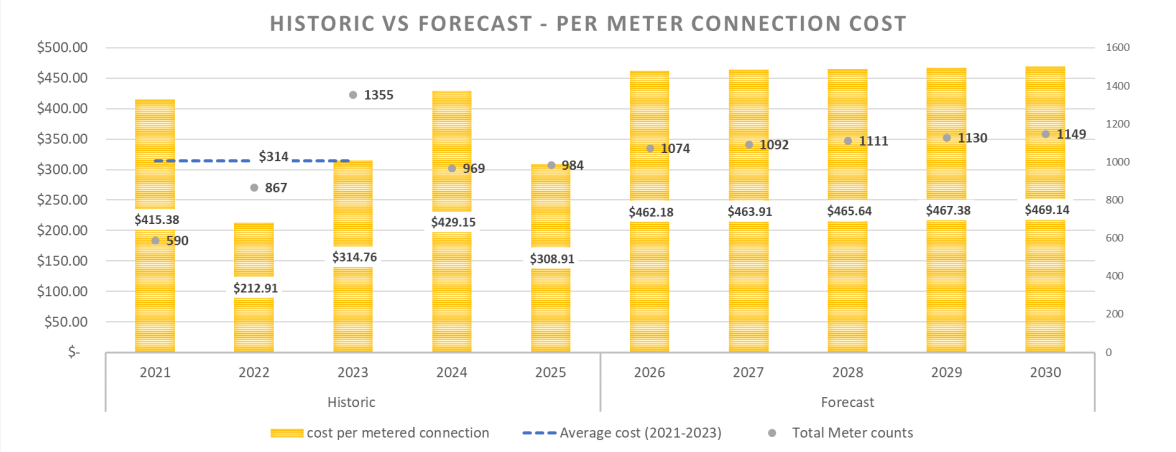
	Q1	Q2	Q3	Q4
2026	$124,000	$124,000	$124,000	$124,000
2027	$126,000	$127,000	$127,000	$127,000
2028	$130,000	$129,000	$129,000	$129,000
2029	$132,000	$132,000	$132,000	$132,000
2030	$134,000	$135,000	$135,000	$135,000

Historical and Forecast Capital Expenditures

Historical and Forecast Program expenditures ($,000) are shown below.

Category	Historical Period				Bridge Year	Test Year	Forecast Period			
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Capital (Gross)	$245	$184	$426	$416	$304	$496	$507	$517	$528	$539
Units	590	867	1355	969	984	1074	1092	1111	1130	1149

Economic Evaluations	The cost of the meter is the only cost applicable to this project.
Historical Comparative Projects	Meter costs for new connections, residential, commercial and Meters Inside Settlement Timeline (Interval) are comparable to historical programs. The average cost per meter is higher in the forecast years compared to historical as the next generation of Elster meters have improved meter reading, read retention, power monitoring

	and analysis technology. Other contributors to increased cost include higher CT and PT costs for commercial applications and increased labor and meter equipment costs. The growth rate adopts a conservative approach by aligning with historical trends, in contrast to the published population growth studies by the City of Oshawa.  **Figure 1 – Historical vs Forecast Meter costs**
Investment Priority	Mandatory priority. Need to commence in 2026 as new revenue meters for new services are required on an on-demand basis.
Alternatives Analysis	No alternatives are available to replace the RexU and A3 series meter as the manufacturer is no longer producing this meter type. The replacement meter is the Elster A4 and A4CI series meter.
Innovative Nature of the Project	Next generation Elster A4 meters provide enhanced and improved meter reading, power monitoring and read retention technology that can be used for future ADMS and home-based DER technologies
Leave to Construct	This project does not require Leave to Construct approval under section 92 of the OEB Act.

Images, Drawings, Maps, & Other Reference Material

The following are images of a typical meter.



Figure 2: RexU Meter



Figure 3: Commercial Meter

B. Evaluation Criteria and Information Requirements

Efficiency, Customer Value, Reliability and Safety

Efficiency	This is a mandatory service requirement that a Measurement Canada approved meter is installed on all services that we charge for energy.
Customer Value	This program will continue to provide accurate electricity measurement and outage alerts.
Reliability	Response time and meter read storage have improved with the new Elster A4 meters. This will assist with more reliable delivery of outage notifications to our OMS system
Safety	Meters and associated equipment will adhere to CSA and Measurement Canada Standards.

Investment Need

Primary Driver	The purpose of this project is to comply with Federal and Provincial regulations. Mainly, The OEB Smart Metering Initiative EB- 210-0218 effective June 14, 2010 and the Electricity and Gas Inspection Act.
Secondary Driver	There are no secondary drivers.

Information Used to Justify the Investment	Mandatory service obligation required by the OEB to connect customers within 5 business days. Revenue meters are a mandatory requirement.

Investment Justification

Demonstrated Utility Practice	Operating efficiency would improve through better reporting from meters. This will also provide better reliability of equipment and meter data and additional data monitoring opportunities for Meter Data Management Repository (MDMR) and Outage Management System (OMS).
Cost-Benefit Analysis	Cost recovery is through rates.
Historical Outcomes	Meters are purchased in parallel with the Meter Replacement program to reduce per unit cost on volume. Minimizing on the number of meters procured and staging when the meters are delivered reduce the inventory carrying costs.

Conservation and Demand Management

Time of use and voltage information collected by the meter per premise may be used. This investment will provide better insight and analytics for demand management.

A. General Project Information

Project Name	Pole Replacement Program	**Project Number**	SR-01
Investment Category	System Renewal	**Project Year**	2026-2030
Project Description	Oshawa Power owns and maintains approximately 11,240 poles across its service territory. These poles are made from a variety of materials, including wood (various species), concrete, and steel. The Asset Condition Assessment (ACA) has identified 518 poles that require replacement within the DSP forecast period. These poles are classified as being in fair, poor, or very poor condition or as posing a high or extreme risk. The pole replacement program aims to prioritize at least 135 high-impact poles, focusing on those supporting critical assets such as three-phase 13.8kV and 44kV primary circuit conductors, combination multi-circuit poles, and those poles with primary dips serving subdivisions. These poles are in scattered locations throughout Oshawa Power's service territory and cannot be targeted within the OH Line Renewal Program which focuses on pole replacement in an area that also requires replacing deteriorating components attached to poles, such as crossarms, pins, insulators, dips, and brackets. This approach optimizes efficiency by addressing associated hardware during pole replacements, reducing the need for additional labor hours to reattach assets that are nearing or at the end of their useful life.		
Start Date	2026-2030	**Expected In-Service Date**	2026-2030

Estimated Expenditure Timing

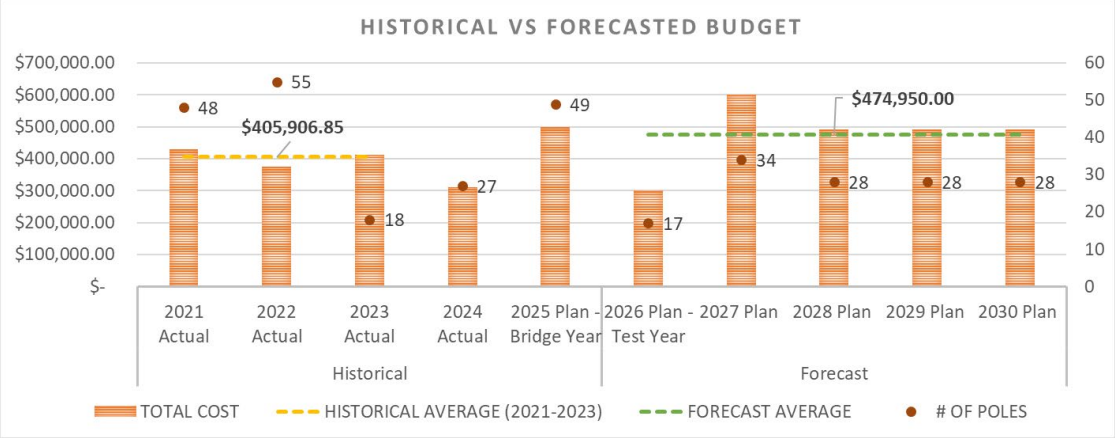
	Q1	Q2	Q3	Q4
2026	$75,000	$75,000	$75,000	$75,000
2027	$150,000	$150,000	$150,000	$150,000
2028	$123,000	$123,000	$123,000	$123,000
2029	$123,000	$123,000	$123,000	$123,000
2030	$123,000	$123,000	$123,000	$123,000

Historical and Forecast Capital Expenditures

Historical and Forecast Program expenditures ($,000) are shown below

Category	Historical Period				Bridge Year	Test Year	Forecast Period			
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Capital (Gross)	$431	$375	$412	$311	$500	$300	$600	$492	$492	$492

Poles	48	55	18	27	49	17	34	28	28	28

Economic Evaluations	Not Applicable
Historical Comparative Projects	The forecast program is similar in spend to the historical program.  The program addresses poles that are at or nearing end of life as per the ACA, which are scattered throughout the service territory and could not be addressed under a typical overhead line renewal program. Clustered poles on the other hand are targeted under the overhead line renewal program, considering future system planning needs. The 2026-2030 forecasted pole replacements are targeted towards poles supporting critical assets such three- phase 44kV and 13.8kV primary circuit conductors, as compared to general mix of poles targeted in the historical period. For this reason and general inflation impacts, the per unit pole replacement cost is higher than the historical average.
Investment Priority	This investment has been given a priority of 1 of the 17 ranked material capital expenditures. The replacement of the aged assets is expected to contribute to Oshawa Power's high safety and reliability standards, specifically the number of outages.
Alternatives Analysis	The project alternatives are run-to-failure or defer. Not replacing end of life poles and pole failures is not an option due to public safety impacts, system reliability and further increasing O&M costs.
Innovative Nature of the Project	Like for like replacement of poles will not enhance future technological functionality. Hence there are no innovative elements within this program.
Leave to Construct	This project is below 50 kV and therefore Leave to Construct is not required, as per O.Reg. 161/99.

Images, Drawings, Maps, & Other Reference Material

Please refer to the ACA in Appendix C, for pole health index formulation and risk evaluation methodology.

Please refer to Figure 1 for scattered poles targeted for replacement under the pole replacement program. Clustered poles enclosed in red polygons are addressed under the Overhead Line Rebuild Program.

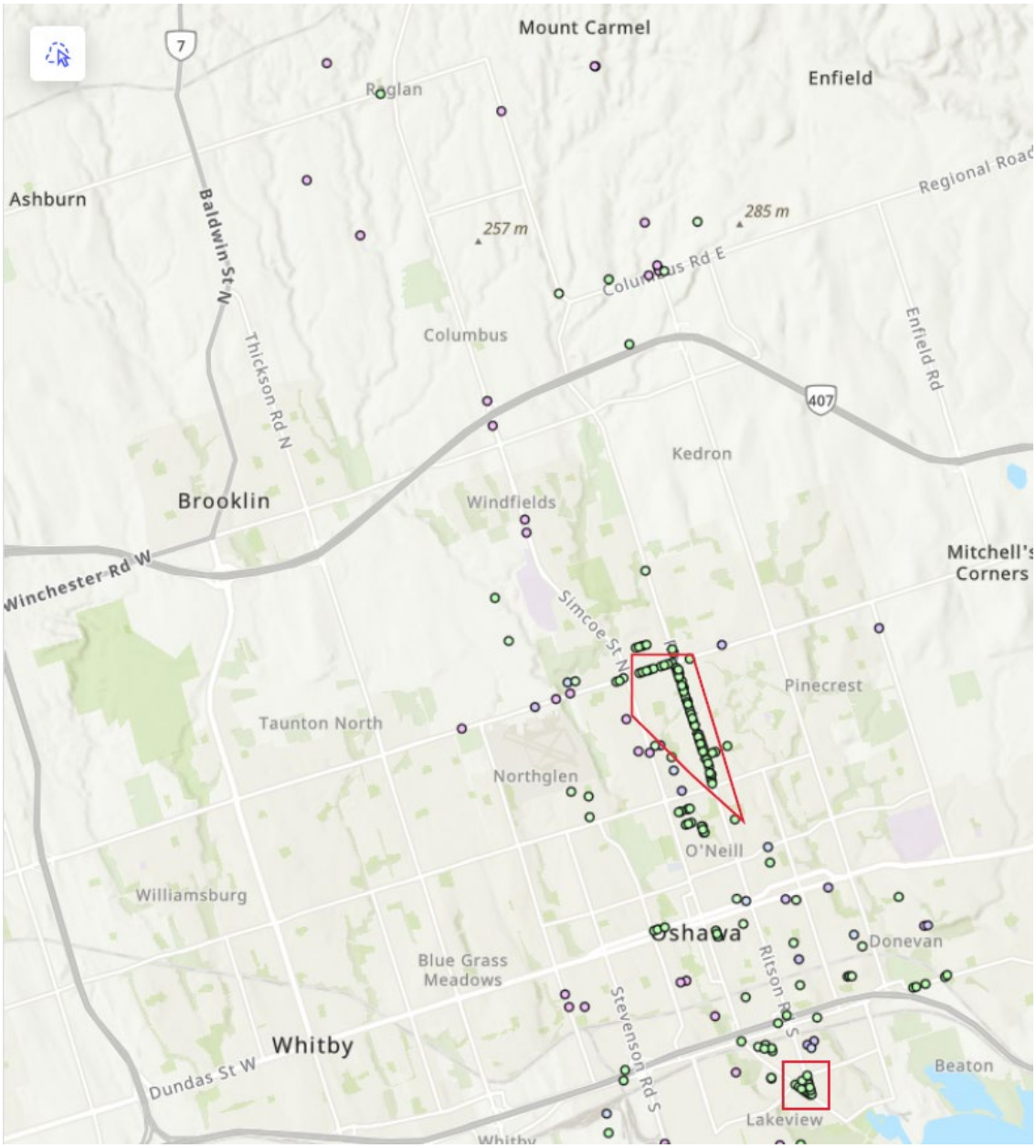


Figure 1 – 2026-2030 Pole Replacement locations

B. Evaluation Criteria and Information Requirements

Efficiency, Customer Value, Reliability and Safety

Efficiency	This investment will result in improved reliability by reducing both the frequency and duration of outages: fewer failures are expected to occur, and planned replacements take less time than replacements following a failure.
Customer Value	Customers will benefit from fewer outages while planned replacement of poles will results in shorter outages than when they are replaced following a failure.
Reliability	Replacing an aged pole before it fails is the ideal case. With reference to reliability and budget, replacing aged poles before failure provides a significant net benefit to Oshawa Power's customer safety, reliability and cost effectiveness.
Safety	Planned replacement reduces the risk of failure leading to a collapse of the pole and a 'wire down' situation. The work is required in order to maintain safety to workers and the public.

Investment Need

Primary Driver	This program falls under System Renewal Investment Driver and is aimed at improving Reliability and Safety. The risk to the utility and the customers is that when a pole fails, it results in an outage that negatively affects reliability and customer satisfaction and depending on the pole location, presents a safety hazard. The program is aligned in addressing OPUNC's Asset management objectives as part of its comprehensive Asset Management system.
Secondary Driver	There are no secondary drivers.
Information Used to Justify the Investment	Oshawa Power's ACA, pole testing data and recent failures are the sources of the information used to justify this project.

Investment Justification

Demonstrated Utility Practice	Oshawa Power utilizes Utility Standards Forum (USF) standards and meets the Ontario Regulations 22/04 requirements from a regulatory compliance aspect. Coordination with other utilities

	and municipalities will be required with this project in order to reduce damage to underground utilities, joint use attachments, and to be efficient. Coordination with customers will be a priority when scheduling outages and access to customer property.
Cost-Benefit Analysis	Run to fail for this asset will increase O&M costs. At the time of the failure, mitigating the effect of the pole failure on the customers will be an O&M expense. This may occur outside of normal business hours and require unplanned overtime hours.
Historical Outcomes	Poles are typically replaced on a like- for- like basis and brought upto current standards. All new construction meets the latest distribution standards and is compliant with O. Reg. 22/04.

Conservation and Demand Management

Not Applicable.

A. General Project Information

Project Name	Overhead System Rebuild Program	**Project Number**	SR-02
Investment Category	System Renewal	**Project Year**	2026-2030
Project Description	The Overhead System Rebuild Program focuses on renewing overhead assets that are at or nearing the end of their useful life due to deteriorating condition and high risk of failure. This includes poles, conductors, and associated hardware. Unlike the Pole Replacement Program, which addresses scattered individual poles, this program is designed to address clusters of overhead conductors and poles. Tackling these clusters as part of a coordinated project enables efficient asset renewal while considering future system planning needs. The Asset Condition Assessment (ACA) recommends poles and conductor segments in a deteriorating condition and that pose high risk to be replaced. Using this data as input, Oshawa Power develops comprehensive overhead rebuild projects that address the immediate need for asset replacement while ensuring alignment with future capacity and compliance requirements. Primary conductors targeted for replacement are small copper (typically #6) types. These have aged to the point of becoming brittle and breaking unexpectedly creating both a safety hazard and a reliability risk. Since copper conductors are no longer installed as standard practice, the poles that support them are often of the same vintage and have similarly aged and deteriorated. Replacing these conductors with larger and heavier standard sized conductors requires pole loading analysis to ensure that there is adequate support available. The increased size and weight of the new conductor often necessitate upgrading to taller and/or higher-class poles to meet structural requirements and comply with safety standards as set out by the Ontario Regulation 22/04. This holistic approach ensures safety and reliability are improved by adhering to current standards and utilizing modern materials. Project selection under this program is guided by Oshawa Power's asset management system, including the Strategic Asset Management Plan (SAMP) and a risk prioritization tool, ensuring that projects address the highest priority needs and provide long-term value. Refer to the reference material for list of planned OH Rebuild projects within this program.		
Start Date	2026-2030	**Expected In-Service Date**	2026-2030

Estimated Expenditure Timing		Q1	Q2	Q3	Q4
	2026	$0	$192,050	$559,475	$320,000
	2027	$85,100	$200,675	$200,675	$0
	2028	$261,338	$261,338	$261,338	$261,338
	2029	$445,050	$445,050	$445,050	$296,125
	2030	$306,188	$306,188	$306,188	$306,188

Historical and Forecast Capital Expenditures

Historical and Forecast Program expenditures ($,000) are shown below

Category	Historical Period				Bridge Year	Test Year	Forecast Period			
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Capital (Gross)	$1,242	$1,703	$3,599	$1,298	$1,770	$1072	$486	$1045	$1631	$1225
Line km	5.6	5.0	6.7	1.65	4.7	2.6	1.05	2.9	2.8	2.55

Economic Evaluations

Not applicable.

Historical Comparative Projects

The number of line sections, their length, the number/type of circuits and equipment differs from year to year which explains the variability in comparable investments in previous years.

Increases in labor and material costs, along with variability in project scope, account for the higher average cost per kilometer anticipated during the forecast period compared to the historical period.

The total budget allocated for the forecast period is lower than the historical expenditure due to the prioritization of other initiatives within the Distribution System Plan (DSP).

Refer to Figure 1 for a comparison of historical and forecasted trends.

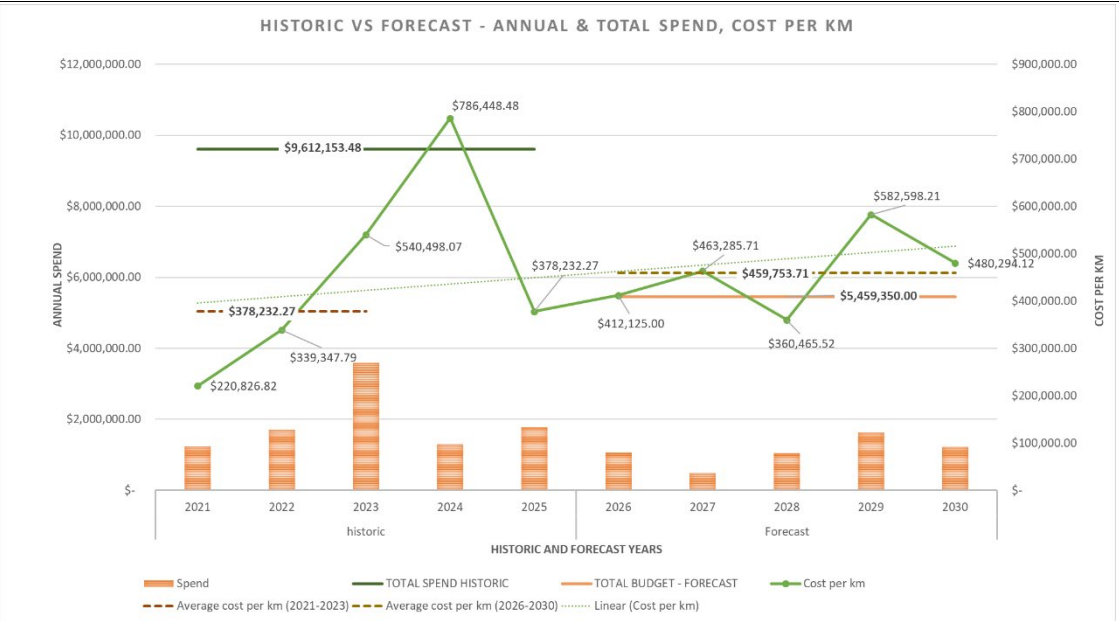


Figure 1 – Historic vs Forecast spend per km

Note that in 2027, this program's spending has been strategically reduced to prioritize increased investments in other system renewal initiatives, including Cable Injection, Firon, Quick Sleeve, and Municipal and Distribution Switchgear Replacement programs.

Investment Priority

This investment has been given a priority of 3 of the 17 ranked material capital expenditures. The timing and priority of the projects takes into account the condition of these assets, reliability and the available resources to design and construct these projects. Delaying these projects will impact renewal work that is required in future years to properly maintain a reliable system. Projects within this program are prioritized based on age of infrastructure, ACA, reliability and safety. Third party work/relocations are also taken into account so that work may be co-ordinated as much as possible. Since System Access projects are a higher priority in the AM process an additional project has the potential to modify the timing of any System Renewal project. Additionally, if Oshawa Power documents any extreme reliability issues due to ageing in a specific area that needs to be addressed projects can be shuffled from year to year during the forecast period.

Alternatives Analysis

Overhead line sections and poles under this project have been recommended for replacement by the ACA and are at or approaching end of useful life. The following alternatives were considered:

1. Do nothing: this option would result in an increased safety risk and decrease in reliability and higher corrective maintenance costs. It is not considered an acceptable option.

	2. Refurbish the lines: these lines are not considered appropriate candidates for refurbishment as the existing overhead pole line could not be rebuilt to current standards without replacing the poles and changing the overhead configuration. This will also not address the condition of the overhead assets other than poles, i.e. conductors and pole mounted transformers that are also approaching the end of their TUL. **3. Replace like for like:** Similar to refurbishing the lines, the overhead pole line could not be rebuilt to current standards without replacing the poles and changing the overhead configuration. Such legacy construction is no longer an acceptable compliant option under O. Reg. 22/04.
Innovative Nature of the Project	Future operational requirements will be considered in the design where appropriate by providing provisions to incorporate remotely operated switches that will enable future technological functionality.
Leave to Construct	This project is below 50 kV and therefore Leave to Construct is not required, as per O. Reg. 161/99.

Images, Drawings, Maps, & Other Reference Material

The following is the list of OH Line Renewal projects that have been identified based on project conditions:

Project #	Project	Year	Cost
SR-2A	Eastwood Ave N and Herbert Ave	2026	$192,050
SR-2B	Cedar Valley Blvd, Patton St, 245 - 298 Seneca Ave	2026	$559,475
SR-2C	Buckingham Ave, Westmoreland Ave, Arlington Ave, Mclaughlin Blvd, Somerville Ave, Christie Ave, Hortop St, Carnegle Ave	2030	$1,224,750
SR-2D	Dearborn Ave, Kendal Ave, Elgin St E, Agnes St, Brock St E, William St, Division St	2028	$1,045,350
SR-2E	Jarvis St	2027	$85,100
SR-2F	Luke St, Cadillac Ave N, Colborne St E (Luke - Oakes), Oakes Ave	2027	$401,350
SR-2G	2 Taunton Rd E - Taunton Rd E & Ritson Rd N	2026	$320,000
SR-2H	Ritson Rd N - Rossland Rd E to Taunton RD E	2029	$1,335,150
SR-2I	Simcoe St S and Ritson Rd S (South of Bloor St E)	2029	$296,125

B. Evaluation Criteria and Information Requirements

Efficiency, Customer Value, Reliability and Safety

Efficiency	The sources of the information used to justify the investment are the results of the ACA that incorporate information and data from GIS registry, asset database, field inspections, pole testing data, reliability data and information from incident reports. Third party work/relocations are also taken into account so that work may be coordinated as much as possible. Future operational requirements will be considered in the design where appropriate by providing provisions to incorporate remotely operated switches that will enable future technological functionality.
Customer Value	Customers within the project area will benefit from this project through the reduction of the risk of outages and will also indirectly benefit from the lower corrective maintenance costs that the improved distribution system will provide.
Reliability	This program will maintain or improve the reliability of the system by replacing overhead assets in poor condition and future proofing the design by meeting all current standards.
Safety	Proper asset management of old and deteriorating equipment in the field mitigates safety concerns for Oshawa Power staff, contractors, third party attachers and customers. New construction will also meet the latest distribution standards for safety.
Investment Need	
Primary Driver	System Renewal is the driver for this project aimed at reducing failure risk – Assets are at the end of their useful life which poses a greater risk of failure. Mitigating failure risk will also minimize safety risks and impact to reliability. Reliability – A planned replacement will minimize the risk of overhead asset failure and mitigate the impact on reliability performance including SAIDI and SAIFI. Safety – The overhead asset renewal will make the lines safer as this will be built to the current standards and regulations which are more capable of withstanding adverse weather conditions.
Secondary Driver	There are no secondary drivers.

Information Used to Justify the Investment	These projects will reduce the probability of equipment failure that may pose a safety risk and could negatively impact one of the performance targets, power supply reliability.
Investment Justification	
Demonstrated Utility Practice	Completion of the overhead renewal program will improve system operational efficiency by maintaining system reliability and reducing overhead asset failures. Current overhead design and industry practices will be incorporated in accordance with all existing standards and regulations, thus, providing a safer and more reliable overhead distribution system. This will also help us in reducing cost of maintenance by proactively replacing OH assets which are addressed under our asset management program.
Cost-Benefit Analysis	There will be no immediate material impact to O&M costs for distribution lines. Without these projects taking place O&M costs would be expected to rise over time at an increasing rate due to equipment failures.
Historical Outcomes	These projects are subject to scheduling risks with respect to external contractors and with other major projects but are prioritized based on condition of assets and failure risks. The majority of the design work and Municipal Consent(s) are completed a year ahead of construction so that construction may begin in Q1 to mitigate this risk. Schedules are also determined the year before, and progress meetings are held to ensure construction stays on track.
Conservation and Demand Management	
Not Applicable	

A. General Project Information

Project Name	Underground System Rebuild Program	**Project Number**	SR-03
Investment Category	System Renewal	**Project Year**	2026-2030

Project Description

The Underground (UG) System Rebuild Program focuses on renewing underground assets that are at or nearing the end of their useful life due to deteriorating condition and high risk. This includes underground cables, ducts, deteriorating pad-mounted transformers, and associated hardware such as elbows and connectors.

Oshawa Power's Asset Condition Assessment (ACA) recommended replacing approximately 32 km of underground primary cable. Following further analysis, guided by Oshawa Power 's Asset Management System, clusters of cables were identified that would benefit from a holistic rebuild program. The analysis also identified candidates that were better suited for cable injection and prioritized key locations for replacement. As part of this program, Oshawa Power will be replacing a total of approximately 12 km of underground primary cable. A detailed list of targeted locations is provided in the reference material section.

The project scope includes the design, construction, and installation of new primary voltage underground cables, complete with an associated duct system. These systems are designed to meet the latest standards and regulations, including Ontario Regulation 22/04 (O. Reg. 22/04). By completing this underground line renewal, Oshawa Power aims to enhance system reliability through the adoption of newer standards and materials.

Start Date	2026-2030	**Expected In-Service Date**	2026-2030

Estimated Expenditure Timing

	Q1	Q2	Q3	Q4
2026	$0	$196,517	$196,517	$0
2027	$0	$0	$54,211	$0
2028	$280,045	$606,993	$577,771	$0
2029	$0	$352,084	$374,681	$0
2030	$423,220	$423,220	$423,220	$423,220

Historical and Forecast Capital Expenditures	Historical and Forecast Program expenditures ($000) are shown below

Category	Historical Period				Bridge Year	Test Year	Forecast Period			
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Capital (Gross)	$827	$1,413	$1,634	$817	$364	$393	$54	$1,185	$727	$1,663
Cable (m)	1334	5371	3722	2280	1049	724	58	2631	1319	3620

Economic Evaluations

Not applicable

Historical Comparative Projects

The number of line sections and their length differs from year to year which explains the variability in comparable investment in previous years.

Increases in labor and material costs, along with variability in project scope, account for the higher average cost per kilometer anticipated during the forecast period compared to the historical period.

The total budget allocated for the forecast period is comparable but slightly lower than the historical expenditure due to the prioritization of other initiatives within the Distribution System Plan (DSP).

Refer to Figure 1 for a comparison of historical and forecasted trends

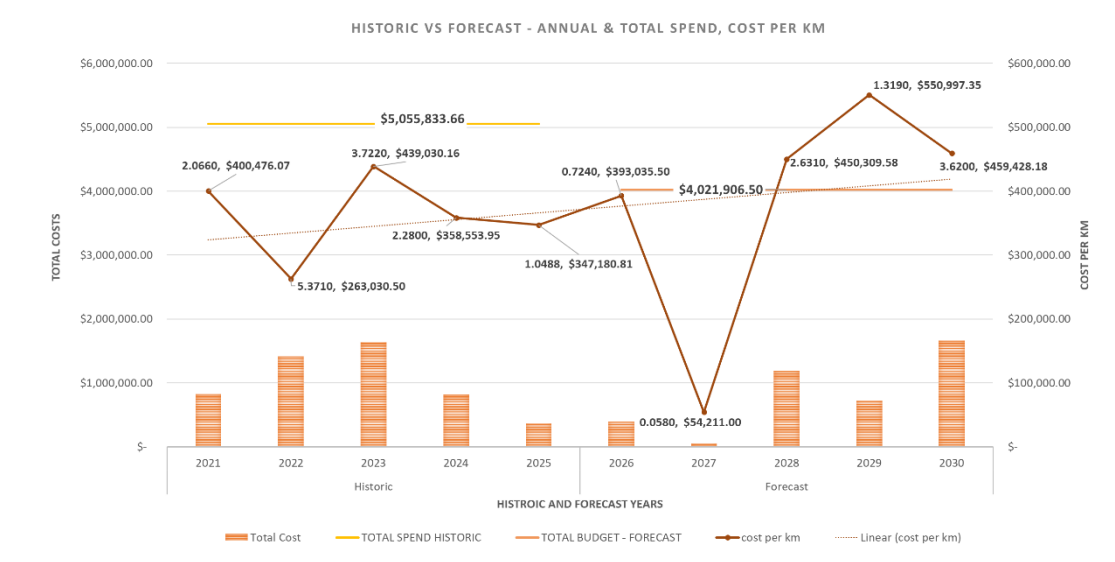


Figure 1 – Historic vs Forecast Cost per KM.

In 2026 & 2027, program spending is reduced to prioritize increased investments in other system renewal initiatives, including Municipal and Distribution Switchgear, Cable Injection, Firon, and Quick Sleeve Replacement programs.

Investment Priority	This investment has been given a priority of 5 of the 17 ranked material capital expenditures. The timing and priority of the projects takes into account the condition of these assets, reliability and the available resources to design and construct these projects. Since System Access projects are a higher priority in the AM process an additional project has the potential to modify the timing of any System Renewal project. Additionally, if Oshawa Power documents any extreme reliability issues due to ageing in a specific area that needs to be addressed projects can be shuffled from year to year during the forecast period.
Alternatives Analysis	All cable sections under this project have been identified as being in poor condition, at the end of their TUL, and in need of replacement. The following alternatives were considered: **1. Do nothing:** this option would result in a decrease in reliability and is not considered an acceptable option. **2. Rejuvenate the cables:** these cables are not considered appropriate candidates for refurbishment as cable segments under this program are better suited for replacement and rejuvenation is not effective. Time Domain Reflectometry (TDR) results and the number of splices in any cable segment determines the feasibility of rejuvenation. Rejuvenation of underground cables involves the use of injection technology to repair insulation ageing issues theoretically minimizing faults and extending the life of the cable. The cables to be replaced under this project are not opportune candidates for this technology due to their age, poor condition, and burial type.
Innovative Nature of the Project	Though not considered innovative within the industry, this project aligns with best practices for replacing end of life underground primary cable. The planning process ensures compliance with current standards, identifies efficiencies such as looping radial systems, and accounts for future growth, including appropriate cable sizing to support increasing EV adoption.
Leave to Construct	This project is below 50 kV and therefore Leave to Construct is not required, as per O.Reg. 161/99.

Images, Drawings, Maps, & Other Reference Material

The following list of UG System Rebuild projects has been identified based on project conditions:

Project #	Project	Year	Cost
SR-3A	Tiffany Circle	2030	$213,980
SR-3B	Cricklewood Dr	2026	$393,035
SR-3C	700 Harmony Rd N	2027	$54,211

SR-3D	Cavendish Crt	2030	$86,733
SR-3E	Apple Valley Lane, Prestwick Crt	2030	$122,475
SR-3F	Mahina St	2030	$126,925
SR-3G	Niagara Dr - Simcoe St N to Canadore Cres	2030	$ 92,793
SR-3H	916 Ridgevalley Dr - 949 Sandcliff Dr	2029	$206,632
SR-3I	296 Niagara Dr - 234 Ryerson Cres	2030	$ 101,545
SR-3J	292 Selerno St - Nevada Crt	2030	$74,819
SR-3K	Summitview Cres	2029	$145,452
SR-3L	Cartref Ave, St Anne Crt - 730 Whistler Dr	2029	$144,428
SR-3M	Courville Crt,Cobblehill Dr, Deauville Crt, Attersley Dr, bayla Crt, McTavish Ave	2028	$606,993
SR-3N	Labrador Dr, Eastlawn St, MaClure Crt	2030	$566,651
SR-3O	Monaghan Ave, Limerick St, Tralee Crt	2028	$401,407
SR-3P	Cumberland Crt, Ellesmere crt	2028	$176,364
SR-3Q	Kensington Cres	2029	$230,253
SR-3R	Tarn Crt, Preston Dr	2030	$277,207

B. Evaluation Criteria and Information Requirements

Efficiency, Customer Value, Reliability and Safety

Efficiency	The sources of the information used to justify the investment are the results of the ACA, GIS registry, asset database, field inspections, primary cable fault analysis, reliability data and information from incident reports. Third party work/relocations are also taken into account so that work may be coordinated with them as much as possible.
Customer Value	Customers within the project area will benefit from this project through the reduction of the risk of an outage that the new system will provide. Customers will also indirectly benefit from the lower maintenance costs that a new system will provide.
Reliability	This program will maintain or improve the reliability of the system by replacing underground assets in poor condition and installing fault indicators on padmount transformers and

	remotely operated padmount switchgears, where applicable, within the project areas
Safety	Proper asset management of old and deteriorating equipment in the field mitigates safety concerns for Oshawa Power staff and customers. New construction will also meet the latest distribution standards for safety and be in compliance with O. Reg. 22/04.
Investment Need	
Primary Driver	This project falls under the System Renewal Investment driver and will mitigate failure risk since cables identified for replacement are at the end of their life. The primary cable could be direct buried or in a duct and many of the cables identified have failed and have been spliced. – A planned replacement will minimize the risk of underground asset failure and mitigate the impact on reliability performance including SAIDI and SAIFI.
Secondary Driver	There are no secondary drivers
Information Used to Justify the Investment	These projects will mitigate the risk of equipment failure that may pose a safety risk and negatively impact power supply reliability.
Investment Justification	
Demonstrated Utility Practice	Completion of the underground renewal program will improve system operation efficiency by maintaining system reliability and reducing the number of underground asset failures. New underground design and industry practice will be introduced based on more robust standards and current regulations providing a safer and more reliable underground distribution system.
Cost-Benefit Analysis	Customers will receive increased reliability and indirectly maintenance costs will be lower. Without these projects taking place, O&M costs would be expected to rise over time at an increasing rate due to equipment failures.
Historical Outcomes	These projects are subject to scheduling risks with respect to external contractors and with other major projects but will be

	mitigated through good planning and project execution. The majority of the design work and Municipal Consent(s) will be completed a year ahead of construction so that construction may begin at the beginning of Q2 of each year as soon as the frost leaves the ground to mitigate this risk. Schedules are also determined the year before, and progress meetings will be held to ensure construction schedule stays on track.

Conservation and Demand Management

Not applicable

A. General Project Information

Project Name	Cable Injection Program	**Project Number**	SR-04
Investment Category	System Renewal	**Project Year**	2027-2029
Project Description	This program addresses the challenges posed by aging, direct-buried primary cables. These cables are decades old and were manufactured to the cable specifications and standards that existed at that time. The cable manufacturing process was neither as sophisticated nor was the material used as pure as it is in present day. Both of these factors (process and material) contributed to having small defects introduced into the manufactured cable product even at the day 1 factory stage. These initial small defects are the start of phenomenon known as "cable treeing". Decades of these cables being in-service, being cycle loaded, exposed to the stress of system faults, as well as being direct buried and exposed to the corrosiveness of the native soil, has caused these trees (electrical trees and water ingress trees) to grow. If these trees are left unaddressed they will eventually cause the cable to fail / short through line-to-ground faults. Insulation in these older cables is typically porous, allowing moisture to seep in and accumulate over time. Replacing these direct-buried cables with new duct and cable is a costly and labor-intensive process. However, when ducts are already in place, pulling in new cables becomes a much more efficient and economical alternative. Cable injection, also known as cable rehabilitation, offers a promising solution to address these challenges. The process involves injecting silicone-based engineered materials into the strands of aged, operational primary cables. These chemicals diffuse into the cable insulation, filling voids (the trees) and strengthening the material's dielectric properties. The treatment not only mitigates the effects of insulation aging but also transforms the insulation chemically, rendering it less porous and more resistant to further moisture absorption. By restoring the integrity of the insulation, cable injection effectively extends the cable's service life. Service providers often describe treated cables as being "better than new" due to the enhancement in insulation properties. While some claim a potential life extension of up to 40 years, Oshawa Power adopts the industry-standard assumption of a 20-year additional service life to maintain a conservative and realistic outlook. Over the forecast period of 2026-2030, Oshawa Power intends to inject approximately 3.85 km of cable. Some potential locations for injection are highlighted in the Table 1 below.		

Project Locations	Cable Lengths (m)	2026	2027	2028	2029	2030
914 Parklane Ave - 210 Baker Court	241				$ 33,000.00	
46 - 450 Bristol Cresent	287		$ 40,000.00			
540 Dorchester Drive	202				$ 28,000.00	
Grandview Dr, Downview Cres, Wesley Drive, Edna Court, Norman Cres	2637		$ 362,000.00			
800 Rossland Rd E	557		$ 77,000.00			

Table 1 – Cable Injection Project Details

To ensure the selected cable segments are suitable candidates for injection, Oshawa Power will perform Time Domain Reflectometry (TDR) testing. This testing will measure the length of cables and pinpoint splice locations, providing insights into the condition of the cable segments and their ability to benefit from the injection process.

Start Date	July 2027	**Expected In-Service Date**	September 2029

Estimated Expenditure Timing

	Q1	Q2	Q3	Q4
2026	$0	$0	$0	$0
2027	$0	$40,000	$362,000	$77,000
2028	$0	$0	$0	$0
2029	$0	$33,000	$28,000	$0
2030	$0	$0	$0	$0

Historical and Forecast Capital Expenditures

Historical and Forecast Program expenditures ($,000) are shown below

Category	Historical Period				Bridge Year	Test Year	Forecast Period			
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Capital (Gross)	$0	$0	$0	$0	$0	$0	$479	$0	$61	$0
Cable injected (m)	0	0	0	0	0	0	3481	0	443	0

Economic Evaluations

Not Applicable

Historical Comparative Projects	First time application for Oshawa Power. This type of cable rehabilitation has been successfully performed by a number of other utilities.
Investment Priority	This investment has been given a priority of 12 of the 17 ranked material capital expenditures. This program aims to mitigate risk of cable faults and to extend cable life. Oshawa Power will inject approximately 3.85 km of underground cable over the 2026 – 2030 forecast period.
Alternatives Analysis	The alternative to injection is to replace cable. SCOPE OF WORK | YEAR 0 | YEAR 20 | YEAR 40 (EOL) | NPV - TOTAL COST PER CABLE REPLACMENT ($/ m) | $ 280.00 | $ - | $ 280.00 | $ 4,905.87 CABLE INJECTION ($/ m) | $ 137.00 | $ 137.00 | $ 137.00 | $ 4,067.88 **Table 2 – Cable Injection and Replacement cost comparison** Plant is rehabilitated through injection to provide an additional 20 years of life minimum. Injection cost ~$137/m versus replacement cost of ~$280/m. It is important to note that Table 2 is based on best-case scenarios for cable replacement, such as easily accessible locations, available right-of-way space for duct placement, and the extraction of the full useful life from both cables and ducts. In contrast, the cable injection scenario conservatively assumes only 20 years of additional service life instead of the potential 40 years claimed by service providers. Opting for cable injection also provides the advantage of deferring or pacing out cable replacement investments and associated efforts over time.
Innovative Nature of the Project	Cable injection does not disrupt the local landscape as much as cable replacement; clean technology extends asset life and defers generation of waste. This project is innovative in nature as it reflects a change in philosophy and process from the usual decision of simply replacing the cable with its associated higher costs.
Leave to Construct	This project is below 50 kV and therefore Leave to Construct is not required, as per OEB Reg. 161/99.

Images, Drawings, Maps, & Other Reference Material

B. Evaluation Criteria and Information Requirements

Efficiency, Customer Value, Reliability and Safety

Efficiency	The investment objectives are to reduce the asset failure risk and to ensure reliable service to customers by mitigating the risk of power outage duration and frequency.
Customer Value	Reduced likelihood of unplanned outages due to cable failure.
Reliability	Cable life will be extended for approximately 20 years.
Safety	Rehabilitated cable will decrease the likelihood of faults which in turn will reduce stress and asset degradation on circuit components from the transformer station to the customer.
Investment Need	
Primary Driver	System Renewal is the driver for this program, and it is aimed at improving Asset Performance and Safety as well as reliability. The risk to the utility and the customer is that the asset will fail and result in an outage that negatively affects reliability and customer satisfaction.
Secondary Driver	There are no secondary drivers.
Information Used to Justify the Investment	Cable injection candidates are derived primarily by the identification of their condition via the ACA. Generally, cable segments that are considered in "Fair" condition and direct buried in nature but not yet at EOL are candidates for this program.
Investment Justification	
Demonstrated Utility Practice	Cable injection is an established technology that can extend the life of underground insulated cables subject to certain test criteria. Injected cable can have service life significantly extended and may be more cost effective than comparative cable replacement options.
Cost-Benefit Analysis	When cable reaches EOL status, it may fail unexpectantly and result in higher replacement costs (overtime, etc.) and higher outage costs to customers due to extended duration of unplanned outage.

Historical Outcomes	This is a new program for Oshawa Power. This type of cable rehabilitation has been successfully performed by a number of other utilities.

Conservation and Demand Management

Not Applicable

A. General Project Information

Project Name	Firon Switch Replacement Program	**Project Number**	SR-06
Investment Category	System Renewal	**Project Year**	2027-2030
Project Description	Oshawa Power owns and maintains Firon in-line solid blade switches in its distribution system. Based off field observations and operational experience, these switches are at the end of their useful life. They create operational problems and are due for replacement. Switches have deteriorated to a condition where the switch blades are corroded and stuck in the closed position. Crews are unable to open them for regular operations and additional work time and costs are incurred to address the issue. Additionally, in some instances known from industry experience, Firon switches have been known to physically come apart due to an internal tracking issue from the manufacturing process. This presents a safety issue to Oshawa Power crews and potentially the public should the switch come apart and the conductors fall to the ground. The plan is to replace 99 switch sets (3 phase) per year over the 2027-2030 period.		
Start Date	2027-2030	**Expected In-Service Date**	2027-2030

Estimated Expenditure Timing

	Q1	Q2	Q3	Q4
2026	$0	$0	$0	$0
2027	$78,000	$78,000	$78,000	$79,000
2028	$78,000	$78,000	$78,000	$79,000
2029	$78,000	$78,000	$78,000	$79,000
2030	$78,000	$78,000	$78,000	$79,000

Historical and Forecast Capital Expenditures

Historical and Forecast Program expenditures ($,000) are shown below

Category	Historical Period				Bridge Year	Test Year	Forecast Period			
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Capital (Gross)	$0	$0	$0	$0	$0	$0	$313	$313	$313	$313
Switch sets	0	0	0	0	0	0	99	99	99	99

Economic Evaluations	Not Applicable
Historical Comparative Projects	This program is similar in nature to the Porcelain Switch and Insulator Replacement Program in the previous DSP.
Investment Priority	This investment has been given a priority of 8 of the 17 ranked material capital expenditures. Oshawa Power will replace approximately 99 switch sets annually during the period of 2027-2030.
Alternatives Analysis	The alternative to replacing switches is to do nothing In this scenario, Oshawa Power would accept the risk of switch non-operation and address it on a reactive basis. This approach was rejected as poor switch performance in the field can result in significant increases in O&M costs to address operational needs Therefore, planned replacements are the preferred alternative. Eliminating the added safety issue from the potential of the switch coming apart further supports the decision.
Innovative Nature of the Project	Not Applicable
Leave to Construct	This project is below 50 kV and therefore Leave to Construct is not required, as per O.Reg. 161/99.
Images, Drawings, Maps, & Other Reference Material	

B. Evaluation Criteria and Information Requirements

Efficiency, Customer Value, Reliability and Safety

Efficiency	The investment objectives are to reduce the asset operational risk and to ensure efficient daily grid operations.
Customer Value	This program will mitigate higher O&M costs that would be required to work with equipment not operating properly.
Reliability	This program will replace switches at the end of useful life that could impact outage restoration timing; hence, improving the reliability of the distribution system.
Safety	This program will reduce the risk of injury to the field crew and to the public and property from impacts of attempts at defective switch operation.

Investment Need

Primary Driver	System Renewal is the driver for this program, and it is aimed at improving Asset Performance and Safety as well as reliability. The risk to the utility and the customer is that the asset will continue to not perform its required function and result in conditions that negatively affect operational performance and reliability.
Secondary Driver	There are no secondary drivers.
Information Used to Justify the Investment	Firon switch replacements are driven primarily by the identification of their condition via field observation and operational feedback. These switches will be replaced by new in-line solid blade switches that address operating and safety concerns.

Investment Justification

Demonstrated Utility Practice	The new switches are more dependable over the long term compared to old units and will improve system operating efficiency. Proactive replacement of switches is more cost effective than reactive replacements due to lower O&M costs to work around the defective switches.
Cost-Benefit Analysis	Replacement of Firon switches in a proactive way will reduce O&M costs of work arounds for defective equipment.
Historical Outcomes	This is a new program addressing a specific switch model with operational concerns. This project is subject to scheduling risks. To ensure that no delays occur, there is consistent consultation among the design and construction teams to ensure proper resource allocation to complete the work on schedule.

Conservation and Demand Management

Not Applicable

A. General Project Information

Project Name	Quick Sleeve Replacement Program	**Project Number**	SR-07
Investment Category	System Renewal	**Project Year**	2027-2030
Project Description	Historically, Oshawa Power utilizes automatic splices, more commonly known as quick sleeves to quickly splice 44kV and 13.8kV overhead primary conductor and to minimize planned and unplanned outage duration. However, Oshawa Power has experienced failures of quick sleeves causing major interruptions to our customers. Quick sleeves used for overhead conductors use metal teeth within internal gripping mechanisms to hold the conductor. Quick sleeves fail due to a combination of factors. Over time, the gripping mechanism can experience fatigue, corrosion, or wear, weakening their ability to grip the conductor securely. Additionally, mechanical stress from wind, ice, reduction in conductor tension, or thermal expansion can cause the mechanism to unexpectedly release the conductor if not properly installed, secured or aligned. Thermal cycling further exacerbates the issue, as temperature fluctuations cause the conductor and mechanism to expand and contract at different rates, loosening its gripping / holding ability. Overloading the conductor can also lead to overheating at the splice, compromising the structural integrity of the mechanism teeth and causing failure through unexpected release of the conductor. As an alternative, full tension compression sleeves are the most reliable means of splicing overhead conductors. Based on the multiple means of failure, quick sleeves have been deemed to be a known risk to be proactively replaced under controlled conditions. With this rationale, and accepting that quick sleeves in our distribution network will continue to fail, it is being proposed to replace approximately 564 sets of quick sleeves with permanent compression sleeves on the 44kV and 13.8kV primary overhead conductor lines during the period of 2027-2030.		
Start Date	2027-2030	**Expected In-Service Date**	2027-2030

Estimated Expenditure Timing

	Q1	Q2	Q3	Q4
2026	$0	$0	$0	$0
2027	$50,000	$75,000	$75,000	$50,000
2028	$50,000	$75,000	$75,000	$50,000
2029	$50,000	$75,000	$75,000	$50,000
2030	$50,000	$75,000	$75,000	$50,000

Historical and Forecast Capital Expenditures	Historical and Forecast Program expenditures ($,000) are shown below.

Category	Historical Period				Bridge Year	Test Year	Forecast Period			
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Capital (Gross)	$102	$91	$0	$0	$0	$0	$250	$250	$250	$250
Sleeves	67	58	0	0	0	0	141	141	141	141

Economic Evaluations	Not Applicable
Historical Comparative Projects	Quick sleeve replacements remain largely in line with historical costs per set, with minor increases reflecting material and labor inflation. To proactively address quick sleeve failures, replacement with compression sleeves is proposed, thus reducing future failures and unplanned expenditures. As a result, a higher number of replacements is planned for the 2026–2030 forecast period.
Investment Priority	This investment has been given a priority of 4 of the 17 ranked material capital expenditures. This program has been given a high priority as the failure may cause a safety concern or a system outage. Oshawa Power will replace approximately 564 sets of quick sleeves on 44kV and 13.8kV primary overhead conductor lines during the period of 2027-2030.
Alternatives Analysis	The alternative to this program is to "do nothing." This alternative was rejected because it will result in significant safety concerns, lengthy customer outages and resulting increases to O&M. Therefore, planned replacements was selected as the preferred alternative.
Innovative Nature of the Project	Not Applicable
Leave to Construct	This project is below 50 kV and therefore Leave to Construct is not required, as per O.Reg. 161/99.

Images, Drawings, Maps, & Other Reference Material



Figure 1 A quick sleeve at the point of failure



Figure 2 The corroded inside of a failed quick sleeve

B. Evaluation Criteria and Information Requirements

Efficiency, Customer Value, Reliability and Safety

Efficiency	This program has the potential to positively impact system reliability, as proactive replacement will greatly reduce the risk of outages and their duration to customers.
Customer Value	As a result of this investment, customers will benefit from improved system reliability and reduced safety risk.
Reliability	This program will replace quick sleeves on 44kV and 13.8kV primary overhead conductor lines before they fail and cause extended outages; hence, improving reliability and safety.
Safety	Multiple factors such as described above can cause unexpected in-service failure of the old and deteriorating equipment leading to safety risks to workers and the public.

Investment Need

Primary Driver	System Renewal is the driver for this program, and it is aimed at improving Asset Performance, Safety and Reliability. The risk to the utility and the customer is that the asset will fail and result in an outage that negatively affects reliability and customer satisfaction and presents safety risks to the public and workers.
Secondary Driver	There are no secondary drivers.
Information Used to Justify the Investment	Quick sleeve replacements on the primary overhead lines are driven primarily by the identification of assets via field observations and feedback. In the historical period there have been quick sleeve failures that have resulted in thousands of customers seeing outages.

Investment Justification

Demonstrated Utility Practice	This program will be completed in a like- for- like manner in terms of installation and configuration but using full tension compression sleeves. All new construction will meet the latest distribution standards and regulations and be compliant with O. Reg. 22/04.
Cost-Benefit Analysis	Replacement of the quick sleeves on 44kV and 13.8kV primary overhead conductor lines in a proactive way will reduce the cost of unplanned failures. This program will help reduce system O&M costs over time through reductions in corrective maintenance spending.
Historical Outcomes	Failed or defective quick sleeves have been successfully replaced as required. As quick sleeves age, their condition deteriorates more rapidly, leading to an increase in the number of replacements required over time. Planned proactive replacement is the optimum solution.

Conservation and Demand Management

Not Applicable

A. General Project Information

Project Name	Overloaded Transformer Replacement Program	**Project Number**	SR-08
Investment Category	System Renewal	**Project Year**	2027-2030

Project Description

Oshawa Power's Asset Condition Assessment identified 147 transformers for re-evaluation using current data to assess their loading status. Of these, 93 transformers—76 pole-mounted and 17 pad-mounted—experienced multiple instances of overload conditions during peak usage periods. This program focuses on replacing the overloaded transformers with larger-capacity units to ensure reliable operation and mitigate the risk of premature equipment failure.

Upgrading to larger-capacity transformers proactively addresses the increasing demand driven by electrification. For example, a 50 kVA unit may be replaced with a 100 kVA unit to accommodate higher loads.

The program budget covers the transformer replacements but does not include costs for upgrading supporting infrastructure. If differences in equipment dimensions or weight necessitate modifications, a design and loading analysis will be conducted to ensure compliance with Ontario Regulation 22/04. Should additional costs fall outside the program's scope, Oshawa Power will utilize its Asset Management System—including the Strategic Asset Management Plan (SAMP) and risk prioritization tools—to guide investment decisions.

Start Date	2027-2030	**Expected In-Service Date**	2027-2030

Estimated Expenditure Timing

	Q1	Q2	Q3	Q4
2026	$0	$0	$0	$0
2027	$66,000	$66,000	$66,000	$67,000
2028	$66,000	$66,000	$66,000	$67,000
2029	$66,000	$66,000	$66,000	$67,000
2030	$66,000	$66,000	$66,000	$67,000

Historical and Forecast Capital Expenditures

Historical and Forecast Program expenditures ($,000) are shown below.

Category	Historical Period				Bridge Year	Test Year	Forecast Period			
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Capital (Gross)	$0	$0	$0	$0	$0	$0	$267	$267	$267	$267
Units replaced	0	0	0	0	0	0	24	23	23	23

Economic Evaluations	Not applicable
Historical Comparative Projects	This program is similar in nature to the other proactive equipment replacement programs that deal with equipment at end of useful life. While not all equipment are at end of TUL, continued operation at overload conditions could lead to premature equipment failure.
Investment Priority	This investment has been given a priority of 14 of the 17 ranked material capital expenditures. This program priority is determined through consideration of the impact of overload affecting equipment performance and leading to premature failure prior to end of TUL. Oshawa Power will replace approximately 93 transformers (76 pole mount transformers and 17 pad mount transformers) during the period of 2027-2030.
Alternatives Analysis	The alternative to replacing transformers is to do nothing. In this scenario, Oshawa Power would accept the risk of premature unexpected transformer failure with accompanying loss of useful life and address it on a reactive basis. This approach was rejected as transformer failure in the field can result in lengthy customer outages that will result to increases in O&M costs. Therefore, planned replacements are the preferred alternative.
Innovative Nature of the Project	Replaced transformers with useful life remaining can be repurposed to installations that have loading levels within the transformer rating and if they been inspected and approved as presenting no undue safety risk under O. Reg. 22/04. New transformers with larger capacity would be capable of handling the increasing electrification that is being predicted on the distribution system.
Leave to Construct	This project is below 50 kV and therefore Leave to Construct is not required, as per O.Reg. 161/99.

Images, Drawings, Maps, & Other Reference Material

B. Evaluation Criteria and Information Requirements

Efficiency, Customer Value, Reliability and Safety

Efficiency	The investment objectives are to reduce the asset failure risk and to ensure reliable service to customers by mitigating the risk of power outage duration and frequency. Replaced transformers can be conditionally repurposed. New transformers sized for growth in electrification.
Customer Value	Reduction of unplanned customer outages due to premature equipment failure. Resizing coordinated with replacement reducing future need for outage to replace unit.
Reliability	This program will maintain reliability and will reduce the potential for unplanned equipment failure prior to end of TUL.
Safety	Proper asset management mitigates safety concerns for Oshawa Power staff and the public that could result in continued operation of overloaded equipment.

Investment Need

Primary Driver	System Renewal is the driver for this project aimed at reducing failure risk – Overloaded assets pose a risk of failure that can be mitigated through proper asset management practices. Mitigating failure risk will also minimize safety risks and impact to reliability.
Secondary Driver	There are no secondary drivers.
Information Used to Justify the Investment	Overloaded transformers are identified by aggregating metered customer consumption, coincident at the transformer level.

Investment Justification

Demonstrated Utility Practice	Proper asset management practices will mitigate potential impact of overloaded equipment and maintain a safe and reliable distribution system. Future system capacity needs addressed at same time.
Cost-Benefit Analysis	Proactive equipment replacement will mitigate unplanned replacement costs and cost of outages to customer. Replaced

	transformers can be conditionally repurposed. New transformers are sized for predicted growth in electrification.
Historical Outcomes	This is a new program. This project is subject to scheduling risks. To ensure that no delays occur, there is consistent consultation among the design and construction teams to ensure proper resource allocation to complete the work on schedule.

Conservation and Demand Management

Not applicable.

A. General Project Information

Project Name	Distribution Switchgear Replacement Program	**Project Number**	SR-09
Investment Category	System Renewal	**Project Year**	2027-2030

Project Description

This program is comprised of replacing distribution switchgear in poor condition and at or approaching End of Useful Life and pose a high safety and reliability risk. Results of the ACA have determined that complete replacement of these assets is the recommended approach due to their condition and risk.

The distribution switchgears recommended for replacement in the ACA were further prioritized to maximize benefit. Distribution switchgears feeding higher number of equipment (i.e Higher number of ways) as well as associated underground primary cable recommended for replacement in the ACA, are being targeted under this program.

New equipment will be manufactured to newer current standards and incorporate motorized functionality thus improving the level of reliability in the distribution system.

The budget includes replacement of switchgear units, and outgoing underground cables that feed individual equipment. Approximately 1.9km of cable is expected to be replaced.

Table 1 shows the switchgears planned for replacement during the 2026-2030 forecast period. Map included in reference material.

LOCATION	# of Ways	Associated primary cable (m)	2026	2027	2028	2029	2030%
2 King St E Vault	5	582		$289,135.00			
44 Bond St W Vault	4	223				$175,655.00	
55 William ST E Vault	5	710		$314,095.00			
OC Vault 1	4	441					$ 175,645.00
57 Simcoe St S Vault	5	-					$ 218,165.00

Table 1 – Distribution Switchgear Replacements

Start Date	Jan - 2027	**Expected In-Service Date**	Mar- 2030

Estimated Expenditure Timing

	Q1	Q2	Q3	Q4
2026	$0	$0	$0	$0
2027	$0	$289,135	$314,095	$0
2028	$0	$0	$0	$0
2029	$175,655	$0	$0	$0

	2030	$175,645	$0	$2178,165	$0

Historical and Forecast Capital Expenditures

Historical and Forecast Program expenditures ($,000) are shown below.

Category	Historical Period				Bridge Year	Test Year	Forecast Period			
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Capital (Net)	$0	$0	$0	$0	$0	$0	$603	$0	$176	$394
Units replaced	0	0	0	0	0	0	2	0	1	2

Economic Evaluations

Not applicable

Historical Comparative Projects

Switchgear replacements do not have a direct comparator. This program begins in 2027.

Investment Priority

This investment has been given a priority of 11 of the 17 ranked material capital expenditures. It is prioritized as such due to the impact of the equipment failure. Oshawa Power will replace five (5) switchgears starting 2027 through 2030.

Alternatives Analysis

The alternative to replacing switchgear is to do nothing. In this scenario, Oshawa Power would accept the risk of switchgear failure and address it on a reactive basis. This approach was rejected as switchgear failure in the field can result in significant safety concerns, and lengthy customer outages that will result to increases in O&M costs. Therefore, planned replacements are the preferred alternative.

Innovative Nature of the Project

Replacement switchgear will be built to current standards and be capable of integrating into the SCADA system for improved operational control.

Leave to Construct

This project is below 50 kV and therefore Leave to Construct is not required, as per OEB O. Reg. 161/99.

Images, Drawings, Maps, & Other Reference Material

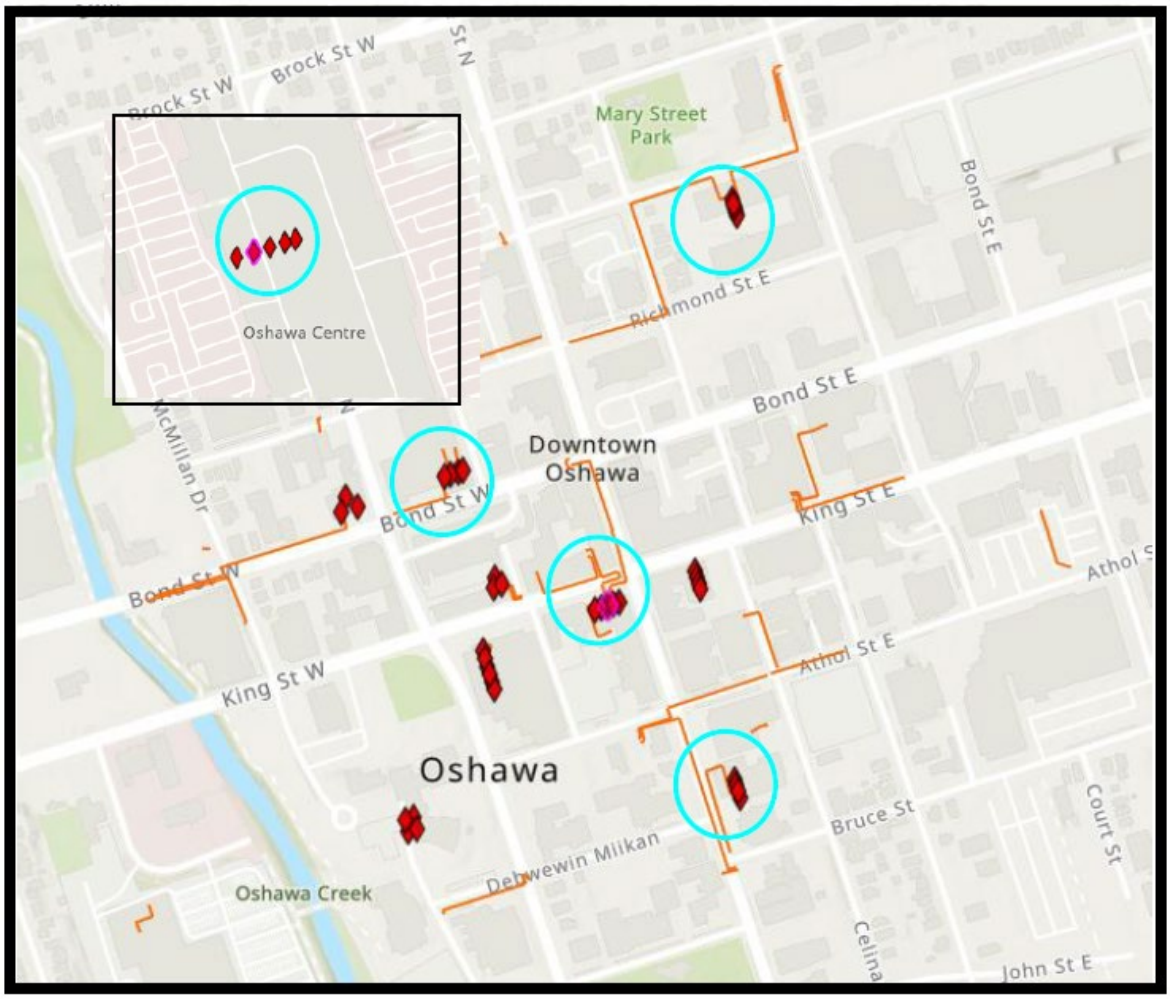


Figure1 – Location of Distribution Switchgear to be Replaced

B. Evaluation Criteria and Information Requirements

Efficiency, Customer Value, Reliability and Safety

Efficiency	The investment objectives are to reduce the asset failure risk and to ensure reliable service to customers by mitigating the risk of power outage duration and frequency.
Customer Value	This program will improve reliability and will reduce the cost to customers of unplanned outages
Reliability	This program will replace switchgear at end of useful life before they fail and cause extended outages; hence, improving the reliability of the distribution system.

Safety	Proper asset management of old and deteriorating equipment in the field mitigates safety concerns for Oshawa Power staff and customers. New construction will also meet the latest distribution standards for safety.
Investment Need	
Primary Driver	System Renewal is the driver for this program and it is aimed at improving Asset Performance and Safety as well as reliability. The risk to the utility and the customer is that the asset will fail and result in an outage that negatively affects reliability and customer satisfaction.
Secondary Driver	There are no secondary drivers
Information Used to Justify the Investment	The sources of the information used to justify the investment are the results of the ACA and field inspections.
Investment Justification	
Demonstrated Utility Practice	New switchgear is more dependable over the long term compared to old units and will improve system operating efficiency. Proactive replacement of switches is more cost effective than reactive replacements due to lower replacement unit cost and reduced equipment failure risk.
Cost-Benefit Analysis	Replacement of switchgear in a proactive way will reduce the cost of unplanned failures and the associated corrective maintenance costs. This program will help reduce system O&M costs over time through reductions in corrective maintenance spending.
Historical Outcomes	This is a new program. This project is subject to scheduling risks. To ensure that no delays occur, there is consistent consultation among the design and construction teams to ensure proper resource allocation to complete the work on schedule.
Conservation and Demand Management	
Not applicable	

A. General Project Information

Project Name	Municipal Substation Switchgear Replacement Program	**Project Number**	SR-10
Investment Category	System Renewal	**Project Year**	2026-2027
Project Description	Station metalclad walk-in type switchgears contain circuit breakers, protection & control relays, fuses, buswork, primary cable terminations, and switches that monitors & control current flow within the distribution system. In the event of a fault, the relays sense the faults, and the circuit breaker isolates and clears the downstream faults. It is also utilized to isolate equipment during maintenance and testing work. Oshawa Power owns and operates 18 switchgear buses at energized at 13.8 kV within its stations. Several switchgears have been identified for intervention—ranging from replacement to refurbishment—due to their high risk and/or having reached the end of their economic life within the planning period. The Health Index formulation methodology, along with the optimal intervention type and timing, is supported by the comprehensive Asset Condition Assessment Report and the Options Analysis Report. Switchgears recommended for replacement undergo additional risk evaluation using Oshawa Power's Asset Management System (SAMP and Risk Prioritization Tool), with input from subject matter experts to determine the best course of action. Existing switchgear located at MS5 and MS11, including their associated relays and e-house, are scheduled for replacement during the 2026–2030 forecast period due to their reliability risks and their role in serving a significant portion of Oshawa Power's customer base. The existing units will be replaced with new switchgear that meets current industry standards. As of 2025, the ages of these switchgears are: MS5: 51 years MS11: 57 years As part of this program, new riser poles and related underground infrastructure will also be installed at MS5. Relay replacements and the installation of a new LAN network are to be installed for both MS5 and MS11.		
Start Date	MS5 – 2026 MS11 - 2027	**Expected In-Service Date**	MS5 – 2026 MS11 - 2027

		Q1	Q2	Q3	Q4
Estimated Expenditure Timing	2026	$0	$ 1,521,134	$ 1,521,134	$0
	2027	$0	$ 1,157,752	$ 1,157,752	$0
	2028	$0	$0	$0	$0
	2029	$0	$0	$0	$0
	2030	$0	$0	$0	$0

Historical and Forecast Capital Expenditures

This program is a continuation of the 2021 – 2025 MS Switchgear Program. Historical and Forecast Program expenditures ($,000) are shown below.

Category	Historical Period				Bridge Year	Test Year	Forecast Period			
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Capital (Gross)	$0	$0	$3,111	$(4)	$3,501	$3,042	$2,316	$0	$0	$0
Station	N/A	N/A	MS2	N/A	MS7	MS5	MS11	N/A	N/A	N/A

Economic Evaluations

Not Applicable

Historical Comparative Projects

Comparative 15 kV switchgear replacement, including e-house and relays, have been undertaken in 2023 for MS2 and 2025 for MS7.

The forecasted costs are aligned with historical spend. Minor variances in costs are due to varying scopes with associated infrastructure to support MS switchgear replacement, such as riser poles, varying egress cable lengths, duct condition, and road crossings etc. For example, MS2 and MS5 whereas MS7 and MS11 are comparable to each other when it comes to overall scope of work.

Investment Priority

This investment has been given a priority of 2 of the 17 ranked material capital expenditures. MS5 and MS11 switchgears are scheduled for replacement during the forecast period. Switchgears identified for intervention in the ACA and Options Analysis Report underwent an additional layer of evaluation using the risk prioritization tool to optimize investment decisions.

The high priority of this program is justified by the poor condition of the assets, their significant potential impact on a large number of customers in the event of a failure, and a quantified options analysis recommending replacement due to their nearing economic end of life. A failure could result in a complete loss of supply from the MS, necessitating load transfer to another MS. Such transfers would be highly challenging, potentially taking several hours and leading to overloading conditions at other facilities.

	The alternative to replacing the switchgear is to run to failure, or refurbish as opposed to replace. A detailed Options Analysis Report has been prepared and included in Appendix C. The options analysis process is outlined below:

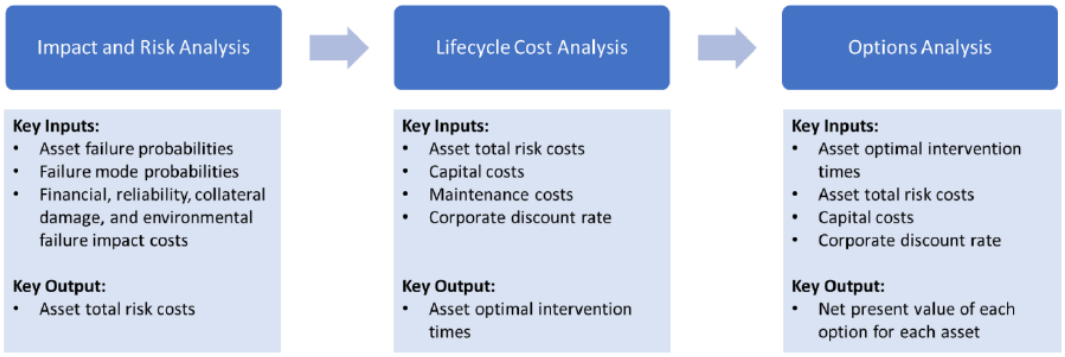


Figure 1 – Options Analysis Process

Alternatives Analysis	The quantified impact and risk analysis represents the socio-economic costs incurred by the utility through continued operation of the asset. Asset risk costs are further combined with the assets' capital costs in order to carry out the Lifecycle Cost Analysis, which is used to calculate the total cost of ownership ("TCO") for each of the assets in the system. By comparing the equivalent annualized cost of the new asset to be installed, against the annual risk costs curve of the existing asset to be replaced, the point in time at which the future annual risk costs of the existing asset will exceed an average annual total cost of the new asset if it's replaced is determined. This represents the Optimal Intervention Time (OIT) at which point in time it would be economically viable to install a new asset instead of continued operation of the existing asset. The option with the highest Net Present Value (NPV) for assets with an OIT within the planning period, is the recommended intervention method. Replacement of MS5 and MS11 is thus the optimal solution because the above analysis indicates that the OIT falls within the upcoming DSP planning period of 2026-2030.
Innovative Nature of the Project	The protection relays are microprocessor based IED (Intelligent Electronic Device) relays that are capable of implementing grid modernization and dealing with reverse power flow to accommodate REG applications. This project also includes new technology with IEC61850 interoperable relays and new substation LAN design.
Leave to Construct	This project is below 50 kV and therefore Leave to Construct is not required, as per O.Reg. 161/99.

Images, Drawings, Maps, & Other Reference Material

Please refer to the ACA and Options Analysis Report in Appendix C

B. Evaluation Criteria and Information Requirements

Efficiency, Customer Value, Reliability and Safety

Efficiency	This program will replace switchgears in poor condition posing high risk and approaching economic end of life within the forecast period, to prevent potential failures that can cause extended outages and safety risks.
Customer Value	Customers will benefit from a more reliable electrical infrastructure. Net benefits accruing to the customers have been qualitatively described and quantified in the Options Analysis Report via anticipated customer interruption costs per customer class.
Reliability	The investment objectives are to mitigate the risk of lengthy customer interruptions.
Safety	These investments are directly linked to public and worker safety, as they aim to eliminate switchgears with high risks of catastrophic failure. Lead cable containing oil will be eliminated during the replacement process thus reducing risk of fires as well as safeguarding the environment. Additionally, modern protection and controls, capable of responding automatically to mitigate unsafe conditions will provide better public safety and keep pace with the demands of a modern distribution network system.

Investment Need

Primary Driver	This program falls under System Renewal Investment driver and aims at addressing existing reliability concerns. When a MS switchgear fails, outages can be extensive and may last for extended periods of time. This program will reduce the risk of prolonged power interruptions and reduce the frequency of power interruptions due to equipment failure. This program will also address Operational Efficiency and Safety. Allowing old and deteriorating equipment in the field can result in significant safety and reliability concerns to Oshawa Power staff and customers. The installation of advanced communication (substation LAN) and new relays will facilitate better communication traffic

	(e.g., lower latencies, more bandwidth) for a smarter and more responsive grid.
Secondary Driver	There are no secondary drivers.
Information Used to Justify the Investment	The source of the information used to justify this project investment is the ACA & Options Analysis Report which was prepared considering all the information pertaining to the condition of the assets.

Investment Justification

Demonstrated Utility Practice	A planned replacement is the preferred alternative for these assets because it allows Oshawa Power to proactively mitigate the failure risk posed by end-of-life and poor condition of MS switchgears within the distribution system and thereby, reduce the risk of outages to customers. The replacement will also provide better system operation efficiency and will minimize preventative maintenance work required. Proceeding with these projects will improve the operational effectiveness of the system and maintain SAIDI and SAIFI performance.
Cost-Benefit Analysis	The switchgear replacement program will help reduce system O&M costs through reductions in reactive maintenance spending.
Historical Outcomes	Timely consultation among the design and construction teams ensures proper resource allocation to complete the work on schedule. Oshawa Power employs contract resources as necessary, to mitigate the scheduling risks. MS2 switchgear successfully replaced over the historical period, and MS7 planned for replacement in 2025.

Conservation and Demand Management

Not applicable

A. General Project Information

Project Name	Reactive Replacement Program	**Project Number**	SR-12
Investment Category	System Renewal	**Project Year**	2026-2030
Project Description	Reactive renewal projects represent unplanned projects that consist of assets that are failed, are about to fail, or present a safety hazard to the public. These projects typically arise from trouble calls, storm damage, equipment failures, dig-in damage, accidents, fires as well as information provided from third parties (ESA, customers, communication companies, etc.)		
Start Date	2026-2030	**Expected In-Service Date**	2026-2030

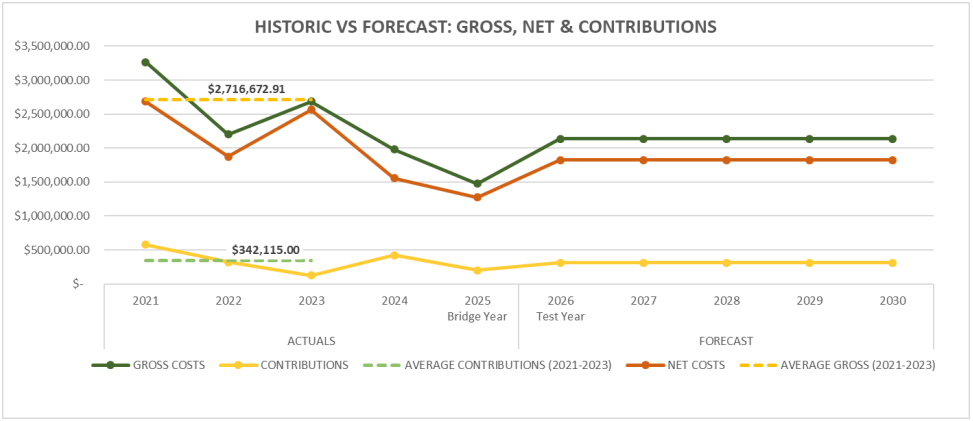
Estimated Expenditure Timing

	Q1	Q2	Q3	Q4
2026	$535,000	$543,000	$543,000	$535,000
2027	$535,000	$543,000	$543,000	$535,000
2028	$535,000	$543,000	$543,000	$535,000
2029	$535,000	$543,000	$543,000	$535,000
2030	$535,000	$543,000	$543,000	$535,000

Historical and Forecast Capital Expenditures

Historical and Forecast Program expenditures ($,000) are shown below.

Category	Historical Period				Bridge Year	Test Year	Forecast Period			
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Capital (Gross)	$3,264	$2,200	$2,686	$1,982	$1,476	$2,138	$2,138	$2,138	$2,138	$2,138
Contributions	$578	$324	$124	$424	$204	$312	$312	$312	$312	$312
Capital (Net)	$2,686	$1,876	$2,562	$1,559	$1,272	$1,826	$1,826	$1,826	$1,826	$1,826

Economic Evaluations	Not applicable
Historical Comparative Projects	The proposed budget is based on average historical expenditures. However, as this budget is influenced by external factors such as weather conditions and traffic accidents, and generally unplanned, unexpected and uncontrollable events, expenditures are assessed on an annual basis and are inherently difficult to predict. A reduced budget, approximately 20% lower than historical levels (2021-2023), has been allocated for the forecast period. This reduction reflects increased focus on proactive replacement programs, including but not limited to quick sleeve, porcelain insulator replacements, and overloaded transformer replacements. The contribution amount remains relatively consistent with historical levels, as reactive costs associated with asset failures do not generate contributed capital. Consequently, billable items arising from events such as dig-ins and accidents are forecasted to follow historical trends.  **Figure 1 – Historic vs Forecast spend amounts**
Investment Priority	Mandatory priority. This project/program deals with addressing system outages and safety concerns. Tasks are typically considered emergency in nature.
Alternatives Analysis	There are no other practical and cost-effective alternatives to this project. This project is a reactive based project that receives a very high priority when tasks arise.
Innovative Nature of the Project	Not applicable.

Leave to Construct	This project is below 50 kV and therefore Leave to Construct is not required, as per O.Reg. 161/99.

Images, Drawings, Maps, & Other Reference Material

B. Evaluation Criteria and Information Requirements

Efficiency, Customer Value, Reliability and Safety

Efficiency	The investment objectives are to continue safe operation of the electrical system and maintain Oshawa Power's reliability by limiting the duration of outages. Emergency replacements are typically constructed like-for-like, but when practical, they are constructed to USF and/or Oshawa Power standards.
Customer Value	Customers benefit from this project is having outage times reduced and safety concerns managed in a timely fashion.
Reliability	This project does not have a direct impact on frequency and duration of outages; however, the reactive work will reduce the probability of future outages at the same location.
Safety	Public and worker safety is a primary purpose in this project. Attending the site, making it safe and replacing the failed infrastructure reduces hazards for both the public and workers. Final installations are completed as per CSA, USF and/or Oshawa Power specific standards which adhere to a high level of safety standards and in compliance with O. Reg. 22/04.

Investment Need

Primary Driver	This program falls under the System Renewal Investment driver and addresses safety to the public and workers when assets fail and need to be repaired/refurbished and also is needed to maintain system reliability and provide customer service.
Secondary Driver	There are no secondary drivers.

Information Used to Justify the Investment	Historical expenditures have been analyzed in conjunction with age and condition of existing infrastructure. Emergency service restoration is an OEB-mandated activity.

Investment Justification

Demonstrated Utility Practice	Failed assets, if not replaced/repaired immediately, pose system reliability hazards. Replacement of failed assets is needed to maintain system reliability. Like- for- like replacements are typical for majority of tasks that arise from outages or safety concerns due to typical timing of tasks.
Cost-Benefit Analysis	This project has a neutral effect on O&M costs.
Historical Outcomes	Replacements constructed using the latest standards and industry standards and practices.

Conservation and Demand Management

Not Applicable

A. General Project Information

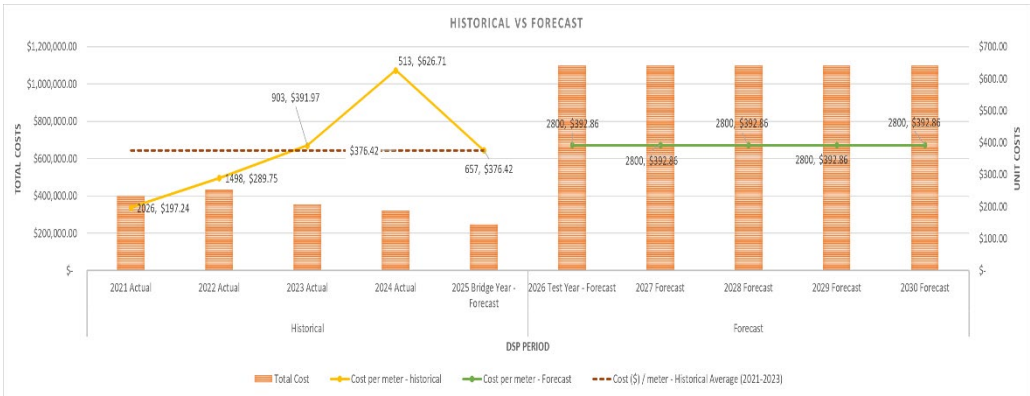
Project Name	Meter Replacement Program	**Project Number**	SR-13
Investment Category	System Renewal	**Project Year**	2026-2030
Project Description	This is an annual program that covers the replacement of Oshawa Power owned metering assets. Meter replacements include older technology Elster residential and commercial meters, required materials and labour and meter room communication upgrades when required. A proactive replacement of selected metering equipment and the reactive replacement of meter equipment failures will be undertaken using Elster next generation A4 technology allowing faster response times and increased data memory and reliability. A reactive approach will be taken to replace failed meters and components as required. As mandated by Measurement Canada, a large number (35,000+) of meters will require reverification testing in 2028. This portion of the. program takes a balanced risk approach where not all batches sent for reverification are expected to fail, however since all meters within this reverification group have already been resealed in 2020, the likelihood of failures is assumed to be higher than normal due to the age of the meter . A proactive approach has been taken to begin replacing meters starting with the 2026 test year such that the problem is not exasperated at the end of life of the next batch of meters when they will all be up for replacement at the same time.		
Start Date	2026-2030	**Expected In-Service Date**	2026-2030

Estimated Expenditure Timing

	Q1	Q2	Q3	Q4
2026	$275,000	$275,000	$275,000	$275,000
2027	$275,000	$275,000	$275,000	$275,000
2028	$275,000	$275,000	$275,000	$275,000
2029	$275,000	$275,000	$275,000	$275,000
2030	$275,000	$275,000	$275,000	$275,000

Historical and Forecast Capital Expenditures	Historical and Forecast Program expenditures ($,000) are shown below.

Category	Historical Period				Bridge Year	Test Year	Forecast Period			
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Capital (Gross)	$400	$434	$354	$321	$248	$1,100	$1,100	$1,100	$1,100	$1,100
Units	2026	1498	903	513	657	2800	2800	2800	2800	2800

Economic Evaluations	Not Applicable
Historical Comparative Projects	Related spending in previous years. Previous years' spending was recorded under AMI system upgrade in the System Access category. In the historic years (2021-2025) meter replacements were on a reactive basis i.e. failed meters were replaced. In the forecast years there are a large number of meters (35,000+) requiring verification and a proactive approach is adopted to balance risk of failures and pace out future reverification groups to avoid bulk investment needs. This has resulted in the move to System Renewal and higher numbers of meters requiring replacement.  **Figure 1 – Historical vs Forecast Meter Replacement** A forecast of 2800 units yearly based on the historical average cost per meter replacement. A higher ask for total spend is a result of the amount of meters reaching end of life potential during the forecast period.
Investment Priority	This investment has been given a priority of 10 of the 17 ranked material capital expenditures.
Alternatives Analysis	All meters that fail in service or reverification testing must be replaced per Measurement Canada regulations. The proactive approach (Option 2 in Table 1) is adopted by assuming reasonable risk while still keeping up with evolving technology, smoothening investments, and replacing end of life metering assets.

Description	Amounts					Benefits	Risks
	2026	2027	2028	2029	2030		
Option 1: No proactive meter replacement program: Run all meters to failure	$325K	$325K	$325K	$325K	$325K	A. Potentially defers spend until next COS B. Extracts maximum life out of existing meters. Note: Currently, it's unknown how many times meters will pass reverification	A. Next COS will have more meters to replace and deferred meters will add on to remaining majority of meters needing reverification / replacement (~15-20MM) B. Meters up for reverification in 2027 have already been through resealing. This means that the probability of failure is higher. Even if batches, they will need resealing sooner as reverfiication timelines are reduced after every reseal. C. If meters fail verification, we may have to spend the $11M in 2028 regardless. D. The problem will be exasperated at the end of life of the next batch of meters when they will all be up for replacement at the same time, creating a more uneven spend. E. Oshawa Power will be late to implement AMI2.0
Option 2: Begin a replacement program to even the spend over the expected lifetime of the meters (18 yrs).	$1.1M	$1.1M	$1.1M	$1.1M	$1.1M	A. Evens out spend over next 3-4 cost of service applications. B. Evens out spend for next replacement cycle as well C. Begins AMI 2.0 deployment over time	A. If meters fail verification, we may have to spend the $11M in 2028 regardless.
Option 3: Assume reverification failure for all meters coming up for reverification in 2028 and proactively plan to replace		$5M	$6M			A. Reduces risk of unexpected re-verification failure. B. Begins more aggressive deployment of AMI 2.0	A. Large spend in 2027/2028. B. Meters may be replaced with useful life remaining

Table 1 – Options Analysis

Innovative Nature of the Project	Implementation of next generation Elster A4 meters will allow alignment with Oshawa Power's strategy to explore and utilize emerging technologies from the manufacturer for additional meter data collection, monitoring and analysis at the organization and customer level.
Leave to Construct	Not Applicable

Images, Drawings, Maps, & Other Reference Material

B. Evaluation Criteria and Information Requirements

Efficiency, Customer Value, Reliability and Safety

Efficiency	Ensuring meters are in good working order mitigates billing errors and associated customer billing complaints. Ensures Oshawa Power meets regulatory obligations with respect to metering customer electricity consumption.
Customer Value	Accurate billing of electrical consumption mitigates customer billing complaints and
Reliability	Meters subject to Measurement Canada regulations and industry standards for consistent and accurate reporting of energy consumption

Safety	Assets will be installed per CSA and 22/04 standards.
Investment Need	
Primary Driver	Meter replacements are driven by regulatory obligations to ensure meters in service meet Measurement Canada standards.
Secondary Driver	There are no secondary drivers.
Information Used to Justify the Investment	Meters that fail in service or fail testing subject to mandatory replacement per Measurement Canada regulations.
Investment Justification	
Demonstrated Utility Practice	Ensuring meters are in good working order mitigates billing errors and associated customer billing complaints. Ensures Oshawa Power meets regulatory obligations with respect to metering customer electricity consumption.
Cost-Benefit Analysis	Not applicable – mandatory program to replace defective or failed meters
Historical Outcomes	Failed or defective meters have been successfully replaced as required.
Conservation and Demand Management	
Not Applicable	

A. General Project Information

Project Name	3 New Feeders from MS9	**Project Number**	SS-01
Investment Category	System Service	**Project Year**	2026
Project Description	This project involves the installation of three (3) new 13.8kV feeders from the MS9 station. The scope of work includes all associated costs for setting up riser poles, duct work (including road crossings), egress, and cable installation. Approximately 1.16 km of feeder egress cable will be installed as part of this project. The project timeline must align with the City of Oshawa's planned road-widening project on Conlin Road, which will require pole line relocations. The new poles along Conlin Road are designed to accommodate the additional feeders from MS9, ensuring compatibility with the expanded infrastructure. The project addresses multiple key needs: • **Alleviation of Existing Burdened Assets** Currently, most of the load in North Oshawa is distributed between MS7 and MS9. MS7 is operating at near-capacity levels, requiring the auto-transfer at the station to be disabled during certain peak periods to avoid station transformer overloading. This compromises system redundancy and operational flexibility. By introducing new feeders from MS9, the system will be better positioned to offload MS7 and enhance overall capacity distribution. • **Meeting New Load Requirements** North Oshawa is experiencing rapid growth, with significant planned developments such as the Kedron development (refer to Figure 1) and the upcoming Columbus community (refer to Figure 1). These new feeders will ensure that the distribution system can accommodate the increasing demand from these new residential and commercial developments. • **Capacity Optimization** Both station transformers at MS9 are fed by 44kV feeders (165M7 and 165M8) from Hydro One's Enfield TS (refer to Figure 2 for location and interconnectivity). Oshawa Power contributed capital during the construction and commissioning of this station to secure capacity for supporting Oshawa's growth. These new feeders will maximize the utilization of the allocated capacity at Enfield TS, ensuring efficient use of resources and supporting long-term growth in the region.		

	By addressing these needs, this project will enhance system reliability, accommodate growth, and optimize existing infrastructure to meet the increasing energy demands of North Oshawa.
Start Date	Jan 2026 **Expected In-Service Date** Dec 2026

Estimated Expenditure Timing

	Q1	Q2	Q3	Q4
2026	$0	$0	$500,000	$500,000
2027	$0	$0	$0	$0
2028	$0	$0	$0	$0
2029	$0	$0	$0	$0
2030	$0	$0	$0	$0

Historical and Forecast Capital Expenditures

Historical and Forecast Program expenditures ($,000) are shown below.

Category	Historical Period				Bridge Year	Test Year	Forecast Period			
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Capital (Gross)	$0	$0	$0	$0	$0	$1,000	$0	$0	$0	$0

Economic Evaluations	Not applicable
Historical Comparative Projects	Not Applicable
Investment Priority	This investment has been given a priority of 6 of the 17 ranked material capital expenditures. The project has been determined as a high priority due to capacity needs from new developments and to alleviate load on MS7. It will also address the need of maintaining system redundancy and operating efficiencies in the north Oshawa area.
Alternatives Analysis	The alternative is to do nothing. This can potentially impede Oshawa Power's ability to connect new developments. MS7 will also continue to remain in capacity constrained state thus compromising on system redundancy. This will result in continued equipment and reliability risk.
Innovative Nature of the Project	Not applicable

Leave to Construct	This project is below 50 kV and therefore Leave to Construct is not required, as per OEB Reg. 161/99.

Images, Drawings, Maps, & Other Reference Material

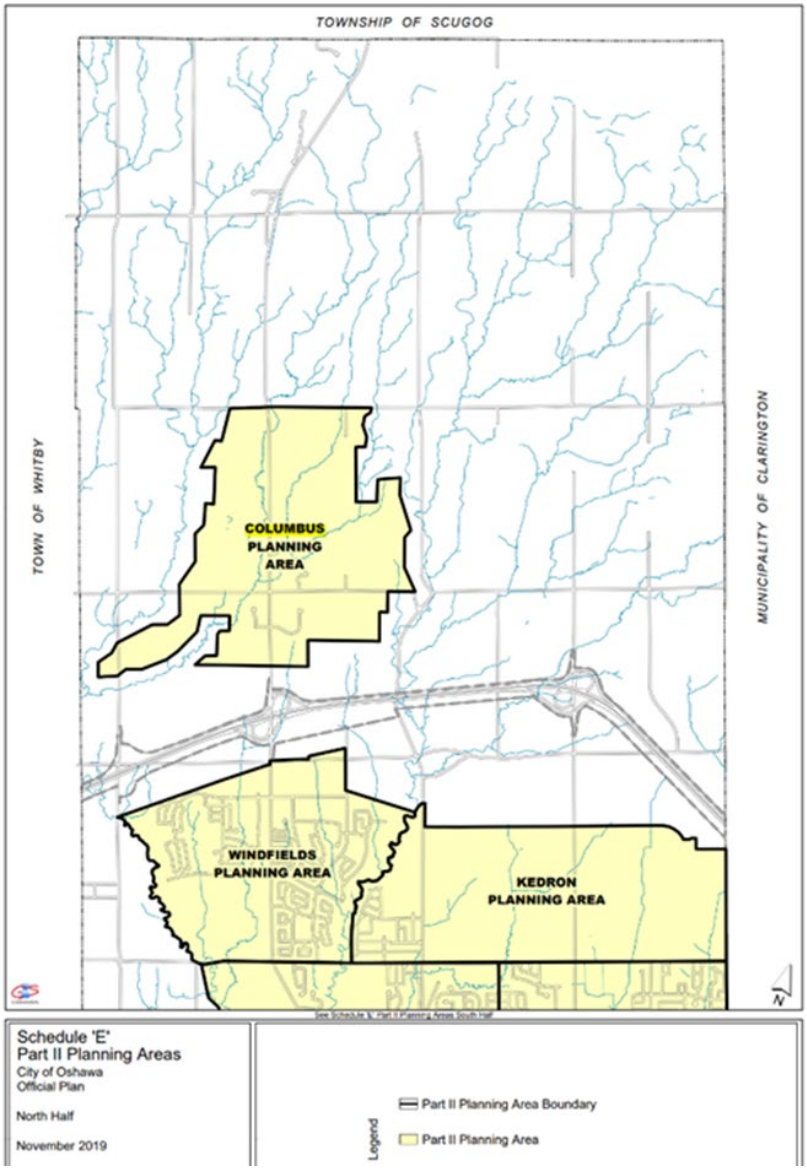


Figure 1: Kedron and Columbus Planning Areas

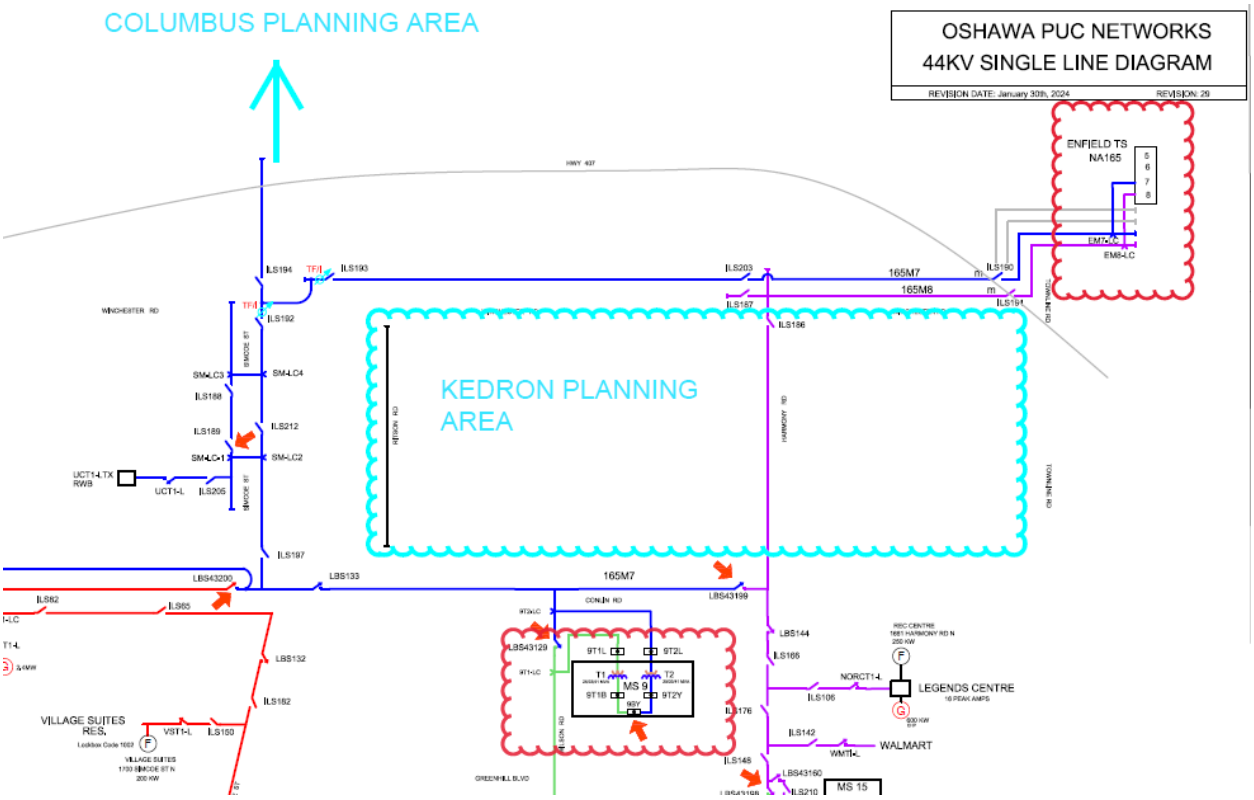


Figure 2: MS9 Network Connectivity & Location w.r.t Planning Areas

B. Evaluation Criteria and Information Requirements

Efficiency, Customer Value, Reliability and Safety

Efficiency	The investment objectives are to ensure capacity availability, mitigate the risk of equipment overloading and service redundancy for MS7 and the north Oshawa area.
Customer Value	The net benefits accruing to Customers will be reduced risk to service reliability and improved operational efficiencies.
Reliability	The installation of three (3) new feeders will enhance operational reliability to the north Oshawa area and reduce loading risk on MS7.
Safety	Feeders will return loading on MS7 to below normal loading levels. Feeders will be installed in compliance with O. Reg. 22/04 and new standards to ensure safety for the general public.

Investment Need

Primary Driver	Ensuring Capacity is available to accommodate customer connection due to growth in North Oshawa is the main driver for this project.
Secondary Driver	System reliability & operational efficiency are the secondary drivers for this project.
Information Used to Justify the Investment	Published population growth studies and reports on new developments by the City of Oshawa, coordinated planning with developers on demand requirements, capacity monitoring on existing assets such as MS7 support the justification of this investments.

Investment Justification

Demonstrated Utility Practice	The project will address the need to plan for future growth and manage load on MS7 and addressing reliability risks in the North Oshawa area.
Cost-Benefit Analysis	This program will improve system capacity, reduce reliability risk and maintain customer service performance levels in the North Oshawa area.
Historical Outcomes	This program is similar to previous capacity addressing works and will result in grid reconfiguration that reduces reliability risk, reduces overloading on equipment and improves grid operational flexibility.

Conservation and Demand Management

Not applicable

D. Project Sign Off

Prepared by		**Authorized by**	
Date		**Date**	
		Completion Date	

A. General Project Information

Project Name	Overhead Automated Self-Healing Switching devices	**Project Number**	SS-02
Investment Category	System Service	**Project Year**	2026-2030
Project Description	This project is a part of Oshawa Power's continuing efforts towards improving service reliability & response times, and reducing outage durations by modernizing the distribution system. During the period 2028-2030, Oshawa Power will install 12 - 44KV and 15 - 13.8kV motorized switching devices on our 44kV and 13.8kV distribution system to enhance the utility's ability to perform switching operations during normal and emergency conditions. This project will include extending the communication network to existing and new smart switches. **13.8kV Distribution System** Oshawa Power's goal for the 13.8kV distribution system automation is to enhance reliability and minimize customer disruptions through strategic feeder sectionalization. The objective is to ensure that feeder faults result in outages affecting no more than half of the connected customers. This goal leverages advanced Fault Location, Isolation, and Service Restoration technology with Loss of Voltage functionality (FLISR LOV), allowing rapid fault isolation and reduced outage scope. ***2026-2030 Goal*** • Expand deployment of SCADA-compatible switching devices capable of fault detection and load-breaking, to 60% (additional 20%) of Oshawa Power's 13.8kV feeders. ***Long Term Goals*** • Achieve full feeder segmentation across the entire 13.8kV system, integrating FLISR LOV logic comprehensively to achieve optimal reliability standards across Oshawa Power's service area. • Further reduce the number of customers impacted by a sustained outage to less than half of the connected customers. ***Current Status*** Presently, Oshawa Power has automated approximately 40% of its 13.8kV feeders, successfully reducing outage impacts to half (or less) of customers connected to these feeders during faults.		

Action Plan (2026-2030)

Oshawa Power's immediate next steps involve strategically automating additional feeders, specifically targeting the 60% not yet automated. Recognizing resource limitations and aiming to achieve maximum reliability benefits, Oshawa Power will initially deploy devices with load breaking and fault detection capabilities to the 10 highest-priority feeders. The high priority feeders are determined based on worst performing feeder analysis using historical Feeder Average Interruption Frequency Index (FAIFI) and Feeder Average Interruption Duration Index (FAIDI) values. Each pair of targeted feeders will require three devices, one per feeder and one at their tie-point, to ensure effective segmentation. Successful completion of this initiative will increase the total automation coverage to approximately 60% (an additional 20%), thus enhancing outage management and customer reliability.

44KV Distribution System

Oshawa Power's goal for the 44KV system is to establish a robust, automated network with autonomous control of all switching points through seamless integration into existing FLISR automation logic. This is aimed at significantly reducing restoration times, particularly during loss of supply (LOS) events.

2026-2030 Goal

- Motorize and remotely enable the existing manual switches at the 12 remaining normally open tie points, to rapidly restore service during LOS events.

Long Term Goals

- Enable full automation with autonomous control of all switching points, leveraging the existing FLISR automation logic, to limit or even eliminate SAIDI & SAIFI impacts resulting from LOS events

Current Status

Currently, Oshawa Power's 44kV system has switches that need to be operated manually in the field, limiting quick restoration capabilities, especially during LOS events.

An illustrative case was the outage on May 26, 2021, resulting from a Hydro One 230kV supply (T24C Circuit) interruption at the Thornton

Transformer Station. This outage affected 10,554 Oshawa Power customers, lasting approximately 78 minutes and demonstrating the limitations of manual switching and external communications for restoration.

Action Plan (2026-2030)

Oshawa Power will prioritize motorization and remote operation capabilities of manual tie-point switches. This near-term solution significantly reduces restoration time during LOS events through direct remote control from the control room. Upon completing motorization efforts that stretch beyond the 12 tie-points proposed within this DSP, Oshawa Power will initiate plans of installing new load-break devices directly downstream of Hydro One breakers, setting the stage for full automation and integration into the FLISR system. This phased approach ensures both immediate and sustained reliability improvements for Oshawa Power's 44kV distribution system.

Start Date	2026-2030	**Expected In-Service Date**	2026-2030	

Estimated Expenditure Timing

	Q1	Q2	Q3	Q4
2026	$0	$0	$0	$0
2027	$0	$0	$0	$0
2028	$30,000	$250,000	$250,000	$35,000
2029	$30,000	$250,000	$250,000	$35,000
2030	$30,000	$250,000	$250,000	$35,000

Historical and Forecast Capital Expenditures

Historical and forecast expenditures are shown below:

Category	Historical Period				Bridge Year	Test Year	Forecast Period			
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Capital (Gross)	$302	$338	$181	$203	$200	$0	$0	$565	$565	$565
44kV Units	2	2	1	2	3	0	0	4	4	4
13.8kV units	3	0	0	1	0	0	0	5	5	5

Economic Evaluations

Not applicable

Historical Comparative Projects	Oshawa Power has installed 7 - 44 kV and 4 - 13.8kV motorized switching devices in the 2021-2024 historical period. There are 3 more, planned for installation in 2025. This cost excludes extending communication to the remote switch and pole replacement. Replacing existing manual 44kV and 13.8kV switches with motorized switching devices allows for faster redirection of 44kV and 13.8kV power flow through remote operation by a System Control Operator. Operators will be given real-time information about fault conditions and loading. Remote overhead motorized switching devices allow faster restoration to customers as it eliminates the requirement for field staff crews to manually operate the switch.
Investment Priority	This investment has been given a priority of 7 of the 17 ranked material capital expenditures. It will address the need for improving system reliability and operating efficiencies.
Alternatives Analysis	The alternative is to do nothing and maintain existing manual switching systems in place. Maintaining existing levels automation will not improve reliability and may prove difficult to maintain existing reliability in the face of increasing load (e.g., electrification) and increasing instances of adverse weather conditions.
Innovative Nature of the Project	The controller for the SCADA operated motorized switching devices will provide additional functionality and will be provisioned to form a communication backbone to a network of multiple SCADA operated motorized switching devices. This will also make the grid ready for an Advanced Distribution Management System (ADMS) implementation in the future.
Leave to Construct	This project is below 50 kV and therefore Leave to Construct is not required, as per O.Reg. 161/99.
Images, Drawings, Maps, & Other Reference Material	

B. Evaluation Criteria and Information Requirements

Efficiency, Customer Value, Reliability and Safety

Efficiency	The investment objectives are to mitigate the risk of service reliability falling below the performance targets as outlined in OEB's annual scorecard for Oshawa Power. New switches will replace existing manual switches and will improve operational

	effectiveness as motorized switching devices can be operated remotely without the need to send field staff to manually operate the devices.
Customer Value	The net benefits accruing to Customers will be a better service reliability and operational efficiencies.
Reliability	The installation of 44kV and 13.8kV SCADA motorized switching devices will be able to provide faster restoration to customers and mitigate the number of customers affected during a power outage. The installation of remote 44kV and 13.8kV motorized switching devices will reduce SAIDI values as the time to perform switching operations would be greatly reduced compared to sending field staff to perform manual operations.
Safety	Switch design, remote switching functionality and the real-time status information through SCADA will improve safety for the line crew. The installation of automatic and remote motorized switching devices eliminates exposing staff to arc-flashes that may occur due to operating defective overhead switches. The installation will be built in compliance with O. Reg. 22/04 and new standards to ensure safety for the general public.
Investment Need	
Primary Driver	Service Reliability & Operational Efficiency is the main driver for this project. The motorized switching devices provide rapid and efficient operation as staff are not required to be sent to perform manual switching. Outage durations will be reduced through remote switching. The SCADA operated motorized switching devices will also allow monitoring of the switch, which will also help reduce the risk of power interruptions due to in-service equipment failures. The installation of automated motorized switching devices will create a smarter and more responsive grid.
Secondary Driver	There are no secondary drivers.
Information Used to Justify the Investment	This is a continuation of Oshawa Power's smart grid program to expand the use of automated motorized switching devices in the 44kV and 13.8kV distribution systems. Customer preferences

	have indicated that a reliable supply of electricity is foremost in their preferences.

Investment Justification

Demonstrated Utility Practice	The project will address the need for improving system reliability and operating efficiencies. Automated motorized switching devices will create a better OMS that is able to respond quickly to outages and also support fault locating (FL).
Cost-Benefit Analysis	This program will improve system reliability and will provide added visibility to the grid. It will also reduce the operational cost as it will reduce the need to dispatch and engage line crew to perform manual switching operations.
Historical Outcomes	This program is a continuation of the 2021-2025 automation program. There were 11 motorized switching devices installed in the 2021-2024 historical period, with 3 more planned for installation in 2025.

Conservation and Demand Management

Not applicable

A. General Project Information

Project Name	SCADA Equipment upgrade	**Project Number**	SS-05
Investment Category	System Service	**Project Year**	2029
Project Description	During 2029, Oshawa Power will upgrade SCADA equipment that has reached the end of its useful life. Oshawa Power will upgrade SCADA equipment with new technology to enhance cyber security on the OT network and to provide more automation features. This cost will cover upgrade on 4-5 Municipal Stations and will include equipment such as Layer 3 Ethernet Switches (Firewall) and Real Time Automation Controller (RTAC).		
.Start Date	Apr 2029	**Expected In-Service Date**	Jun 2029

Estimated Expenditure Timing

	Q1	Q2	Q3	Q4
2026	$0	$0	$0	$0
2027	$0	$0	$0	$0
2028	$0	$0	$0	$0
2029	$0	$200,000	$150,000	$0
2030	$0	$0	$0	$0

Historical and Forecast Capital Expenditures

Historical and Forecast Program expenditures ($,000) are shown below.

Category	Historical Period				Bridge Year	Test Year	Forecast Period			
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Capital (Gross)	$0	$0	$0	$0	$0	$0	$0	$0	$350	$0

Economic Evaluations

Not Applicable

Historical Comparative Projects

This program is similar to other computer hardware and software replacement programs where the existing assets have reached end of useful life.

Investment Priority	This investment has been given a priority of 6 of the 17 ranked material capital expenditures. The project will enhance cyber security and support system reliability and operating efficiencies.
Alternatives Analysis	The do-nothing option is not economical as the system would continue to run as status quo without additional cyber security enhancements and additional automation features to modernize the grid and improve operational efficiency and reliability.
Innovative Nature of the Project	This project will enhance cyber security of the network and provide more automation features for municipal stations to enhance reliability and operational flexibility.
Leave to Construct	This project is below 50 kV and therefore Leave to Construct is not required, as per O.Reg. 161/99.

Images, Drawings, Maps, & Other Reference Material

B. Evaluation Criteria and Information Requirements

Efficiency, Customer Value, Reliability and Safety

Efficiency	The investment objectives are to mitigate the risk of service reliability falling below the performance targets.
Customer Value	The net benefits accruing to Customers will be a better service reliability and operational efficiency.
Reliability	SAIDI and SAIFI will be improved due to enhanced SCADA performance and additional automation features for the stations.
Safety	SCADA installations will be built in compliance with O. Reg. 22/04 and new utility standards to ensure safety for Oshawa Power crews and the general public.

Investment Need

Primary Driver	Service Reliability & Operational Efficiency is the main driver for this project. Existing assets are at end of useful life.
Secondary Driver	There are no secondary drivers.

Information Used to Justify the Investment	Service Reliability & Operational Efficiency will be improved. Enhanced cyber security and automation will improve operational performance and maintain reliability of supply.
Investment Justification	
Demonstrated Utility Practice	Implementing this project will enhance system cyber security and station automation performance.
Cost-Benefit Analysis	This program will benefit the customer with enhanced automation capability at municipal stations that will maintain/ improve system reliability.
Historical Outcomes	This program is similar to other computer hardware and software replacement programs where the existing assets have reached end of useful life.
Conservation and Demand Management	
Not applicable	

A. General Project Information

Project Name	Non-Wires Solutions	**Project Number**	SS-06
Investment Category	System Service	**Project Year**	2026-2030

Project Description

This is a new program, created in response to the Ontario Energy Board's new Non-Wires Solutions Guidelines. NWS investments consist of distributed energy resources, demand side management programs, and automated controls systems that target areas of anticipating accelerated load growth and aim to enhance the system's flexibility and capacity, positioning it to potentially defer future capital investments in traditional wires solutions, cost-effectively ensuring continued reliability for Oshawa Power's customers. Four NWS investments in the forecast period have been identified:

1. Managed Residential Electric Vehicle (EV) Charging: Incentives for EV owners to shift charging load off-peak.
2. Northwood Business Park and Thornton Transit Electrification Embedded Low Carbon Smart Grids: Collaborate with large customers to address new loads through an embedded smart grid with renewables.
3. Incremental Incentives for Save On Energy Solar Management Systems: Design incentives to leverage residential solar energy storage for load management.
4. Port of Oshawa Battery Energy Storage Solution: Defer or avoid the need for a new TS station through a multi-investor battery energy storage project.

Please review the NWS Business Case in Appendix A for full descriptions of the NWS projects.

Start Date	2026-2030	**Expected In-Service Date**	2026-2030

Estimated Expenditure Timing

	Q1	Q2	Q3	Q4
2026	$0	$86,000	$85,000	$0
2027	$0	$150,000	$150,000	$0
2028	$0	$100,000	$100,000	$0
2029	$0	$34,000	$0	$0
2030	$0	$10,000	$0	$0

Historical and Forecast Capital Expenditures

Historical and Forecast Program expenditures ($,000) are shown below.

Category	Historical Period				Bridge Year	Test Year	Forecast Period			
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Capital (Gross)	$0	$0	$0	$0	$0	$171	$300	$200	$34	$10

Economic Evaluations	The OEB BCA Framework for Addressing Electricity System Needs will be utilized to confirm that the NWS proposal offers a superior benefit/cost solution compared to traditional wires investment strategies. Where applicable, the IESO's Filing Guidelines for Incentives for Electricity Distributors to Use Third-Party DERs as Non-Wires Alternatives will also be used, as third party DERs are an aspect of the proposed projects.
Historical Comparative Projects	There are no comparable NWS projects as these projects fall under a new regulatory policy, released in March 2024.
Investment Priority	This investment has been given a priority of 15 of the 17 ranked material capital expenditures. The investments are justified for the following reasons: • The projects represent a direct response to mandatory Ontario Energy Board policy. • Should they be implemented, each of the projects would result in cost savings for Oshawa's rate base. • The projects drive positive externalities such as enhanced affordability for customers, enhanced reliability for critical loads, carbon reductions and/or grid modernization.
Alternatives Analysis	Traditional wires investment alternatives were considered to compare to the NWS proposal. Please note that the proposed NWSs do not replace any projects in the DSP. The traditional wires investment alternatives are projects that have been deferred but will be required if new loads materialize and if NWSs are not implemented during the DSP timeframe. The NWS Business Case provides significantly more detail regarding this strategy.
Innovative Nature of the Project	The proposed NWS projects are innovative in four ways: 1. NWS investments are a new tool in the distribution system planning process. 2. NWS assets are configured in such a way to drive multiple energy and non-energy benefits for the distributor and the customer(s) impacted. 3. The proposed financing of the NWSs includes cost sharing and external investment via grants

	4. The NWS projects proposed are proactive in nature – they aim to keep deferred projects out of this DSP timeline.
Leave to Construct	Not applicable.

Images, Drawings, Maps, & Other Reference Material

Please see the NWS Business Case in Appendix A and section 5.3.5 of the DSP for more detailed information about the proposed NWS.

B. Evaluation Criteria and Information Requirements

Efficiency, Customer Value, Reliability and Safety

Efficiency	The NWSs address the identified distribution system needs at a superior benefit/cost value than traditional wires solution. In some cases, NWSs can also be implemented in a shorter timeline, or without significant LDC staff efforts (for example, a managed charging program would require less LDC staff involvement than scaling-up secondary services and transformers to support EV loads).
Customer Value	The NWSs address the identified distribution system needs at a superior benefit/cost value than traditional wires solution. In many cases, NWSs provide benefits directly to customers, in addition to overall cost-savings at the utility level. Such benefits can include incentives, or programs that support lower bills through demand side management.
Reliability	The NWSs will be implemented in a manner that maintains utility security of supply, safety and reliability. Some portions of the NWS solutions implemented may directly target reliability increases and/or redundancy measures for new critical loads. Where third party ownership of DERs that will supply resources is contemplated, Oshawa Power will look to the IESO's resource contracting standards to ensure reliability needs are appropriately managed from a legal perspective.
Safety	The NWSs shall be implemented in a manner that maintains utility security of supply, safety and reliability. Where third party

	resources are contracted, Oshawa Power will ensure it has sufficient visibility and protections in place to ensure safety.
Investment Need	
Primary Driver	Service Reliability & Operational Efficiency is the main driver for this project.
Secondary Driver	The secondary driver is to achieve compliance with the new Ontario Energy Board guidelines.
Information Used to Justify the Investment	Information to justify the investment will include: • An identified system requirement of $2 million or more. • The results of a binary screening indicate that the load can be addressed with an NWS. • Where applicable, an Offer to Connect economic evaluation for the traditional service approach. • Results from a benefit cost analysis. • Other information about the non-energy costs and benefits of the project. • Information regarding customer preferences about the project. • Where applicable, results from the IESO's Filing Guidelines for Incentives for Electricity Distributors to Use Third-Party DERs as Non-Wires Alternatives.
Investment Justification	
Demonstrated Utility Practice	The NWS solution shall be implemented in a manner that maintains utility security of supply, safety and reliability.
Cost-Benefit Analysis	Using the Distribution System Test, the NWS solution will demonstrate a benefit/cost ratio greater than or equal to 1. The proposed NWS will have a positive net present value (i.e., present value of benefits minus present value of costs). The Energy System Test may, where applicable also be done and yield at least the same outcomes as the DST.
Historical Outcomes	There are no previous projects of this nature.

Conservation and Demand Management

Oshawa Power plans to participate in the new eDSM framework announced by the Province of Ontario and the IESO in January of 2025. The organization will deploy NWSs that may include conservation and demand management programs, as well as load management programs that achieve system needs that are different and non-duplicative of the IESO's programming.

A. General Project Information

Project Name	Enterprise Server Hardware/Software replacement	**Project Number**	GP-04
Investment Category	General Plant	**Project Year**	2026-2030
Project Description	This capital program comprises ongoing business requirements to maintain and upgrade critical IT infrastructure at Oshawa Power, including network hardware, phone systems, server infrastructure, and uninterruptible power supply (UPS) systems. These investments are essential for maintaining Oshawa Power's operational capabilities and ensuring reliable service delivery to its customers. Oshawa Power's IT hardware and software program encompasses several critical components that support the utility's operations. The network hardware replacement component ensures continuous maintenance and upgrades to keep network infrastructure current and secure. The phone system refresh addresses the need to replace obsolete telecommunication systems to maintain effective communication channels. The server infrastructure refresh follows a five-year cycle for hardware replacement, while ongoing server upgrades provide annual maintenance for hardware infrastructure updates. Additionally, the UPS upgrade component involves the replacement of existing UPS infrastructure to ensure continuous power supply to critical systems. These investments are critical to maintaining Oshawa Power's operational efficiency, ensuring cyber security, and providing reliable service to customers. Oshawa Power follows industry best practices for hardware lifecycles, typically 5 years for IT hardware and 3 years for software, ensuring optimal performance and security while managing costs effectively.		
Start Date	2026-2030	**Expected In-Service Date**	2026-2030

Estimated Expenditure Timing

	Q1	Q2	Q3	Q4
2026	$0	$116,000	$0	$0
2027	$0	$66,000	$0	$0
2028	$0	$300,000	$291,000	$0
2029	$0	$116,000	$0	$0
2030	$0	$66,000	$0	$0

Historical and Forecast Capital Expenditures	Historical and Forecast Program expenditures ($,000) are shown below.

Category	Historical Period				Bridge Year	Test Year	Forecast Period			
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Capital (Gross)	$0	$0	$0	$0	$0	$116	$66	$591	$116	$66

Economic Evaluations	Not Applicable
Historical Comparative Projects	There are no historical costs for this program. Capital purchases are influenced by ongoing business requirements, supporting new and evolving software applications, ensuring network and data security, and managing risk. Due to the nature of the projects within this program and the fact that work is completed on an as-needed basis, there are no good cost comparators available, and a comparison of historical projects and future projects is not indicative of any particular trend.
Investment Priority	This investment has been given a priority of 17 of the 17 ranked material capital expenditures. This investment is necessary to maintain operational capabilities and ensure system security. The prioritization process considers several key factors including operational impact, security requirements, regulatory compliance, risk mitigation, cost effectiveness, and system reliability. These factors are evaluated comprehensively to ensure that investments align with Oshawa Power's strategic objectives and maintain the highest standards of service delivery.
Alternatives Analysis	Oshawa Power considered the following alternatives: **i. Do Nothing:** This option was rejected as it would expose Oshawa Power to significant risks including increased security vulnerabilities, system reliability issues, potential operational failures, and non-compliance with regulatory requirements. This approach would ultimately compromise service quality and increase long-term costs. **ii. Delayed Implementation:** This option was evaluated but ultimately rejected due to the increased risk of system failure, higher maintenance costs, security vulnerabilities, and operational inefficiencies. Delaying necessary upgrades would create additional risks and potentially higher costs in the future. **iii. Recommended Option**: Planned Implementation: This option was selected as it provides the optimal balance of cost and risk management. The planned approach ensures a structured implementation of system

	updates, maintained security compliance, operational efficiency, and reliable service delivery. This strategy allows Oshawa Power to manage its resources effectively while maintaining high service standards.
Innovative Nature of the Project	Not Applicable
Leave to Construct	This project is below 50 kV and therefore Leave to Construct is not required, as per OEB.Reg. 161/99.

Images, Drawings, Maps, & Other Reference Material

The following is a list of investments covered under this program.

Enterprise/Hardware / Software	2026	2027	2028	2029	2030
Networking Hardware Replacement	$36,000	$36,000	$36,000	$36,000	$36,000
Phone System Refresh	$0	$0	$75,000	$0	$0
Server Infrastructure Refresh	$0	$0	$450,000	$0	$0
Server Upgrades	$30,000	$30,000	$30,000	$30,000	$30,000
UPS Upgrade (HO)		$0	$0	$50,000	$0
UPS Upgrade (MS9)	$50,000	$0	$0	$0	$0

B. Evaluation Criteria and Information Requirements

Efficiency, Customer Value, Reliability and Safety

Efficiency	Oshawa Power's strategic investment in hardware infrastructure drives remarkable operational excellence across the organization. The modernized technology platform accelerates staff performance while enabling around-the-clock service delivery to customers. Through careful implementation of industry-leading practices, Oshawa Power maximizes space utilization and minimizes energy consumption. This technological foundation supports the seamless integration of advanced applications, enhanced business capabilities, and robust cybersecurity measures. The comprehensive approach to infrastructure management results in decreased maintenance requirements, streamlined resource allocation, and substantial long-term cost benefits for the organization.

Customer Value	Information Technology stands as the cornerstone of Oshawa Power's service excellence, enabling superior customer support through advanced hardware systems and rigorous cybersecurity measures. The strategic deployment of modern technology empowers staff members to deliver swift, efficient responses to customer needs while safeguarding sensitive information. Through comprehensive security protocols, Oshawa Power maintains the highest data privacy and system integrity standards, ensuring reliable service delivery for all customers. The enhanced communication channels and streamlined service capabilities result in an elevated customer experience, characterized by faster response times and dependable service quality. This technological foundation reinforces Oshawa Power's dedication to protecting customer interests while delivering exceptional utility services to the community.
Reliability	Oshawa Power's commitment to service reliability is demonstrated through continuous enhancement of Information Technology systems and comprehensive security measures. The implementation of advanced security protocols, including state-of-the-art firewalls and monitoring equipment, stems from rigorous external audit recommendations. A dedicated offsite disaster recovery facility ensures uninterrupted service delivery during unexpected events or equipment failures. This multi-layered approach to system maintenance and backup capabilities minimizes service disruptions through preventative measures and swift recovery procedures. The strategic deployment of robust infrastructure, combined with proactive system monitoring, establishes a dependable foundation for consistent, reliable service delivery to the community.
Safety	The safety of community members and workforce personnel remains paramount through Oshawa Power's advanced network infrastructure. Remote system monitoring and administration capabilities enable swift identification and resolution of potential safety concerns. The fortified security measures and enhanced surveillance systems establish a foundation for rapid emergency response protocols. Through sustained technological advancement, Oshawa Power maintains secure communication channels vital for safe utility operations while safeguarding sensitive customer information. This comprehensive approach to infrastructure management reinforces Oshawa Power's

	dedication to creating a secure operational environment for both the public and workforce teams.
Investment Need	
Primary Driver	The strategic modernization of Information Technology infrastructure represents a fundamental investment necessity for Oshawa Power. The replacement of end-of-life equipment and enhanced cybersecurity measures establish a robust foundation for operational excellence. This systematic infrastructure renewal enables Oshawa Power to maintain regulatory compliance while delivering safe, efficient service that aligns with customer expectations. The strategic deployment of updated network infrastructure and associated hardware components strengthens Oshawa Power's capacity to execute core operations effectively.
Secondary Driver	The evolving technological landscape necessitates continuously adapting Oshawa Power's digital infrastructure to maintain operational excellence. Oshawa Power optimizes resource allocation by strategically implementing emerging technologies while enhancing operational capabilities. Modernizing technical systems enables effective risk management practices while optimizing costs across all operational areas. Oshawa Power maintains alignment with technological advancements and establishes a robust foundation for sustained operational success and service excellence.
Information Used to Justify the Investment	A systematic five-year hardware lifecycle refresh strategy guides Oshawa Power's technology investment decisions. The organization executes targeted equipment replacements through asset monitoring and documentation at optimal intervals. The ongoing comprehensive audit of Information Technology infrastructure provides valuable insights for future investment planning and resource allocation. Regularly evaluating emerging cybersecurity requirements enables Oshawa Power to identify and prioritize essential system upgrades. This data-driven approach to infrastructure management ensures timely compliance with industry standards while maintaining operational effectiveness.

Investment Justification

Demonstrated Utility Practice	In alignment with established industry practices, Oshawa Power manages Information Technology infrastructure through a strategic five-year lifecycle framework. Classifying hardware components as critical business assets ensures consistent performance and operational reliability. A comprehensive approach to system updates guarantees alignment with current cybersecurity standards while addressing evolving organizational requirements. Oshawa Power maintains technology standards that support essential business functions through systematic hardware monitoring and periodic assessments. This structured methodology for infrastructure management demonstrates Oshawa Power's commitment to industry-leading practices in utility operations.
Cost-Benefit Analysis	Rigorous financial evaluation guides all technology acquisitions at Oshawa Power, ensuring adherence to established corporate procurement standards. The strategic assessment of multiple vendor proposals facilitates cost-effective purchasing decisions while maintaining timely project delivery.
Historical Outcomes	Oshawa Power IT hardware and software assets have been successfully upgraded/replaced over previous periods as planned for.

Conservation and Demand Management

Not applicable

A. General Project Information

Project Name	ERP Software	**Project Number**	GP-05
Investment Category	General Plant	**Project Year**	2027

Project Description

Oshawa Power's current Microsoft Dynamics GP Enterprise Resource Planning (ERP) system will need to be replaced with a new solution. The existing ERP system primarily serves as a Financial Information System (FIS) supporting core business functions, including general ledger management, financial accounting, payroll, accounts payable, accounts receivable, billing, purchasing, and inventory management. Microsoft announced the discontinuation of Dynamics GP support by late 2029, necessitating a system replacement to maintain operational reliability and security. The new ERP implementation will maintain existing functionality while adding enhanced budgeting, procurement, and warehouse management features. The project includes integration with other critical business systems, including the Customer Information System (CIS), Geo-spatial Information System (GIS), Human Resource Information System (HRIS), and Work Estimating and Planning System. These investments are essential for maintaining Oshawa Power's operational capabilities, ensuring system security, and providing reliable service delivery to customers.

The capital costs associated with a cloud-based solution are captured under this program. It includes costs associated with interfacing a cloud solution with on-premise systems, such as CIS and Dayforce, and for any customizations required to meet niche industry needs, such as fixed asset modules.

Please refer to the business case on "Oshawa Power Enterprise Resource Planning (ERP) Upgrade Project in Appendix A.

Start Date	Apr 2027	**Expected In-Service Date**	Sep 2027

Estimated Expenditure Timing

	Q1	Q2	Q3	Q4
2026	$0	$0	$0	$0
2027	$0	$250,000	$250,000	$0
2028	$0	$0	$0	$0
2029	$0	$0	$0	$0
2030	$0	$0	$0	$0

Historical and Forecast Capital Expenditures	Historical and Forecast Program expenditures ($000) are shown below.

Category	Historical Period				Bridge Year	Test Year	Forecast Period			
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Capital (Gross)	$0	$0	$0	$0	$0	$0	$500	$0	$0	$0

Economic Evaluations	Not Applicable
Historical Comparative Projects	There is no direct comparable ERP software program within the current and previous DSP historical period. Historical software acquisition costs (e.g. CIS acquisition) have varied year over year in accordance with specific needs identified and works undertaken. Capital purchases are influenced by ongoing business requirements, supporting new and evolving software applications, ensuring network and data security, and managing risk. Due to the nature of the projects within this program and the fact that work is completed on an as-needed basis, there are no good cost comparators available, and a comparison of historical projects and future projects is not indicative of any particular trend.
Investment Priority	This investment has been given a priority of 9 of the 17 ranked material capital expenditures. The prioritization process considers several key factors: operational impact, security requirements, regulatory compliance, risk mitigation, and system reliability. These factors are evaluated thoroughly to ensure that investments align with Oshawa Power's strategic objectives while upholding high service standards.
Alternatives Analysis	Oshawa Power considered the following alternatives: **i. Do Nothing:** This option was rejected as it would expose Oshawa Power to significant operational risks after Microsoft's end-of-support date in 2029. Continuing with an unsupported system would create unacceptable security vulnerabilities and reliability risks. **ii. New Like-for-like ERP (with Enhancements):** This is the recommended option, providing a balanced approach to system replacement while adding strategic enhancements. This option addresses immediate needs while enabling future operational improvements through enhanced functionality and system integration. **iii. New Full Suite ERP:** This option was evaluated but rejected due to significantly higher costs (estimated at ten times the recommended

	option), greater project complexity, and resource constraints. The option would have replaced multiple existing systems but was deemed too resource-intensive for the current organizational capacity. For further details on the alternative analysis, please refer to Oshawa Power's business case in Appendix A.
Innovative Nature of the Project	Not Applicable
Leave to Construct	This project is below 50 kV and therefore Leave to Construct is not required, as per OEB.Reg. 161/99.

Images, Drawings, Maps, & Other Reference Material

Please refer to the business case on "Oshawa Power Enterprise Resource Planning (ERP) Upgrade Project" in Appendix A.

B. Evaluation Criteria and Information Requirements

Efficiency, Customer Value, Reliability and Safety

Efficiency	The ERP replacement project drives operational excellence by modernizing core business systems. The new platform will facilitate increased process automation, enhanced internal controls, and minimized manual tasks. Integration with other business systems will optimize data flow and lessen duplicate efforts. This solution supports Oshawa Power's Business Transformation initiative to modernize business management through technological enablement.
Customer Value	The new ERP system enhances customer value by improving business process efficiency, strengthening financial controls, and ensuring more reliable service delivery. Enhanced integration with customer-facing systems will facilitate better customer billing and account adjustment management. The project guarantees the ongoing reliable operation of core business functions that support customer service delivery.
Reliability	Integrating modern technology with comprehensive vendor support will improve system reliability. The project mitigates the risks of using an unsupported legacy system while introducing new process automation and system integration features.

	Contemporary security measures and frequent updates will ensure ongoing system reliability and data protection.
Safety	The new ERP system will incorporate modern security standards and controls to safeguard sensitive business and customer information. Integration with other operational systems will facilitate safe and efficient business operations through enhanced data accuracy and process automation.
Investment Need	
Primary Driver	The primary driver is the vendor's announcement to cease support for the current Microsoft Dynamics GP system by September 2029. Running an unsupported system would pose significant business continuity and security risks.
Secondary Driver	The secondary driver is business transformation and modernization. The new system will facilitate greater process automation, enhance controls, and improve integration with other business systems to support operational efficiency.
Information Used to Justify the Investment	The decision to replace the ERP system stems from a comprehensive analysis of various factors impacting business operations. Microsoft's formal announcement regarding the end of support for Dynamics GP establishes a clear timeline for system replacement. A detailed assessment of operational risks tied to unsupported systems informs the implementation schedule. Analyzing current system limitations and manual processes reveals opportunities for efficiency improvements through the new system. Assessing integration requirements with other business systems guarantees that the chosen solution will support end-to-end business processes. Reviewing the organizational resource capacity and implementation timelines facilitates effective project planning and execution. This systematic approach to infrastructure management ensures timely compliance with industry standards while maintaining operational effectiveness.
Investment Justification	
Demonstrated Utility Practice	The approach aligns with utility industry practices for managing critical business systems. The project follows a structured

	implementation strategy with defined phases for vendor selection, system implementation, and integration. The chosen option reflects a sensible balance between cost, risk, and organizational capacity.
Cost-Benefit Analysis	Rigorous financial evaluation guides the ERP system replacement project, ensuring compliance with established corporate procurement standards. The recommended option offers optimal value by mitigating risks and improving operations. A strategic assessment of various implementation approaches enables cost-effective decision-making while ensuring timely project delivery. The staged implementation strategy aligns with organizational capacity and provides incremental benefits through process automation, enhanced controls, and system integration. This balanced approach to system replacement guarantees sustainable long-term value while managing implementation costs and risks.
Historical Outcomes	Oshawa Power IT software assets have been successfully acquired over previous periods as planned for.

Conservation and Demand Management

Not applicable

A. General Project Information

Project Name	Fleet Replacement Program	**Project Number**	GP-17
Investment Category	General Plant	**Project Year**	2026-2030
Project Description	Oshawa Power plans to acquire two (2) aerial devices (bucket trucks), one (1) Radial Boom Derrick (RBD) (digger truck), six (6) light duty vehicles (pick-ups and panel van) and one (1) pole trailer. The existing vehicles have reached or are nearing end-of-service life based on an assessment of age, condition, and increased maintenance and repair costs. Oshawa Power's assessment of its fleet complement, where applicable, is aligned with its operational themes – Safety, Reliability, Customer Focus, Stewardship, and Innovation. A systematic approach is employed to determine fleet replacement decisions, emphasizing diligent maintenance practices and comprehensive record-keeping. Internally, the company tracks fleet utilization on a monthly basis, monitors operational costs associated with each vehicle, and assesses life-to-date mileage against established renewal thresholds. This diligent internal tracking ensures that fleet vehicles are evaluated objectively for their economic viability and reliability. Over a 3 year historical period (2022-2024), overall maintenance spending on fleet increased by 13%. Oshawa Power's fleet includes two relatively newer specialized utility vehicle, an aerial device (bucket truck) and a Radial Boom Derrick (RBD), which served as direct comparators to their older counterparts. Analysis revealed that the older vehicles incurred approximately $28,000 in additional operational costs per truck per year. This cost differential formed a key basis for the decision to proceed with the proposed heavy-duty fleet replacements. Additionally, Oshawa Power supplements its internal assessments with external evaluations performed by qualified third-party specialists. These evaluations encompass required maintenance reviews to maintain vehicles in optimal working condition without compromising safety or reliability. Specialized utility vehicles, such as bucket trucks, undergo additional mandated assessments, including dielectric tests, to confirm their safety standards for working near energized infrastructure.		

	While these external assessments effectively identify necessary repairs and maintenance actions, they typically do not determine fleet replacement timing on their own. Consequently, Oshawa Power integrates multiple factors when evaluating fleet replacements. Key considerations include escalating operational costs, vehicle age, accumulated mileage, utilization rates, and environmental impact (CO2 emissions). Oshawa Power aligns its fleet management practices with industry best practices, ensuring strategic and economically sound replacement decisions that prioritize both safety and operational efficiency. The small bucket truck is being procured to enhance operational efficiency and safety in densely constructed or space-constrained areas where full-sized bucket trucks cannot be effectively deployed. This vehicle will allow crews to perform aerial work without the need to climb poles, thereby reducing safety risks and improving productivity in urban or limited-access environments. Investment amounts and timing are shown in the table below. All investments, except for the small bucket truck, are replacements. The small bucket truck is a new addition to the fleet.
Start Date	2026-2030
Expected In-Service Date	2026-2030

Estimated Expenditure Timing

	2026	2027	2028	2029	2030
1 x 50’ Aerial Device (Replaces Tr.# 19)	$200,000	$400,000			
1 x RBD (Replaces Tr.# 12)		$200,000	$400,000		
1 x 42’ Small Aerial Device (New)			$100,000	$300,000	
5 x Light-Duty Vehicles (Replace Tr. #27, 68, 69, 83, 84)				$160,000	$240,000
1 x Panel Van (Replaces Tr.# 44)	$150,000				

	1 x Pole Trailer (Replaces Tr. #531)	$150,000				

Historical and Forecast Capital Expenditures

Historical and Forecast Program expenditures ($,000) are shown below.

Category	Historical Period				Bridge Year	Test Year	Forecast Period			
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Capital (Gross)	($4)	$438	$767	$61	$150	$500	$600	$500	$460	$240

Economic Evaluations

Not applicable.

Historical Comparative Projects

Capital expenditure within this program varies from year to year depending on the type of fleet required to be replaced as per the Fleet Management Policy and up-to-date maintenance records.

- Investments in 2022 included the finalization to purchase one (1) 55' single bucket aerial device and one (1) 900 series RBD
- Investments in 2023 included receiving one (1) 55' aerial device and one (1) 900 series RBD (those from 2022), as well as the purchase of four (4) hybrid light-duty half-tonne vehicles.
- Investments in 2024 included the purchase of one (1) a half-tonne light-duty vehicles.
- Investments in 2025 include procurement of one (1) forklift and one (1) trailer

Investment Priority

This investment has been given a priority of 13 out of the 17 ranked material capital expenditures. Without proper fleet maintenance program which schedules proactive inspections and preventative maintenance work under controlled circumstances, relying only on reactive maintenance leads to unplanned vehicle downtime thus increasing unnecessary and avoidable risks to safety, reliability, while increasing costs and delaying completion of work or connections of customers.

Alternatives Analysis

Do nothing - This option involves extending the use of the existing vehicle(s) through ongoing maintenance and reactive repairs. Oshawa Power has noticed increasing frequency and costs of repairs. Additionally, extended downtime due to mechanical issues would be operationally

	inefficient. This approach is not aligned with Oshawa Power's commitment to cost efficiency and reliable service delivery and is therefore not considered a viable long-term solution. Reduced vehicle specialization – Selecting a vehicle with reduced specifications or capabilities would limit its functional utility, particularly in supporting complex field operations. This would affect service reliability and diminish field crew productivity by restricting the types of tasks that can be performed efficiently. Moreover, this approach is misaligned with Oshawa Power's growth-oriented strategy, which anticipates increasing system demands, including the installation of larger poles, transformers, and associated infrastructure. Meeting these needs requires continued investment in specialized fleet assets to ensure safe and effective execution of system improvements. Purchase Used Vehicle – Acknowledging Oshawa Power's statutory and regulatory obligation to its customers in providing safe and reliable power, purchase of used vehicles is not an optimal option for this investment. Used vehicles present reliability concerns, especially for specialized utility functions where performance and safety are paramount. Furthermore, used vehicles generally lack warranty coverage and do not lend themselves to competitive procurement processes, reducing transparency and lifecycle value.
Innovative Nature of the Project	All vehicles that routinely leave the yard are equipped a system that collects GPS, speed, and distance data for analytical and safety use. All new vehicles will have this system installed to be able to analyze vehicle use and any safety issues that arise.
Leave to Construct	This project is below 50 kV and therefore Leave to Construct is not required, as per O.Reg. 161/99.
Images, Drawings, Maps, & Other Reference Material	

B. Evaluation Criteria and Information Requirements

Efficiency, Customer Value, Reliability and Safety

Efficiency	Ensuring vehicles are safe and reliable during daily operation supports and achieves operational efficiencies.

Customer Value	Having a reliable fleet avoids any delays in meeting customer service requests or outage response.
Reliability	Having a fleet that is constantly available ensures that necessary reactive and maintenance work can be completed to support the reliability of the system.
Safety	Planned replacement of fleet mitigates any significant vehicle downtime or potential catastrophic failure which may threaten the safety of employees and the public.
Investment Need	
Primary Driver	The driver of this project is General Plant Investment Category associated with addressing the risk of vehicle failure due to asset's end of TUL and operational effectiveness.
Secondary Driver	There are no secondary drivers.
Information Used to Justify the Investment	Fleet requirements are evaluated based on usage data, asset condition, and operational costs, helping to identify where investments are to be focused. Vehicles to be replaced have completed Fleet Replacement Request Forms.
Investment Justification	
Demonstrated Utility Practice	To effectively manage Fleet assets, Oshawa Power follows a Fleet Management Policy which outlines the roles and responsibilities of the Fleet Management Committee and the condition criteria that is reviewed for replacement considerations.
Cost-Benefit Analysis	Fleet vehicle replacement is based on criteria mentioned above where continued operational cost is determined to exceed the cost of replacement.
Historical Outcomes	Fleet units were replaced in the 2021-2025 historical period as noted in Section A.
Conservation and Demand Management	
Not Applicable	

Appendix C

Asset Condition Assessment and Options Analysis Report

Please note that METSCO added a disclaimer on page 4 of their report that this document contains proprietary information that is confidential to METSCO and is delivered to the recipient on the condition that it is used exclusively to evaluate the technical contents therein, and that it shall not be disclosed, duplicated, or reproduced in whole or in part, without prior written consent of an authorized representative of METSCO. However, Oshawa Power has received written permission to share this material publicly.


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ASSET CONDITION ASSESMENT REPORT 2023

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Executive Summary

Context of the Study

Oshawa PUC Networks Inc. ("OPUCN") engaged METSCO Energy Solutions Inc. ("METSCO) to develop Health Index Formulations ("HIFs") and conduct an Asset Condition Assessment ("ACA") on the utility's distribution and substation assets to improve awareness of system health demographics in preparation for their upcoming Cost of Service application in 2025. To assist OPUCN with further asset condition data integration efforts, Section 8 of this report contains a set of recommendations for the utility's management to consider going forward.

Scope of the Study

The ACA methodology comprising this study assessed multiple categories of assets within OPUCN'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
  - Wood poles;
  - Concrete poles;
  - Steel poles;
  - Overhead primary conductors;
  - Underground primary cables;
  - Pole-mount transformers;
  - Pad-mount transformers;
  - Vault transformers;
  - Overhead switches;
  - Smart switches;
  - Distribution switchgears;
  - Cut-out arrestors;
  - Elbow connectors;
  - Reclosers; and
  - Vaults & manholes.
- Station assets
  - Power transformers;
  - Circuit breakers;
  - Switchgears;
  - Relays & RTUs;
  - Battery & chargers;
  - Egress cables;
  - Fences;
  - Buildings; and
  - Bus structures.

Methodology and Findings

For all asset classes that underwent assessment, METSCO used a consistent scale of asset health from Very Good to Very Poor. The numerical Health Index ("HI") corresponding to each condition category serves as an indicator of an asset's remaining life, expressed as a percentage. Table E-1 presents the HI range corresponding to each condition score and the corresponding implications for recommended follow-up actions for OPUCN.

Table E-1: HI Ranges and Corresponding Implications for the Asset Condition Assessment

Score (%)	Condition Category	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 select components to be managed through normal maintenance	Normal Maintenance
[50-70)	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; start the planning process for possible remedial work or replacement – station assets are critical to the utility warranting remedial planning beginning at the fair stage of the asset lifecycle
[30-50)	Poor	Widespread serious deterioration across multiple components	Plan to replace or rehabilitate, consider the risk and consequences of failure
[0-30)	Very Poor	Extensive serious deterioration – an asset has reached its end-of-life	The asset has reached its end-of-life; immediately assess risk and replace or refurbish based on assessment

Using this scale, METSCO calculated the HI for the assets using the applicable and available "condition parameters". Each condition parameter has its own sub-scale of assessment and a weighting contribution that represents the percentage in the overall HI made up by the parameter. The Data Availability Index ("DAI") represents the weighted percentage of condition parameters with valid data.

Using this methodology, METSCO calculated HI results for every asset class in the scope of the assessment. The ACA results are summarized in Figure E - 1 and Figure E - 2. Section 4 of this report provides an extensive discussion of the HI calculations for each asset class, outlines the assumptions underlying our interpretation of the data provided by OPUCN, and provides recommendations for future enhancements.

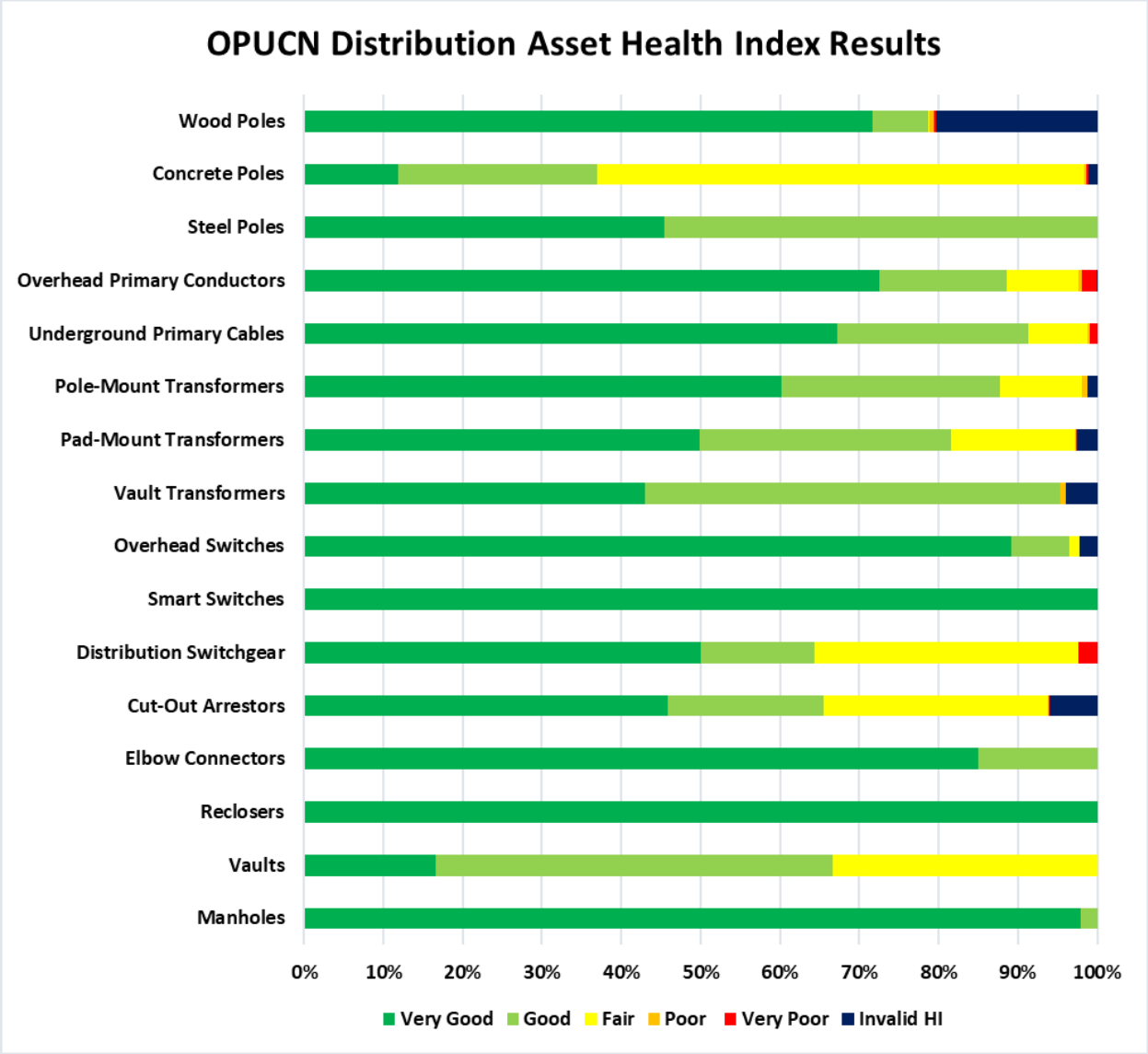


Figure E - 1: Distribution ACA Results

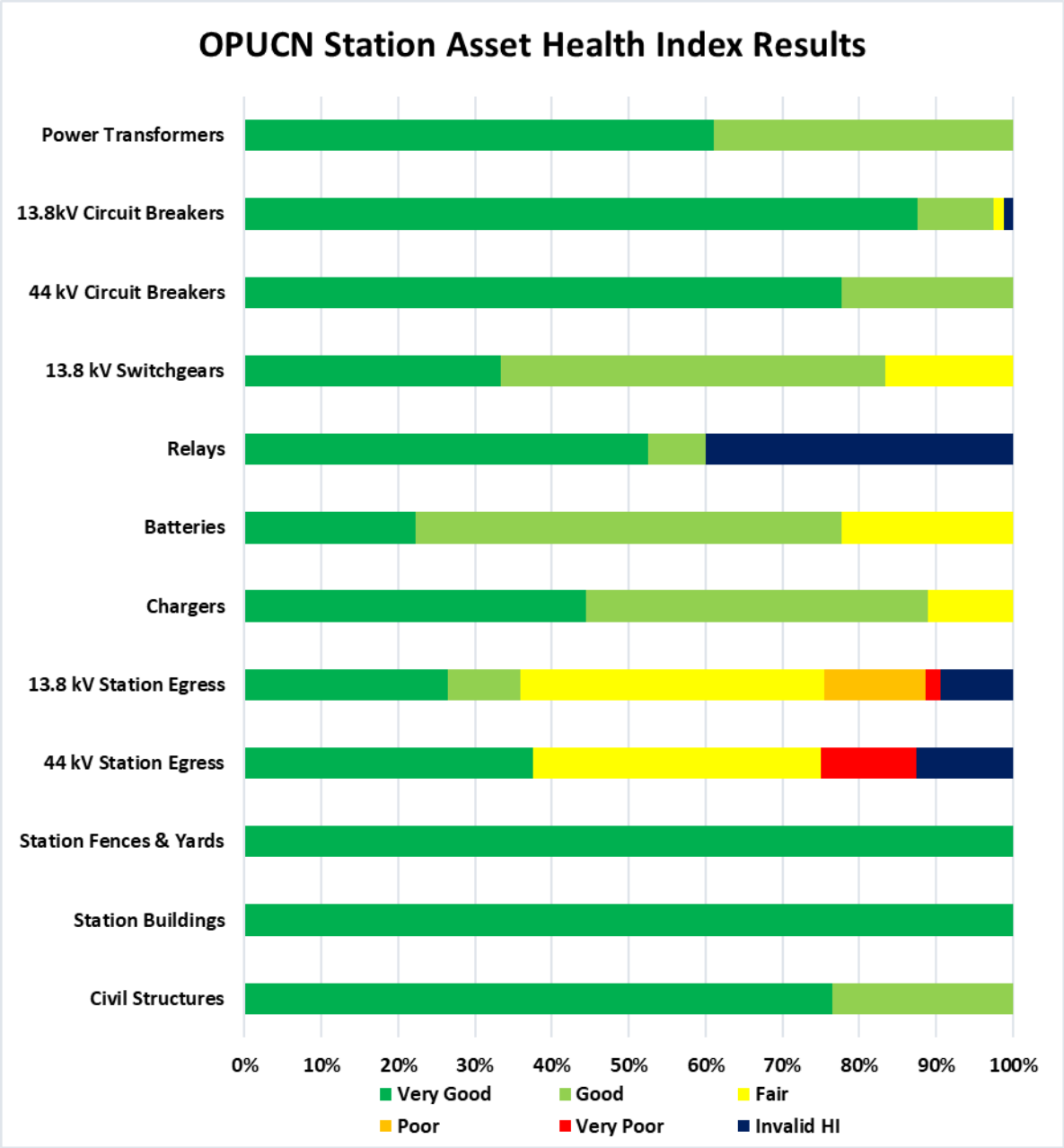


Figure E - 2: Station ACA Results

In a 2010 study by Kinectrics Inc. called the *Asset Depreciation Study for the Ontario Energy Board*, minimum, maximum, and Typical Useful Life ("TUL") values were established that have created a basis for planning and depreciation assumptions. The HI for each asset is used to calculate an HI-suggested age. From this the asset age is adjusted to get the effective age. This can then be used to find the remaining life.

The purpose of the risk evaluation is to first assess and quantify (or qualify) the potential risks to both OPUCN and its customers in the event of a capacity deficit, and then outline potential mitigation measures that could partially or completely mitigate these risks. The following definitions are used:

- Probability is the likelihood of an event occurring;
- Consequence is the outcome or impact of that event; and
- Risk is the product of the probability that an event will materialize multiplied by the consequence of that event.

METSCO calculated the impact for the assets using the applicable and available "risk factors". Each risk factor has its own sub-scale of assessment and a weighting contribution that represents the percentage in the overall impact made up by the parameter.

The averaged HI scores and Impact scores were then applied to the risk evaluation grid in Table E-2 to get the Risk Score. If an asset has an invalid HI, then a ratio of age over TUL is used to determine the probability. This is applied to Table E-3.

Table E-2: Condition-Based Risk Evaluation Grid

		HI Score				
		Very Good	**Good**	**Fair**	**Poor**	**Very Poor**
Impact Score	**Very High**	Moderate	Moderate	High	Extreme	Extreme
	High	Low Mod	Moderate	High	Extreme	Extreme
	Moderate	Low Mod	Moderate	Moderate	High	Extreme
	Low	Low	Low Mod	Moderate	Moderate	High
	Very Low	Low	Low	Low Mod	Low Mod	High

Table E-3: Age Based Risk Evaluation Grid

		Age/TUL				
		[0-33)%	**[33-67)%**	**[67-100)%**	**[100-133)%**	**>=133%**
Impact Score	**Very High**	Moderate	Moderate	High	Extreme	Extreme
	High	Low Mod	Moderate	High	Extreme	Extreme
	Moderate	Low Mod	Moderate	Moderate	High	Extreme
	Low	Low	Low Mod	Moderate	Moderate	High
	Very Low	Low	Low	Low Mod	Low Mod	High

METSCO recommends asset replacements over the next five years for assets in Poor or Very Poor condition, assets classified as high or extreme risk, and assets that are past their economic end of life. For distribution assets, METSCO recommends the number of assets which should be replaced each year to eliminate the Poor and Very-Poor condition assets and high-risk assets from OPUCN's system. For stations, specific assets are identified for intervention between 2024 and 2028. A summary of recommended replacements for 2026-2030 can be found in Table E-4 and Table E-5 for distribution and station assets respectively. A summary of recommended station refurbishments for 2026-2030 can be found in Table E-6. OPUCN's Five-Year Forecast Capital Investment Plan has the scope of 2026-2030 and is part of their Distribution System Plan ("DSP"). Section 7 can be referenced for the detailed replacement plan.

Table E-4: Distribution Assets Recommended for Replacement

Asset Class	Unit	Assets to Replace Each Year				
		2026	2027	2028	2026	2030
Wood Poles	#	82	81	81	81	81
Concrete Poles	#	22	23	22	23	22
Overhead Conductors	m	6,081	6,081	6,081	6,081	6,081
Underground Cables	m	6,432	6,433	6,432	6,433	6,432
Pole-Mount Transformers	#	26	26	26	26	26
Pad-Mount Transformers	#	55	55	55	55	55
Vault Transformers	#	2	2	2	2	2
Overhead Switches	#	1	2	1	2	1
Distribution Switchgears	#	2	3	2	3	2
Cut-Out Arrestors	#	11	11	11	11	11

Table E-5: Station Assets Recommended for Replacement

Asset Class	Asset ID	Recommended Replacement Year
Switchgears	MS11	2026
Relays	MS7T1	2026
	MS5T1	2027
	MS5T2	2027
44-kV Egress Cables	10T1	2026
	15T2	2027
13.8-kV Egress Cables	10F3	2026
	10F4	2026
	10F6	2026
	15F1	2027
	15F3	2027
	15F6	2027
	14F1	2028

Table E-6: Station Assets Recommended for Refurbishment

Asset Class	Asset ID	Recommended Replacement Year
Switchgears	MS10	2027
	MS15	2028
	MS13	2029

Current Health Index Maturity and Continuous Improvement

On top of a condition assessment and risk analysis of OPUCN's major distribution and station asset classes, this report provides OPUCN with a broad range of recommendations with respect to specific types of information that it may choose to collect and the metrics it may deploy to enhance it's AM analytics. Detailed recommendations can be found in Section 8.

Keeping records of 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. METSCO recommends that OPUCN begin transitioning their inspection records to a digital collection format. This will help OPUCN 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.

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List of Acronyms, Abbreviations, and Initialisms

The following acronyms, abbreviations, and initialisms are used within the Asset Condition Assessment report:

Acronym	Definition
ACA	Asset Condition Assessment
AM	Asset Management
DAI	Data Availability Index
DGA	Dissolved Gas Analysis
eHouse	Electrical House
EOL	End of Life
FP	Failure Probability
GIS	Geographic Information System
HI	Health Index
HIF	Health Index Formulation
IR	Infrared
ISO	International Organization for Standardization
LDC	Local Distribution Company
METSCO	METSCO Energy Solutions Inc.
MS	Municipal Substation
OPUCN	Oshawa PUC Networks Inc.
OQ	Oil Quality
OH	Overhead
PF	Power Factor
SAMP	Strategic Asset Management Plan
TUL	Typical Useful life
UG	Underground

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 Oshawa PUC Network Inc. ("OPUCN"). 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.

OPUCN is an electricity distributer serving approximately 62,700 customers in the City of Oshawa. OPUCN owns and operates nine Municipal Substations ("MS") at distribution voltages within its service territory.

1.1 Purpose and Scope

OPUCN engaged METSCO to develop Health Index Formulations ("HIFs") and conduct an ACA on the utility's distribution and substation assets to improve awareness of system health demographics in preparation for their upcoming Cost of Service application in 2025. To assist OPUCN with further asset condition data integration efforts, Section 8 of this report contains a set of recommendations for the utility's management to consider going forward.

The ACA methodology comprising this study assessed multiple categories of assets within OPUCN'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 Health Index ("HI") for distribution and station 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
  - Wood poles;
  - Concrete poles;
  - Steel poles;
  - Overhead primary conductors;
  - Underground primary cables;
  - Pole-mount transformers;
  - Pad-mount transformers;
  - Vault transformers;
  - Overhead switches;
  - Smart switches;
  - Distribution switchgears;
  - Cut-out arrestors;
  - Elbow connectors;
  - Reclosers; and
  - Vaults & manholes.
- Station assets
  - Power transformers;
  - Circuit breakers;

- Switchgears;
- Relays & RTUs;
- Battery & chargers;
- Egress cables;
- Fences;
- Buildings; and
- Bus structures.

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

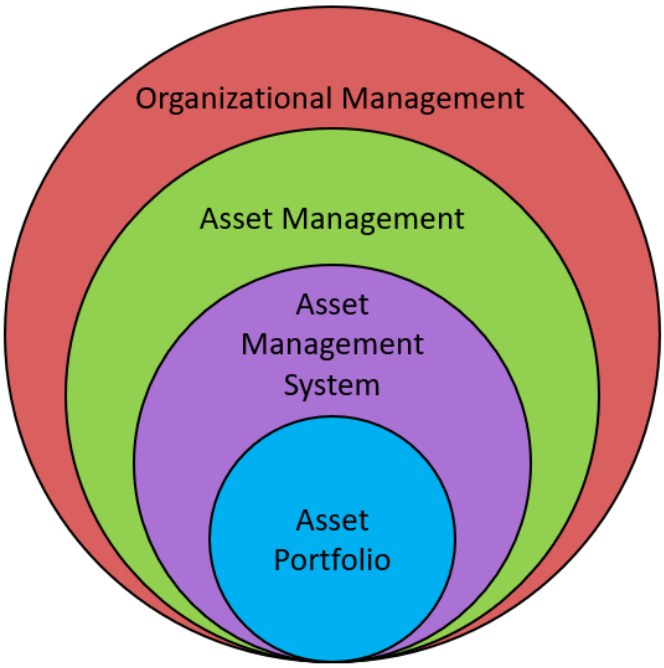


Figure 2-1: Relationship Between Key AM Terms[1]

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

[2] ISO 55002 – Asset management – Management systems – Guidelines for the application of ISO 55001

ACA quantifies the condition of each asset under study and is an appropriate indicator of its Failure Probability ("FP"). 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: realized financial profits, better classified and managed risk among assets, better-informed investment decisions, demonstrated compliance among the asset base, increased public and worker safety, and corporate sustainability.[1]

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 Strategic Asset Management Plan ("SAMP"). The SAMP should be used as a guide for the organization to apply its AM principles and practices for its specific use case. Distribution of the SAMP should be well-publicized within an organization and updated on a regular basis, to best quantify the most current and comprehensive AM practices being implemented. Just as the asset base performance is subject to an in-depth review, the AM process and system should be reviewed with the same rigor.1

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 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 Methodology

3.1 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;
2. Gateway models – select parameters deemed to be most impactful on the asset's overall functionality act as "gates" to drive the overall condition of an asset, by effectively "deflating" the scores of other (less impactful) components;
3. Subtractive models – consider that a relatively Poor condition for any of several major assets within a broader system of assets could act as a sufficient justification to drive investments into the entire system; and
4. Multiplicative models – a HI that dynamically shifts the calculation towards specific degradation factors, if they are a leading indicator to show that an asset is failing.

In general, most distribution utilities employ an additive model, while some will also apply select gateway model elements. METSCO used an additive approach when conducting the ACA for all distribution and station assets, which is in alignment with other utilities in Ontario, OPUCN's previous ACA and METSCO's best practice.

3.1.1 Data Sources

To assess the demographics and establish the unit population of OPUCN's distribution and station assets, METSCO was provided with asset registries for each asset class. Inspection records were provided per asset class in pdf, word, and excel format.

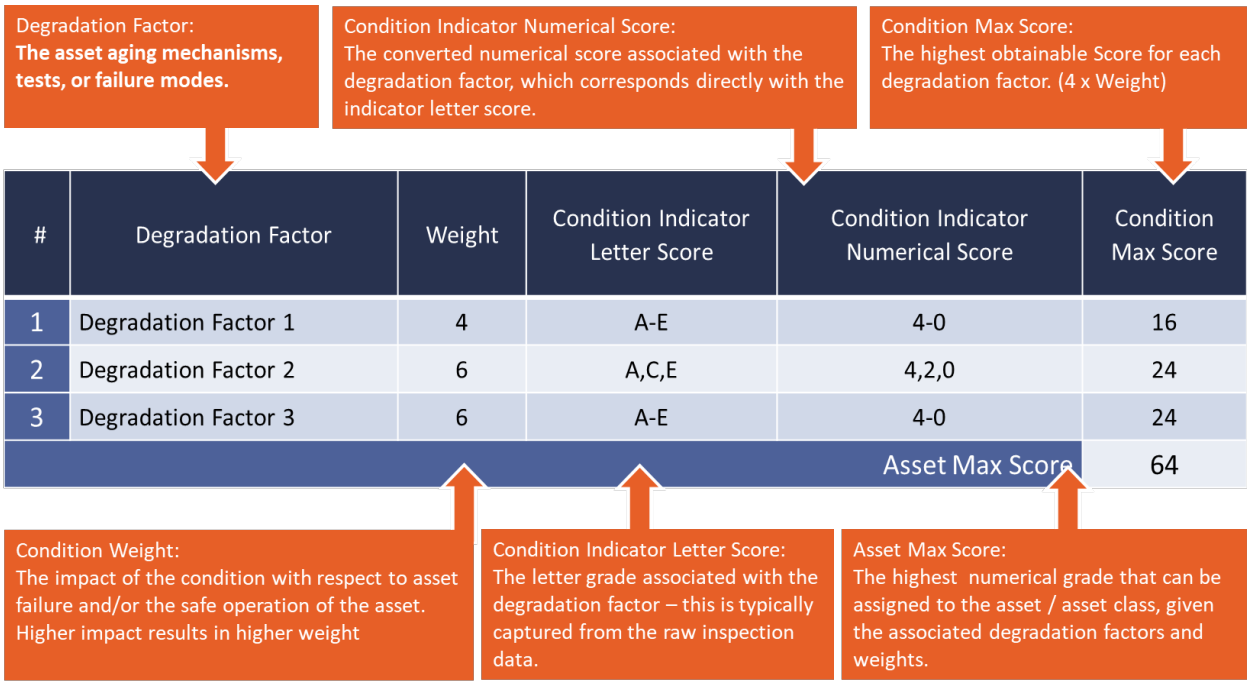
Additional sources of information that were leveraged to complete the ACA are:

- Historical loading data;
- Substation inspection reports;
- Transformer Dissolved Gas Analysis ("DGA") and Oil Quality ("OQ") results; and
- Input from OPUCN technicians.

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

Figure 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

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.

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

3.1.3 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. An asset requires a DAI of 70% for a valid HI result.

3.2 Remaining Life Assessment Methodology

The 2010 *Asset Depreciation Study for the Ontario Energy Board*[3] established minimum, maximum, and Typical Useful Life ("TUL") values for a number of asset classes that have created a basis for planning and depreciation assumptions. TUL is defined as the age when 50% of the assets have failed and been replaced; in other words, the median life. Per the origins of the HI concept, TUL also corresponds to the point at which the HI changes from Fair condition to Poor condition[4]

The TUL is then used to calculate the shape and scale of a Weibull curve. The Weibull curve shape and scale are used to create a hazard rate vs condition-suggested age table.

The HI for each asset calculated in the ACA step is then used to determine the FP by comparing the HI against a standard HI vs FP table[4]. The FP is then compared to the hazard rate vs condition-suggested age table to determine a condition-suggested age for each asset. From this the asset age is adjusted to get the effective age. This can then be used to find the remaining life.

3.3 Risk Assessment Methodology

The purpose of the risk evaluation is to first assess and quantify (or qualify) the potential risks to both OPUCN and its customers in the event of a capacity deficit, and then outline potential mitigation measures that could partially or completely mitigate these risks. To provide clarity, the following definitions are provided:

- Probability is the likelihood of an event occurring;
- Consequence is the outcome or impact of that event; and
- Risk is the product of the probability that an event will materialize multiplied by the consequence of that event.

First the impact is calculated in for each asset using risk factors. Three risk categories are included in the analysis; reliability, safety and environmental. These risk categories have relative weighting that is consistent across all asset classes (Reliability 40%, Safety 40%, Environment 20%). Within each risk category are individual risk factors which are specific and uniquely graded for each asset class. The impact is determined using the same methodology as HI calculations.

[3] "Asset Depreciation Study for the Ontario Energy Board," Kinectrics, Jul. 2010
[4] T. Hjarstaron and S. Otal, "Predicting Future Asset Condition Based on Current Health Index and Maintenance Level", ESMO 2006 - 2006 IEEE 11th International Conference on Transmission & Distribution Construction, Operation and Live-Line Maintenance, Oct. 2006

The HI score and Impact scores are then applied to the risk evaluation grid in Table 3-2 to get the Risk Score. If an asset has an invalid HI then a ratio of age over TUL is used to determine the probability. This is applied to Table 3-3.

Table 3-2: Condition-Based Risk Evaluation Grid

		HI Score				
		Very Good	**Good**	**Fair**	**Poor**	**Very Poor**
Impact Score	**Very High**	Moderate	Moderate	High	Extreme	Extreme
	High	Low Mod	Moderate	High	Extreme	Extreme
	Moderate	Low Mod	Moderate	Moderate	High	Extreme
	Low	Low	Low Mod	Moderate	Moderate	High
	Very Low	Low	Low	Low Mod	Low Mod	High

Table 3-3: Age Based Risk Evaluation Grid

		Age/TUL				
		[0-33)%	**[33-67)%**	**[67-100)%**	**[100-133)%**	**>=133%**
Impact Score	**Very High**	Moderate	Moderate	High	Extreme	Extreme
	High	Low Mod	Moderate	High	Extreme	Extreme
	Moderate	Low Mod	Moderate	Moderate	High	Extreme
	Low	Low	Low Mod	Moderate	Moderate	High
	Very Low	Low	Low	Low Mod	Low Mod	High

4 Asset Condition Assessment

This section presents the current HIF for each asset class, the calculated HI scores, and the data available to perform the study.

For most of the asset classes, an HIF was previously developed in the 2018 ACA. Where applicable, these HIFs were modified based on the most recent industry best practices and OPUCN-specific data availability. Most notably the weighting of service age has decreased for some assets as the industry has moved away from purely age driven asset management plans. As such the HI results of these asset classes may have improved since the last ACA as newly available data has shown the assets to be in good condition despite their age being near or past the TUL.

In the case of Overhead ("OH") conductors, Underground ("UG") cables, and cut-out arrestors, condition information was limited given the lack of available visual inspection results for these asset classes. In other cases, demographic data from the asset registry was used along with the results of visual field inspections to calculate the asset's HI.

Depending on the data availability for each asset class, HI formulations used in this report range in complexity from two to twenty condition parameters. While two data points are not sufficient for a rigorous HI (which requires a minimum of three input parameters to qualify as a full HI), the availability of some condition data is significantly better than none. For the sake of consistency in reviewing the study's results, all of our findings are presented in the same visual distribution format – separating assets into five condition bands between Very Poor and Very Good with the sixth category of Invalid HI to identify the number of assets where data availability was insufficient to meet the threshold of 70%.

Table 4-1, Figure 4-1, and Figure 4-2 present the results of the ACA study.

Table 4-1: Numerical Summary of HI Results

Asset Category	Population – Note 1	HI Distribution						DAI
		Very Good	Good	Fair	Poor	Very Poor	Invalid HI	
Distribution Assets								
Wood Poles	9,435	6,762	663	12	50	39	1,909	83%
Concrete Poles	370	44	93	227	1	1	4	96%
Steel Poles	11	5	6	0	0	0	0	100%
Overhead Primary Conductors (m)	534,458	387,632	85,800	48,164	2,585	10,218	59	100%
Underground Primary Cables (m)	463,792	311,709	111,550	34,893	1,318	4,322	0	100%
Pole-Mount Transformers	2,250	1,356	619	231	15	2	27	100%
Pad-Mount Transformers	3,953	1,973	1,250	618	7	3	102	99%
Vault Transformers	151	65	79	0	1	0	6	97%
Overhead Switches	718	640	53	9	0	0	16	95%
Smart Switches	31	31	0	0	0	0	0	100%

Asset Category	Population – Note 1	HI Distribution						DAI
		Very Good	Good	Fair	Poor	Very Poor	Invalid HI	
Distribution Switchgear	42	21	6	14	0	1	0	100%
Cut-Out Arrestors	1,761	807	347	498	2	3	104	97%
Elbow Connectors	7,114	6,048	1,066	0	0	0	0	99%
Reclosers	3	3	0	0	0	0	0	100%
Vaults	6	1	3	2	0	0	0	100%
Manholes	49	48	1	0	0	0	0	54%
Station Assets								
Power Transformers	18	11	7	0	0	0	0	99%
13.8kV Circuit Breakers	81	71	8	1	0	0	1	99%
44 kV Circuit Breakers	18	14	4	0	0	0	0	97%
13.8 kV Switchgear Buses	18	6	9	3	0	0	0	100%
Relays	80	42	6	0	0	0	32	70%
Batteries	9	2	5	2	0	0	0	100%
Chargers	9	4	4	1	0	0	0	100%
13.8 kV Station Egress	53	14	5	21	7	1	5	96%
44 kV Station Egress	8	3	0	3	0	1	1	97%
Station Fences & Yards	9	9	0	0	0	0	0	100%
Station Buildings	9	9	0	0	0	0	0	100%
Bus Structures	17	13	4	0	0	0	0	94%

Note 1: Minor differences to be expected between ACA population count and other data sources due to data scrubbing and assumptions process.

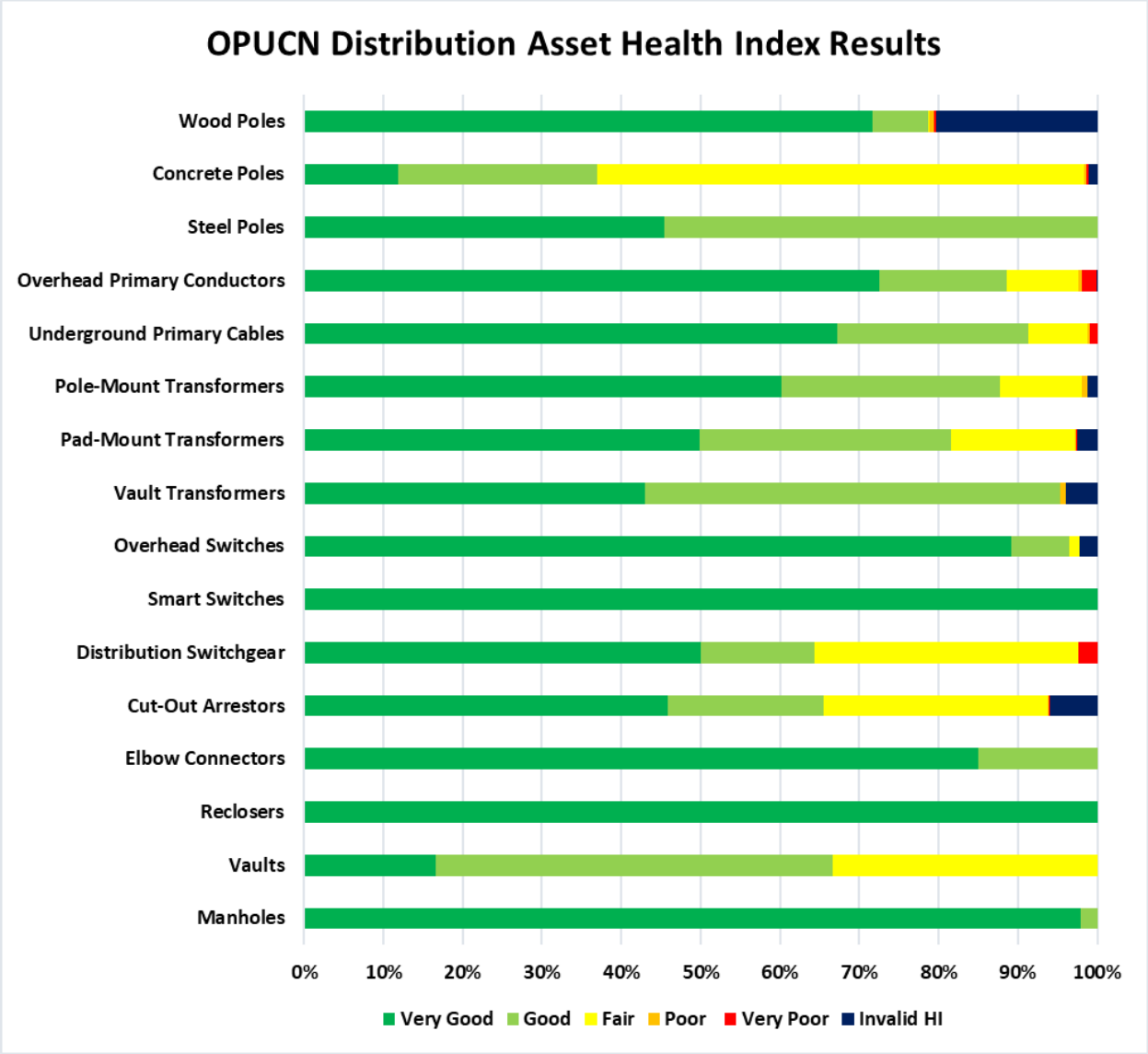


Figure 4-1: Distribution ACA Results

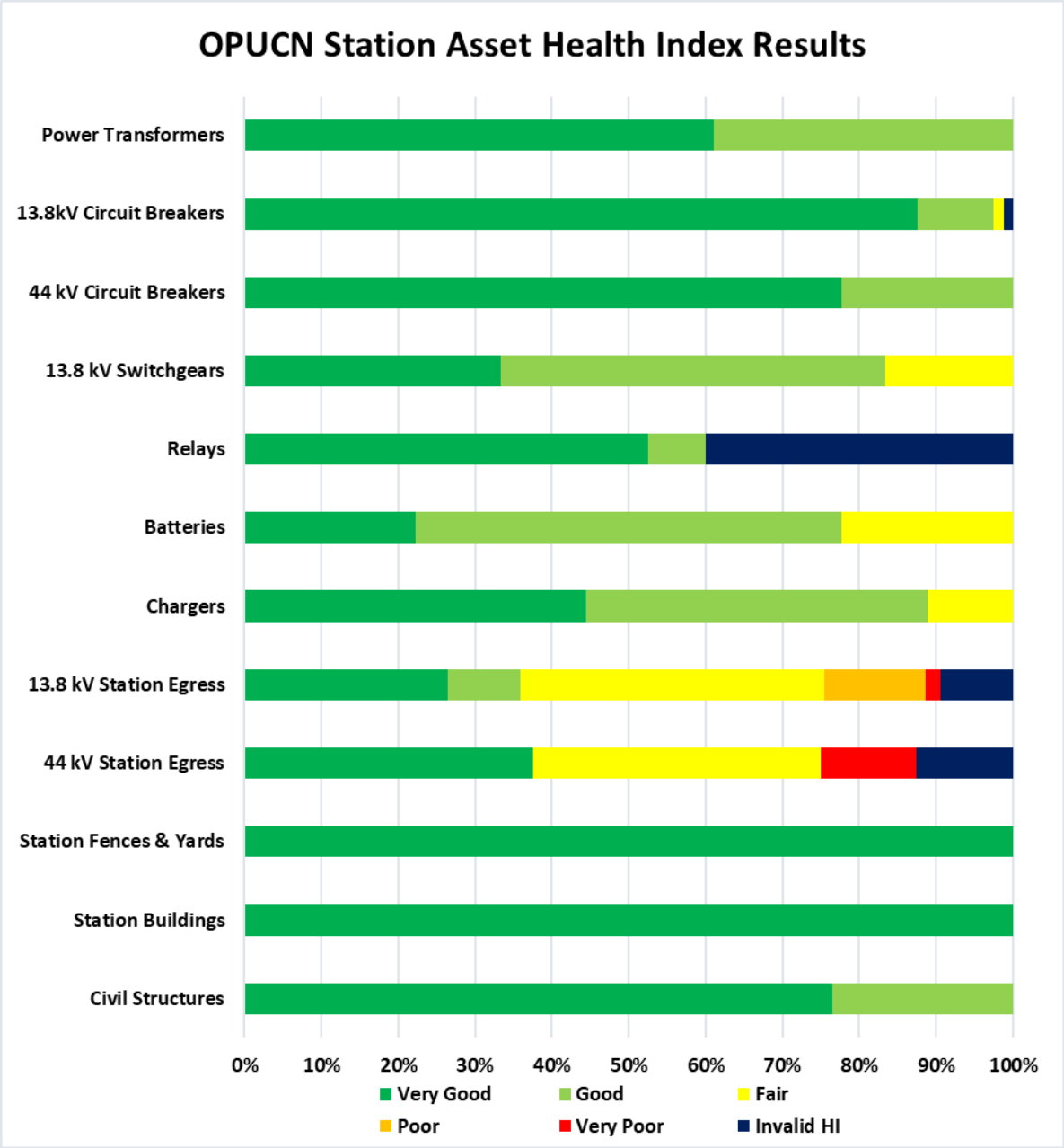


Figure 4-2: Station ACA Results

4.1 Distribution Assets

4.1.1 Wood Poles

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, switches, and reclosers. OPUCN owns and maintains 9,435 wood poles within its service territory.

Health Index Formulation

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.

The HI for wood poles is calculated based on EOL criteria summarized in Table 4-2.

Table 4-2: Wood Pole HI Formulation

Condition Parameter	DAI	Weight	Ranking	Numerical Grade	Max Score
Remaining Strength	68%	42	A,B,C,D,E	4,3,2,1,0	168
Service Age	100%	20	A,B,C,D,E	4,3,2,1,0	80
Mechanical Damage[5]	74%	6	A,B,C,D,E	4,3,2,1,0	24
Wood Rot[5]	74%	6	A,B,C,D,E	4,3,2,1,0	24
Surface Decay[5]	74%	4	A,B,C,D,E	4,3,2,1,0	16
Pole Top Feathering[5]	74%	4	A,B,C,D,E	4,3,2,1,0	16
Crossarm Condition	93%	2	A,B,C,D,E	4,3,2,1,0	8
Woodpecker Damage[5]	74%	1	A,B,C,D,E	4,3,2,1,0	4
Insect Damage[5]	74%	1	A,B,C,D,E	4,3,2,1,0	4
Cracks[5]	74%	1	A,B,C,D,E	4,3,2,1,0	4
Pole Lean[5]	74%	1	A,B,C,D,E	4,3,2,1,0	4
Overall Condition	93%	1	A,B,C,D,E	4,3,2,1,0	4
Total Score					**356**

Data Collection and Assumptions

OPUCN provided both an asset registry and an inspection record for its wood poles. There were two fields within the asset registry which were used to determine the service age of each wood pole. "INSTALLATION DATE" was taken as the primary input and "POLE YEAR" was taken as a secondary input where the primary input was not available. The pole asset registry included duplicate entries for a number of wood poles. In some cases, the duplicate entries had different installation dates and locations recorded from a single pole number. OPUCN should work towards cleansing the pole asset registry so that all pole numbers are unique and the installation date recorded for each pole is accurate.

The remainder of the condition parameters were provided in the pole inspection record. Wood poles installed less than fifteen years ago were assumed to be in good condition and a pole inspection record was not required for these assets. Visual inspections were available for 74% of the assets installed more than fifteen years ago. For poles where inspections have been completed, the inspection record was generally comprehensive including results for all of the

[5] Only required for wood poles installed more than fifteen years ago.

condition parameters listed in Table 4-2. Most of the visual inspection parameters for wood poles are graded using a scale of 0-Good, 1-Fair, 2-Poor, 3-Danger. Insect Infestation and Woodpecker Damage are and exception to this and are graded in the inspection record as "Yes" or "No".

As a secondary input, the overall condition and crossarm condition for wood poles was taken from the previous ACA. This assumption raised the DAI for these condition parameters to 93%.

The overall DAI for OPUCN's wood poles is 83%.

Results

OPUCN owns and maintains 9,435 wood poles within its service territory. Installation dates are known for all but 45 of OPUCN's wood poles. The demographic analysis for wood poles is provided in Figure 4-3. The TUL for wood poles is 45 years and assets are considered to be approaching their TUL if they were installed more than 30 years ago. The 45 assets with an unknown service age are not shown in Figure 4-3. It can be assumed that assets with unknown service ages are close to the TUL of 45 years.

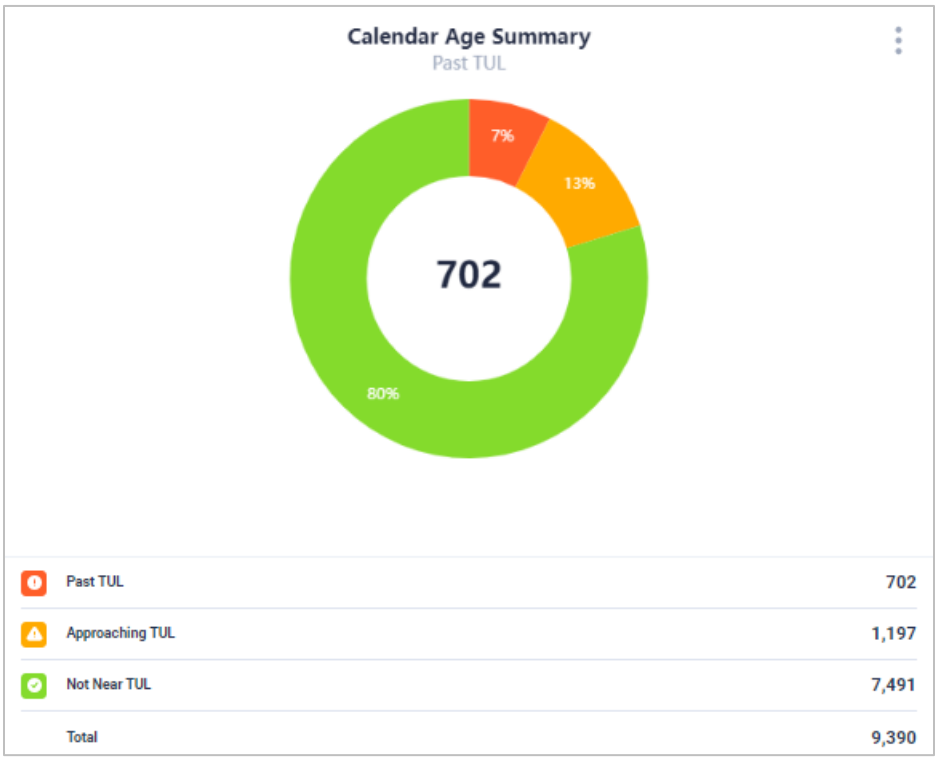


Figure 4-3: Wood Pole Demographic Assessment

The ACA results for OPUCN's wood poles are summarized in Figure 4-4. Valid HI results were outputted for 80% of the assets.

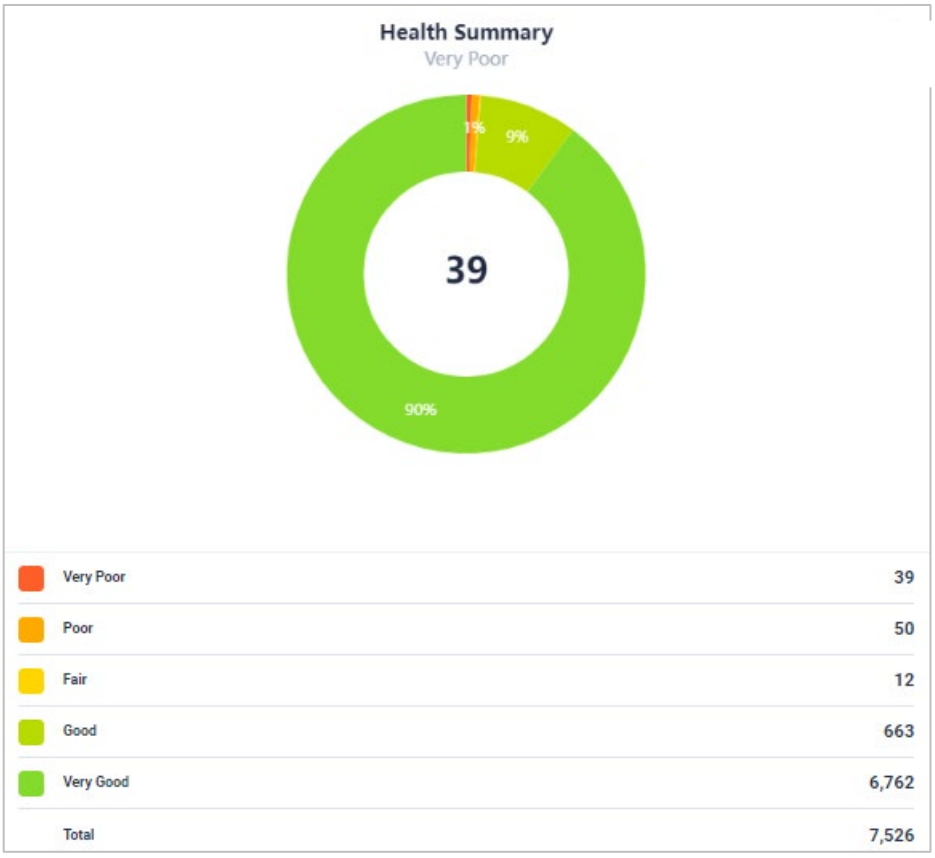


Figure 4-4: Wood Pole ACA Results

4.1.2 Concrete Poles

OPUCN owns and maintains 370 concrete poles within its service territory.

Health Index 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 4-3.

Table 4-3: Concrete Pole HI Formulation

Condition Parameter	DAI	Weight	Ranking	Numerical Grade	Max Score
Visual Inspection	99%	4	A,B,C,D,E	4,3,2,1,0	16
Service Age	100%	3	A,B,C,D,E	4,3,2,1,0	12
Pole Lean	70%	1	A,B,C,D,E	4,3,2,1,0	4
Total Score					**32**

Data Collection and Assumptions

OPUCN provided both an asset registry and an inspection record for its concrete poles. There were two fields within the asset registry which were used to determine the service age of each concrete pole. "INSTALLATION DATE" was taken as the primary input and "POLE YEAR" was taken as a secondary input where the primary input was not available.

The pole lean and overall condition parameters were provided in the pole inspection record which included results for 70% of OPUCN's concrete poles. For poles where inspections have been completed, the inspection record was generally comprehensive. The overall condition of OPUCN's concrete poles was determined as a combination of the following inspection parameters recorded in the visual inspection:

- Cracks
- Cross-arm condition
- Overall Condition

As a secondary input, the overall condition of concrete poles was taken from the previous ACA. This assumption raised the DAI for overall condition to 99%.

The overall DAI for OPUCN's concrete poles is 96%.

Results

OPUCN owns and maintains 370 concrete poles within its service territory. Installation dates are known for all of OPUCN's concrete poles. The demographic analysis for concrete poles is provided in Figure 4-5. The TUL for concrete poles is 60 years and assets are considered to be approaching their TUL if they were installed more than 40 years ago.

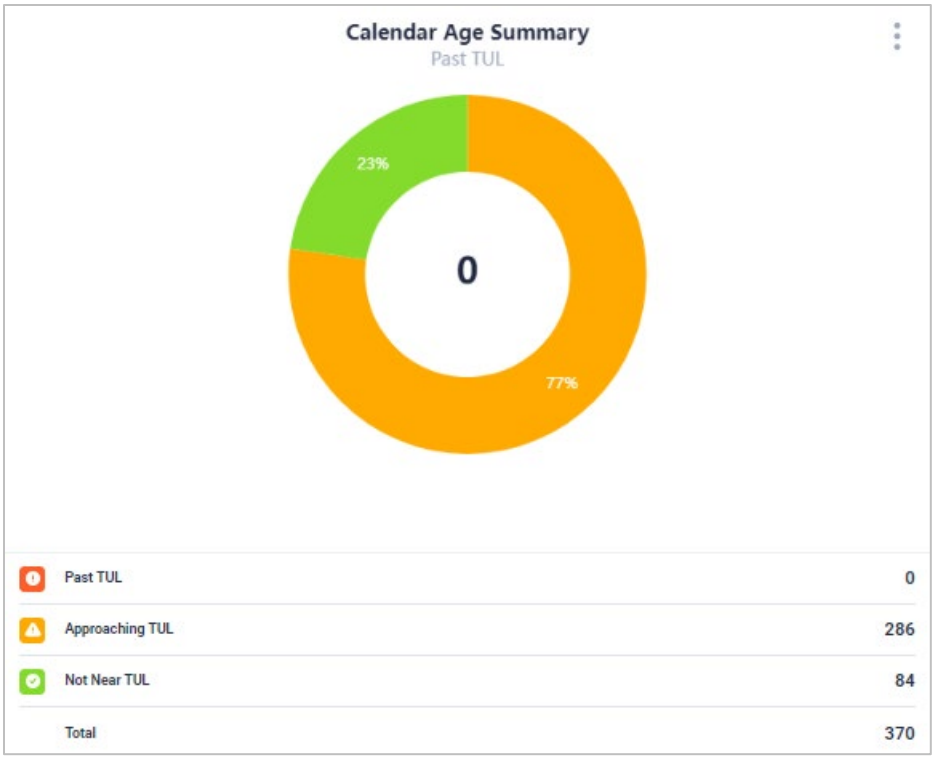


Figure 4-5: Concrete Pole Demographic Assessment

The ACA results for OPUCN's concrete poles are summarized in Figure 4-6. Valid HI results were outputted for 98% of the assets.

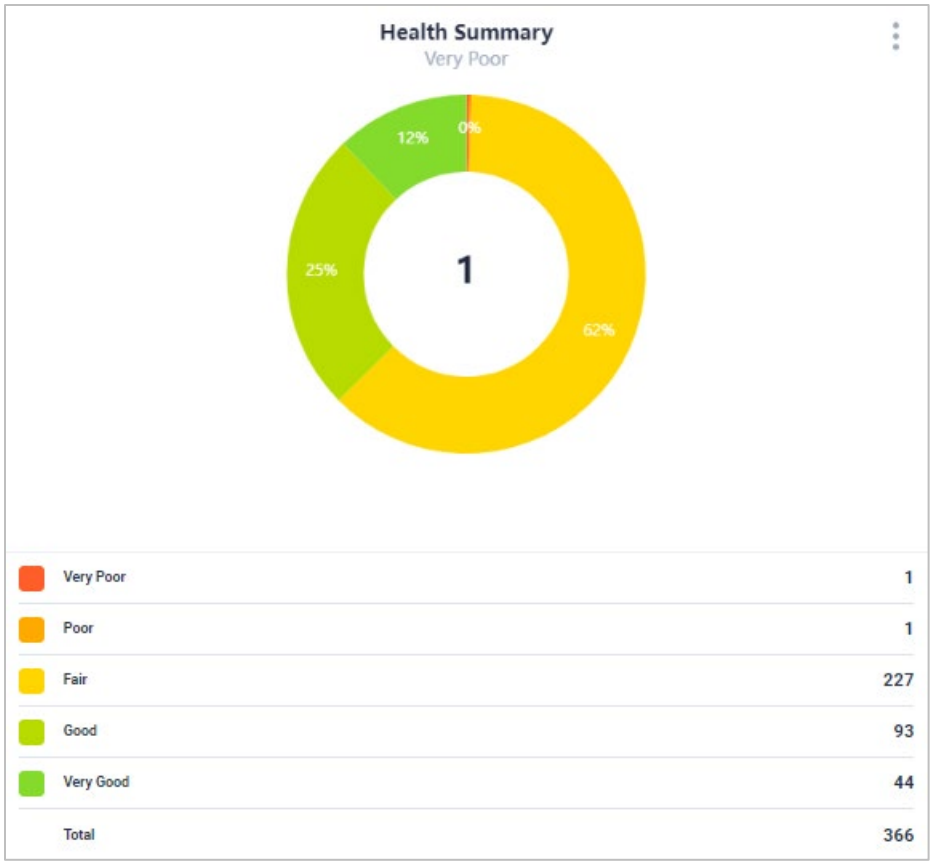


Figure 4-6: Concrete Pole ACA Results

4.1.3 Steel Poles

Steel poles have a similar use as wood poles in the distribution system. Replacing aging wood poles with steel distribution poles benefits the utility through higher durability and lower asset lifecycle costs. OPUCN owns and maintains eleven steel poles within its service territory.

Health Index Formulation

Steel poles have different degradation mechanisms than wood poles. There is no practical "pole test" for steel poles, but since poles are hollow, there are also limited opportunities for invisible degradation and interior rot. Similar to wood rot, the presence of rust on steel poles compromises the pole's strength and should be identified through visual inspections.

The HI for steel poles is calculated based on EOL criteria summarized in Table 4-4.

Table 4-4: Steel Pole HI Formulation

Condition Parameter	DAI	Weight	Ranking	Numerical Grade	Max Score
Visual Inspection	100%	5	A,B,C,D,E	4,3,2,1,0	20
Service Age	100%	4	A,B,C,D,E	4,3,2,1,0	16
Pole Lean	100%	1	A,B,C,D,E	4,3,2,1,0	4
Total Score					**40**

Data Collection and Assumptions

OPUCN provided both an asset registry and an inspection record for its steel poles. There were two fields within the asset registry which were used to determine the service age of each steel pole. "INSTALLATION DATE" was taken as the primary input and "POLE YEAR" was taken as a secondary input where the primary input was not available.

The pole lean and overall condition parameters were provided in the pole inspection record which included results for 100% of OPUCN's steel poles. For poles where inspections have been completed, the inspection record was generally comprehensive. The overall condition of OPUCN's steel poles was determined as a combination of the following inspection parameters recorded in the visual inspection:

- Cross-arm condition
- Overall Condition

The overall DAI for OPUCN's steel poles is 100%.

Results

OPUCN owns and maintains eleven steel poles within its service territory. Installation dates are known for all of OPUCN's steel poles. The demographic analysis for steel poles is provided in Figure 4-7. The TUL for steel poles is 60 years and assets are considered to be approaching their TUL if they were installed more than 40 years ago.

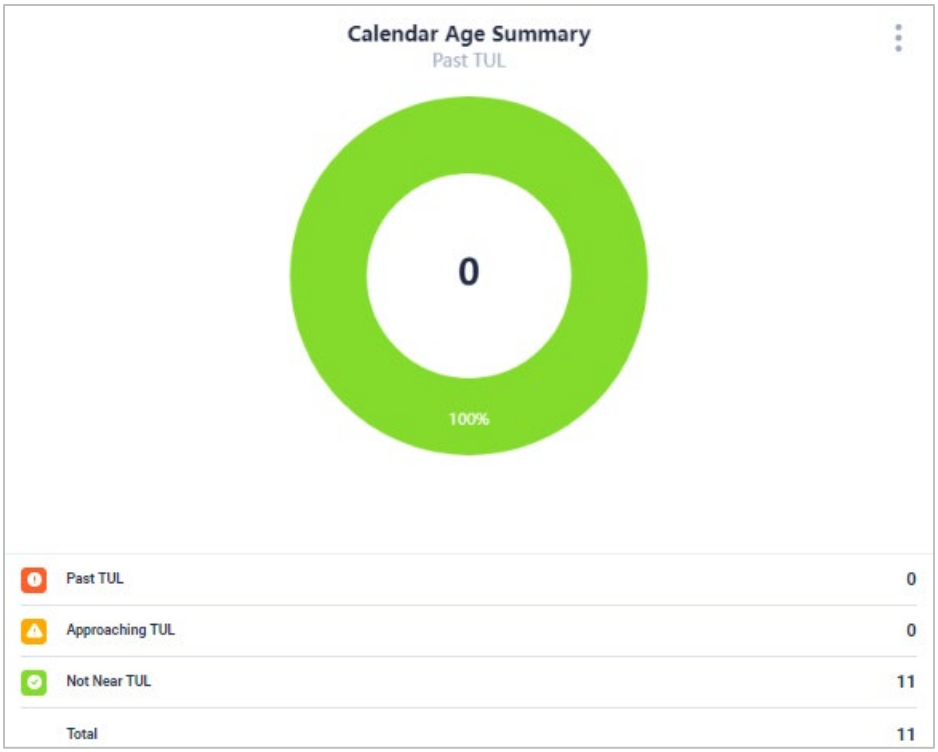


Figure 4-7: Steel Pole Demographic Assessment

The ACA results for OPUCN's steel poles are summarized in Figure 4-8. Valid HI results were outputted for all of the assets.

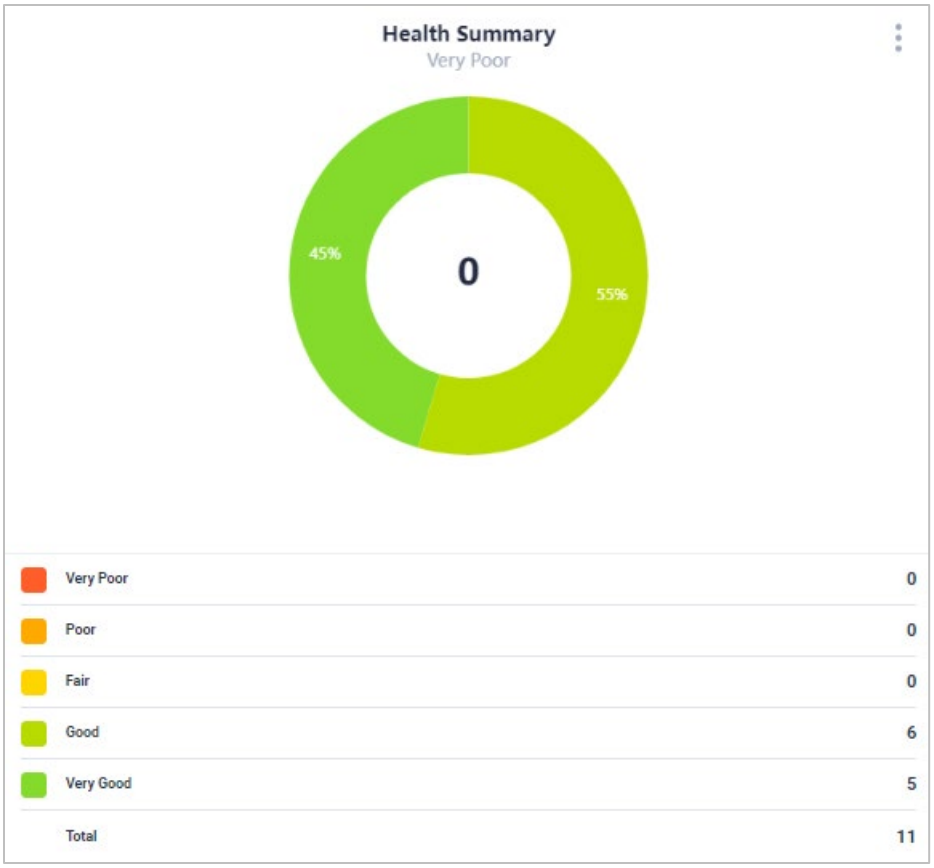


Figure 4-8: Steel Pole ACA Results

4.1.4 Overhead Primary Conductors

OPUCN owns and maintains approximately 534 km of OH primary conductor within its service territory.

Health Index Formulation

OH conductor segments tend to be renewed when poles are replaced, when voltages are upgraded, or when lines are restrung for technical reasons. 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 4-5.

Table 4-5: OH Primary Conductor HI Formulation

Condition Parameter	DAI	Weight	Ranking	Numerical Grade	Max Score
Service Age	100%	1	A,B,C,D,E	4,3,2,1,0	4
Small Conductor Risk	100%	1	A,E	4,0	4
Total Score					**8**

Data Collection and Assumptions

An asset registry was provided for OPUCN's OH primary conductors. The installation date, conductor material, and conductor size were all extracted directly from the asset registry.

The service age is known for 70% of the asset population while the remaining ages are approximated based on the age of poles which are within 10 m of the OH conductor segment in the Geographic Information System ("GIS").

The overall DAI for OH primary conductors is 100%.

Results

OPUCN owns and maintains approximately 534 km of OH primary conductor within its service territory. Installation dates are available for all of OPUCN's conductor segments. The demographic analysis for OH primary conductors is provided in Figure 4-9. The TUL for OH primary conductor is 60 years and segments are considered to be approaching their TUL if they were installed more than 40 years ago.

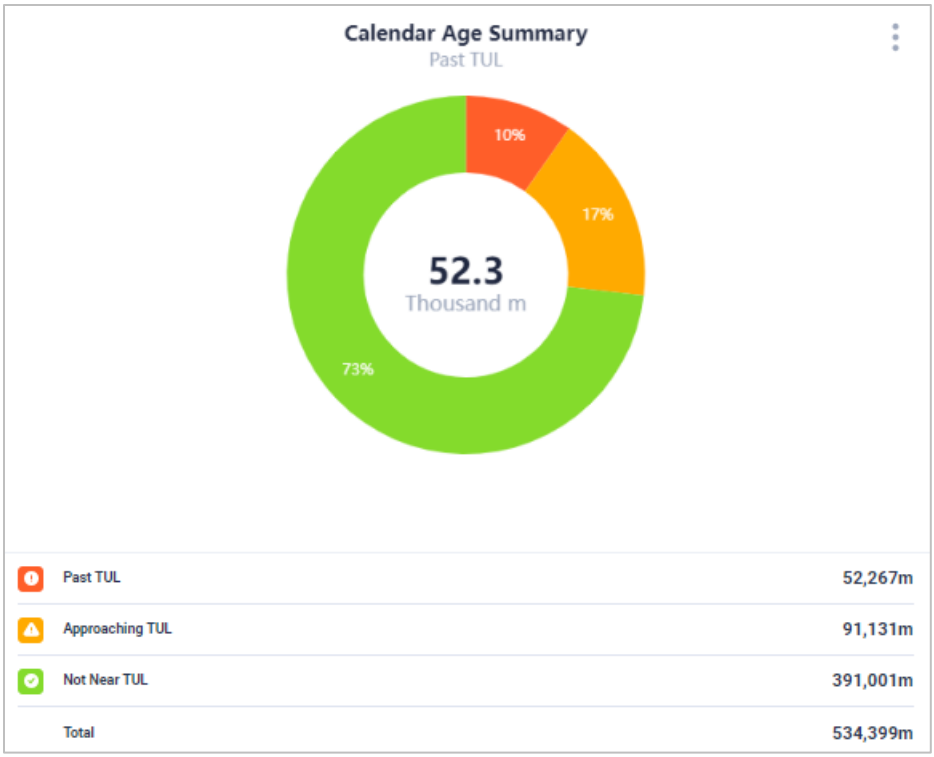


Figure 4-9: OH Primary Conductor Demographic Assessment

The ACA results for OPUCN's OH primary conductors are summarized in Figure 4-10. Valid HI results were outputted for all the assets.



Figure 4-10: OH Primary Conductor ACA Results

4.1.5 Underground Primary Cables

OPUCN owns and maintains approximately 464 km of UG primary cable within its service territory.

Health Index 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 4-6.

Table 4-6: UG Primary Cable HI Formulation

Condition Parameter	DAI	Weight	Ranking	Numerical Grade	Max Score
Service Age	100%	1	A,B,C,D,E	4,3,2,1,0	4
Failure Rate	100%	1	A,B,C,D,E	4,3,2,1,0	4
Total Score					**8**

Data Collection and Assumptions

An asset registry was provided for OPUCN's UG primary cables. Installation dates, where available, were taken directly from the UG cable asset registry. As a secondary input, installation dates were taken from the previous ACA.

A listing of primary cables faults was also provided which was linked to the UG cables by section ID. The failure rate for UG primary cables was assessed based on the number of failures experienced per 8,667 m of cable, which is the average feeder cable length. OPUCN provided cable failures per cable segment. The failure rate of each cable segment was then scaled to the average feeder cable length to normalize the results.

The overall DAI for UG primary cables is 100%.

Results

OPUCN owns and maintains approximately 464 km of UG primary cable within its service territory. Installation dates are available for 100% of OPUCN's cable segments. The demographic analysis for UG primary cables is provided in Figure 4-11. The TUL for UG primary cable is 30 years and segments are considered to be approaching their TUL if they were installed more than twenty years ago.

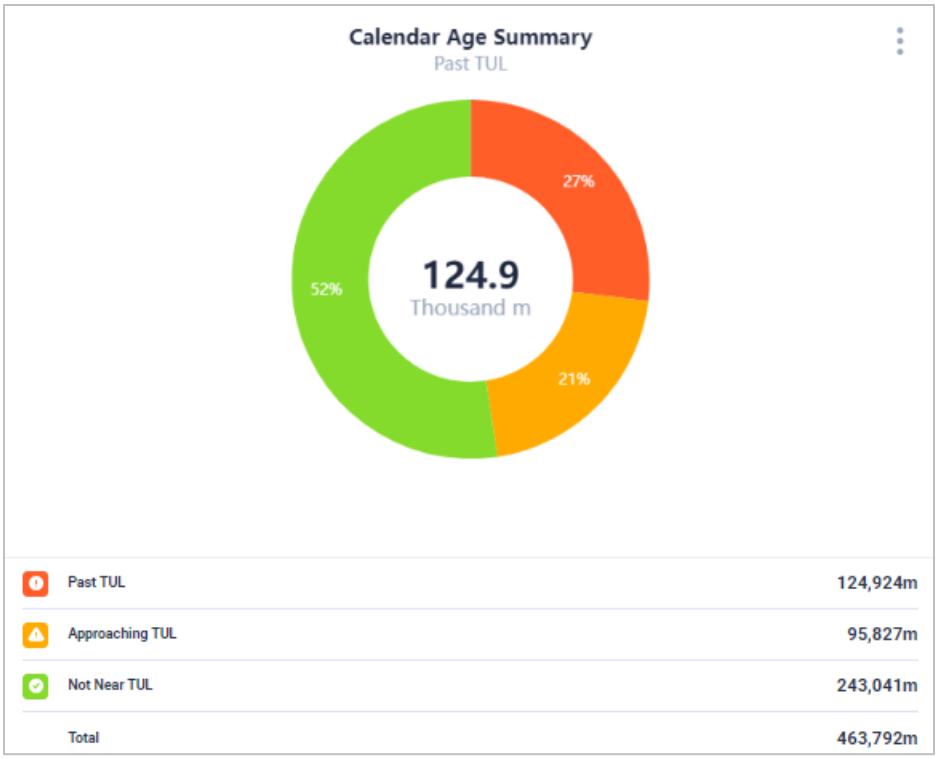


Figure 4-11: UG Primary Cable Demographic Assessment

The ACA results for OPUCN's UG primary cables are summarized in Figure 4-12. Valid HI results were outputted for all the assets.

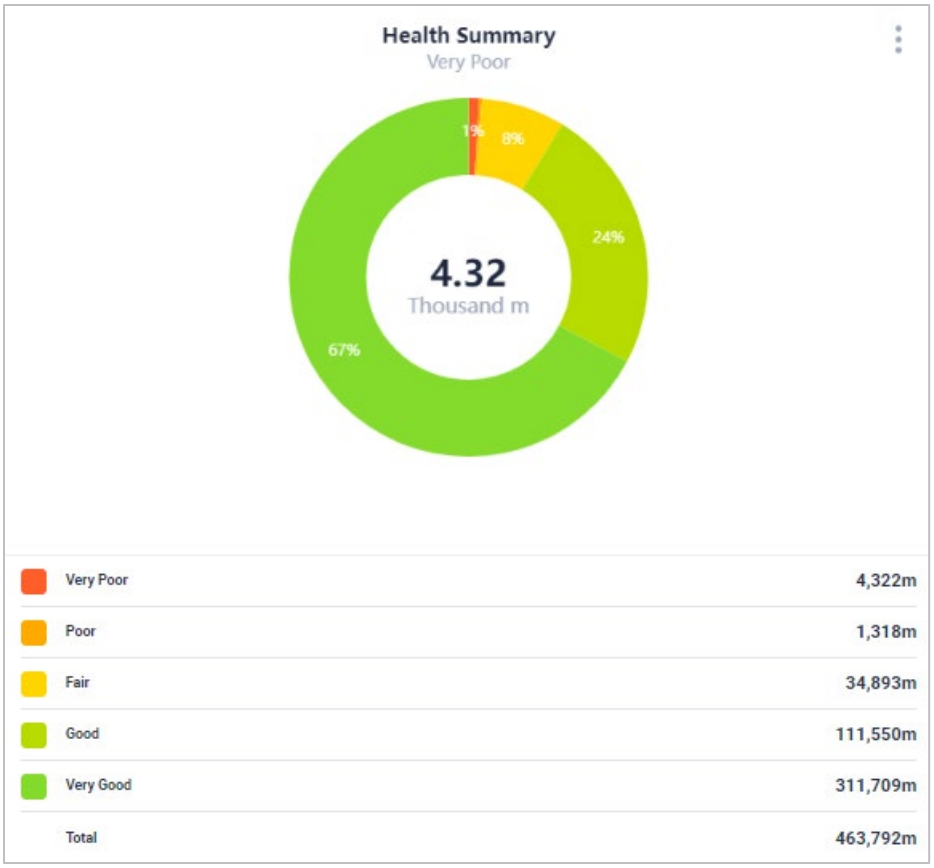


Figure 4-12: UG Primary Cable ACA Results

4.1.6 Pole-Mount Transformers

OPUCN owns and maintains 2,250 pole-mount transformers within its service territory.

Health Index Formulation

Pole-mounted transformers are another large asset class within the utility system. This asset category is made up of a large number of units, each with a modest replacement value. Transformers are generally considered to be a run-to-failure asset class with little maintenance other than visual inspections. Transformers may be replaced in planned projects based on identifiable degradation, pole line rebuilds, road relocations, and upgrade projects in response to customer load growth.

Transformers typically reach their EOL due to physical tank deterioration such as corrosion, which in extreme cases can lead to an instance of leaking oil. Where corrosion is detected, a transformer may be cycled back to the shop and re-painted with gaskets being replaced. Other modes of failure include overheated connections due to loosened connectors, which are typically detected in infrared scanning and tightened to reduce the failure risk.

Most commonly, utilities replace distribution transformers as part of overhead or underground rebuild projects. 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 pole-mount transformers is calculated based on EOL criteria summarized in Table 4-7.

Table 4-7: Pole-Mount Transformer HI Formulation

Condition Parameter	DAI	Weight	Ranking	Numerical Grade	Max Score
IR Scan	100%	4	A,B,C,D,E	4,3,2,1,0	16
Service Age	99%	3	A,B,C,D,E	4,3,2,1,0	12
Total Score					**28**

Data Collection and Assumptions

OPUCN provided an asset registry and overhead IR scan report which were used as inputs for the pole-mount transformer analysis. No visual inspections were provided for pole-mount transformers. Installation Date was taken directly from the pole-mount transformer asset registry. Assets of concern were identified in the OH IR scan report. All assets that were not mentioned in the report were assumed to have no issues from the IR scan.

The DAI for pole-mount transformers is effectively 100%.

Results

OPUCN owns and maintains 2,250 pole-mount transformers within its service territory. Installation dates are known for 99% of OPUCN's pole-mount transformers. The demographic analysis for pole-mount transformers is provided in Figure 4-13. The TUL for pole-mount transformers is 40 years and assets are considered to be approaching their TUL if they were installed more than 27 years ago. The 27 assets with an unknown service age are not shown in Figure 4-13. It can be assumed that assets with unknown service ages are close to the TUL of 40 years.

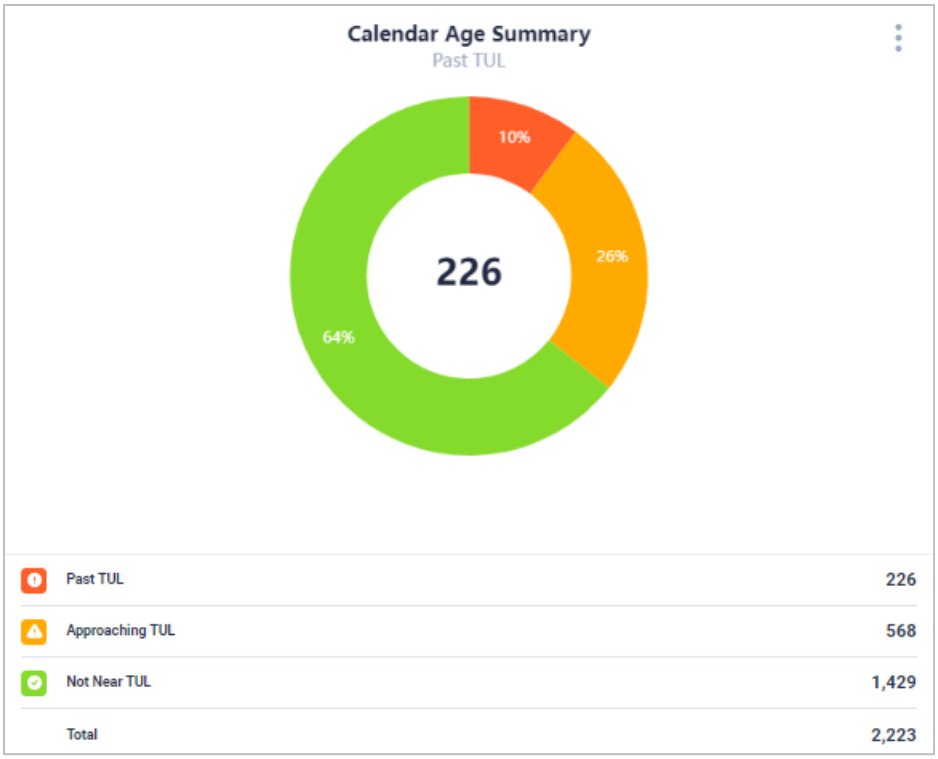


Figure 4-13: Pole-Mount Transformer Demographic Assessment

The ACA results for OPUCN's pole-mount transformers are summarized in Figure 4-14. Valid HI results were outputted for 99% of the assets.

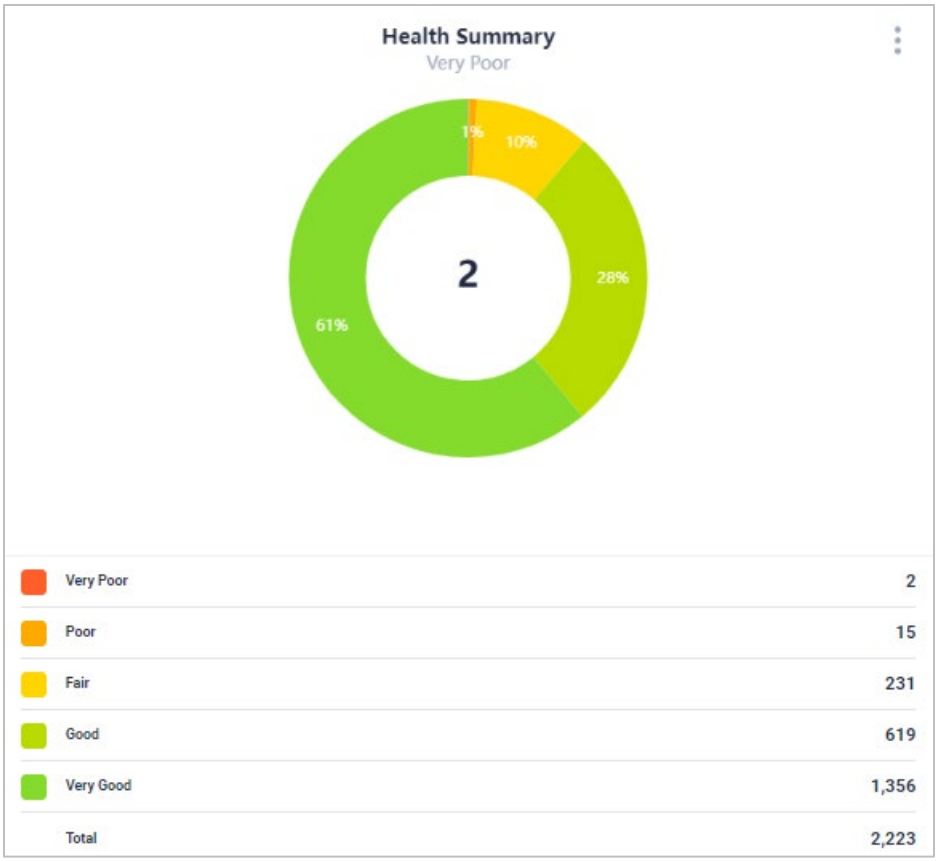


Figure 4-14: Pole-Mount Transformer ACA Results

4.1.7 Pad-Mount Transformers

OPUCN owns and maintains 3,953 pad-mount transformers within its service territory.

Health Index Formulation

Pad-mount 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.

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 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.

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 4-8.

Table 4-8: Pad-Mount Transformer HI Formulation

Condition Parameter	DAI	Weight	Ranking	Numerical Grade	Max Score
Service Age	100%	12	A,B,C,D,E	4,3,2,1,0	48
Overall Condition	96%	5	A,B,C,D,E	4,3,2,1,0	20
Oil Leaks	93%	5	A,B,C,D,E	4,3,2,1,0	20
Corrosion	93%	4	A,B,C,D,E	4,3,2,1,0	16
Condition of Civil Structure	91%	2	A,B,C,D,E	4,3,2,1,0	8
Total Score					**112**

Data Collection and Assumptions

OPUCN provided an asset registry and visual inspection record for the pad-mount transformers. Installation Date was taken directly from the pad-mount transformer asset registry. The visual inspection record for pad-mount transformers was provided in pdf format with hand-written notes which were manually entered to perform this condition assessment.

As a secondary input, the service age and overall condition of pad-mount transformers was taken from the previous ACA. Additionally, assets installed less than five years ago were assumed to be in Very Good condition with respect to oil leaks, corrosion, and the condition of the civil structure.

The overall DAI for pad-mount transformers is 99%.

Results

OPUCN owns and maintains 3,953 pad-mount transformers within its service territory. Installation dates are available for all but sixteen of OPUCN's pad-mount transformers. The demographic analysis for pad-mount transformers is provided in Figure 4-15. The TUL for pad-mount transformers is 40 years and assets are considered to be approaching their TUL if they were installed more than 27 years ago. The sixteen assets with an unknown service age are not shown in Figure 4-15. It can be assumed that assets with unknown service ages are close to the TUL of 40 years.

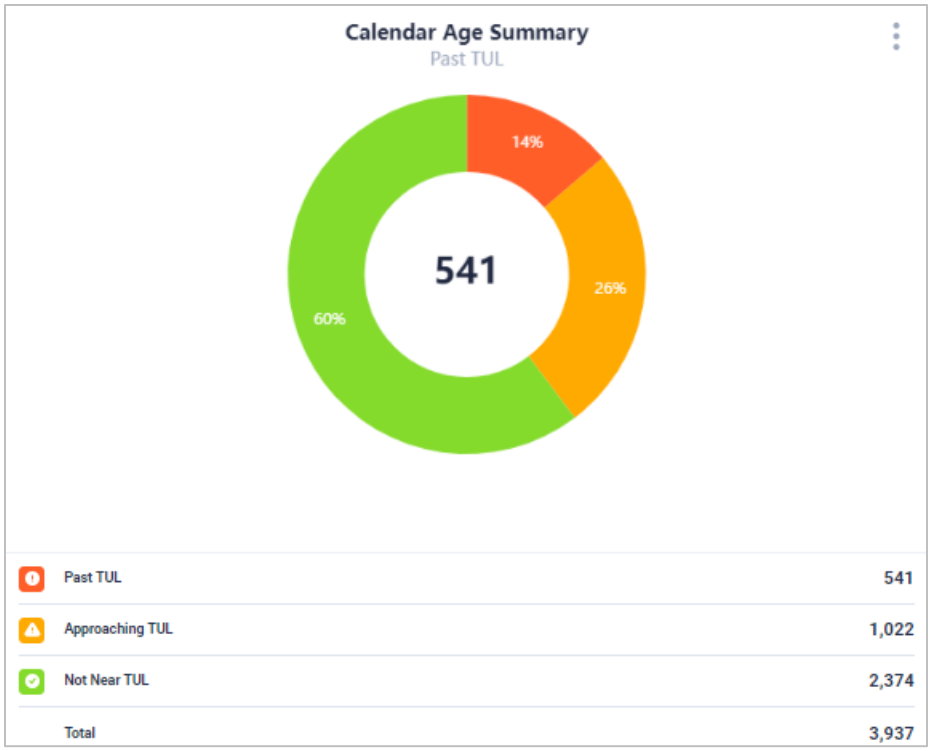


Figure 4-15: Pad-Mount Transformer Demographic Assessment

The ACA results for OPUCN's pad-mount transformers are summarized in Figure 4-16. Valid HI results were outputted for 97% of the assets.

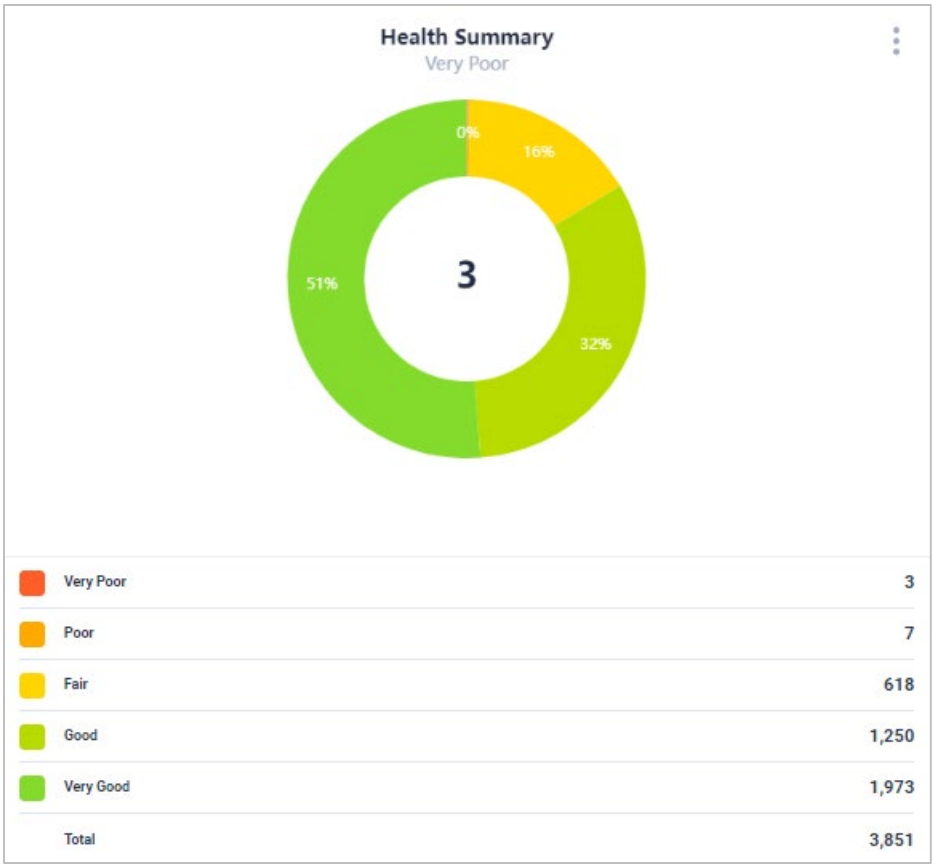


Figure 4-16: Pad-Mount Transformer ACA Results

4.1.8 Vault Transformers

OPUCN owns and operates 151 vault transformers within its service territory.

Health Index Formulation

Vault transformers can be located on a customer's premises in a vault accessible only to Local Distribution Company ("LDC") staff, or sometimes are located in a sidewalk vault on the right of way. 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.

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 observed, a 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 the doors and vents, contributes to the decision to rehabilitate a vault transformer.

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 vault transformers is calculated based on EOL criteria summarized in Table 4-9.

Table 4-9: Vault Transformer HI Formulation

Condition Parameter	DAI	Weight	Ranking	Numerical Grade	Max Score
Service Age	99%	3	A,B,C,D,E	4,3,2,1,0	12
Overall Condition	97%	3	A,B,C,D,E	4,3,2,1,0	12
Corrosion	96%	3	A,B,C,D,E	4,3,2,1,0	12
Oil Leaks	96%	2	A,B,C,D,E	4,3,2,1,0	8
Condition of Civil Structure	96%	2	A,B,C,D,E	4,3,2,1,0	8
Total Score					**52**

Data Collection and Assumptions

OPUCN provided an asset registry for vault transformers and visual inspection records for its vaults. Where possible, installation date was taken directly from the vault transformer asset registry. The visual inspection records for vaults were provided in pdf format with hand-written notes which were manually entered to perform this condition assessment. Fields specific to the transformer in each vault were extracted from the vault inspection records.

As a secondary input, the service age and overall condition of vault transformers was taken from the previous ACA. Additionally, assets installed less than five years ago were assumed to be in Very Good condition with respect to oil leaks, corrosion, and the condition of the civil structure.

The overall DAI for vault transformers is 97%.

Results

OPUCN owns and maintains 151 vault transformers within its service territory. Installation dates are known for 99% of OPUCN's vault transformers. The demographic analysis for vault transformers is provided in Figure 4-17. The TUL for vault transformers is 35 years and assets are considered to be approaching their TUL if they were installed more than 23 years ago. The asset with an unknown service age is not shown in Figure 4-17. It can be assumed that this asset is close to the TUL of 35 years.

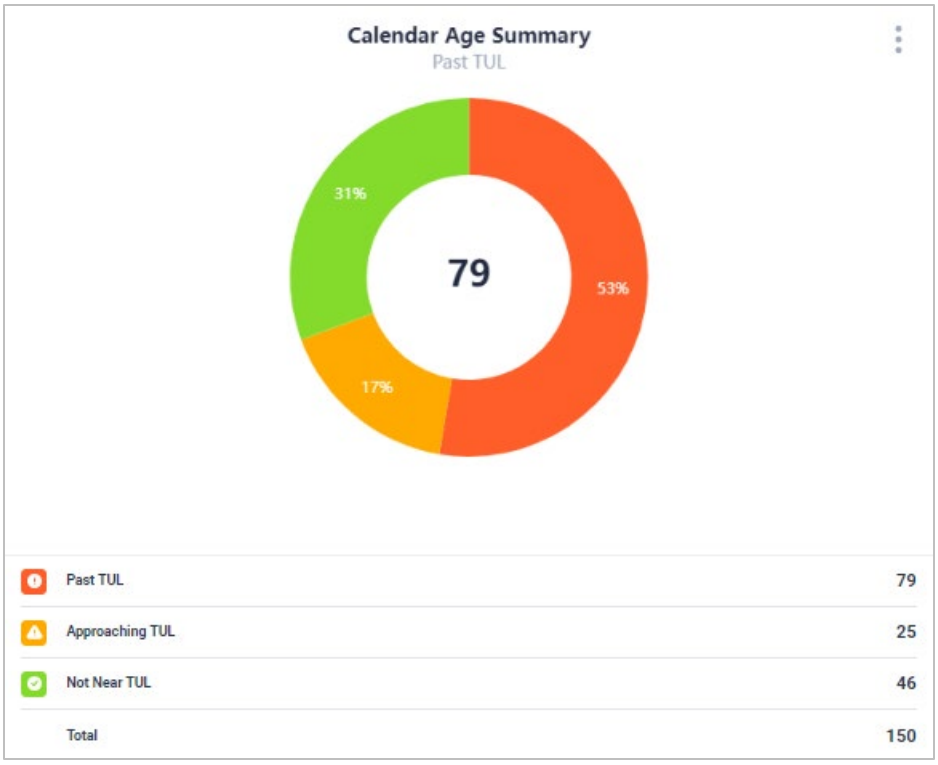


Figure 4-17: Vault Transformer Demographic Assessment

The ACA results for OPUCN's vault transformers are summarized in Figure 4-18. Valid HI results were outputted for 96% of the assets.

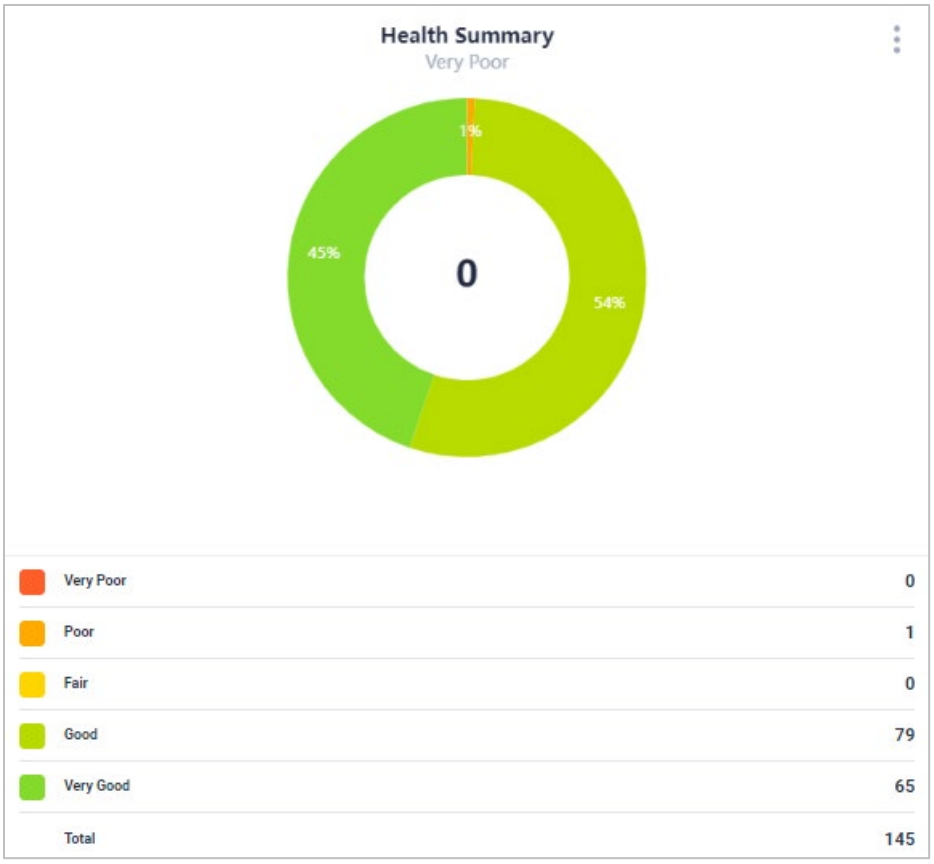


Figure 4-18: Vault Transformer ACA Results

4.1.9 Overhead Switches

Switches that are not operated under load are called air-break switches, whereas switches with load-breaking capability are called load-break switches, and switches that can break under fault current are called fault-interrupter switches. Solid-blade riser switches are used to isolate underground cable sections and do not break load. OPUCN owns and maintains 718 OH switches within its service territory.

Health Index Formulation

OH switches represent critical infrastructure for a distribution utility. The primary means of inspecting and maintaining switches are to visually identify dirt and corrosion and to use IR scans to find "hot" connections. Traditional air-insulated, handle-operated switches are highly maintainable and can often be extended indefinitely and nearly completely rebuilt on the pole.

The HI for OH switches is calculated based on EOL criteria summarized in Table 4-10.

Table 4-10: OH Switch HI Formulation

Condition Parameter	DAI	Weight	Ranking	Numerical Grade	Max Score
Overall Condition	98%	3	A,B,C,D,E	4,3,2,1,0	12
Service Age	85%	2	A,B,C,D,E	4,3,2,1,0	8
IR Scan	100%	2	A,B,C,D,E	4,3,2,1,0	8
Total Score					**28**

Data Collection and Assumptions

OPUCN provided an asset registry, visual inspection record, and OH IR scan report for OH switches. Where available, installation date was taken directly from the OH switch asset registry. The visual inspection records for OH switches were provided in pdf format with hand-written notes which were manually entered to perform this condition assessment. The visual inspection record only indicated whether or not an inspection or maintenance had been completed on the asset. It was assumed that the condition of the asset was very good if an inspection or maintenance had been completed. If an inspection had not been completed, no assumption was made about the condition of the asset.

As a secondary input, the service age and overall condition of OH switches was taken from the previous ACA. Additionally, assets installed less than five years ago were assumed to be in Very Good overall condition.

The overall DAI for OH switches is 95%.

Results

OPUCN owns and maintains 718 OH switches within its service territory. Installation dates are available for 85% of OPUCN's OH switches. The demographic analysis for OH switches is provided in Figure 4-19. The TUL for OH switches is 45 years and assets are considered to be approaching their TUL if they were installed more than 30 years ago. The 108 assets with an unknown service age are not shown in Figure 4-19. It can be assumed that assets with unknown service ages are close to the TUL of 45 years.

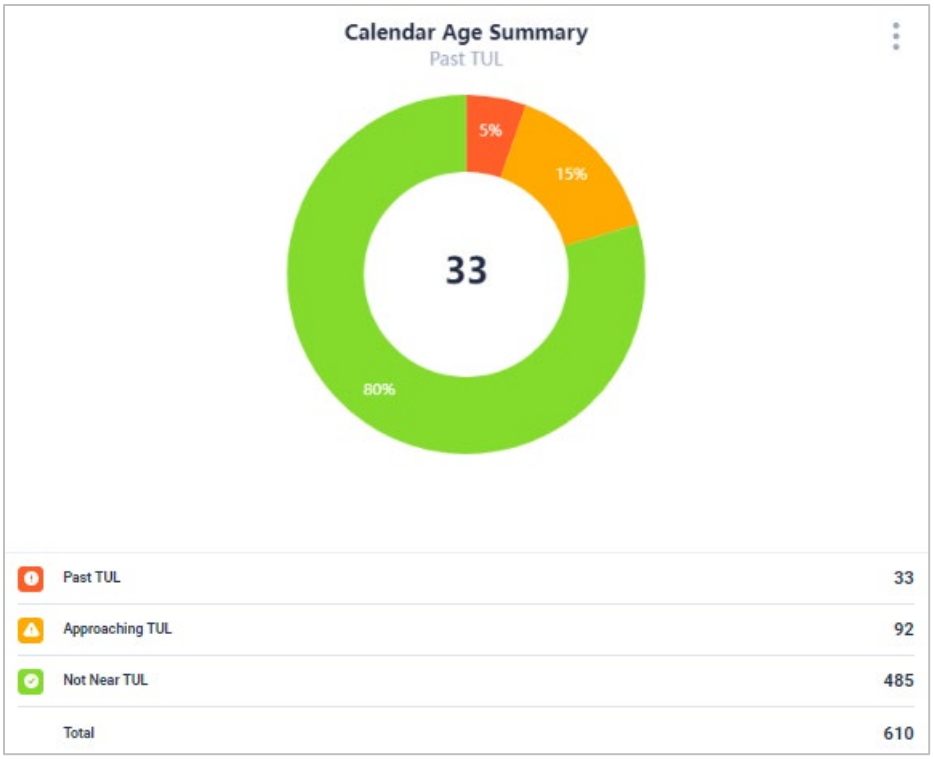


Figure 4-19: OH Switch Demographic Assessment

The ACA results for OPUCN's OH switches are summarized in Figure 4-20. Valid HI results were outputted for 98% of the assets.

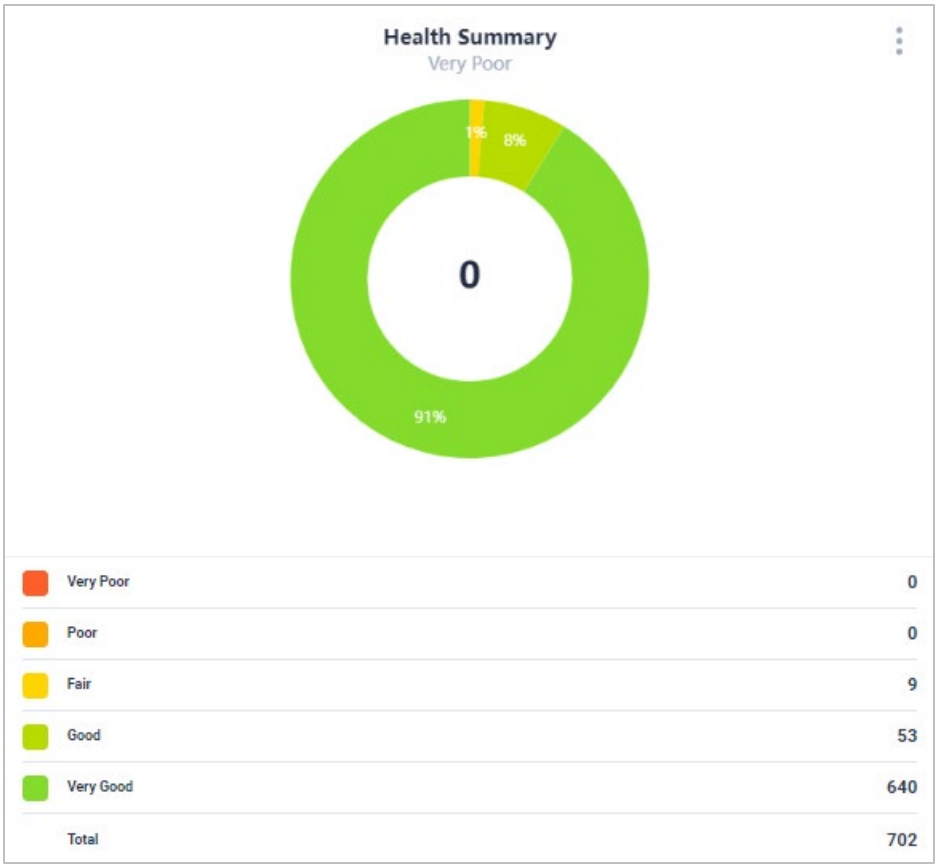


Figure 4-20: OH Switch HI Results

4.1.10 Smart Switches

OPUCN owns and maintains 31 smart switches within is service territory.

Health Index Formulation

This asset class includes switches which are controlled via SCADA. Smart switches experience similar degradation mechanisms to OH switches and use the same HI formulation which is summarized in Table 4-11.

Table 4-11: Smart Switch HI Formulation

Condition Parameter	DAI	Weight	Ranking	Numerical Grade	Max Score
Overall Condition	100%	3	A,B,C,D,E	4,3,2,1,0	12
Service Age	100%	2	A,B,C,D,E	4,3,2,1,0	8
IR Scan	100%	2	A,B,C,D,E	4,3,2,1,0	8
Total Score					**28**

Data Collection and Assumptions

OPUCN provided an asset registry, visual inspection record, and OH IR scan report for smart switches. Installation dates were taken directly from the smart switch asset registry. The visual inspection records for smart switches were provided in pdf format with hand-written notes which were manually entered to perform this condition assessment. The visual inspection record only indicated whether or not an inspection or maintenance had been completed on the asset. It was assumed that the condition of the asset was very good if an inspection or maintenance had been completed. If an inspection had not been completed, no assumption was made about the condition of the asset.

As a secondary input, the service age and overall condition of smart switches was taken from the previous ACA. Additionally, assets installed less than five years ago were assumed to be in Very Good overall condition.

The overall DAI for smart switches is 100%.

Results

OPUCN owns and maintains 31 smart switches within its service territory. Installation dates are known for all of OPUCN's smart switches. The demographic analysis for smart switches is provided in Figure 4-21. The TUL for smart switches is 45 years and assets are considered to be approaching their TUL if they were installed more than 30 years ago.

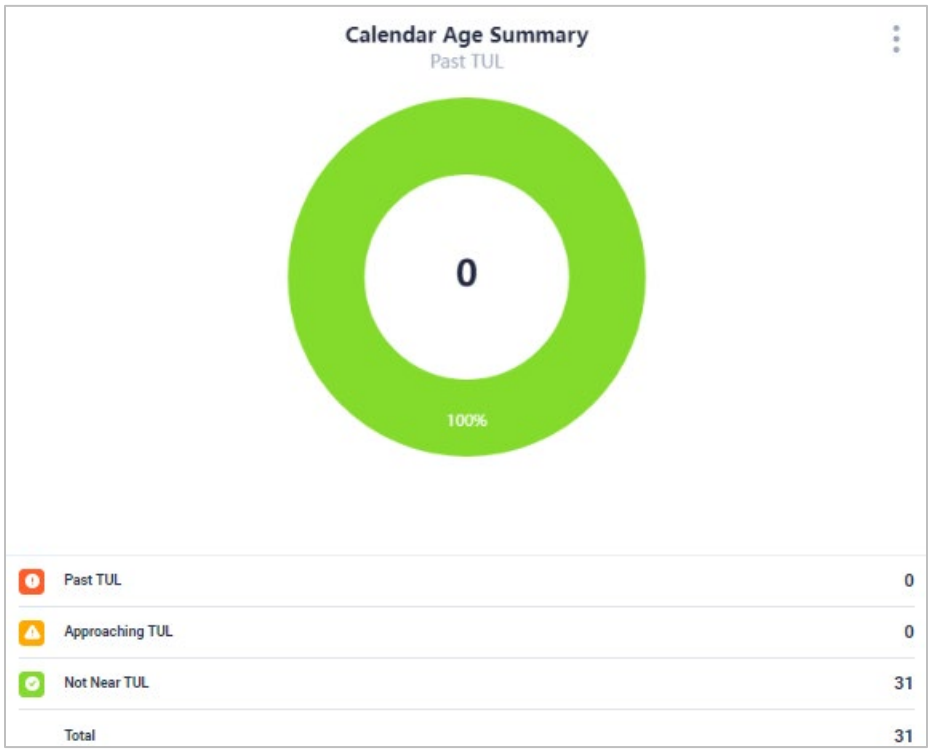


Figure 4-21: Smart Switch Demographic Assessment

The ACA results for OPUCN's smart switches are summarized in Figure 4-22. Valid HI results were outputted for all of the assets.

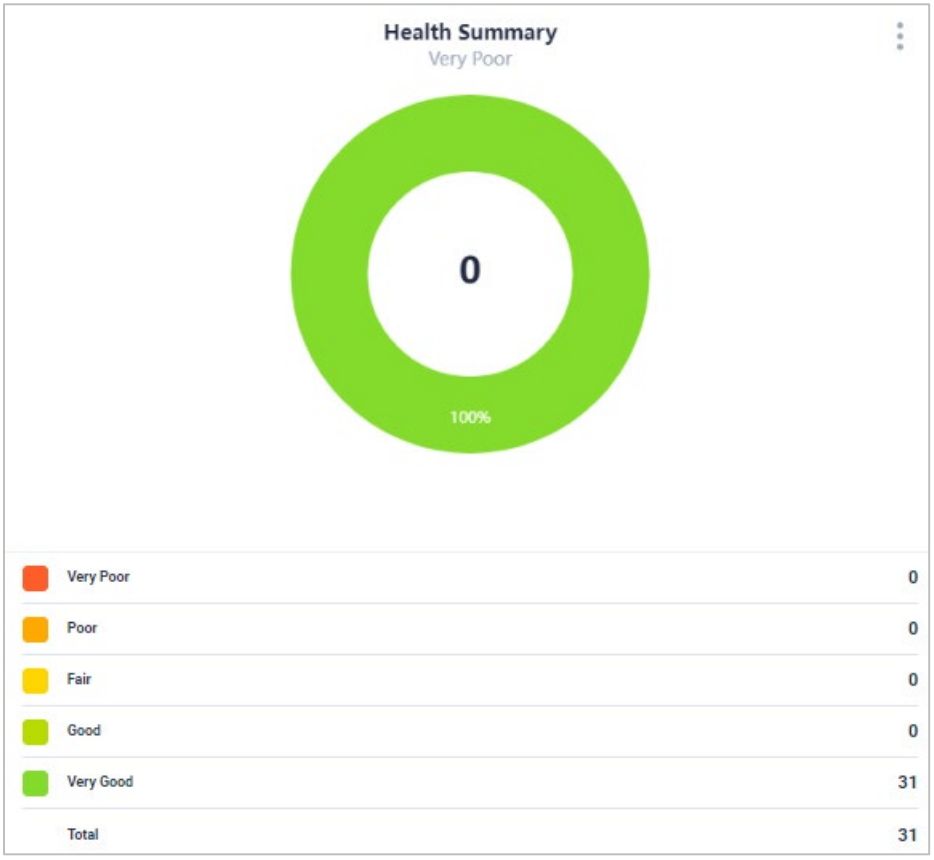


Figure 4-22: Smart Switch HI Results

4.1.11 Distribution Switchgear

OPUCN owns and maintains 42 distribution switchgears within its service territory.

Health Index Formulation

Typical EOL indicators for distribution switchgear 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 distribution switchgear is calculated based on EOL criteria summarized in Table 4-12.

Table 4-12: Distribution Switchgear HI Formulation

Condition Parameter	DAI	Weight	Ranking	Numerical Grade	Max Score
Service Age	100%	1	A,B,C,D,E	4,3,2,1,0	4
Overall Condition	100%	1	A,B,C,D,E	4,3,2,1,0	4
Total Score					**8**

Data Collection and Assumptions

OPUCN provided an asset registry, visual inspection record, and OH IR scan report for distribution switchgear. Installation dates were taken directly from the distribution switchgear asset registry.

The visual inspection records for distribution switchgears were provided in pdf format with hand-written notes which were manually entered to perform this condition assessment. The visual inspection record only indicated whether or not an inspection or maintenance had been completed on the asset. It was assumed that the condition of the asset was very good if an inspection or maintenance had been completed. If an inspection had not been completed, no assumption was made about the condition of the asset.

The overall DAI for distribution switchgears is 100%.

Results

OPUCN owns and maintains 42 distribution switchgears within its service territory. Installation dates are known for all of OPUCN's distribution switchgear. The demographic analysis for distribution switchgear is provided in Figure 4-23. The TUL for distribution switchgear is 30 years and assets are considered to be approaching their TUL if they were installed more than twenty years ago.

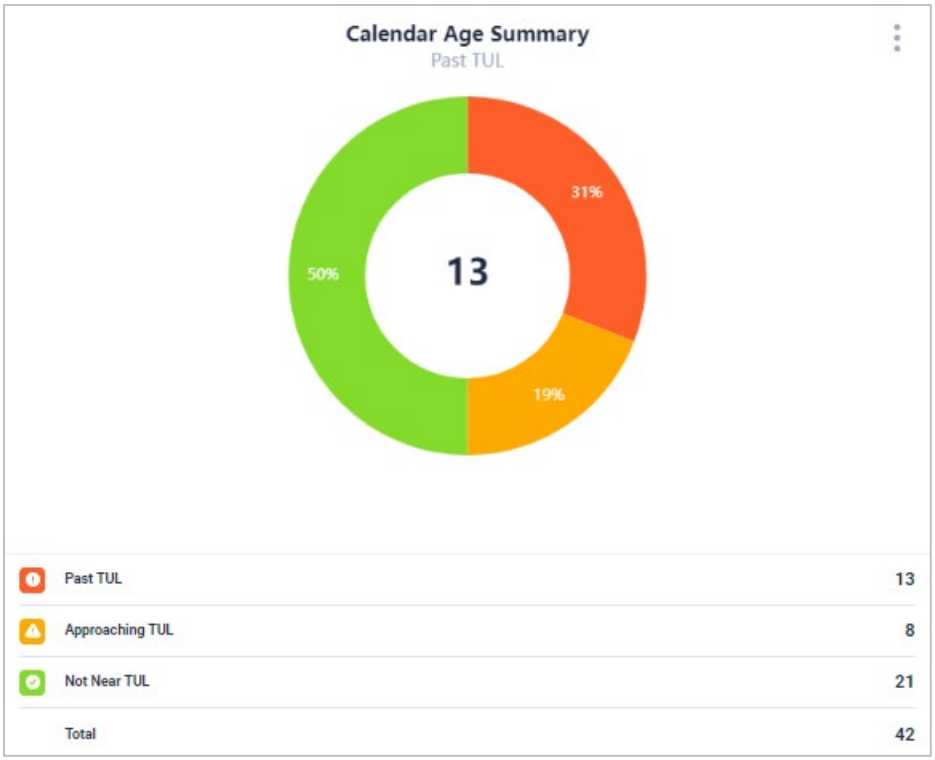


Figure 4-23: Distribution Switchgear Demographic Assessment

The ACA results for OPUCN's distribution switchgears are summarized in Figure 4-24. Valid HI results were outputted for all of the assets.

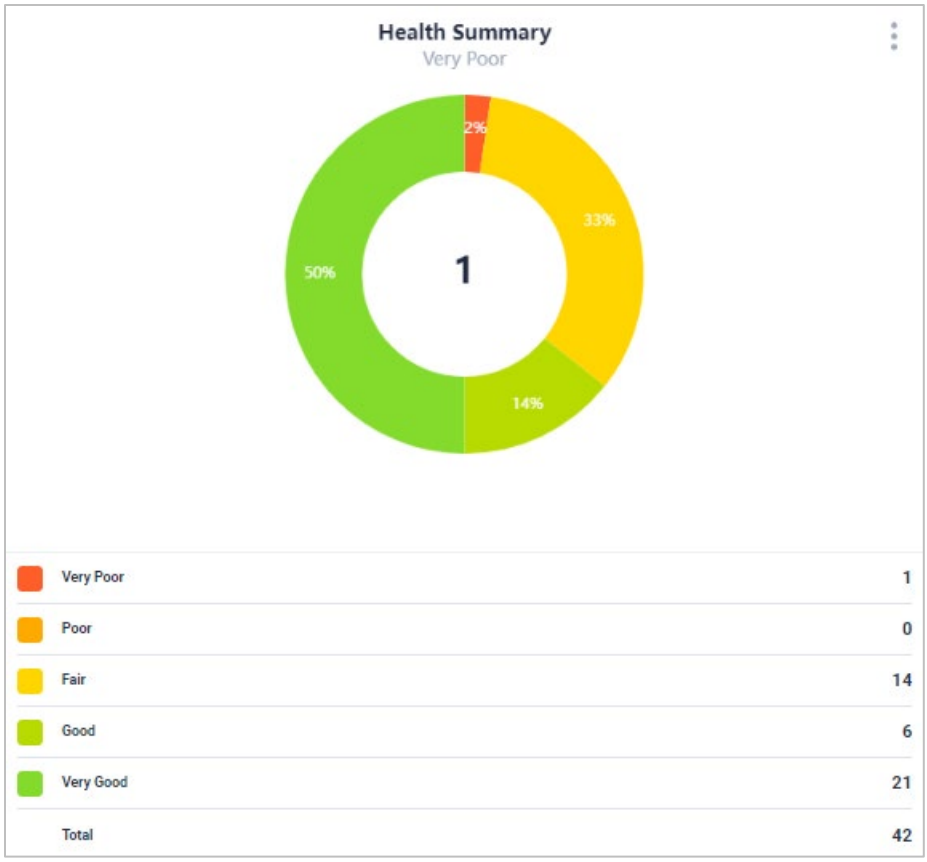


Figure 4-24: Distribution Switchgear HI Results

4.1.12 Cut-Out Arrestors

OPUCN owns and operates 1,761 cut-out arrestors within its service territory.

Health Index Formulation

The HI for cut-out arrestors is calculated based on EOL criteria summarized in Table 4-13.

Table 4-13: Cut-Out Arrestor HI Formulation

Condition Parameter	DAI	Weight	Ranking	Numerical Grade	Max Score
Service Age	94%	1	A,B,C,D,E	4,3,2,1,0	4
IR Scan	100%	1	A,B,C,D,E	4,3,2,1,0	4
Total Score					**8**

Data Collection and Assumptions

OPUCN provided an asset registry and overhead IR scan report which were used as inputs for the cut-out arrestors analysis.

Installation dates were taken directly from the cut-out arrestor asset registry. Assets of concern were identified in the OH IR scan report. All assets that were not mentioned in the report were assumed to have no issues from the IR scan.

The overall DAI for cut-out arrestors is 97%.

Results

OPUCN owns and maintains 1,761 cut-out arrestors within its service territory. Installation dates are known for 94% of OPUCN's cut-out arrestors. The demographic analysis for cut-out arrestors is provided in Figure 4-25. The TUL for cut-out arrestors is 30 years and assets are considered to be approaching their TUL if they were installed more than twenty years ago. The 104 assets with an unknown service age are not shown in Figure 4-25. It can be assumed that assets with unknown service ages are close to the TUL of 30 years.

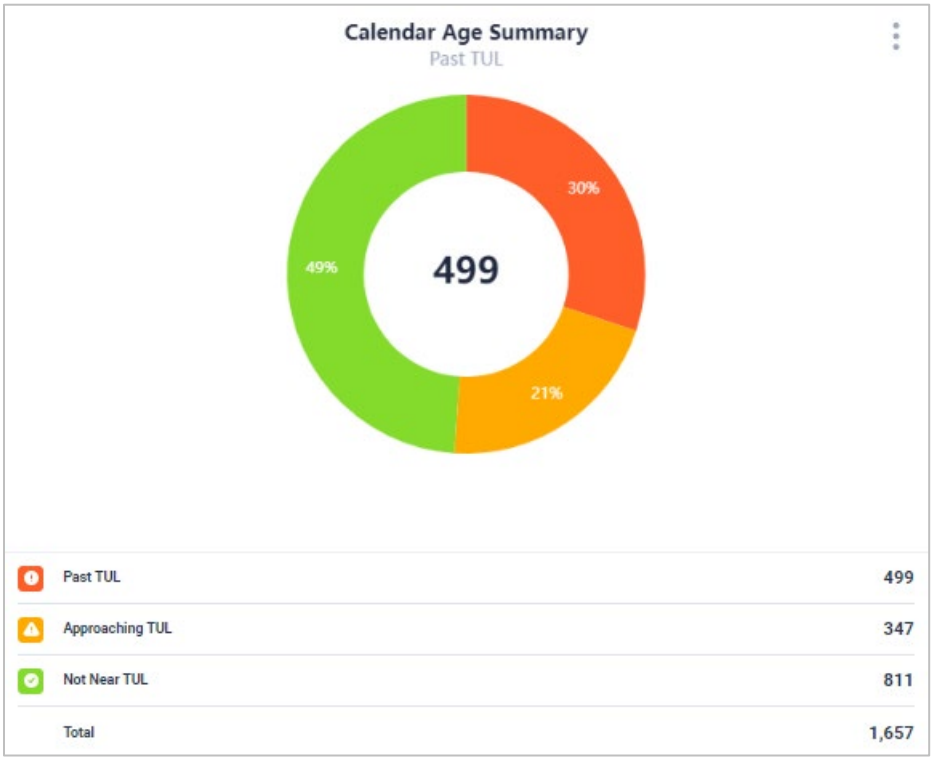


Figure 4-25: Cut-Out Arrestor Demographic Assessment

The ACA results for OPUCN's cut-out arrestors are summarized in Figure 4-26. Valid HI results were outputted for 94% of the assets.

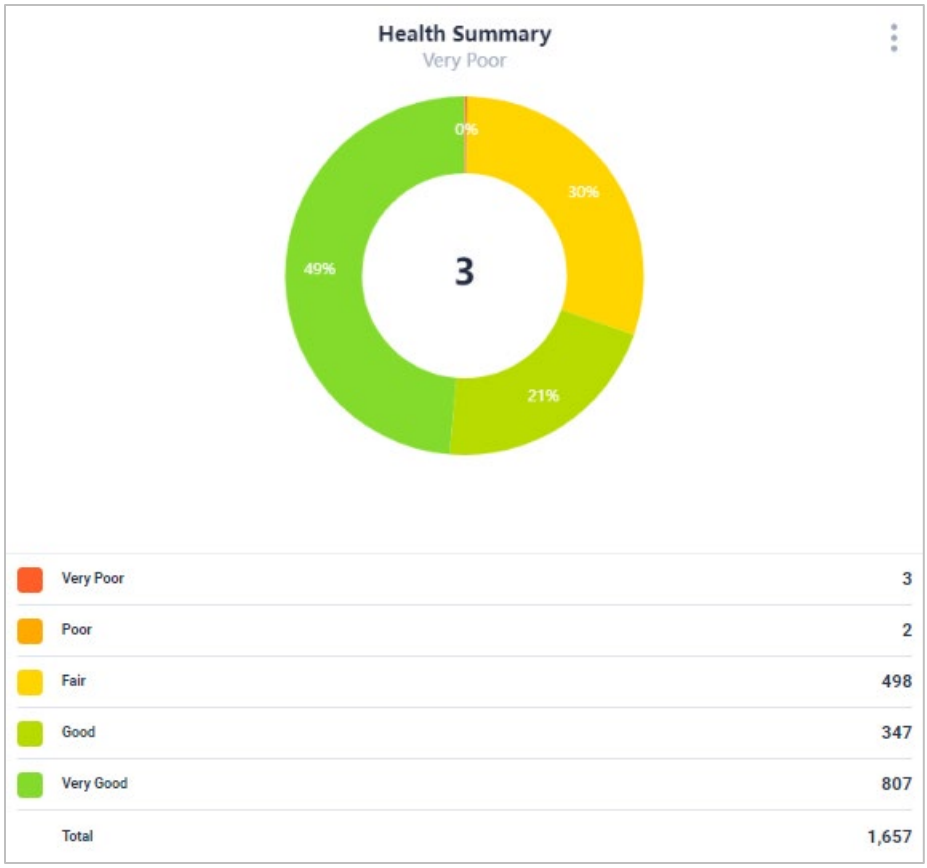


Figure 4-26: Cut-Out Arrestor HI Results

The cut-out arrestor HI results were also extrapolated to estimate the distribution of health across the entire asset class. The extrapolation is done based on the HI distribution across ten-year age bands. The assets with an unknown HI are distributed within the HI categories using the distribution of the known HIs for assets with similar ages. Assets with an unknown HI and an unknown age are distributed into HI categories using the HI distribution of the entire asset class. The known HI distribution for cut-out arrestors in each ten-year age band is shown in Table 4-14. The extrapolated HI results for cut-out arrestors are shown in Figure 4-27.

Table 4-14: Cut-Out Arrestor HI Distribution for Ten-Year Age Bands

	HI Category					
Age Range	Very Good	Good	Fair	Poor	Very Poor	Unknown
0 – 10	100%	0%	0%	0%	0%	0%
11 – 20	99%	0%	1%	0%	0%	0%
21 – 30	0%	99%	0%	0%	0%	0%
31 – 40	0%	0%	99%	0%	0%	0%
41 – 50	0%	0%	99%	0%	1%	0%
51+	0%	0%	100%	0%	0%	0%
Unknown	0%	0%	0%	0%	0%	100%

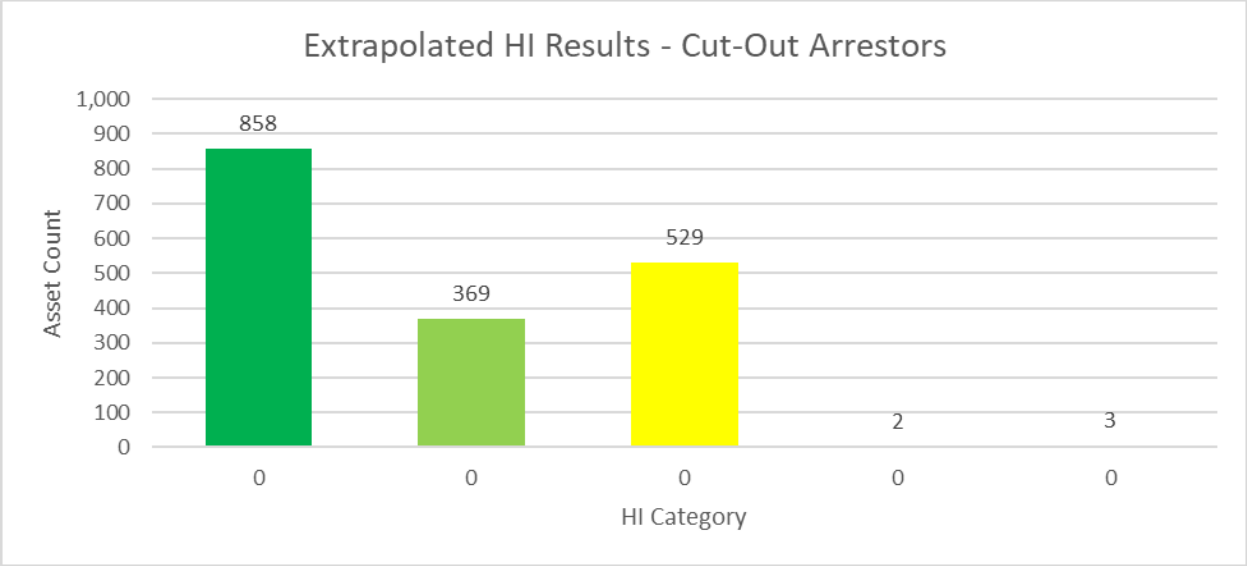


Figure 4-27: Extrapolated HI Results for Cut-Out Arrestors

4.1.13 Elbow Connectors

OPUCN owns and maintains 7,114 elbow connectors within its service territory.

Health Index Formulation

The HI for elbow connectors is calculated based on EOL criteria summarized in Table 4-15.

Table 4-15: Elbow Connector HI Formulation

Condition Parameter	DAI	Weight	Ranking	Numerical Grade	Max Score
Overall Condition	100%	3	A,B,C,D,E	4,3,2,1,0	12
Service Age	95%	1	A,B,C,D,E	4,3,2,1,0	4
Total Score					**16**

Data Collection and Assumptions

Data was provided from 2018 for OPUCN's elbow connectors. The asset IDs, installation years, a visual inspection scores were provided in the 2018 file. The visual inspections were provided using a scale of 1-5 which was directly translated into METSCO's A-E grading scheme.

The overall DAI for elbow connectors is 99%

Results

OPUCN owns and maintains 7,114 elbow connectors within its service territory. Installation dates are known for 95% of OPUCN's elbow connectors. The demographic analysis for elbow connectors is provided in Figure 4-28. The TUL for elbow connectors is 30 years and assets are considered to be approaching their TUL if they were installed more than twenty years ago.

The 286 assets with an unknown service age are not shown in Figure 4-28. It can be assumed that assets with unknown service ages are close to the TUL of 30 years.

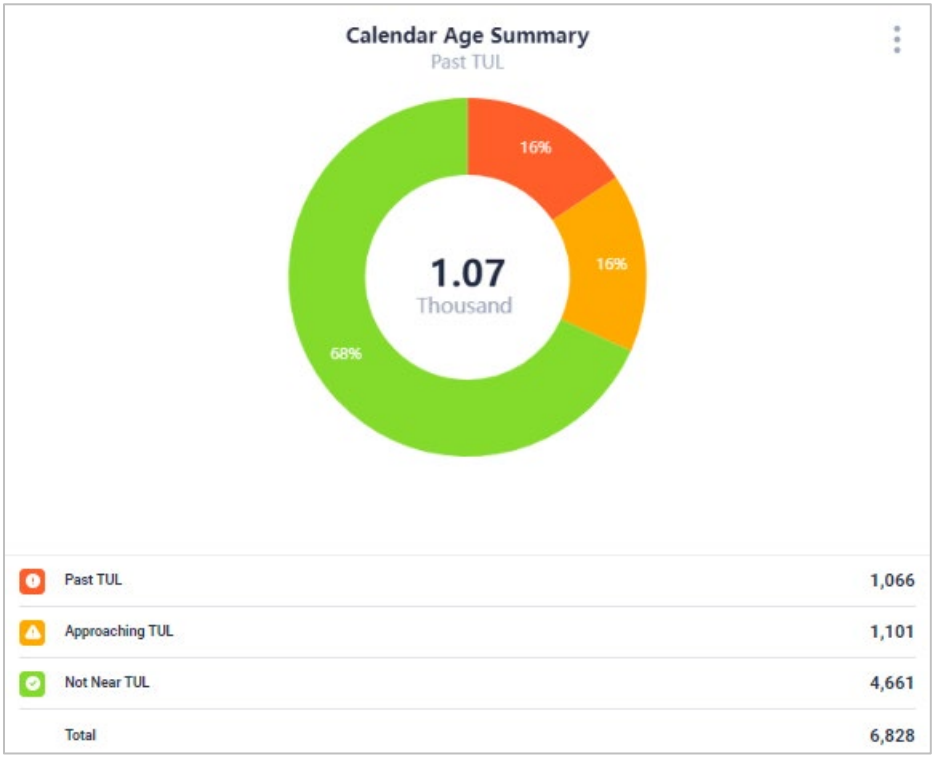


Figure 4-28: Elbow Connector Demographic Assessment

The ACA results for OPUCN's elbow connectors are summarized in Figure 4-29. Valid HI results were outputted for all of the assets.

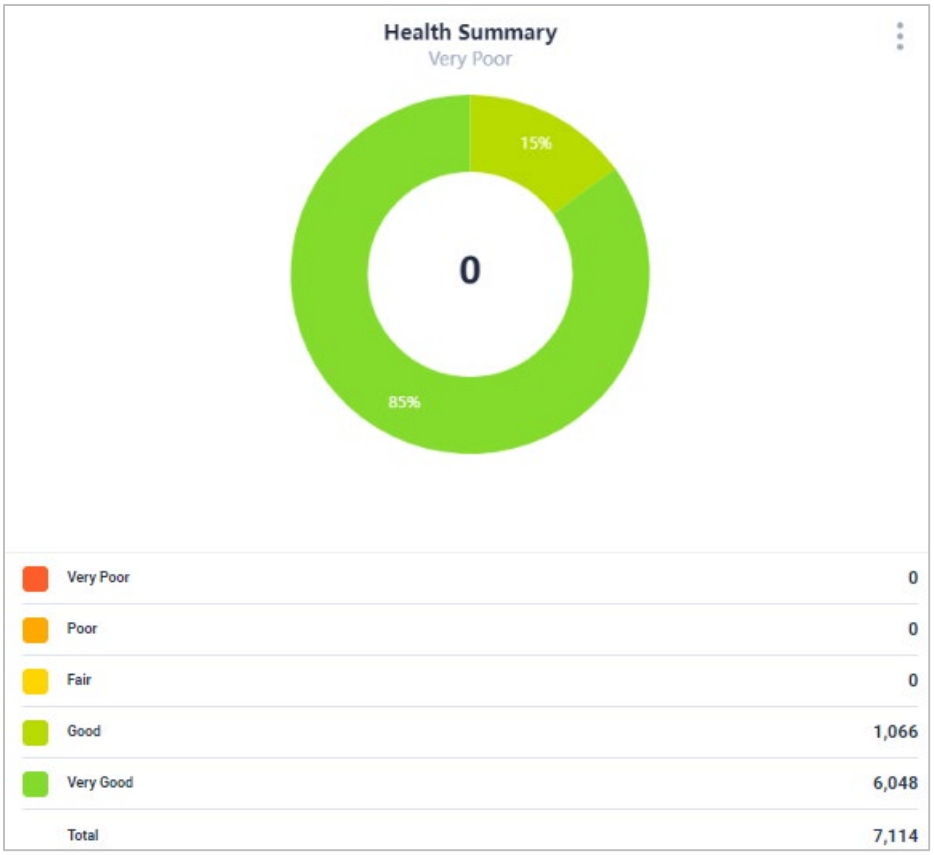


Figure 4-29: Elbow Connector HI Results

4.1.14 Reclosers

OPUCN owns and maintains three reclosers within its service territory.

Health Index Formulation

The HI for reclosers is calculated based on EOL criteria summarized in Table 4-16.

Table 4-16: Recloser HI Formulation

Condition Parameter	DAI	Weight	Ranking	Numerical Grade	Max Score
Overall Condition	100%	3	A,B,C,D,E	4,3,2,1,0	12
Service Age	100%	1	A,B,C,D,E	4,3,2,1,0	4
Total Score					**16**

Data Collection and Assumptions

An asset registry was provided for OPUCN's reclosers which included the installation date for each asset. OPUCN's substation crew performed a visual inspection of the three reclosers and recorded that the assets all are in good overall condition.

The overall DAI for reclosers is 100%.

Results

OPUCN owns and maintains three reclosers within its service territory. Installation dates are known for all of OPUCN's reclosers. The demographic analysis for reclosers is provided in Figure 4-30. The TUL for reclosers is 40 years and assets are considered to be approaching their TUL if they were installed more than 27 years ago.

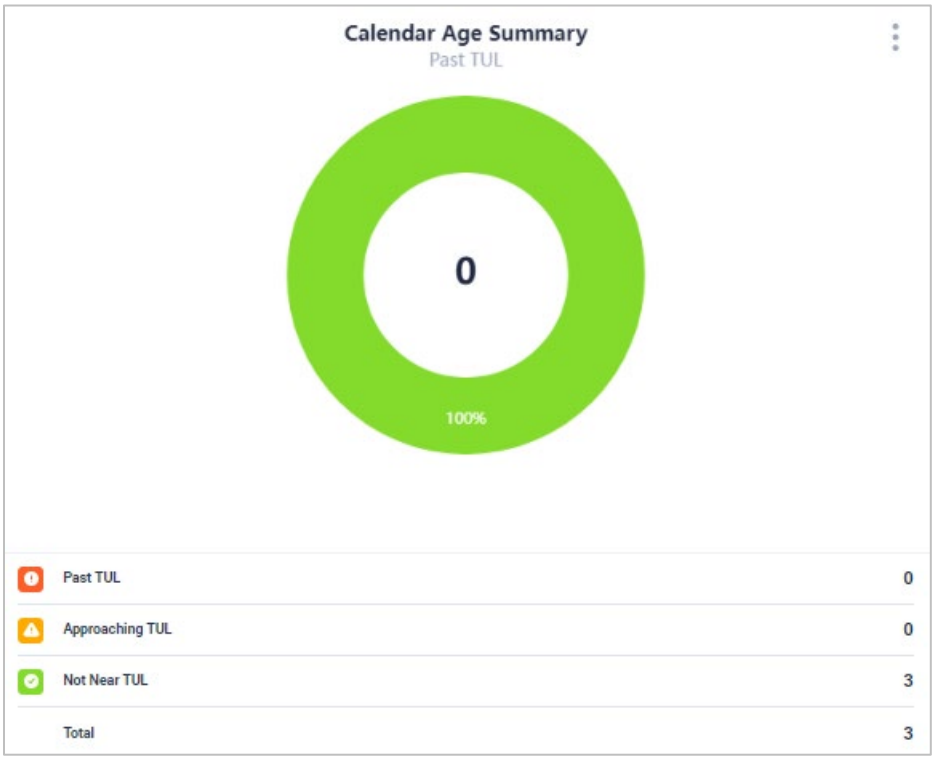


Figure 4-30: Recloser Demographic Assessment

The ACA results for OPUCN's reclosers are summarized in Figure 4-31. Valid HI results were outputted for all of the assets.

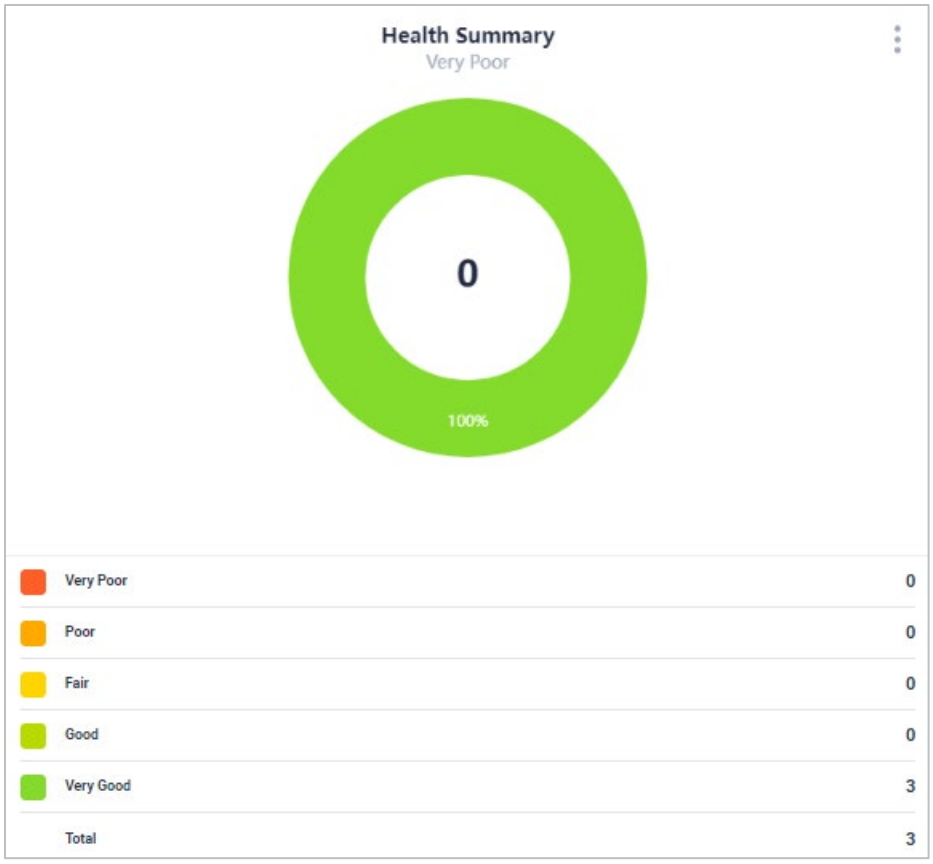


Figure 4-31: Recloser HI Results

4.1.15 Vaults & Manholes

OPUCN owns and operates 6 vaults and 121 manholes within its service territory.

Health Index Formulation

The HI results for vaults and manholes are calculated based on EOL criteria summarized in Table 4-17 and Table 4-18, respectively.

Table 4-17: Vault HI Formulation

Condition Parameter	DAI	Weight	Ranking	Numerical Grade	Max Score
Size and Access	100%	9	A,C,E	4,2,0	36
Condition of Flooding Mitigation Equipment	100%	8	A,C,E	4,2,0	32
Structural Integrity	100%	8	A,B,C,D,E	4,3,2,1,0	32
Service Age	100%	7	A,B,C,D,E	4,3,2,1,0	28
Condition of Ventilation Equipment	100%	3	A,C,E	4,2,0	12
Condition of Door	100%	3	A,C,E	4,2,0	12
Total Score					**152**

Table 4-18: Manhole HI Formulation

Condition Parameter	DAI	Weight	Ranking	Numerical Grade	Max Score
Condition of Flooding Mitigation Equipment	40%	8	A,C,E	4,2,0	32
Structural Integrity	40%	8	A,B,C,D,E	4,3,2,1,0	32
Service Age	100%	7	A,B,C,D,E	4,3,2,1,0	28
Condition of Roof	40%	7	A,B,C,D,E	4,3,2,1,0	28
Total Score					**120**

Data Collection and Assumptions

OPUCN provided asset registries for its vaults and manholes. The date of construction of the vaults was taken directly from the asset registry while an estimated date of construction was provided separately for manholes.

A visual inspection record was provided for vaults and manholes. Only a limited number of fields were filled out on the inspection sheet which were used to grade the relevant condition parameters for the civil assets.

The overall DAI for vaults is 100% and the overall DAI for manholes is 54%.

Results

OPUCN owns and operates six vaults and 121 manholes within its service territory.

Installation dates are known for all of OPUCN's vaults. The demographic analysis for vaults is provided in Figure 4-32. The TUL for vaults is 60 years and assets are considered to be approaching their TUL if they were installed more than 40 years ago.

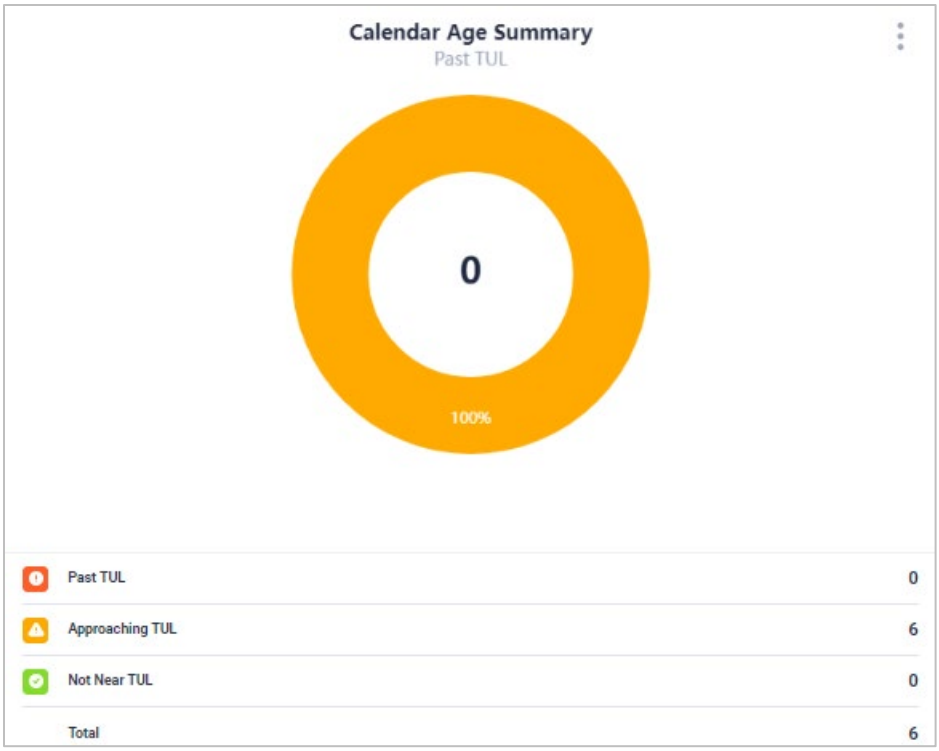


Figure 4-32: Vault Demographic Assessment

The ACA results for OPUCN's vaults are summarized in Figure 4-33. Valid HI results were outputted for all of the assets.

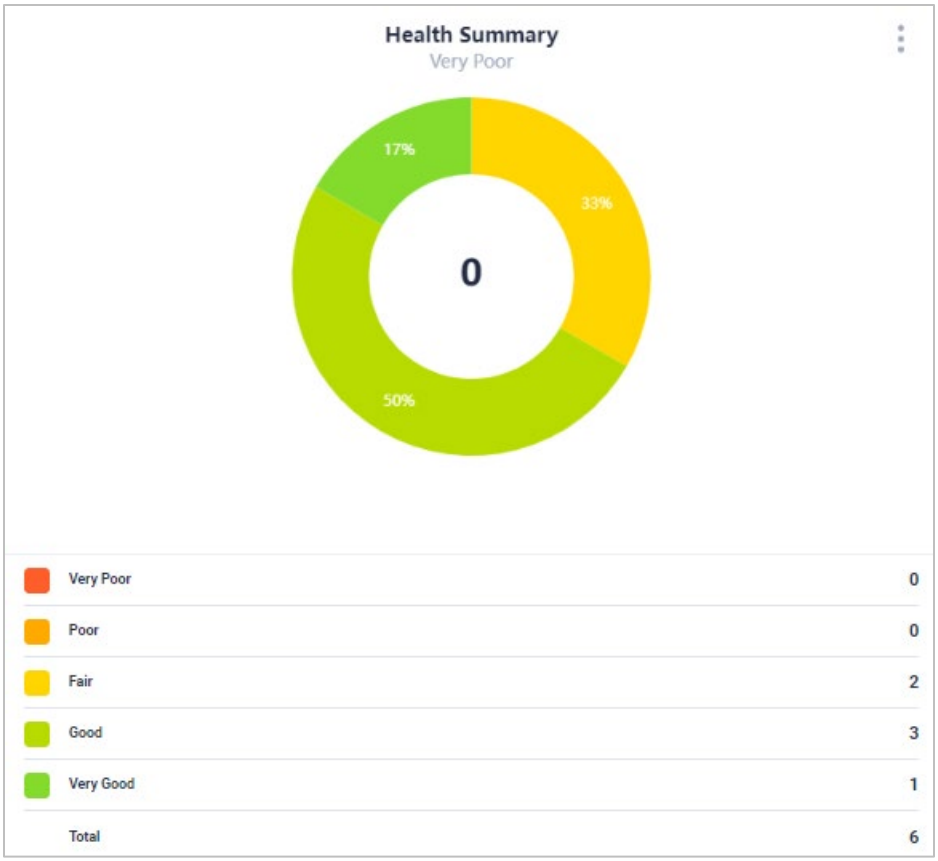


Figure 4-33: Vault HI Results

Installation dates were estimated for all of OPUCN's manholes. The demographic analysis for manholes is provided in Figure 4-34. The TUL for manholes is 60 years and assets are considered to be approaching their TUL if they were installed more than 40 years ago.

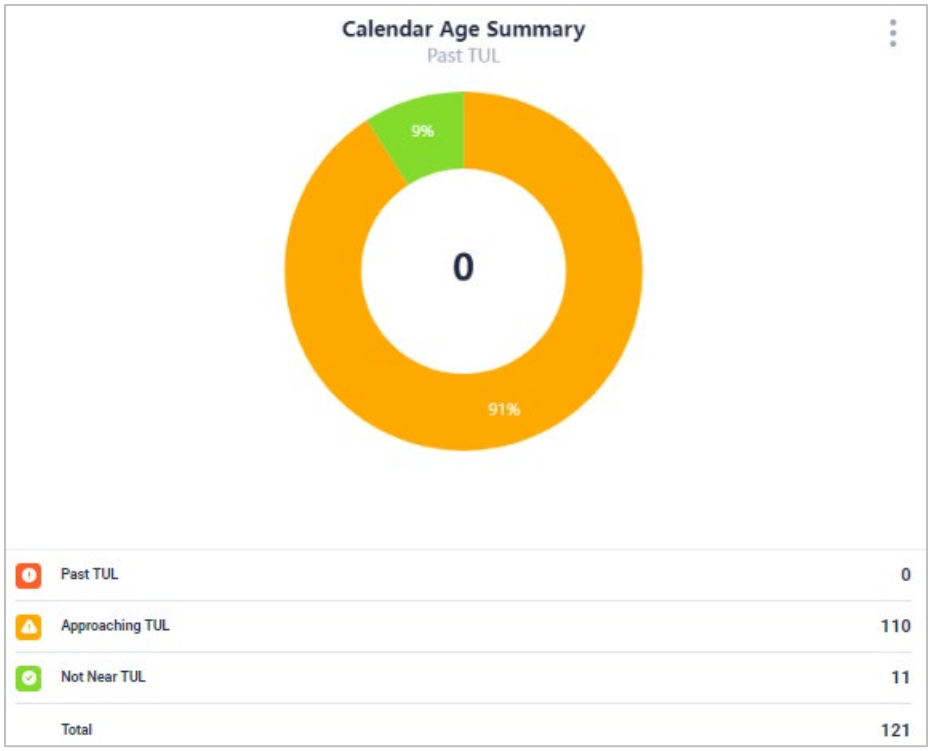


Figure 4-34: Manholes Demographic Assessment

The ACA results for OPUCN's manholes are summarized in Figure 4-35. Valid HI results were outputted for 40% of the assets.

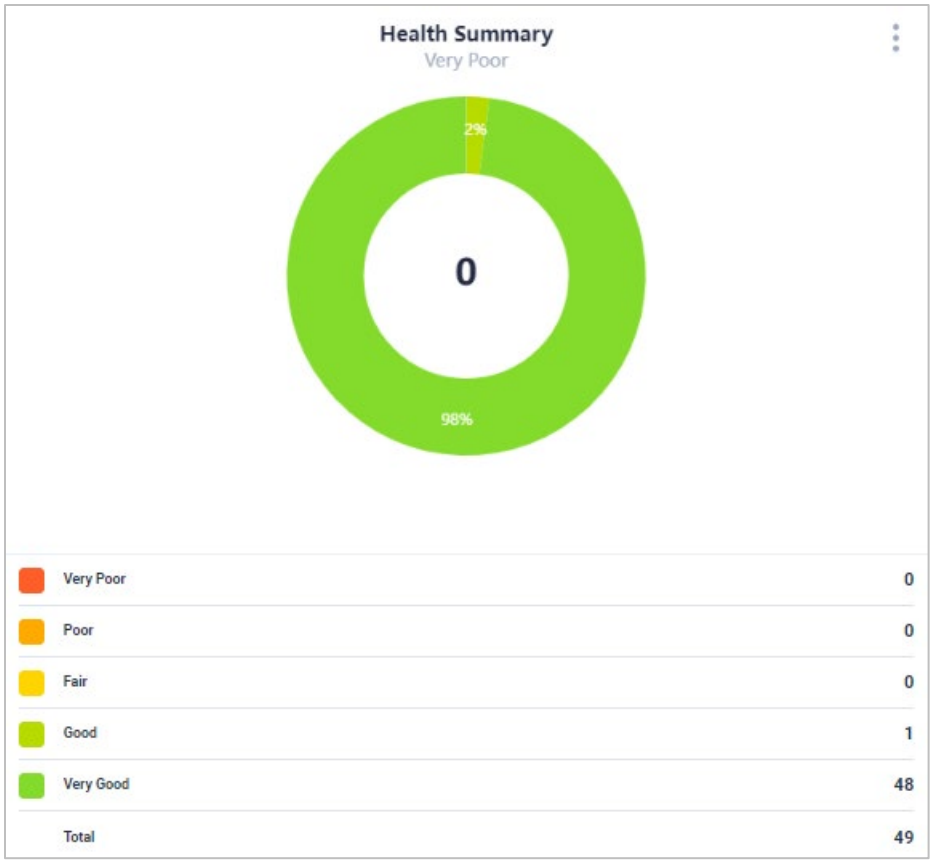


Figure 4-35: Manhole HI Results

4.2 Station Assets

4.2.1 Power Transformers

Power transformers are the single most critical asset class 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. OPUCN owns and maintains eighteen power transformers within its stations.

Health Index Formulation

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 place.

The HI for power transformers is calculated based on EOL criteria summarized in Table 4-19.

Table 4-19: Power Transformer HI Formulation

Condition Parameter	DAI	Weight	Ranking	Numerical Grade	Max Score
Service Age	100%	12	A,B,C,D,E	4,3,2,1,0	48
Load History	100%	12	A,B,C,D,E	4,3,2,1,0	48
DGA (Main Tank)	100%	10	A,B,C,D,E	4,3,2,1,0	40
Oil Quality (Main Tank)	100%	8	A,C,E	4,2,0	32
Winding Resistance	89%	6	A,B,C,D,E	4,3,2,1,0	24
Turns Ratio	100%	5	A,B,C,D,E	4,3,2,1,0	20
Oil Leaks	100%	5	A,B,C,D,E	4,3,2,1,0	20
Condition of Bushings	100%	5	A,B,C,D,E	4,3,2,1,0	20
Corrosion of Main Tank	100%	4	A,B,C,D,E	4,3,2,1,0	16
Condition of Cooling Equipment	100%	4	A,B,C,D,E	4,3,2,1,0	16
Insulation Resistance	100%	4	A,B,C,D,E	4,3,2,1,0	16
Winding Temperature	100%	4	A,B,C,D,E	4,3,2,1,0	16
Dissipation Factor	100%	4	A,B,C,D,E	4,3,2,1,0	16
Condition of LTC	100%	4	A,B,C,D,E	4,3,2,1,0	16
DGA (LTC)	100%	4	A,B,C,D,E	4,3,2,1,0	16
Oil Quality (LTC)	100%	4	A,C,E	4,2,0	16
Oil Level	100%	3	A,B,C,D,E	4,3,2,1,0	12
Condition of Foundation	100%	1	A,B,C,D,E	4,3,2,1,0	4
Condition of Grounding	100%	1	A,B,C,D,E	4,3,2,1,0	4
Condition of Gaskets	100%	1	A,B,C,D,E	4,3,2,1,0	4
Condition of Connectors	100%	1	A,B,C,D,E	4,3,2,1,0	4
Total Score					**408**

Data Collection and Assumptions

OPUCN provided an asset registry for its power transformers which provided the service age for each asset. The power transformer peak loading was provided in excel format for historical years 2020-2022. The average peak load on each transformer within these three years was used to grade the transformer loading history. A comprehensive DGA and OQ report was provided with results for all power transformers. Transformer visual inspection and electrical test sheets were provided for the stations in word or pdf format, and the results were manually entered to perform the condition assessment.

The overall DAI for power transformers is 99%.

Results

OPUCN owns and maintains eighteen power transformers within its stations. Installation dates are known for all of OPUCN's power transformers. The demographic analysis for power

transformers is provided in Figure 4-36. The TUL for power transformers is 45 years and assets are considered to be approaching their TUL if they were installed more than 30 years ago.

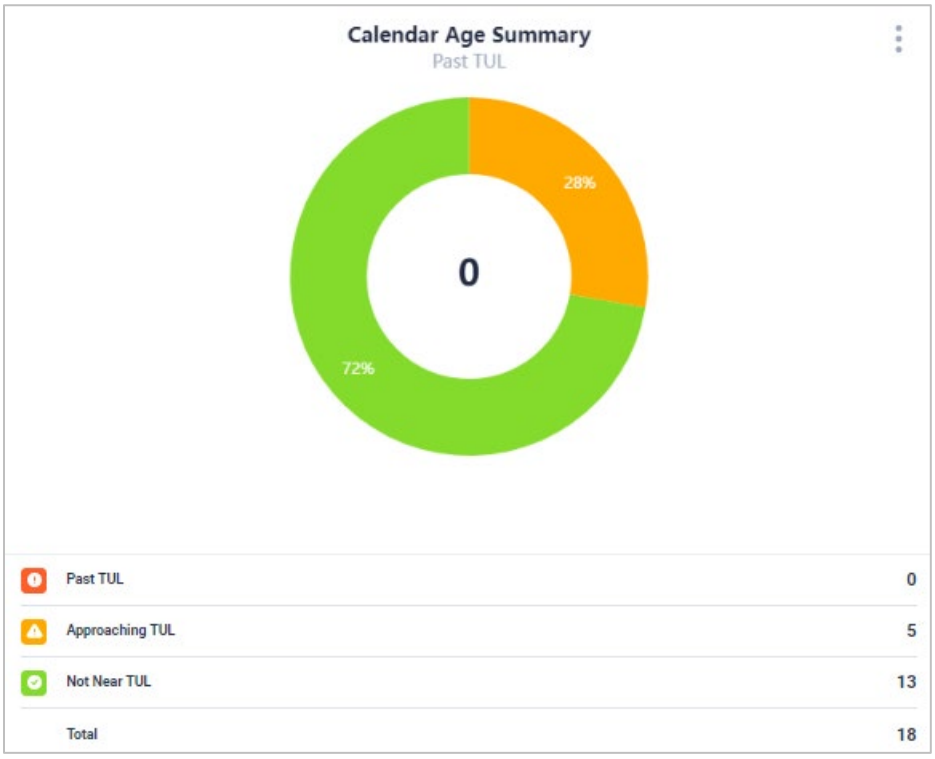


Figure 4-36: Power Transformer Demographic Assessment

The ACA results for OPUCN's power transformers are summarized in Figure 4-37. Valid HI results were outputted for all of the assets.

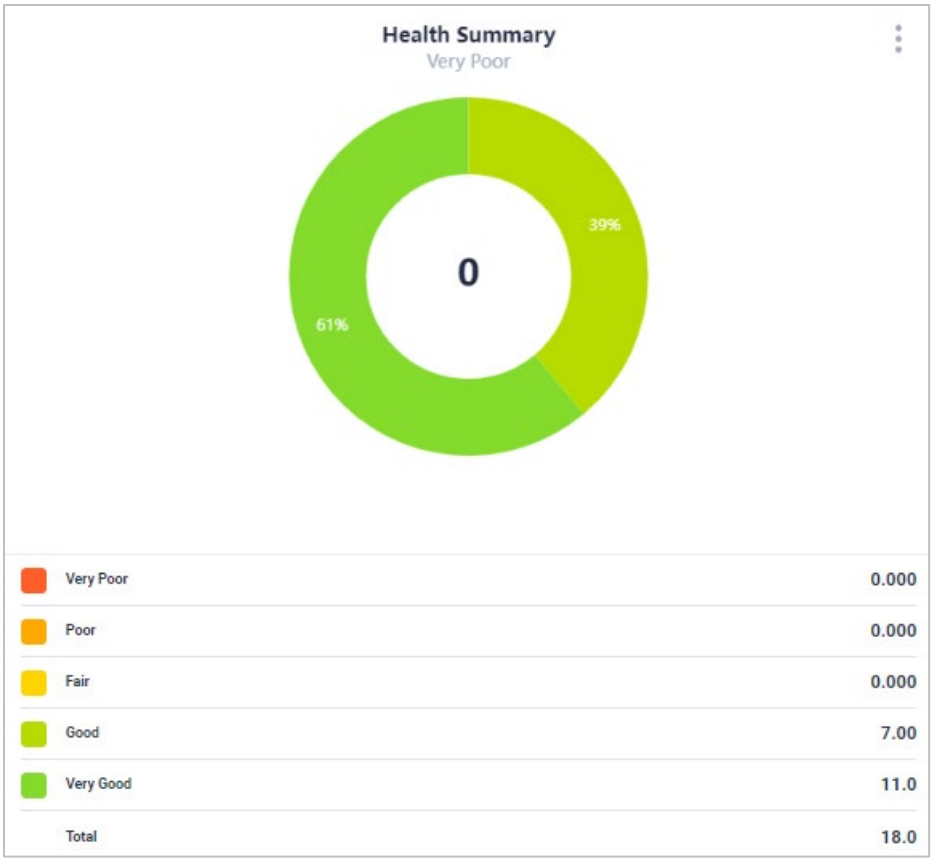


Figure 4-37: Power Transformer HI Results

4.2.2 Circuit Breakers

Circuit breakers are critical substation assets and are the primary protective devices for maintaining public safety and protecting other station equipment. Breakers work with station relays to open, either in a fault situation, as directed by the operations center, or as part of the automation scheme.

OPUCN owns and maintains 99 circuit breakers within its stations. Eighteen of these circuit breakers are rated to 44 kV and use SF_6 as an insulating medium. The remaining 81 circuit breakers are 13.8 kV and are either vacuum- or SF_6-insulated.

Health Index Formulation

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 44-kV and 13.8-kV circuit breakers are calculated based on EOL criteria summarized in Table 4-20 and Table 4-21, respectively.

Table 4-20: 44-kV Circuit Breaker HI Formulation

Condition Parameter	DAI	Weight	Ranking	Numerical Grade	Max Score
Insulation Resistance	100%	5	A,B,C,D,E	4,3,2,1,0	20
Contact Resistance	100%	4	A,B,C,D,E	4,3,2,1,0	16
Overall Condition	100%	4	A,B,C,D,E	4,3,2,1,0	16
Condition of Truck	89%	3	A,B,C,D,E	4,3,2,1,0	12
Condition of Control & Operating Mechanism	89%	2	A,B,C,D,E	4,3,2,1,0	8
Counter Reading	100%	2	A,B,C,D,E	4,3,2,1,0	8
Total Score					**120**

Table 4-21: 13.8-kV Circuit Breaker HI Formulation

Condition Parameter	DAI	Weight	Ranking	Numerical Grade	Max Score
Insulation Resistance	99%	5	A,B,C,D,E	4,3,2,1,0	20
Contact Resistance	99%	4	A,B,C,D,E	4,3,2,1,0	16
Overall Condition	99%	4	A,B,C,D,E	4,3,2,1,0	16
Condition of Truck	99%	3	A,B,C,D,E	4,3,2,1,0	12
Condition of Control & Operating Mechanism	99%	2	A,B,C,D,E	4,3,2,1,0	8
Counter Reading	99%	2	A,B,C,D,E	4,3,2,1,0	8
Total Score					**120**

Data Collection and Assumptions

Asset registries were provided for OPUCN's 44-kV and 13.8-kV circuit breakers. A separate inspection record was provided in excel, word, or pdf format for each circuit breaker which included visual inspections and electrical test results.

The overall DAI for 44-kV circuit breakers is 97% and the overall DAI for 13.8-kV circuit breakers is 99%.

Results

OPUCN owns and maintains eighteen 44-kV circuit breakers and eighty-one 13.8-kV circuit breakers within its stations. Installation dates are known for all of OPUCN's circuit breakers.

The demographic analysis for 44-kV circuit breakers is provided in Figure 4-38. The TUL for circuit breakers is 45 years and assets are considered to be approaching their TUL if they were installed more than 30 years ago.

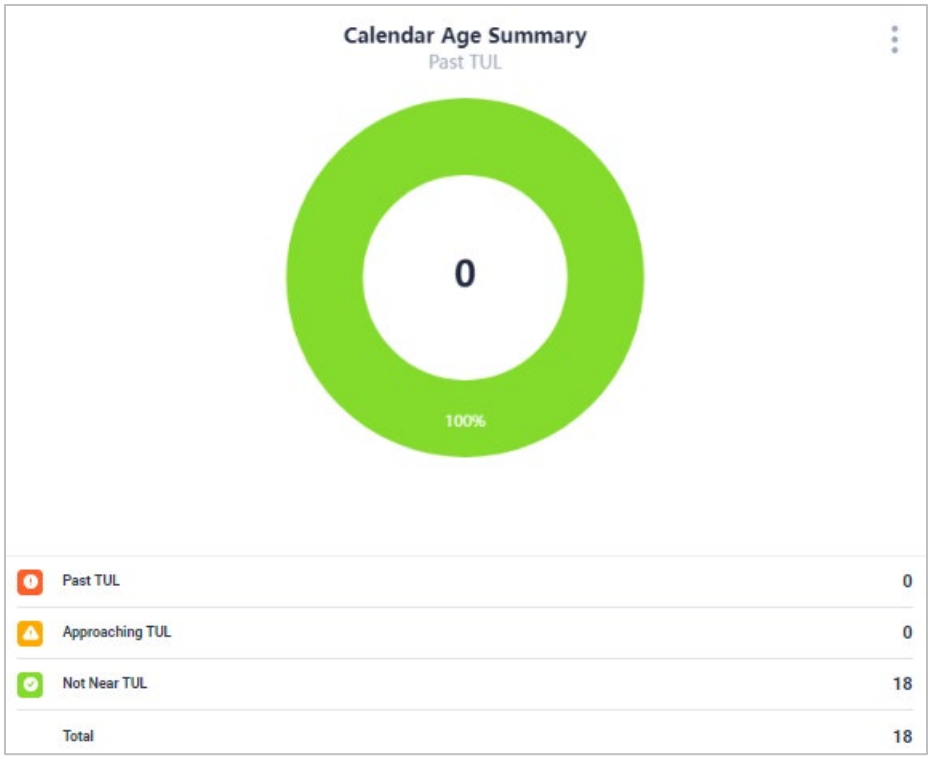


Figure 4-38: 44-kV Circuit Breaker Demographic Assessment

The ACA results for OPUCN's 44-kV circuit breakers are summarized in Figure 4-39. Valid HI results were outputted for all of the assets.

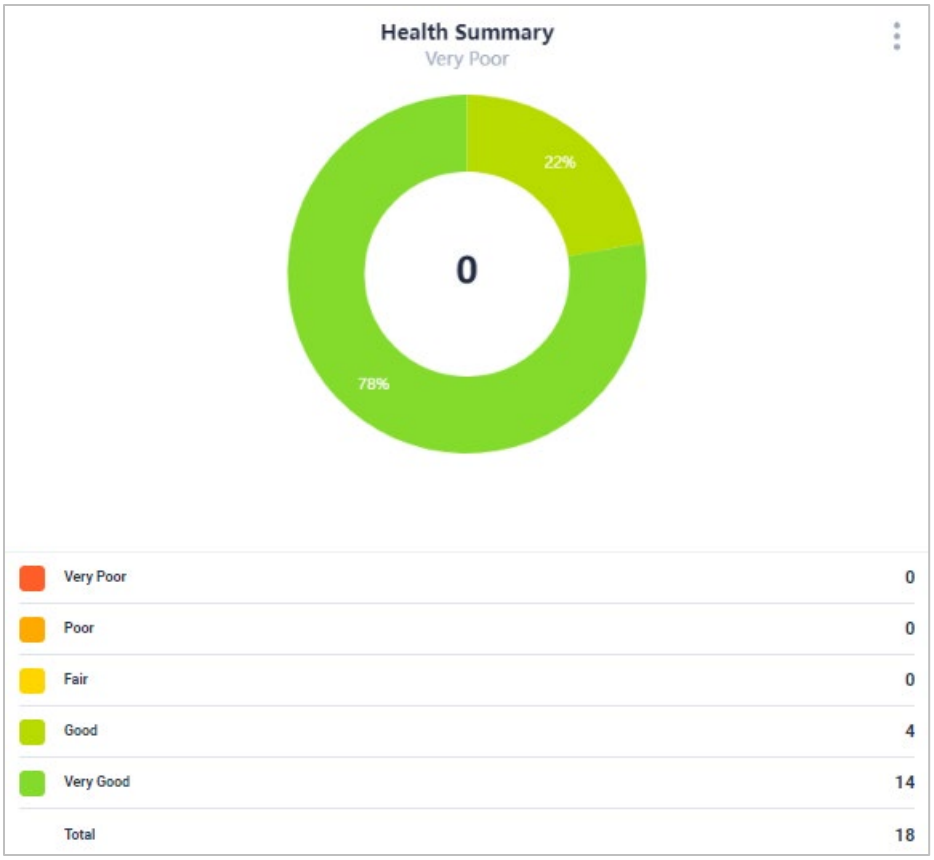


Figure 4-39: 44-kV Circuit Breaker HI Results

The demographic analysis for 13.8-kV circuit breakers is provided in Figure 4-40. The TUL for circuit breakers is 45 years and assets are considered to be approaching their TUL if they were installed more than 30 years ago.

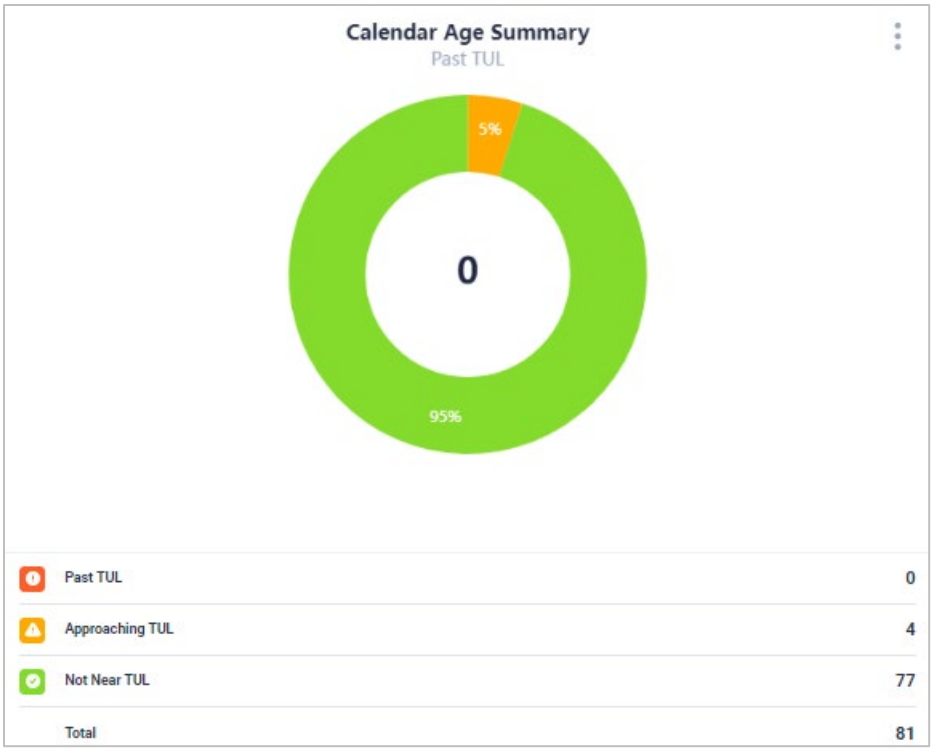


Figure 4-40: 13.8-kV Circuit Breaker Demographic Assessment

The ACA results for OPUCN's 13.8-kV circuit breakers are summarized in Figure 4-41. Valid HI results were outputted for all but one breaker at MS 11.



Figure 4-41: 13.8-kV Circuit Breaker HI Results

4.2.3 Switchgears

Station switchgears consist of breakers, fuses, and switches that control and regulate the current flowing through the distribution system. During a fault, the primary switchgear isolates and clears the faults downstream. It is also used to de-energize equipment during maintenance and testing. OPUCN owns and maintains eighteen 13.8-kV switchgear busses within its stations.

Health Index Formulation

Switchgear degradation occurs primarily through physical processes, such as corrosion, accumulation of debris, or operations under load. The HI for 13.8-kV switchgears is calculated based on EOL criteria summarized in Table 4-22.

Table 4-22: 13.8-kV Switchgear HI Formulation

Condition Parameter	DAI	Weight	Ranking	Numerical Grade	Max Score
Service Age	100%	7	A,B,C,D,E	4,3,2,1,0	28
Circuit Breaker Condition	100%	4	A,B,C,D,E	4,3,2,1,0	16
Enclosure Condition	100%	3	A,B,C,D,E	4,3,2,1,0	12
Insulation Resistance	100%	3	A,B,C,D,E	4,3,2,1,0	12
Control & Operating Mechanism	100%	2	A,B,C,D,E	4,3,2,1,0	8
Overall Condition	100%	2	A,B,C,D,E	4,3,2,1,0	8
Total Score					**84**

Data Collection and Assumptions

Switchgear bus installation dates were provided in insulation resistance and potential transformer test reports for certain assets. Switchgear busses with unknown installation dates were assumed to have the same installation date as the station building.

An individual inspection record was provided in excel, word, or pdf format for each station switchgear bus which included the visual inspection and electrical test results.

The circuit breaker HI calculation was completed first and the average HI of all of the circuit breakers on each switchgear was used to grade the circuit breaker condition parameter for the switchgear.

The overall DAI for 13.8-kV switchgears is 100%.

Results

OPUCN owns and maintains eighteen 13.8-kV switchgear busses within its stations. Installation dates are either known or assumed for all of OPUCN's switchgear buses.

The demographic analysis for 13.8-kV switchgear busses is provided in Figure 4-42. The TUL for switchgears is 40 years and assets are considered to be approaching their TUL if they were installed more than 27 years ago.

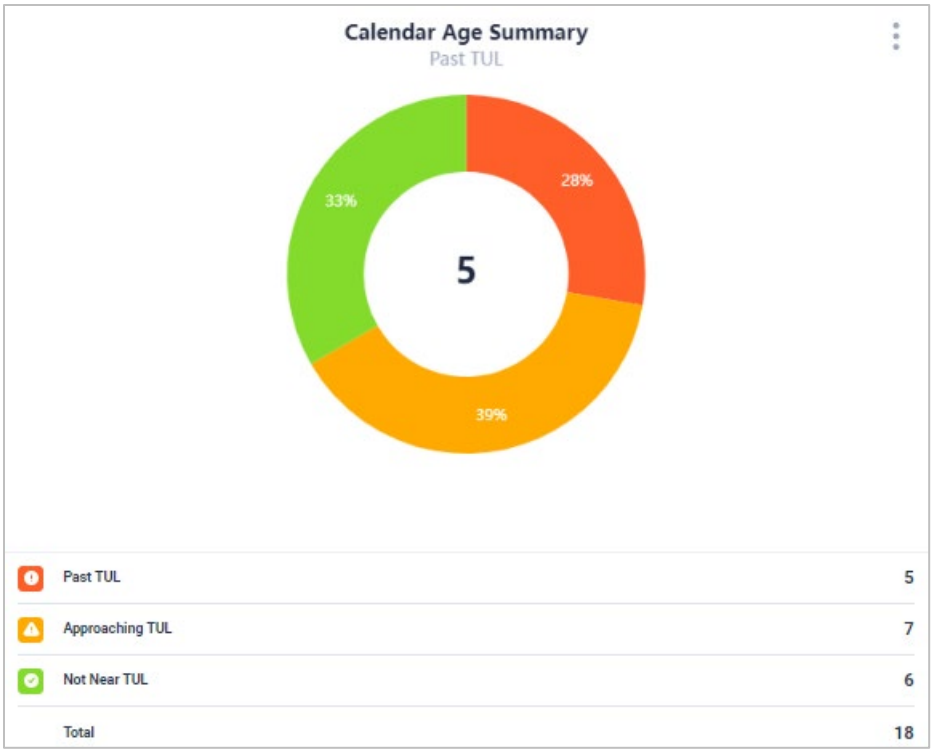


Figure 4-42: 13.8-kV Switchgear Bus Demographic Assessment

The ACA results for OPUCN's 13.8-kV switchgear busses are summarized in Figure 4-43. Valid HI results were outputted for all of the assets.

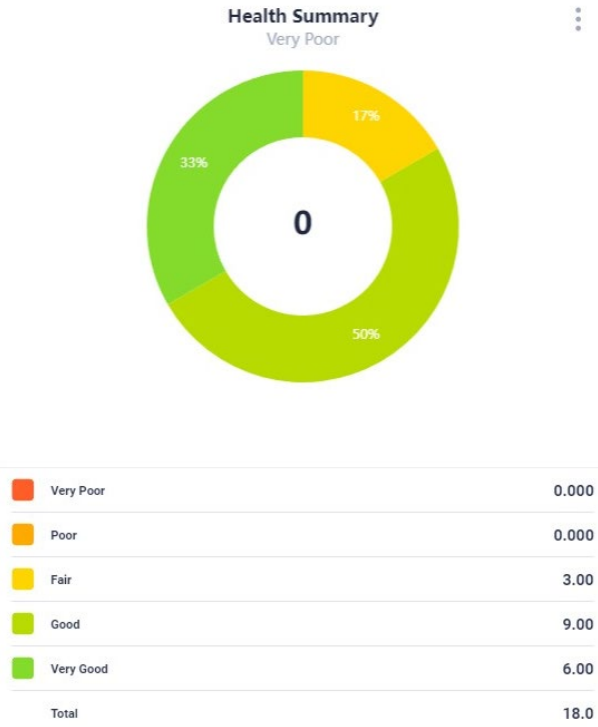


Figure 4-43: 13.8-kV Switchgear Bus HI Results

4.2.4 Relays & RTUs

OPUCN owns and maintains 80 solid-state relays and nine RTUs within its stations.

Health Index Formulation

Protective relays are an asset used in substation operations to trip a circuit breaker when a fault is detected. Modern relays are typically microprocessor types and include programmable features and communications. Legacy relays are mechanical and require regular calibration; however, most mechanical relays have been replaced with newer models. RTUs are related devices which are used to communicate with the SCADA system.

Protection devices are more likely to become obsolete based on functionality and communication needs rather than physically deteriorating due to environmental conditions.

The HI results for solid-state relays are calculated based on EOL criteria summarized in Table 4-23. The analysis for RTUs is based only on age so there is no HI formulation for the asset class.

Table 4-23: Solid-State Relay HI Formulation

Condition Parameter	DAI	Weight	Ranking	Numerical Grade	Max Score
Non-Discretionary Obsolescence	60%	5	A,E	4,0	20
Service Age	100%	4	A,B,C,D,E	4,3,2,1,0	16
Relay Testing	60%	4	A,B,C,D,E	4,3,2,1,0	16
Overall Condition	60%	3	A,B,C,D,E	4,3,2,1,0	12
Total Score					**64**

Data Collection and Assumptions

Asset registries were provided for OPUCN's relays and RTUs. The installation dates were taken directly from the asset registries for all assets.

Individual relay test reports were also provided for each of the 60% of the relays in excel or pdf format which contained inspection and relay test results used in the condition assessment.

The overall DAIs for solid state relays is 70%.

Results

OPUCN owns and maintains 80 solid-state relays and nine RTUs within its stations. Installation dates are known for all of the assets.

The demographic analysis for solid state relays is provided in Figure 4-44. The TUL for relays is twenty years and assets are considered to be approaching their TUL if they were installed more than thirteen years ago.

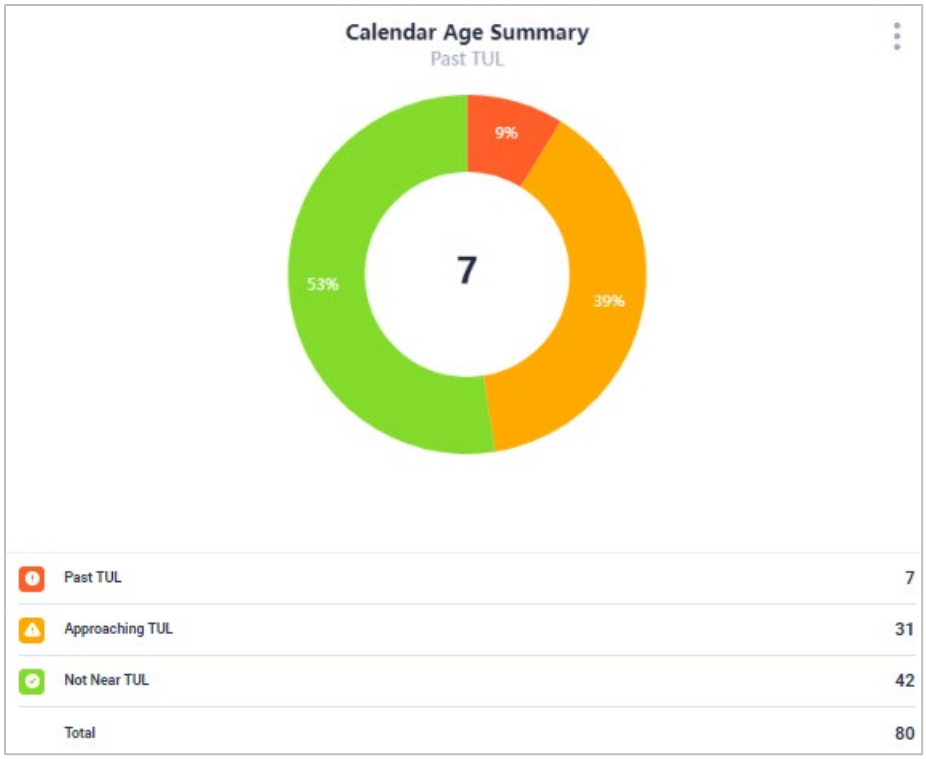


Figure 4-44: Relay Demographic Assessment

The ACA results for OPUCN's solid-state relays are summarized in Figure 4-45. Valid HI results were outputted for 60% of the assets.

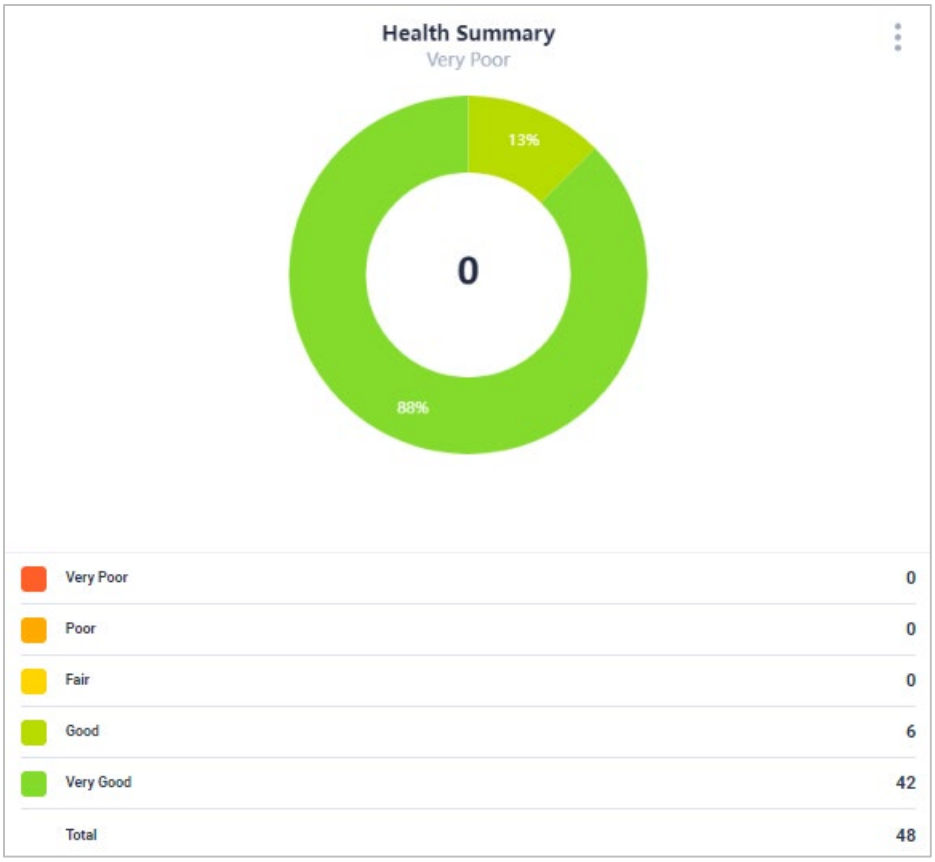


Figure 4-45: Relay HI Results

The demographic analysis for RTUs is provided in Figure 4-46. The TUL for RTUs is twenty years and assets are considered to be approaching their TUL if they were installed more than thirteen years ago.

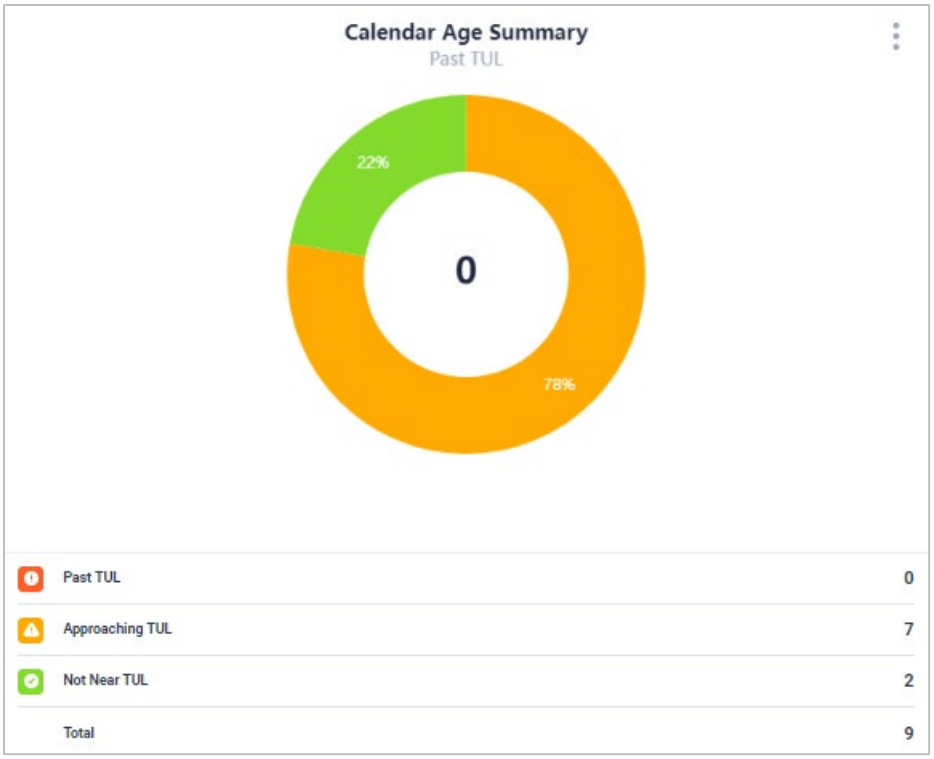


Figure 4-46: RTU Demographic Assessment

ACA results were not outputted for RTUs since age is the only data point available for the asset class.

4.2.5 Batteries & Chargers

The purpose of substation batteries is to provide power for critical control functions such as trip coils of circuit breakers. Batteries are carefully sized to store adequate energy for system operation during an AC power failure. OPUCN owns and maintains nine batteries and chargers within its stations.

Health Index Formulation

Both the electrodes and electrolytes in control batteries undergo aging with repeated charge and discharge cycles, which result in a gradual reduction of battery storage capacity. The end-of-life is reached when the battery is no longer able to retain adequate charge for required functions. Battery chargers can experience component failures, but these can be easily replaced, resulting in instances of chargers frequently outlasting the battery units.

The HI results for batteries and chargers are calculated based on EOL criteria summarized in Table 4-24 and Table 4-25, respectively.

Table 4-24: Station Battery HI Formulation

Condition Parameter	DAI	Weight	Ranking	Numerical Grade	Max Score
Service Age	100%	10	A,B,C,D,E	4,3,2,1,0	40
Electrical Testing	100%	10	A,B,C,D,E	4,3,2,1,0	40
Corrosion	100%	3	A,B,C,D,E	4,3,2,1,0	12
Heating	100%	3	A,B,C,D,E	4,3,2,1,0	8
Overall Condition	100%	2	A,B,C,D,E	4,3,2,1,0	8
Condition of Rack	100%	1	A,B,C,D,E	4,3,2,1,0	4
Condition of Connections & Cables	100%	1	A,B,C,D,E	4,3,2,1,0	4
Condition of Monitoring Device	100%	1	A,B,C,D,E	4,3,2,1,0	4
Condition of Grounding	100%	1	A,B,C,D,E	4,3,2,1,0	4
Total Score					**124**

Table 4-25: Station Charger HI Formulation

Condition Parameter	DAI	Weight	Ranking	Numerical Grade	Max Score
Service Age	100%	1	A,B,C,D,E	4,3,2,1,0	4
Overall Condition	100%	1	A,B,C,D,E	4,3,2,1,0	4
Total Score					**8**

Data Collection and Assumptions

A single asset registry was provided for OPUCN's batteries and chargers which contained the installation dates for all assets. Individual battery maintenance reports were also provided for each station which included visual inspection results for the batteries and chargers and electrical test results for the batteries.

The overall DAI for batteries and chargers are both 100%.

Results

OPUCN owns and maintains nine batteries and chargers within its stations. Installation dates are known for all of the batteries and chargers.

The demographic analysis for batteries is provided in Figure 4-47. The TUL for batteries is ten years and assets are considered to be approaching their TUL if they were installed more than seven years ago.

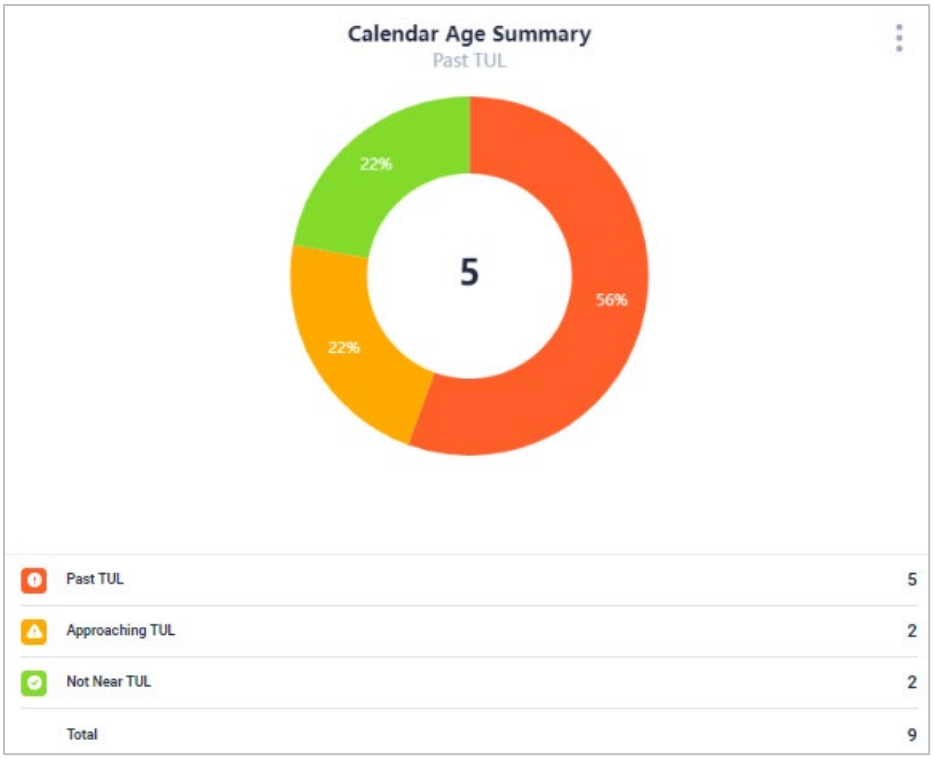


Figure 4-47: Station Battery Demographic Assessment

The ACA results for OPUCN's batteries are summarized in Figure 4-48. Valid HI results were outputted for all of the assets.

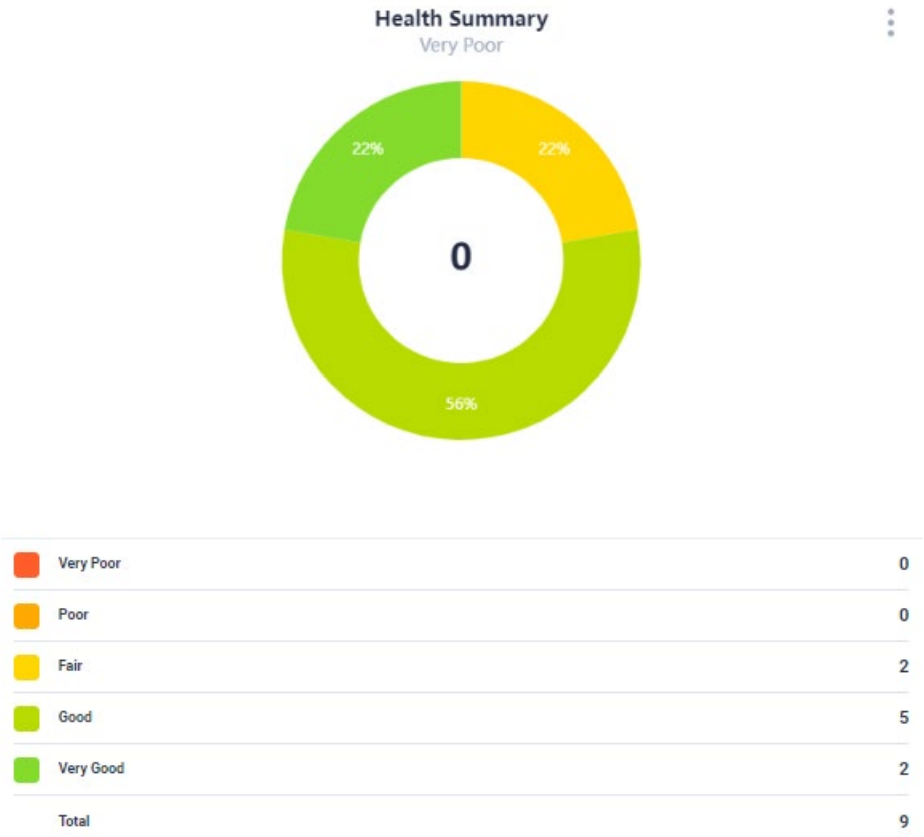


Figure 4-48: Station Battery HI Results

The demographic analysis for battery chargers is provided in Figure 4-49. The TUL for chargers is twenty years and assets are considered to be approaching their TUL if they were installed more than thirteen years ago.

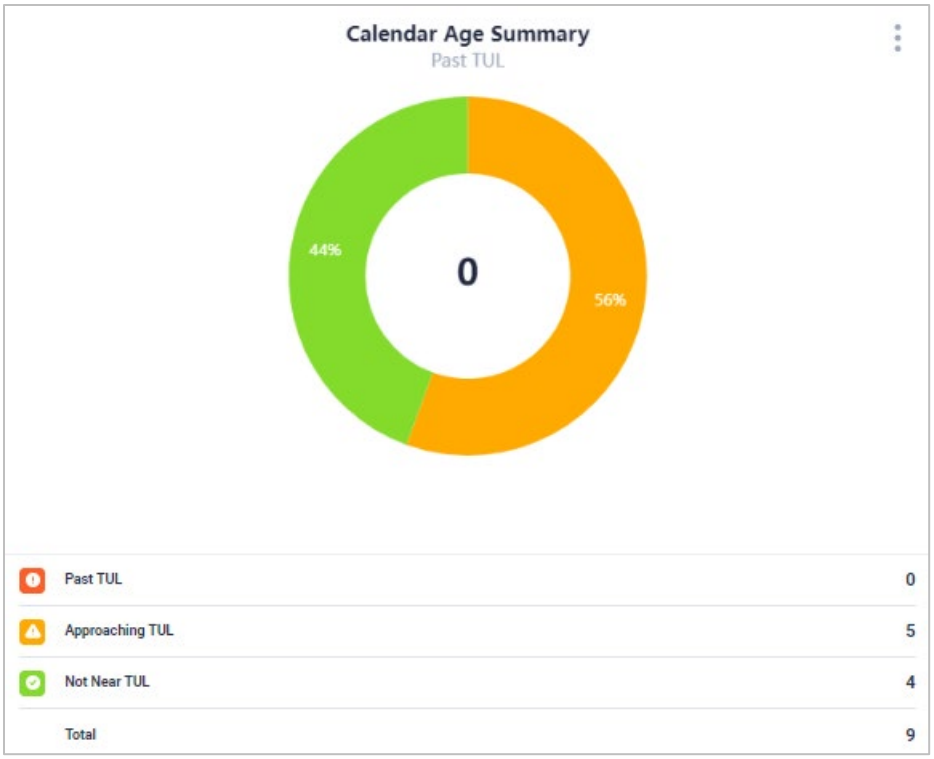


Figure 4-49: Station Charger Demographic Assessment

The ACA results for OPUCN's battery chargers are summarized in Figure 4-50. Valid HI results were outputted for all of the assets.

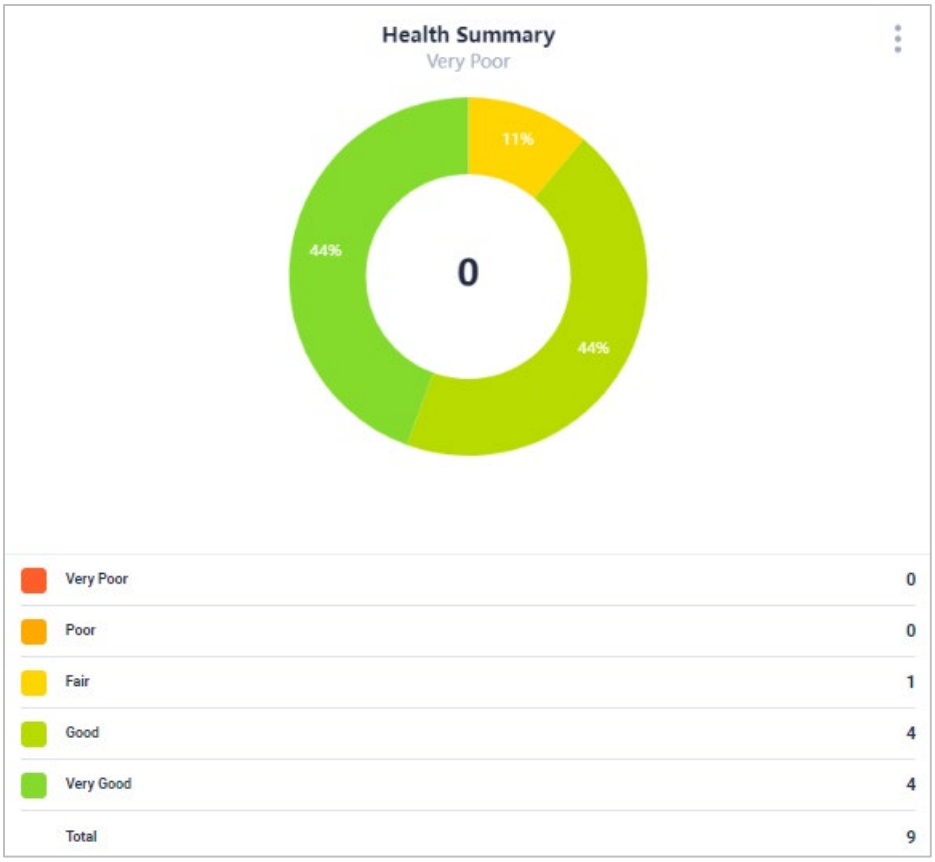


Figure 4-50: Station Charger HI Results

4.2.6 Station Egress Cables

Station egress cables are the first length of cable out of the station, before the first riser pole. They carry the entire load of each feeder. OPUCN owns and maintains eight 44-kV station egress cables and fifty-three 13.8-kV egress cables at its stations.

Health Index Formulation

The HI for 44-kV and 13.8-kV station egress cables are calculated based on EOL criteria summarized in Table 4-26 and Table 4-27, respectively.

Table 4-26: 44-kV Station Egress Cable HI Formulation

Condition Parameter	DAI	Weight	Ranking	Numerical Grade	Max Score
Service Age	100%	2	A,B,C,D,E	4,3,2,1,0	8
Insulation Resistance	88%	2	A,B,C,D,E	4,3,2,1,0	8
Condition of Terminations	88%	1	A,B,C,D,E	4,3,2,1,0	4
Total Score					**20**

Table 4-27: 13.8-kV Station Egress Cable HI Formulation

Condition Parameter	DAI	Weight	Ranking	Numerical Grade	Max Score
Service Age	100%	2	A,B,C,D,E	4,3,2,1,0	8
Insulation Resistance	91%	2	A,B,C,D,E	4,3,2,1,0	8
Condition of Terminations	100%	1	A,B,C,D,E	4,3,2,1,0	4
Total Score					**20**

Data Collection and Assumptions

Data for the station egress cables was provided with the distribution UG cables. Testing reports were provided for each egress cable which included service ages, insulation resistance tests, and comments on the condition of the cable terminations.

The overall DAIs for 44-kV and 13.8-kV station egress cables are 97% and 96%, respectively.

Results

OPUCN owns and maintains eight 44-kV station egress cables and fifty-three 13.8-kV station egress cables at its stations. Installation dates are known for all of the assets.

The demographic analysis for 44-kV station egress cables is provided in Figure 4-51. The TUL for station egress cables is twenty-five years and assets are considered to be approaching their TUL if they were installed more than seventeen years ago.

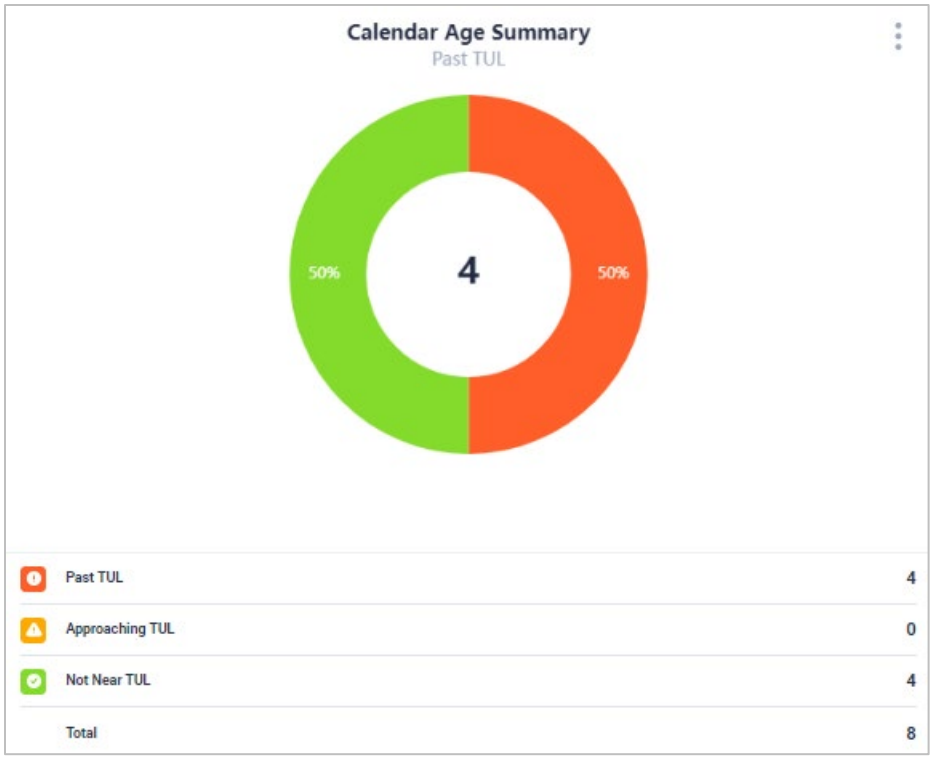


Figure 4-51: 44-kV Station Egress Cable Demographic Assessment

The ACA results for OPUCN's 44-kV egress cables are summarized in Figure 4-52. Valid HI results were outputted for 88% of the assets.



Figure 4-52: 44-kV Station Egress Cable HI Results

The demographic analysis for 13.8-kV station egress cables is provided in Figure 4-53. The TUL for station egress cables is twenty-five years and assets are considered to be approaching their TUL if they were installed more than seventeen years ago.

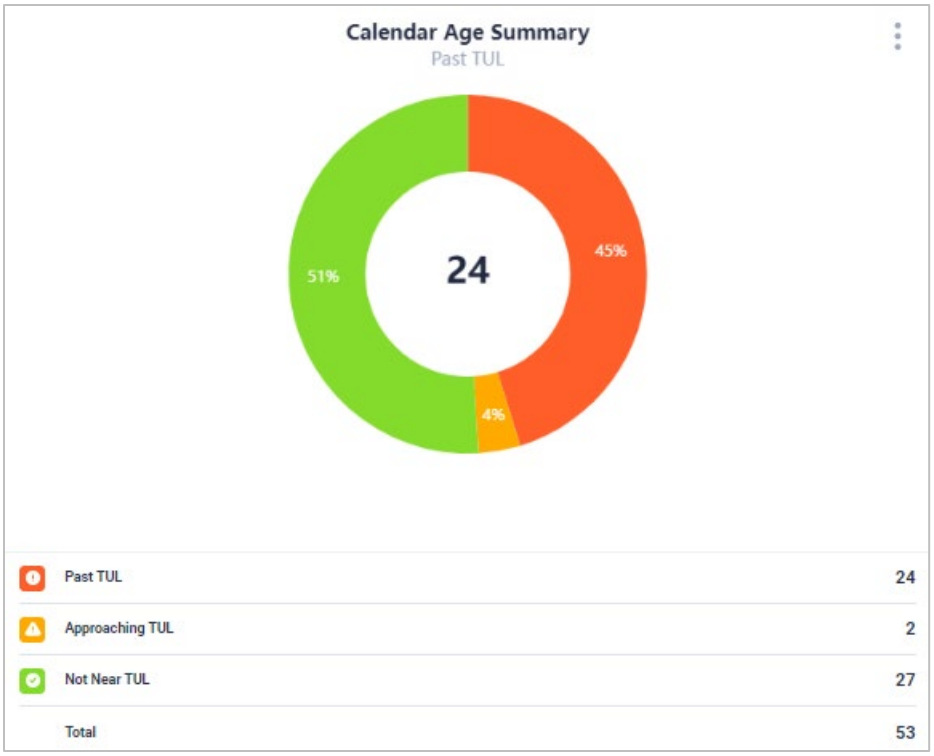


Figure 4-53: 13.8-kV Station Egress Cable Demographic Assessment

The ACA results for OPUCN's 13.8-kV station egress cables are summarized in Figure 4-54. Valid HI results were outputted for 91% of the assets.



Figure 4-54: 13.8-kV Station Egress Cable HI Results

4.2.7 Station Fences & Yards

OPUCN owns and maintains nine substations within its service territory. Station fences and yards are the major outdoor civil infrastructure components of a utility substation. Fences and yards are regularly inspected, and the assets will be maintained as issues arise. In some cases, these assets can be scheduled for replacement, especially where configurations of the station are inadequate or where projects exist to replace the entirety of the substation. Generally, however, fences are maintained, gates are repaired, and yards are cleaned up as needed to remain functional.

Health Index Formulation

The HI for stations fences and yards is calculated based on EOL criteria summarized in Table 4-28.

Table 4-28: Station Fence & Yard HI Formulation

Condition Parameter	DAI	Weight	Ranking	Numerical Grade	Max Score
Condition of Grounding	100%	8	A,B,C,D,E	4,3,2,1,0	32
Condition of Fence	100%	6	A,B,C,D,E	4,3,2,1,0	24
Condition of Yard	100%	3	A,B,C,D,E	4,3,2,1,0	12
Condition of Fence Signage	100%	2	A,B,C,D,E	4,3,2,1,0	8
Total Score					**76**

Data Collection and Assumptions

Station yard visual inspections were provided in word or pdf format for all of OPUCN's stations. All of the condition parameters used to formulate the HI for station fences & yard were taken from the station yard inspection sheets. Station building inspection records were used as a secondary input of visual inspection results where yard visual inspection records were not available.

The overall DAI for station fences and yards is 100%.

Results

OPUCN owns and maintains nine substations within its service territory. Construction dates are not recorded for OPUCN's stations.

The ACA results for station fences and yards are summarized in Figure 4-55. Valid HI results were outputted for all of the stations.

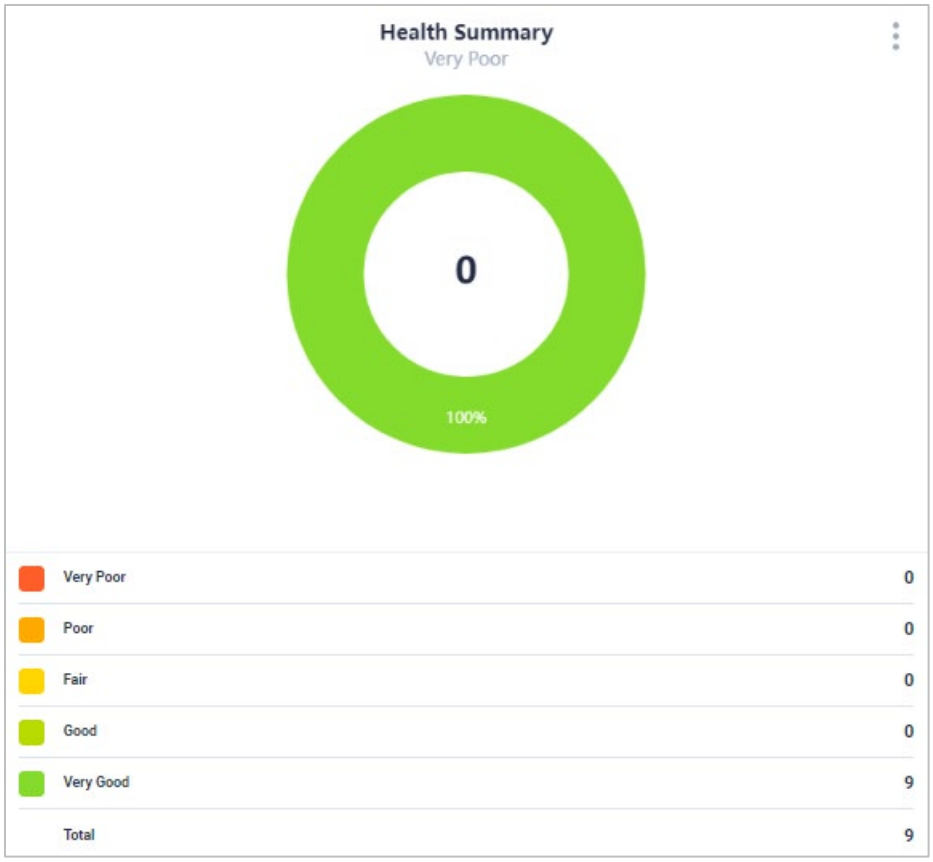


Figure 4-55: Station Fence & Yard HI Results

4.2.8 Station Buildings

Station buildings refer to the walls, roof, floors, doors etc. of the station. The civil infrastructure components of a station are regularly inspected, and the assets are be maintained as issues arise. In some cases, stations can be scheduled for replacement, especially where configurations of the station are inadequate or where projects exist to replace the entirety of the substation. Generally, however, station building civil infrastructure is patched up as needed to remain functional.

OPUCN owns and maintains nine substations within its service territory. Three of OPUCN's stations, MS 9, MS 10, and MS 15, are residential style buildings. The remaining six stations are Electrical Houses ("eHouses") which are custom metal enclosures for the station switchgear and other assets that would typically be within the station building.

Health Index Formulation

The HI for station buildings is calculated based on EOL criteria summarized in Table 4-29.

Table 4-29: Station Building HI Formulation

Condition Parameter	DAI	Weight	Ranking	Numerical Grade	Max Score
Overall Condition	100%	4	A,B,C,D,E	4,3,2,1,0	16
Condition of Lighting, Power & HVAC	100%	2	A,B,C,D,E	4,3,2,1,0	8
Condition of Doors	100%	2	A,B,C,D,E	4,3,2,1,0	8
Service Age	100%	1	A,B,C,D,E	4,3,2,1,0	4
Total Score					**36**

Data Collection and Assumptions

The year of construction was provided for all of OPUCN's stations.

Station building visual inspections were provided in pdf format for all of OPUCN's stations. All of the condition parameters used to formulate the HI for station buildings were taken from the station building inspection sheets. The most recent station building inspection sheet was used in cases where multiple inspection sheets were provided.

The overall DAI for station buildings is 100%.

Results

OPUCN owns and maintains nine substations within its service territory. Construction dates are known for all station buildings.

The demographic analysis for station buildings is provided in Figure 4-56. The TUL for residential station buildings is 60 years and the TUL for eHouses is 50 years. Station buildings are considered to be approaching their TUL if they were installed more than 33 years ago.

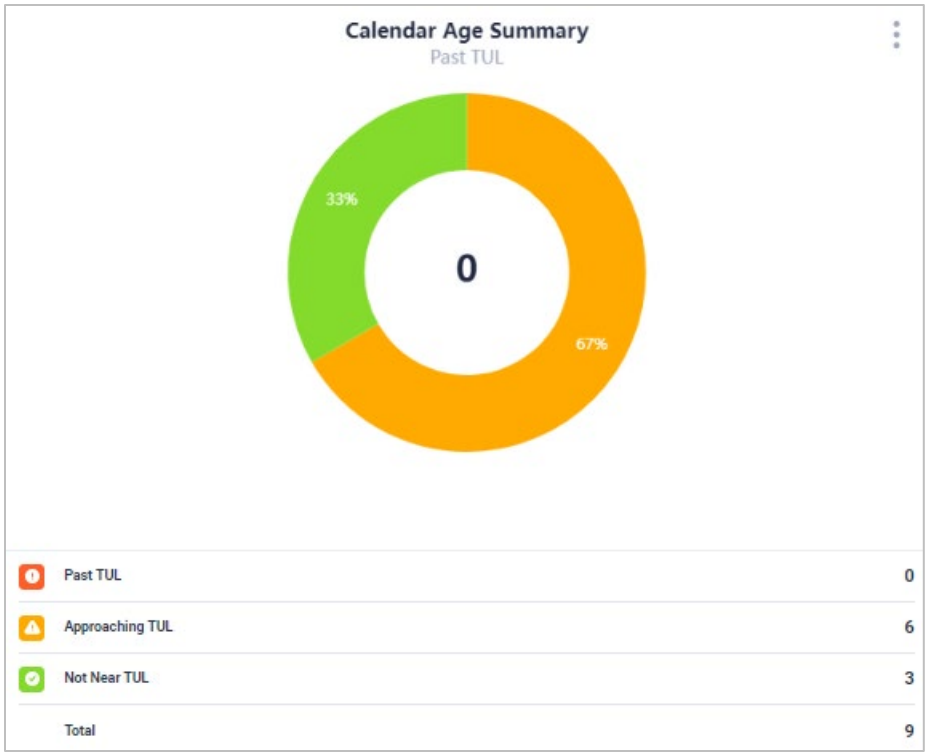


Figure 4-56: Station Building Demographic Assessment

The ACA results for station buildings are summarized in Figure 4-57. Valid HI results were outputted for all of the stations.

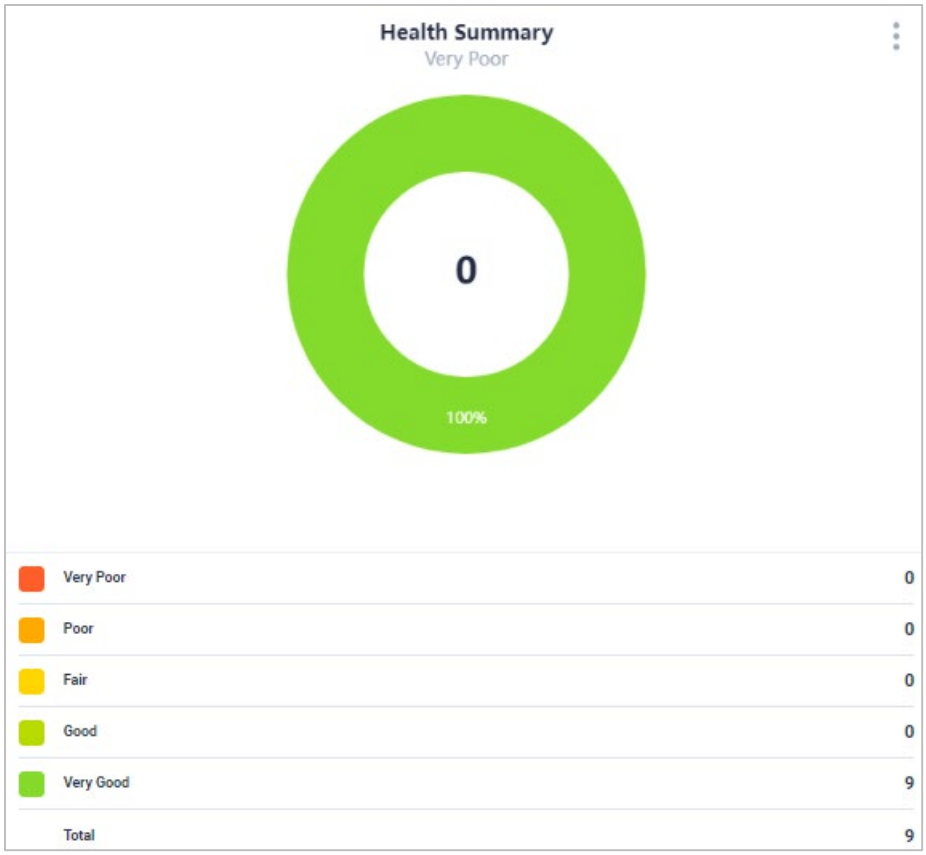


Figure 4-57: Station Building HI Results

4.2.9 Bus Structures

Bus structures are the civil components which secure the switching equipment within the station. OPUCN owns and maintains seventeen bus structures within its stations.

Health Index Formulation

The HI for bus structures is calculated based on EOL criteria summarized in Table 4-30.

Table 4-30: Bus Structure HI Formulation

Condition Parameter	DAI	Weight	Ranking	Numerical Grade	Max Score
Condition of Support Structure	100%	10	A,B,C,D,E	4,3,2,1,0	40
Primary Insulation Resistance	100%	5	A,B,C,D,E	4,3,2,1,0	20
Secondary Insulation Resistance	72%	5	A,B,C,D,E	4,3,2,1,0	20
Insulator Condition	100%	3	A,B,C,D,E	4,3,2,1,0	12
Arrestor Condition	89%	3	A,B,C,D,E	4,3,2,1,0	12
Condition of Connectors	100%	2	A,B,C,D,E	4,3,2,1,0	8
Condition of Grounding	100%	2	A,B,C,D,E	4,3,2,1,0	8
Total Score					**120**

Data Collection and Assumptions

Inspection sheets were provided for OPUCN's lightning arrestors and insulators which were used to determine the condition of the bus structures for this analysis. These reports provided both visual inspection results and insulation resistance tests for the bus structures.

The overall DAI for bus structures is 94%.

Results

OPUCN owns and maintains seventeen bus structures within its stations. Installation dates are not available for bus structures.

The ACA results for OPUCN's bus structures are summarized in Figure 4-58. Valid HI results were outputted for all of the assets.

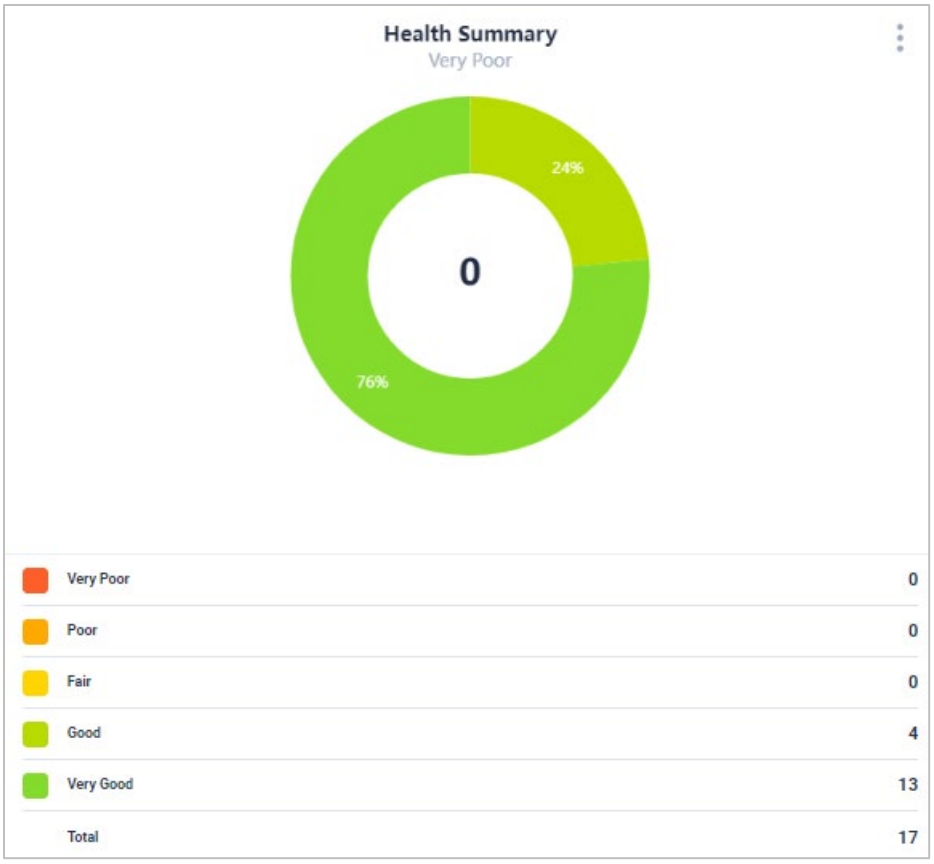


Figure 4-58: Bus Structure HI Results

5 Remaining Life Assessment

This section presents the estimated remaining life of the assets based on their current age, condition, and TUL for the asset classes in scope.

5.1 Distribution Assets

5.1.1 Wood Poles

The TUL of wood poles is 45 years. The remaining life was calculated for 100% of wood poles, of which 92% have not yet reached TUL. The remaining life results are shown in Figure 5-1.

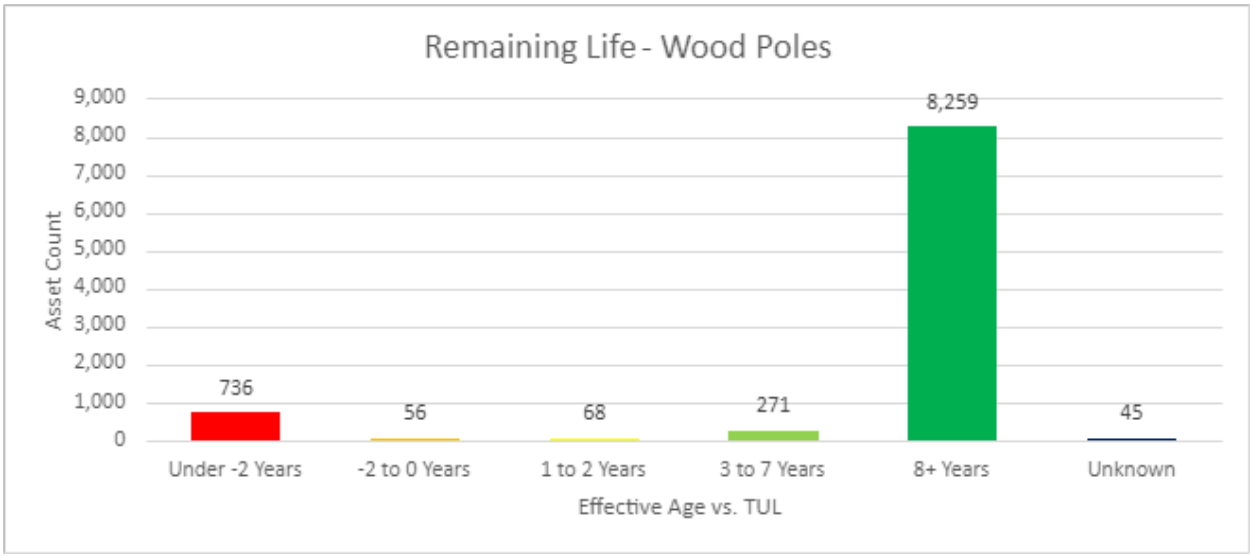


Figure 5-1: Wood Pole Remaining Life Results

5.1.2 Concrete Poles

The TUL of concrete poles is 60 years. The remaining life was calculated for all concrete poles, of which 88% have not yet reached TUL. The remaining life results are shown in Figure 5-2.

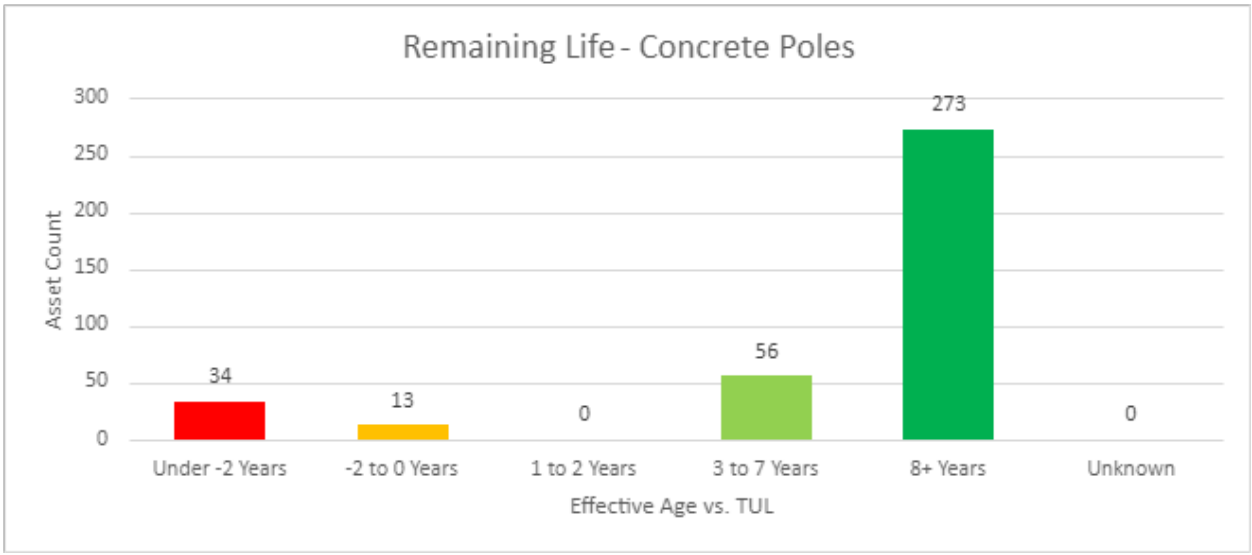


Figure 5-2: Concrete Pole Remaining Life Results

5.1.3 Steel Poles

The TUL of steel poles is 60 years. The remaining life was calculated for all steel poles, all of which have not yet reached TUL. The remaining life results are shown in Figure 5-3.

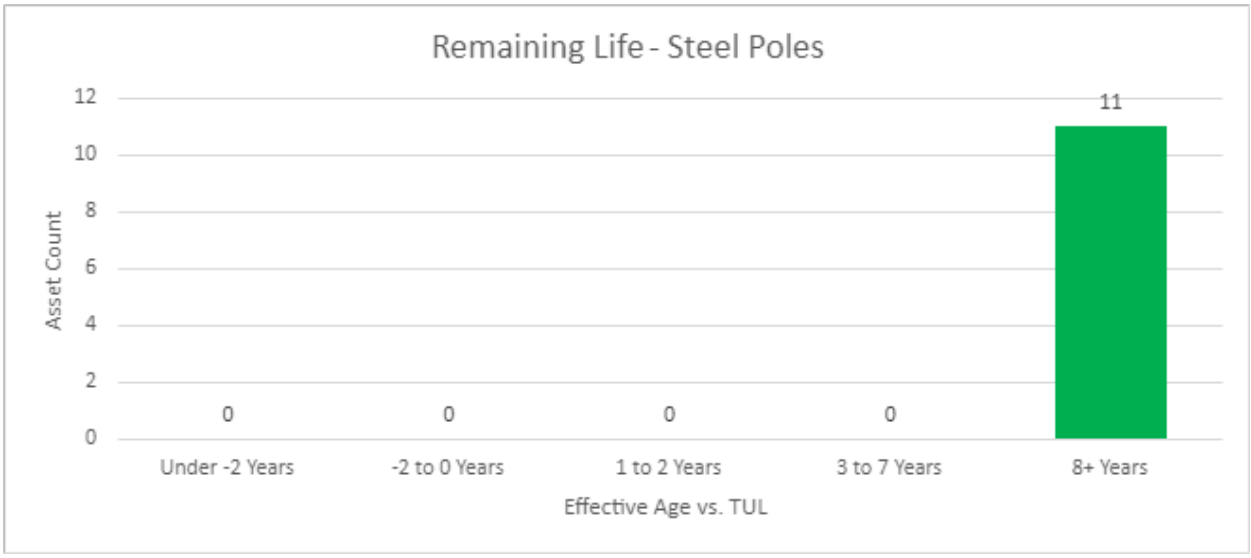


Figure 5-3: Steel Pole Remaining Life Results

5.1.4 Overhead Primary Conductors

The TUL of OH conductors is 60 years. The remaining life was calculated for 100% of OH conductors, of which 88% have not yet reached TUL. The remaining life results are shown in Figure 5-4.

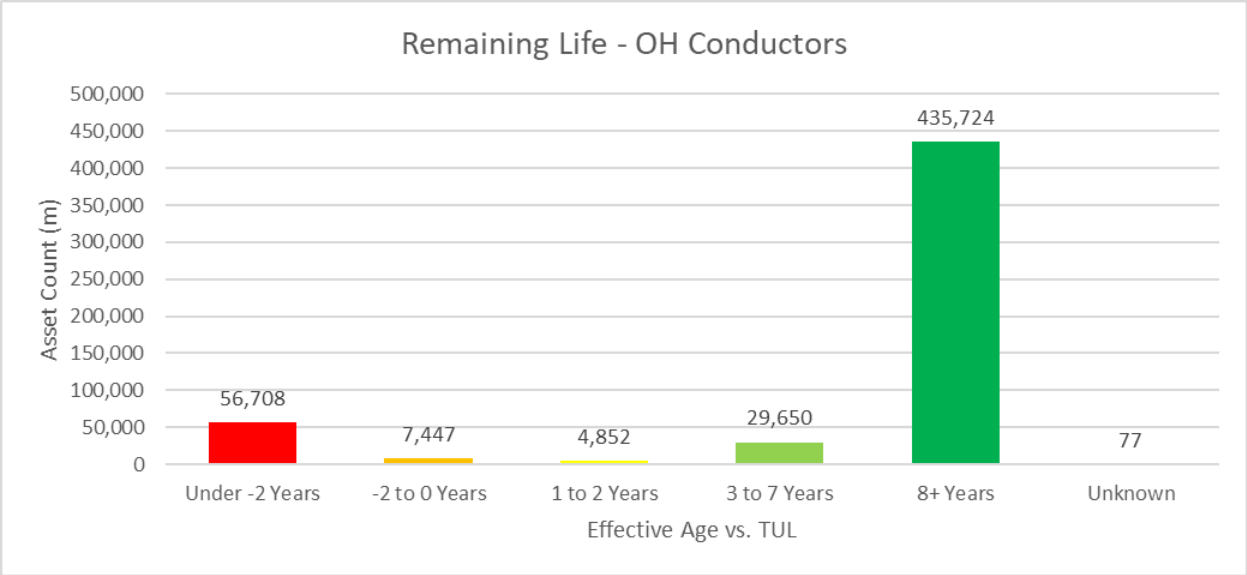


Figure 5-4: OH Conductor Remaining Life Results

5.1.5 Underground Primary Cables

The TUL of UG cables is 30 years. The remaining life was calculated for all UG cables, of which 72% have not yet reached TUL. The remaining life results are shown in Figure 5-5.

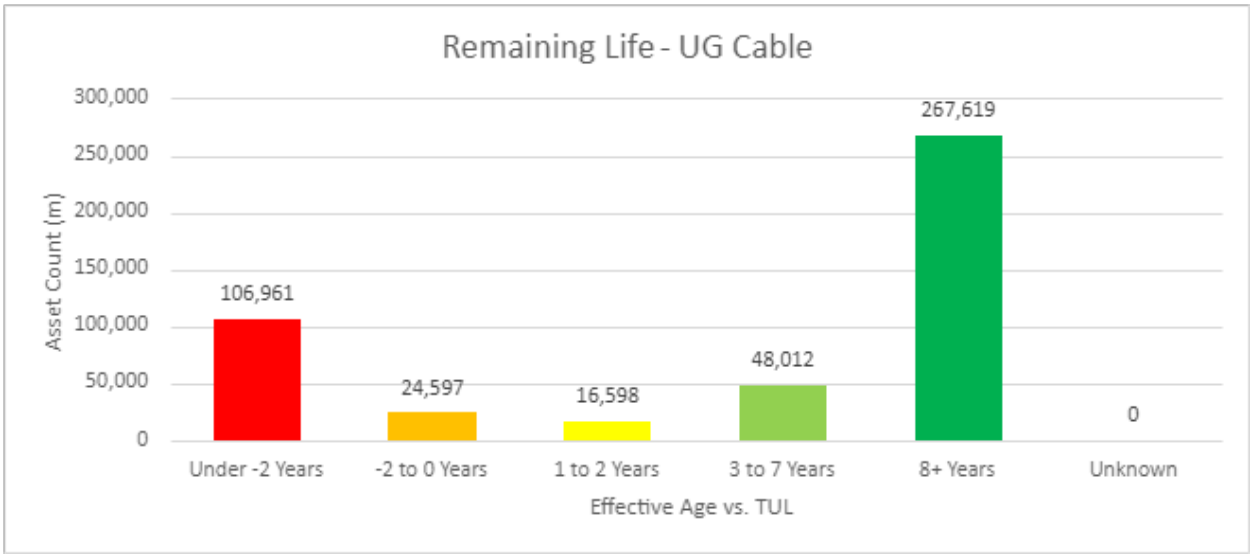


Figure 5-5: UG Cable Remaining Life Results

5.1.6 Pole-Mount Transformers

The TUL of pole-mount transformers is 40 years. The remaining life was calculated for 99% of assets, of which 87% have not yet reached TUL. The remaining life results are shown in Figure 5-6.

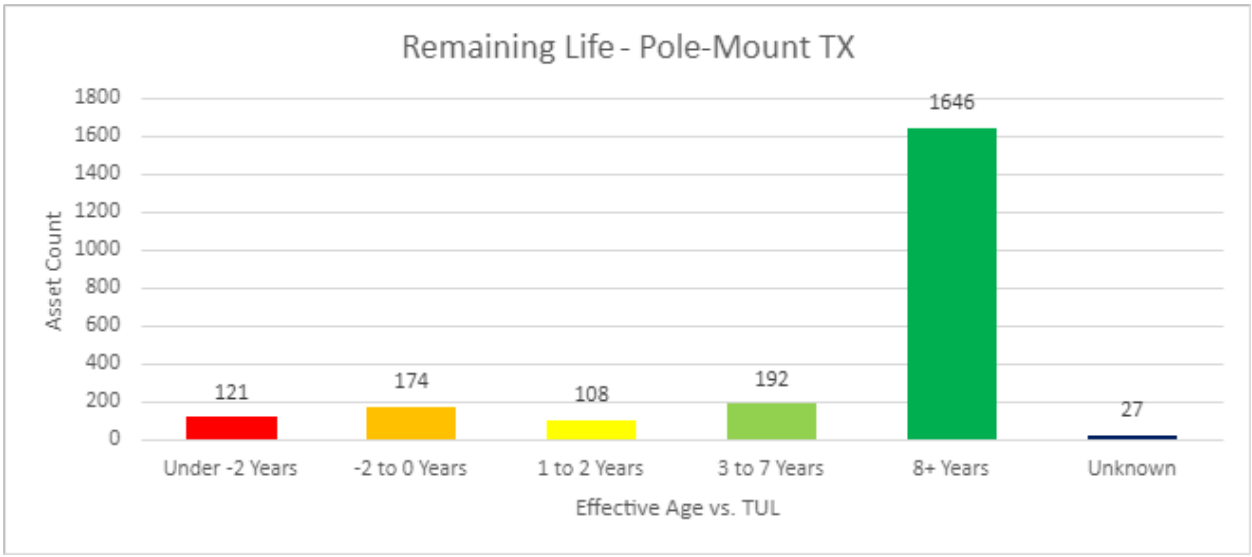


Figure 5-6: Pole-mount Transformer Remaining Life Results

5.1.7 Pad-Mount Transformers

The TUL of pad-mount transformers is 40 years. The remaining life was calculated for 100% of assets, of which 84% have not yet reached TUL. The remaining life results are shown in Figure 5-7.

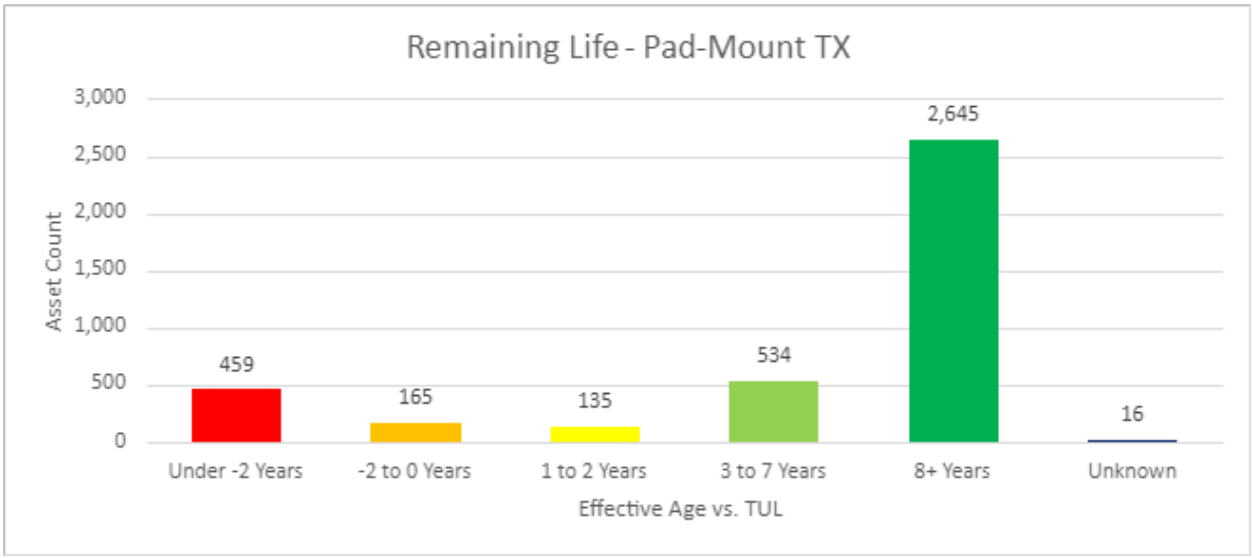


Figure 5-7: Pad-mount Transformer Remaining Life Results

5.1.8 Vault Transformers

The TUL of vault transformers is 35 years. The remaining life was calculated for 99% of vault transformers, of which 46% have not yet reached TUL. The remaining life results are shown in Figure 5-8.

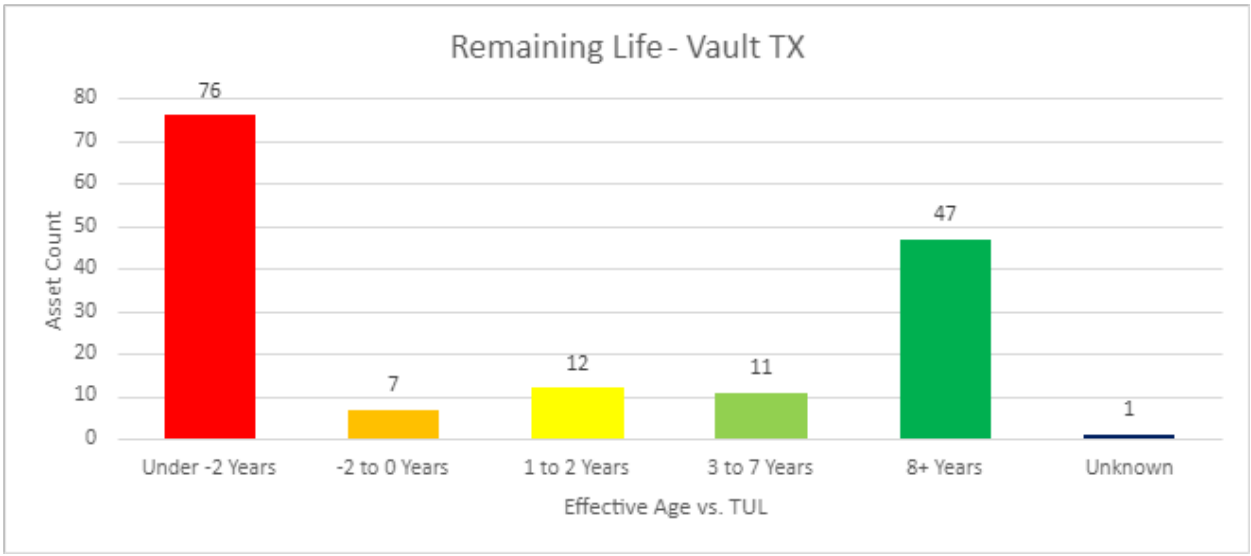


Figure 5-8: Vault Transformer Remaining Life Results

5.1.9 Overhead Switches

The TUL of OH switches is 45 years. The remaining life was calculated for 85% of assets, of which 94% have not yet reached TUL. The remaining life results are shown in Figure 5-9.

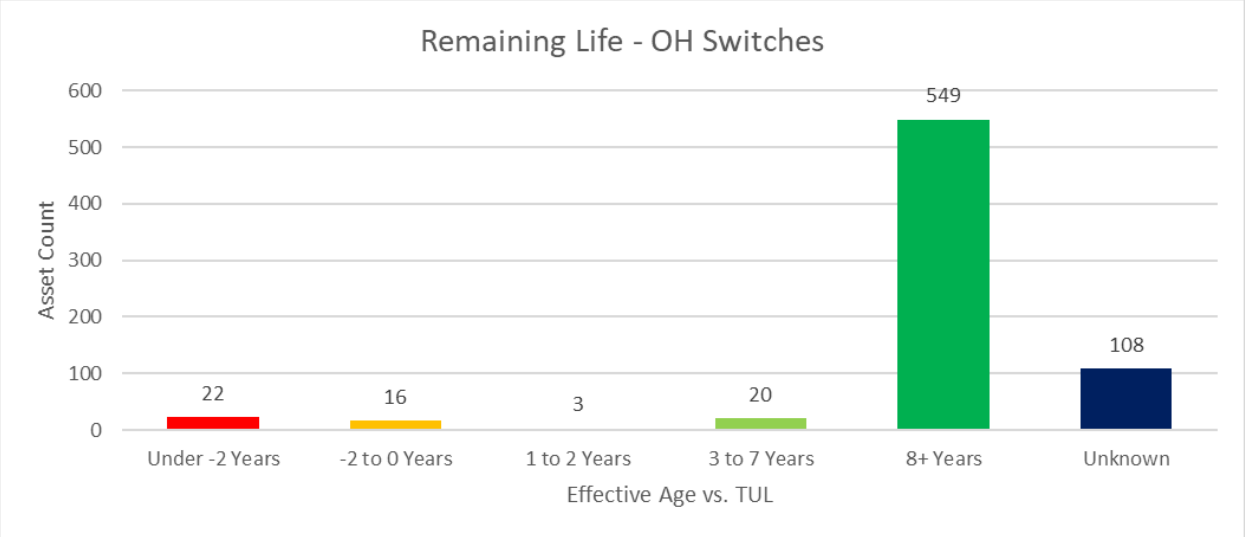


Figure 5-9: OH Switch Remaining Life Results

5.1.10 Smart Switches

The TUL of OH switches is 45 years. The remaining life was calculated for all OH switches, all of which have not yet reached TUL. The remaining life results are shown in Figure 5-10.

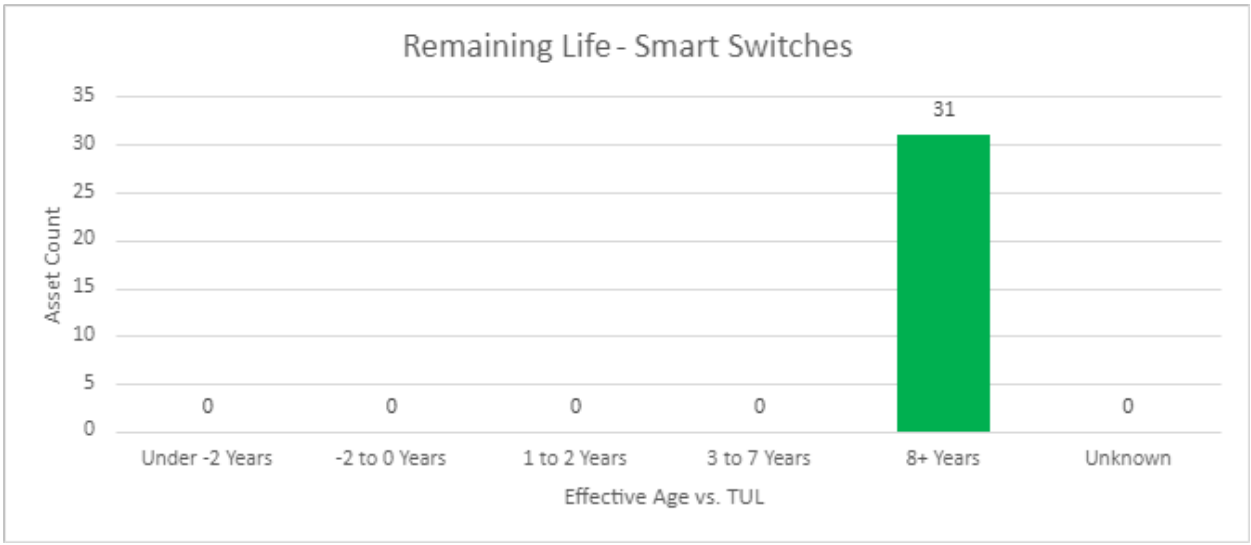


Figure 5-10: Smart Switch Remaining Life Results

5.1.11 Distribution Switchgear

The TUL of distribution switchgear is 30 years. The remaining life was calculated for all assets, of which 69% have not yet reached TUL. The remaining life results are shown in Figure 5-11.

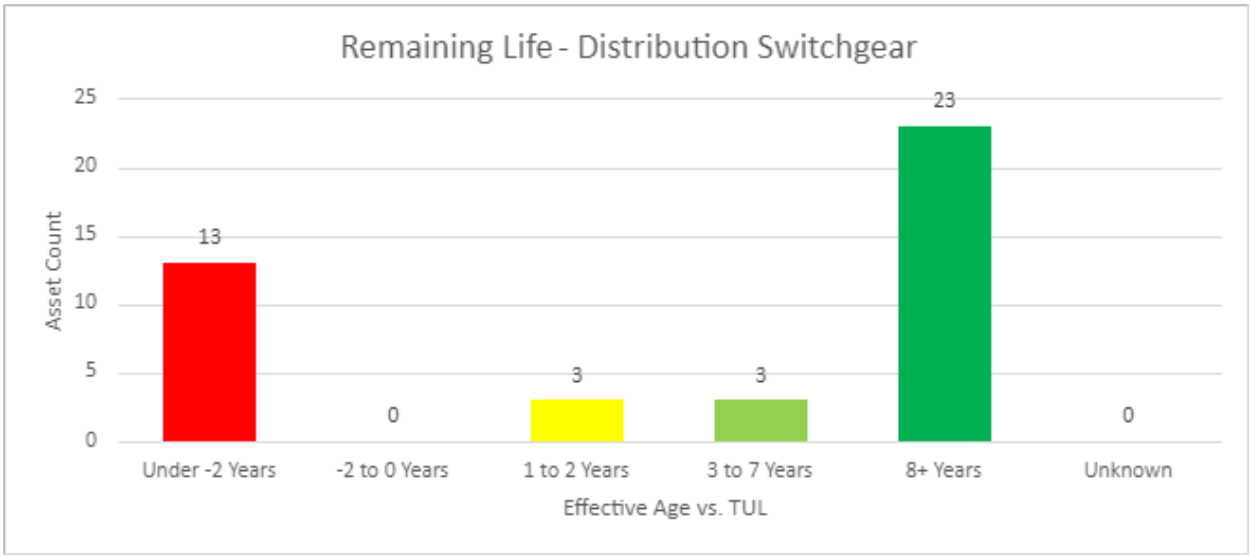


Figure 5-11: Distribution Switchgear Remaining Life Results

5.1.12 Cut-Out Arrestors

The TUL of cut-out arrestors is 30 years. The remaining life was calculated for 94% of cut-out arrestors, of which 68% have not yet reached TUL. The remaining life results are shown in Figure 5-12 .

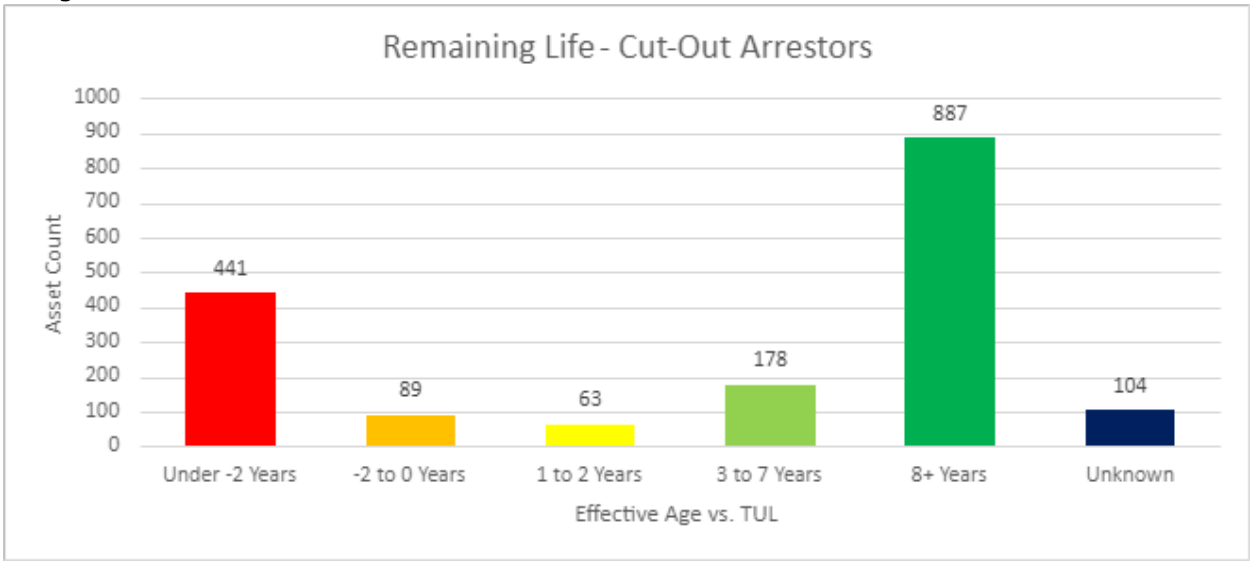


Figure 5-12: Cut-Out Arrestor Remaining Life Results

5.1.13 Elbow Connectors

The TUL of elbow connectors is 30 years. The remaining life was calculated for 96% of assets, of which 84% have not yet reached TUL. The remaining life results are shown in Figure 5-13.

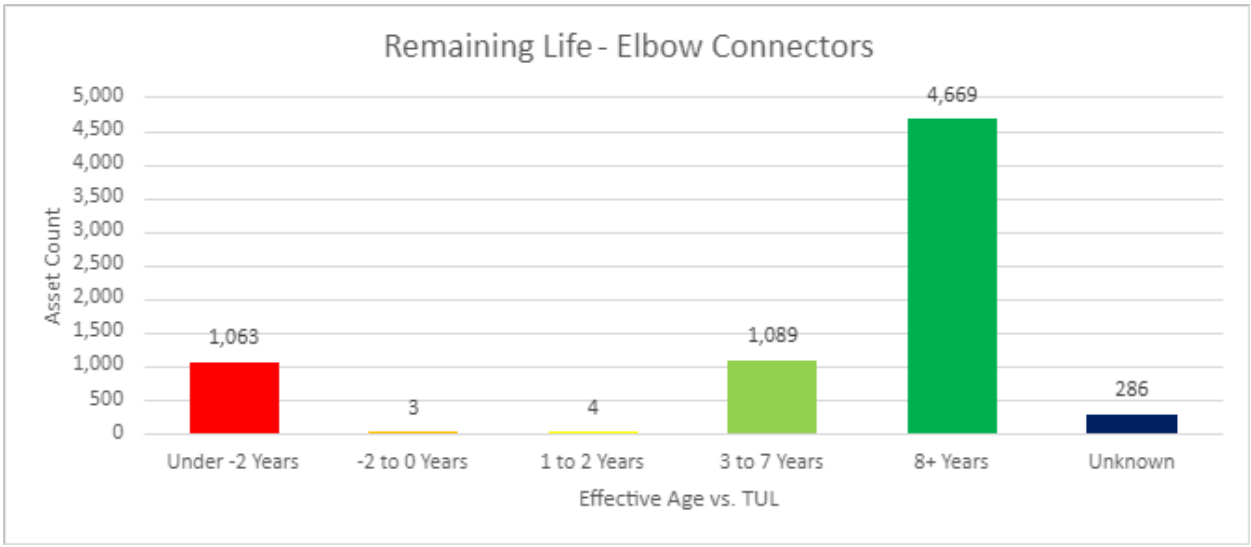


Figure 5-13: Elbow Connector Remaining Life Results

5.1.14 Reclosers

The TUL of reclosers is 40 years. The remaining life was calculated for all reclosers, all of which have not yet reached TUL. The remaining life results are shown in Figure 5-14.

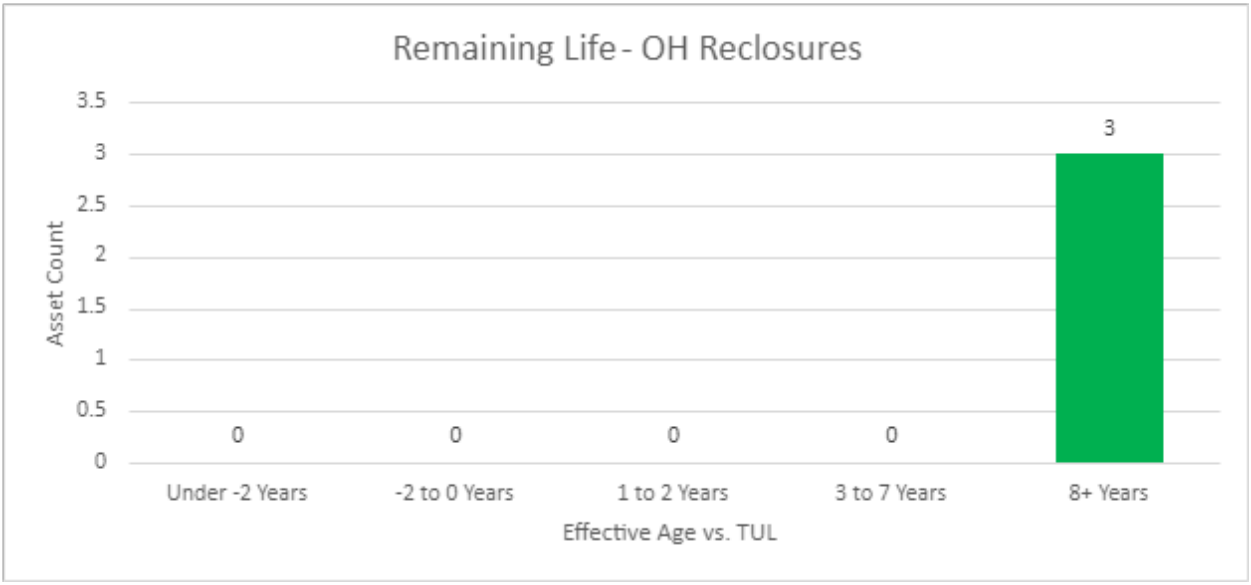


Figure 5-14: OH Recloser Remaining Life Results

5.1.15 Vaults & Manholes

The TUL of vaults and manholes is 60 years. The remaining life was calculated for all vaults and manholes, all of which have not yet reached TUL. The remaining life results are shown in Figure 5-15.

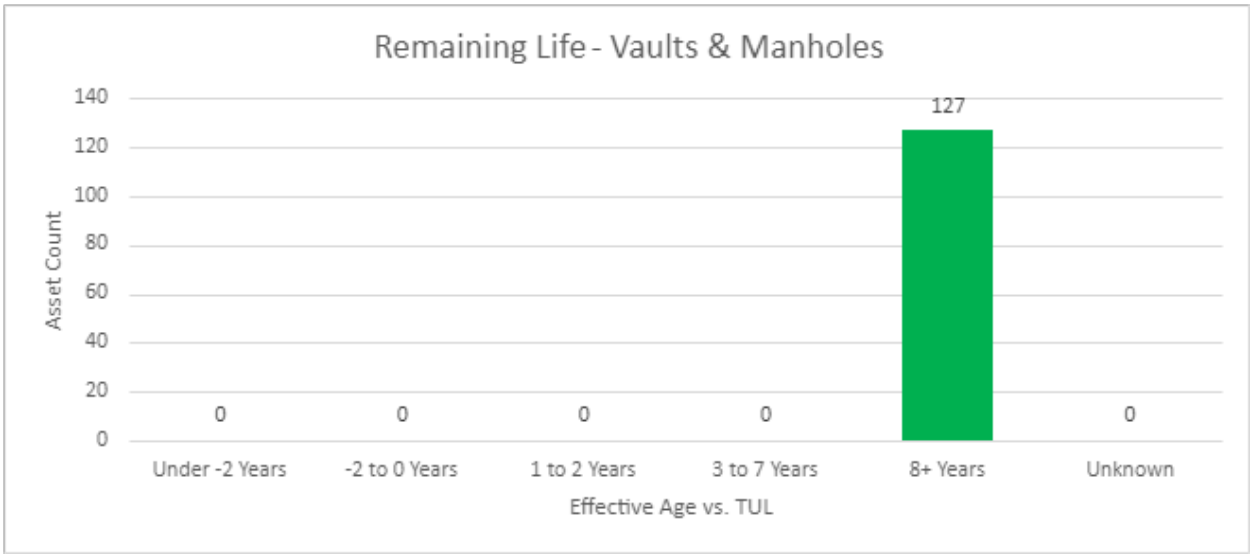


Figure 5-15: Vault & Manhole Remaining Life Results

5.2 Station Assets

5.2.1 Power Transformers

The TUL of power transformers is 45 years. The remaining life was calculated for all power transformers, 94% of which have not yet reached TUL. The remaining life results are shown in Figure 5-16.

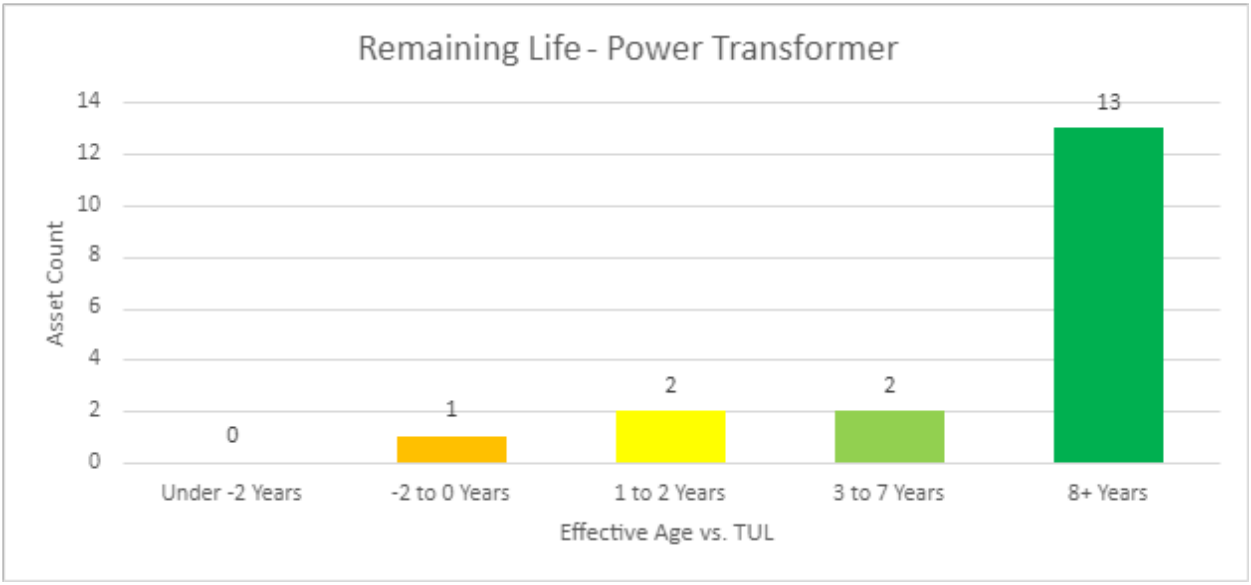


Figure 5-16: Power Transformer Remaining Life Results

5.2.2 Circuit Breakers

The TUL of 13.8-kV and 44-kV circuit breakers is 45 years. The remaining life was calculated for all circuit breakers, all of which have not yet reached TUL. The remaining life results of 13.8-kV and 44-kV circuit breakers are shown in Figure 5-17 and Figure 5-18, respectively.

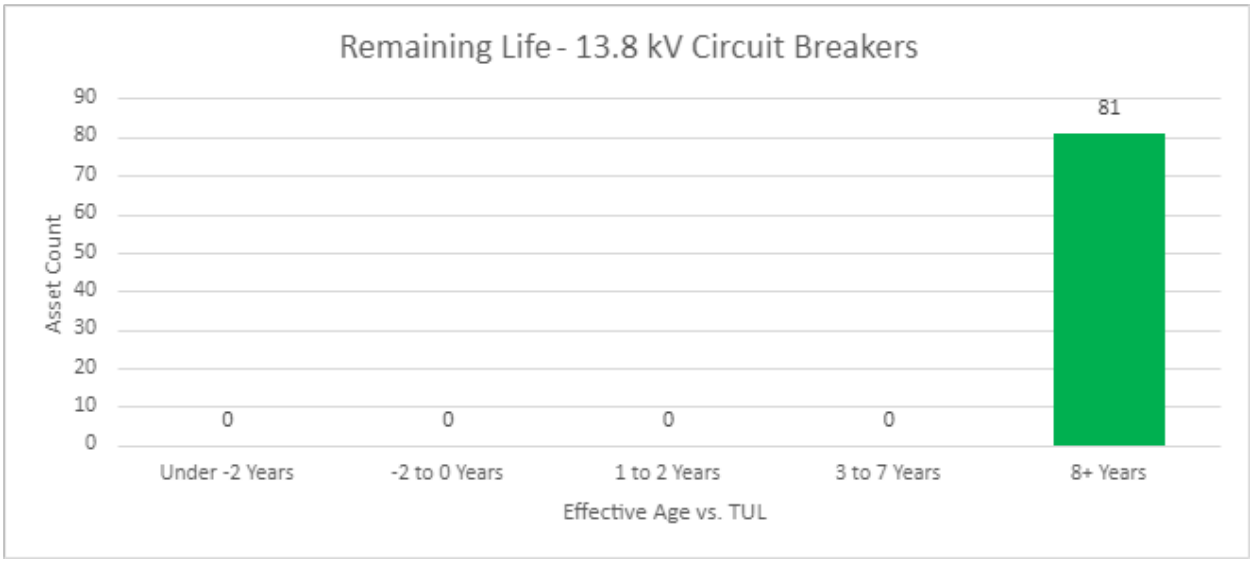


Figure 5-17: 13.8-kV Circuit Breaker Remaining Life Results

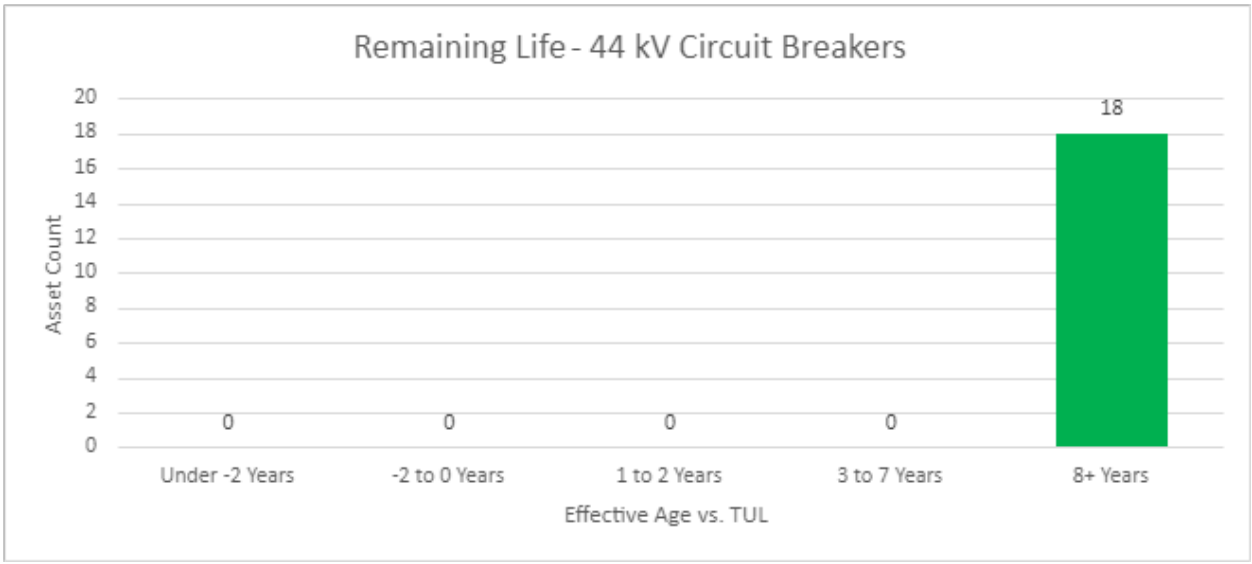


Figure 5-18: 44-kV Circuit Breaker Remaining Life Results

5.2.3 Switchgears

The TUL of station switchgears is 40 years. The remaining life was calculated for all station switchgear busses, of which 67% have not yet reached TUL. The remaining life results are shown in Figure 5-19. Table 5-1 indicates which switchgear buses have an effective age past their TUL.

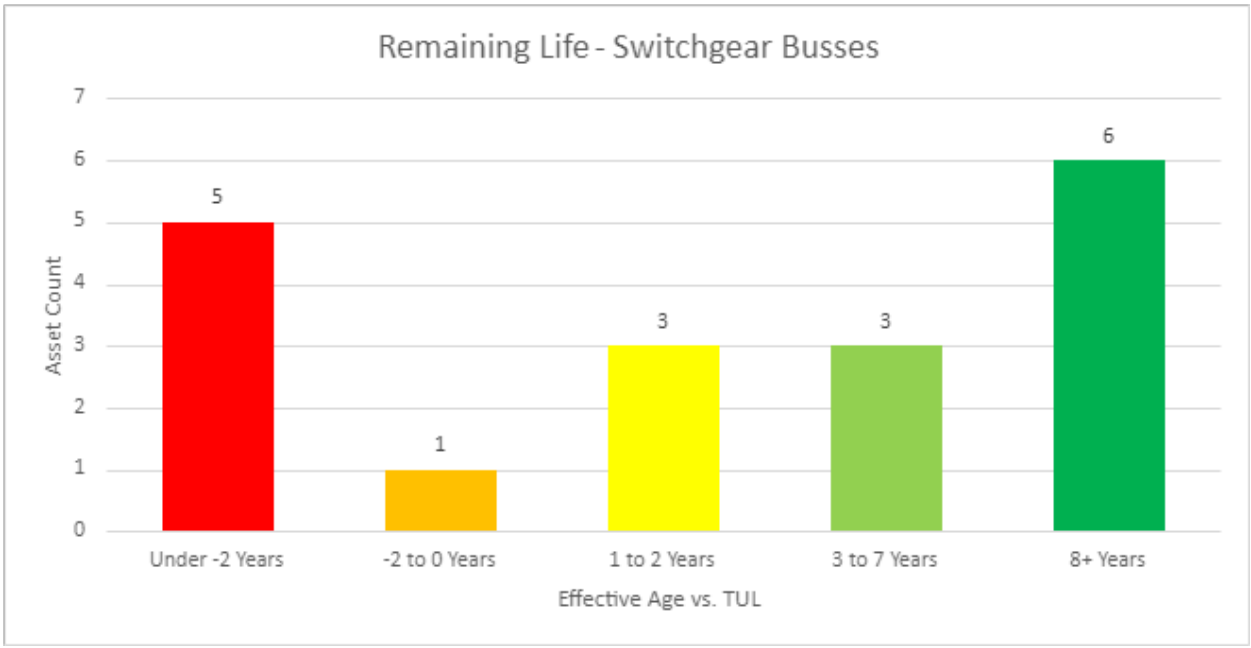


Figure 5-19: Station Switchgear Busses Remaining Life Results

Table 5-1: Switchgear Busses Past TUL

Switchgear Bus	Effective Age vs. TUL
MS10-B Bus	-3
MS10-Y Bus	-3
MS13-Y Bus	-8
MS7-B Bus	-8
MS7-Y Bus	-8

5.2.4 Relays & RTUs

The TUL of relays is twenty years. The remaining life was calculated for all relays, of which 90% have not yet reached TUL. The remaining life results are shown in Figure 5-20.

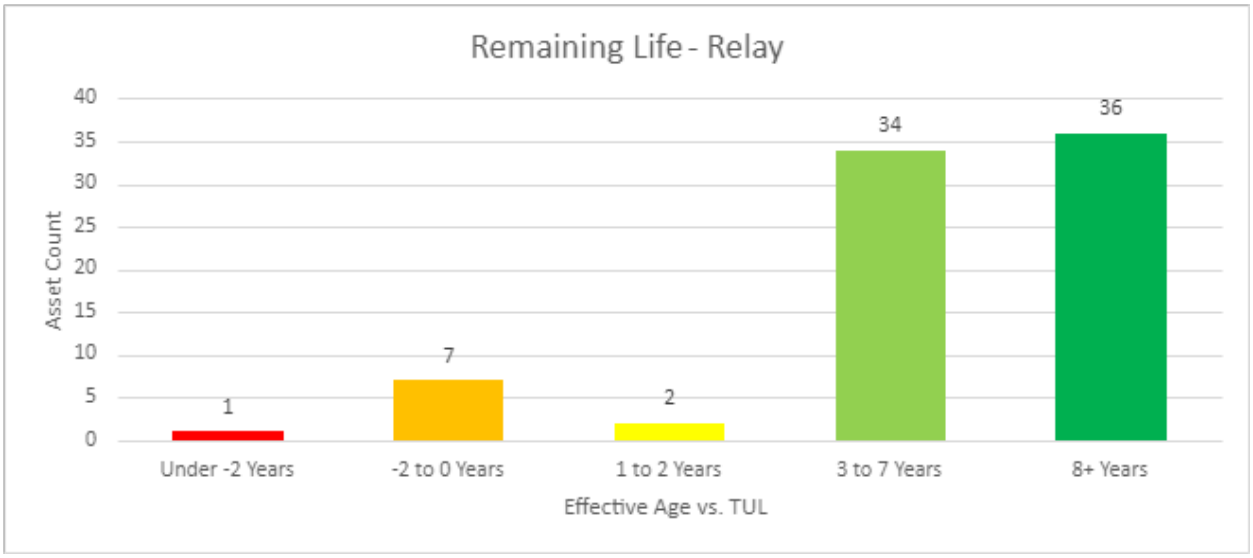


Figure 5-20: Relay Remaining Life Results

The TUL of RTUs is also twenty years. The remaining life was calculated for all RTUs, all of which have not yet reached TUL. The remaining life results are shown in Figure 5-21.

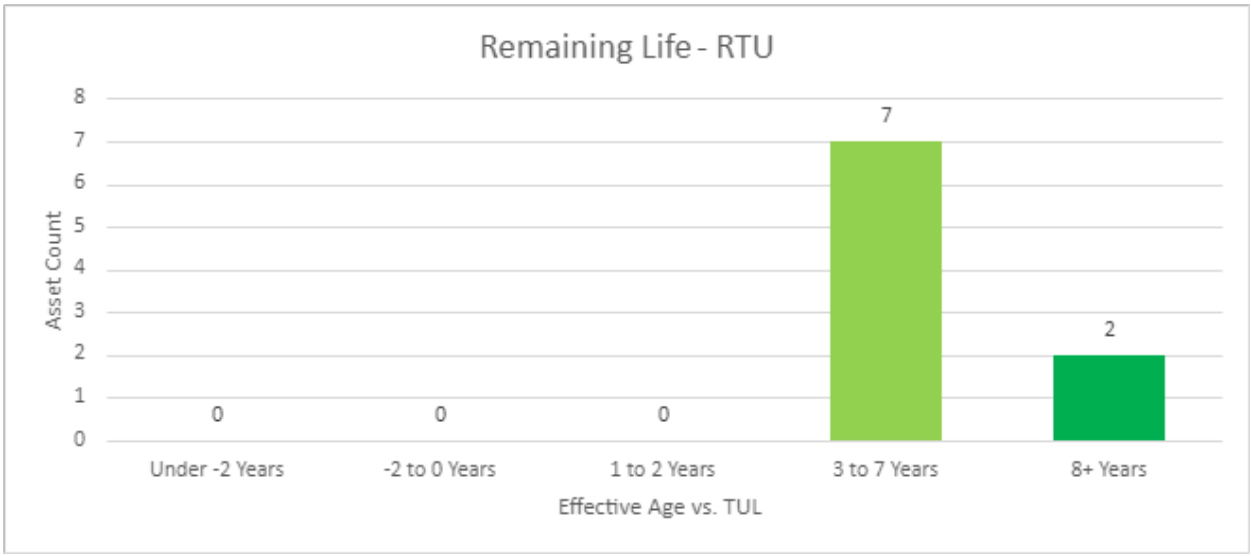


Figure 5-21: RTU Remaining Life Results

5.2.5 Batteries & Chargers

The TUL of station batteries is ten years. The remaining life was calculated for all station batteries, of which 44% have not yet reached TUL. The remaining life results are shown in Figure 5-22.

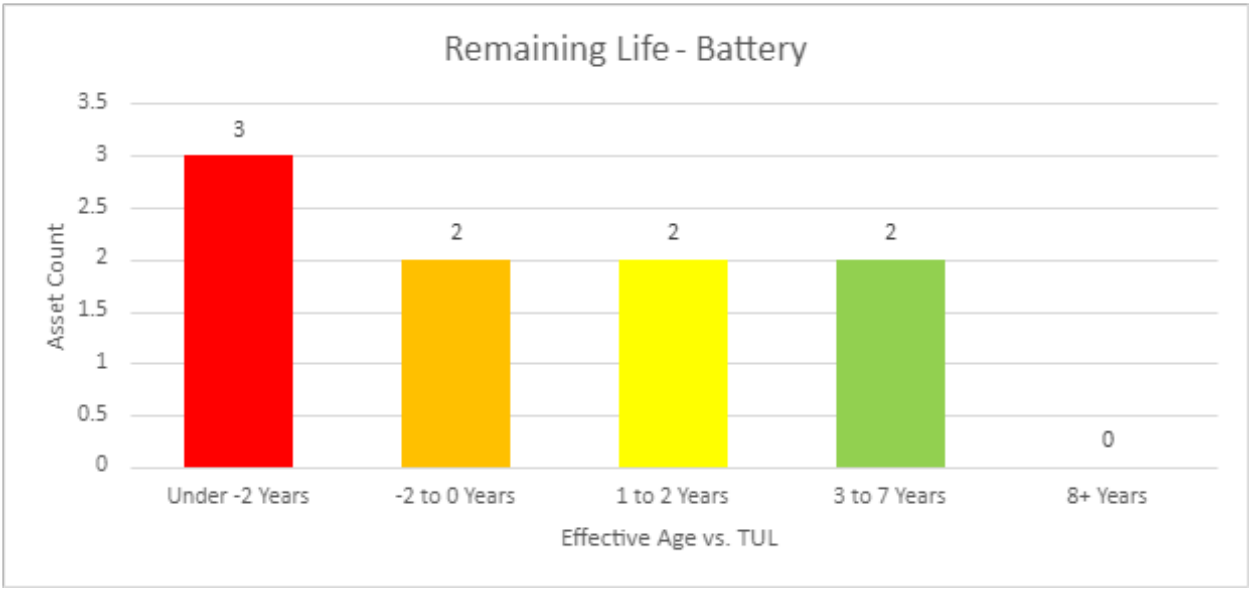


Figure 5-22: Station Battery Remaining Life Results

The TUL of station chargers is twenty years. The remaining life was calculated for all station chargers, of which 78% have not yet reached TUL. The remaining life results are shown in Figure 5-23.

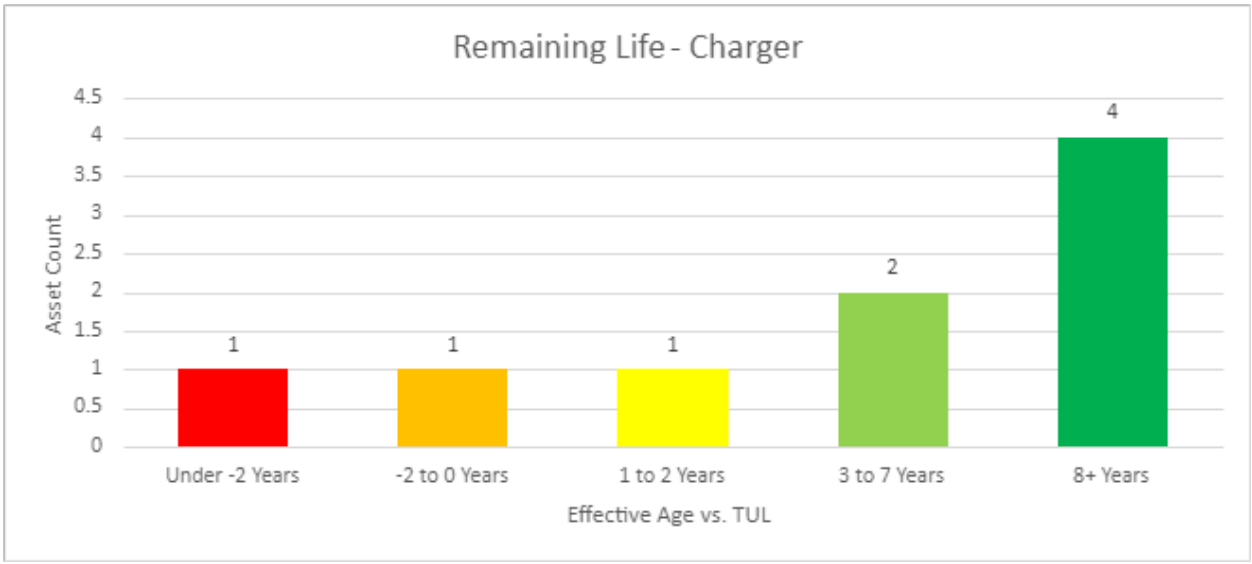


Figure 5-23: Station Charger Remaining Life Results

5.2.6 Station Egress

The TUL of station egress cables is 25 years. The remaining life was calculated for all station cables, of which 47% have not yet reached TUL. The remaining life results are shown in Figure 5-24.

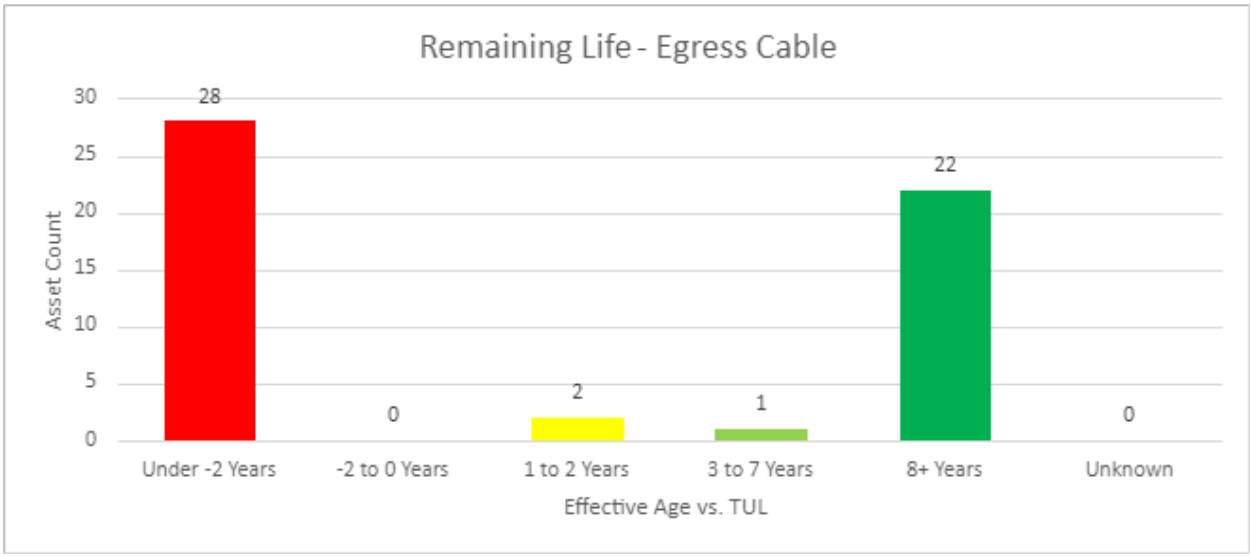


Figure 5-24: Station Egress Cable Remaining Life Results

5.2.7 Station Fences & Yards

No age data were available for station fences and yards.

5.2.8 Station Buildings

The TUL of residential style station buildings is 60 years and the TUL for eHouses is 50 years. The remaining life was calculated for all station buildings, all of which have not yet reached TUL. The remaining life results are shown in Figure 5-25 and Figure 5-26.

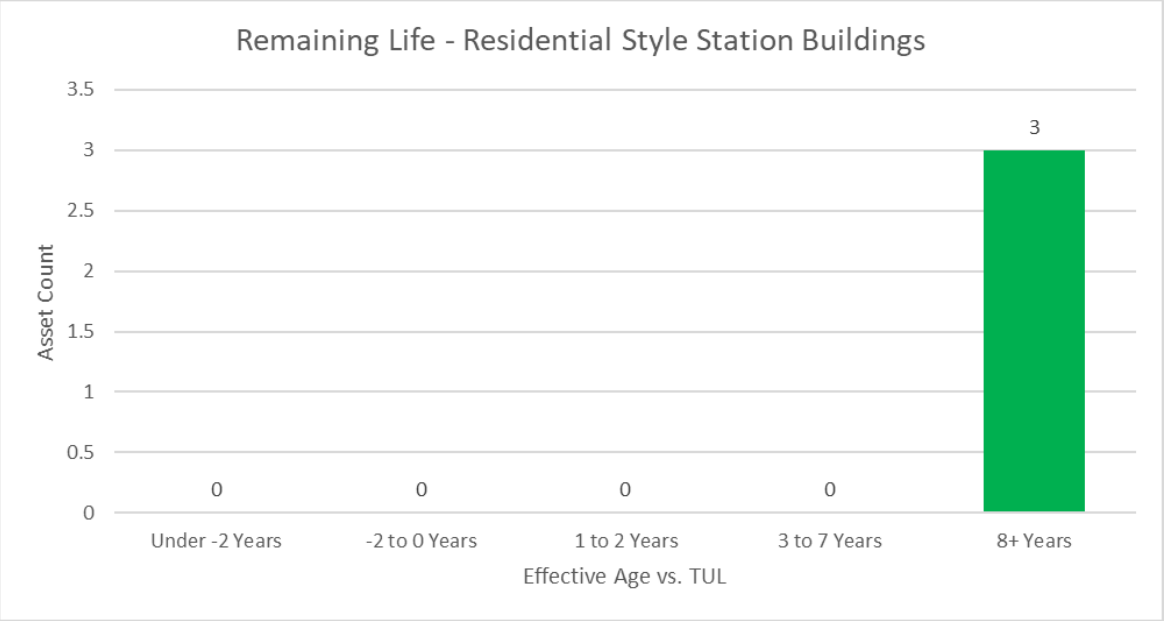


Figure 5-25: Residential Style Station Building Remaining Life Results

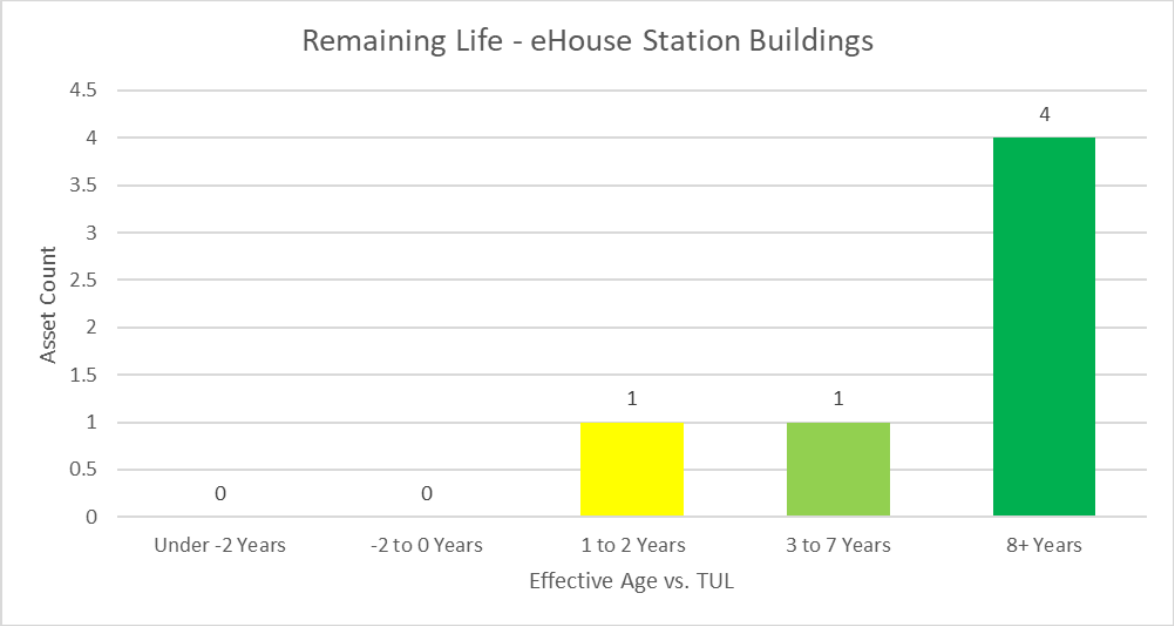


Figure 5-26: eHouse Station Building Remaining Life Results

5.2.9 Bus Structures

No age data were available for station bus structures.

6 Risk Assessment

6.1 Distribution Assets

6.1.1 Wood Poles

Impact Index Formulation

Wood pole failures can cause severe outages. These can be caused by a number of events including severe weather, vehicle accidents and internal rotting. The failure of a pole will impact all assets attached to the pole causing outages and loss of assets. Customer count, feeder load and usage type are used to approximate the poles importance within the feeder. Usage type considers if the pole has primary or secondary circuits and the number of circuits on the pole.

The impact for wood poles is calculated based on the impact assessment criteria summarized in Table 6-1.

Table 6-1: Wood Pole Impact Formulation

Risk Category	Risk Factor	DAI	Weight	Ranking	Numerical Grade	Max Score
Reliability	Customer Count	100%	1	A,B,C,D,E	4,3,2,1,0	4
	Feeder Load	100%	1	A,B,C,D,E	4,3,2,1,0	4
	Usage Type	100%	4	A,C,E	4,2,0	16
Total Score						**24**

Results

A risk score was calculated for 99% of wood poles, of which 96% have Moderate or lower risk. The risk assessment results are shown in Figure 6-1.

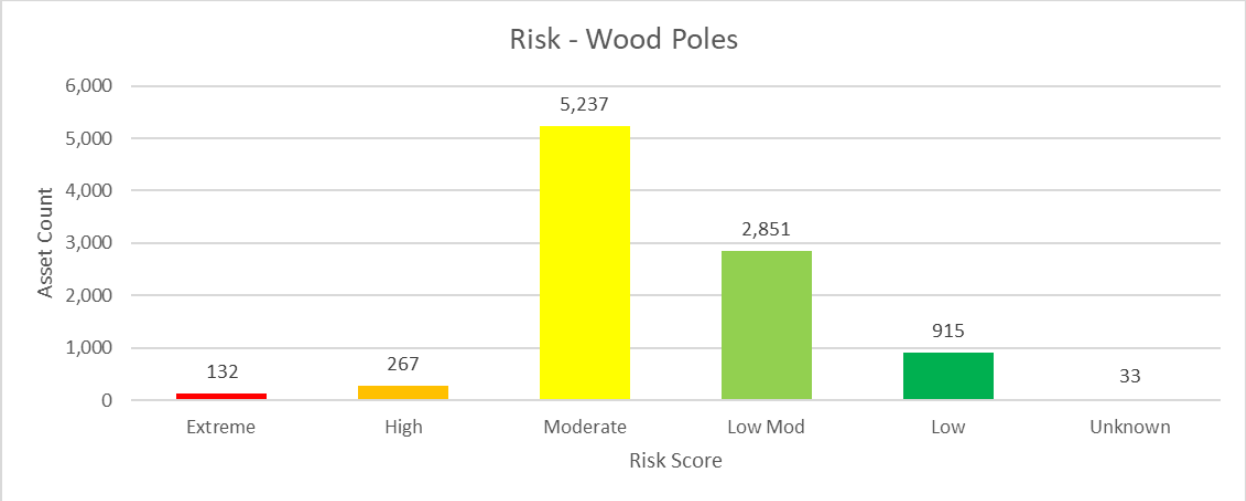


Figure 6-1: Wood Pole Risk Assessment Results

6.1.2 Concrete Poles

Impact Index Formulation

Concrete pole failures can be caused by a number of events including severe weather, vehicle accidents and spalling. The failure of a pole will impact all assets attached to the pole causing outages and loss of assets. Customer count, feeder load and usage type are used to approximate the poles importance within the feeder. Usage type considers if the pole has primary or secondary circuits and the number of circuits on the pole.

The impact for concrete poles is calculated based on the impact assessment criteria summarized in Table 6-2.

Table 6-2: Concrete Pole Impact Formulation

Risk Category	Risk Factor	DAI	Weight	Ranking	Numerical Grade	Max Score
Reliability	Customer Count	100%	1	A,B,C,D,E	4,3,2,1,0	4
	Feeder Load	100%	1	A,B,C,D,E	4,3,2,1,0	4
	Usage Type	100%	4	A,C,E	4,2,0	16
Total Score						**24**

Results

A risk score was calculated for all concrete poles, of which 70% have Moderate or lower risk. The risk assessment results are shown in Figure 6-2.

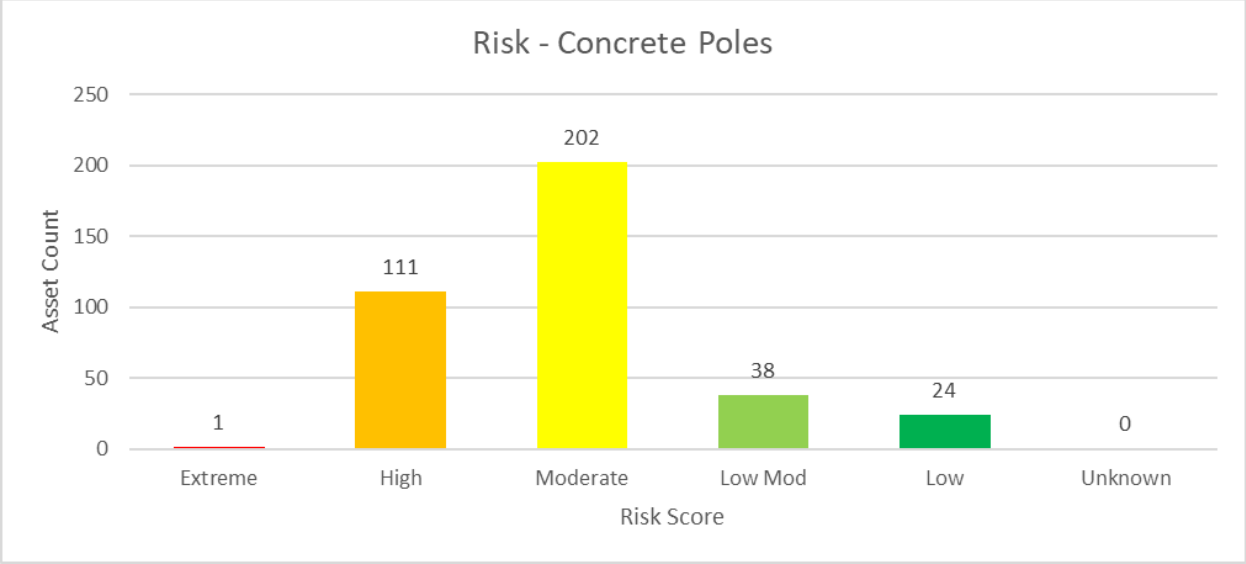


Figure 6-2: Concrete Pole Risk Assessment Results

6.1.3 Steel Poles

Impact Index Formulation

Concrete pole failures can be caused by several events including severe weather, vehicle accidents and rusting. The failure of a pole will impact all assets attached to the pole causing outages and loss of assets. Customer count, feeder load and usage type are used to approximate the poles importance within the feeder. Usage type considers if the pole has primary or secondary circuits and the number of circuits on the pole.

The impact for steel poles is calculated based on the impact assessment criteria summarized in Table 6-3.

Table 6-3: Steel Pole Impact Formulation

Risk Category	Risk Factor	DAI	Weight	Ranking	Numerical Grade	Max Score
Reliability	Customer Count	100%	1	A,B,C,D,E	4,3,2,1,0	4
	Feeder Load	100%	1	A,B,C,D,E	4,3,2,1,0	4
	Usage Type	100%	4	A,C,E	4,2,0	16
Total Score						**24**

Results

A risk score was calculated for all steel poles, all of which have Moderate or lower risk. The risk assessment results are shown in Figure 6-3.

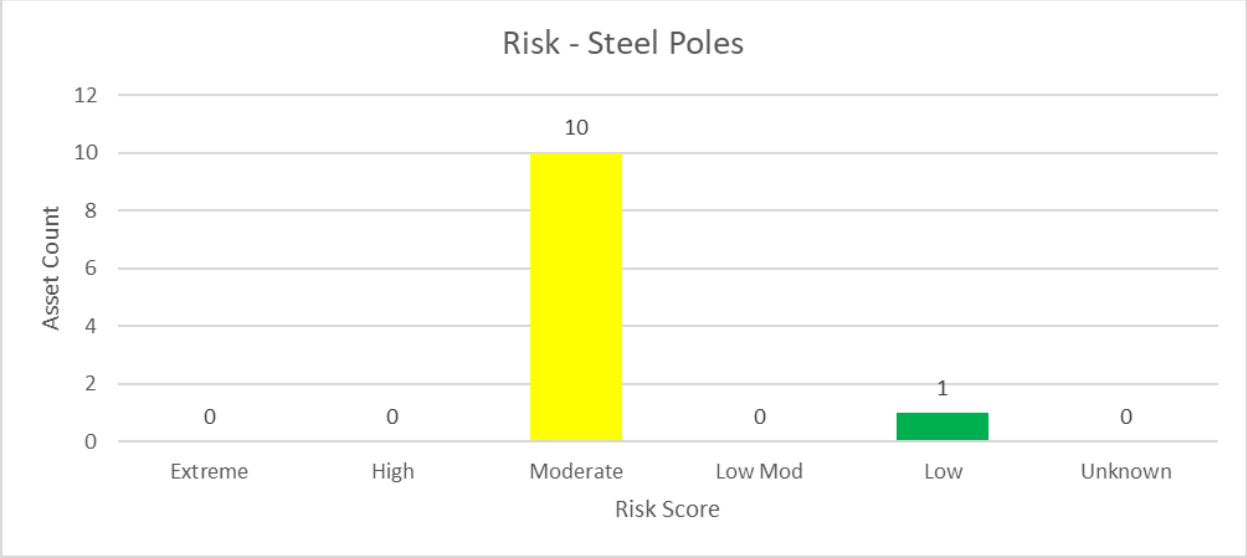


Figure 6-3: Steel Pole Risk Assessment Results

6.1.4 Overhead Primary Conductors

Impact Index Formulation

OH primary line failures are one of the most common causes of outages. These can be caused by a number of events including severe weather, vehicle accidents and tree contact. A cables strength can contribute to the likelihood of surviving such an event. Conductor material is used as a proxy for strength. Conductor size and phase are used to approximate the conductor's importance within the feeder. The impact for OH primary conductors is calculated based on the impact assessment criteria summarized in Table 6-4.

Table 6-4: OH Conductor Impact Formulation

Risk Category	Risk Factor	DAI	Weight	Ranking	Numerical Grade	Max Score
Reliability	Customer Count	100%	1	A,B,C,D,E	4,3,2,1,0	4
	Feeder Load	100%	1	A,B,C,D,E	4,3,2,1,0	4
	Size	100%	3	A,C,E	4,2,0	12
	Material	100%	2	A,B,C,D,E	4,3,2,1,0	8
	Phase	100%	2	A,E	4,0	8
Total Score						**36**

Results

A risk score was calculated for 99% of OH conductors, of which 94% have Moderate or lower risk. The risk assessment results are shown in Figure 6-4.

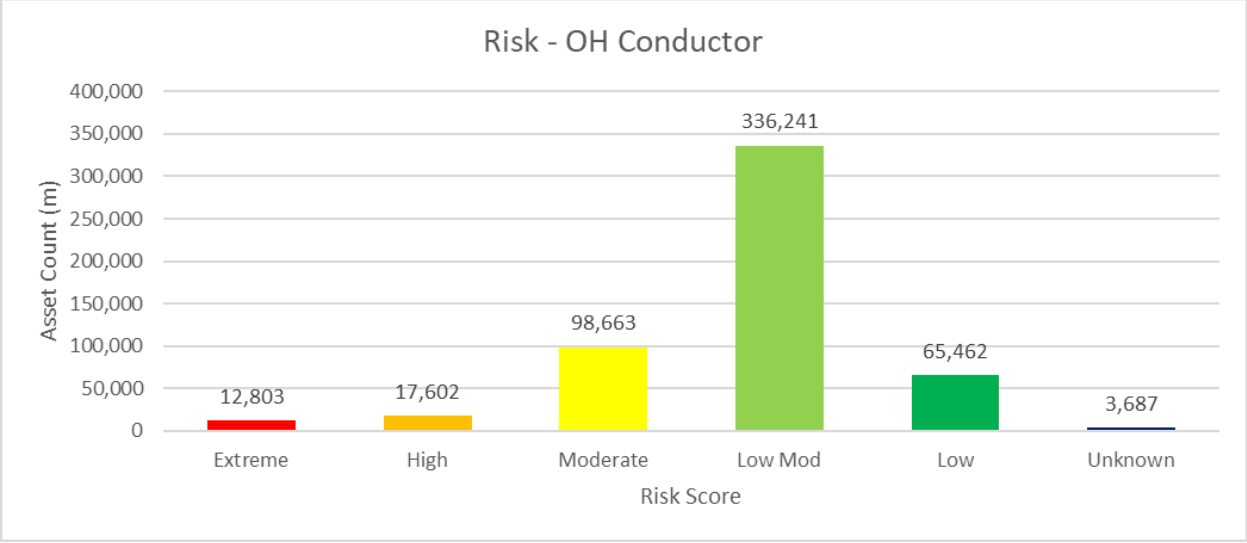


Figure 6-4: OH Conductor Risk Assessment Results

6.1.5 Underground Primary Cables

Impact Index Formulation

One of the major risks to primary cables is damage caused by digging. Burial type is used as a metric to determine how likely a cable is to be damaged due to a digging accident. Cable size and phase are used to approximate the cables importance within the feeder.

The impact for UG cables is calculated based on the impact assessment criteria summarized in Table 6-5.

Table 6-5: UG Cables Impact Formulation

Risk Category	Risk Factor	DAI	Weight	Ranking	Numerical Grade	Max Score
Reliability	Customer Count	100%	1	A,B,C,D,E	4,3,2,1,0	4
	Feeder Load	100%	1	A,B,C,D,E	4,3,2,1,0	4
	Size	100%	3	A,C,E	4,2,0	12
	Phase	100%	2	A,E	4,0	8
	Burial Type	99%	2	A,C,E	4,2,0	8
Total Score						**36**

Results

A risk score was calculated for 99% primary UG cables, of which 93% have Moderate or lower risk. The risk assessment results are shown in Figure 6-5.

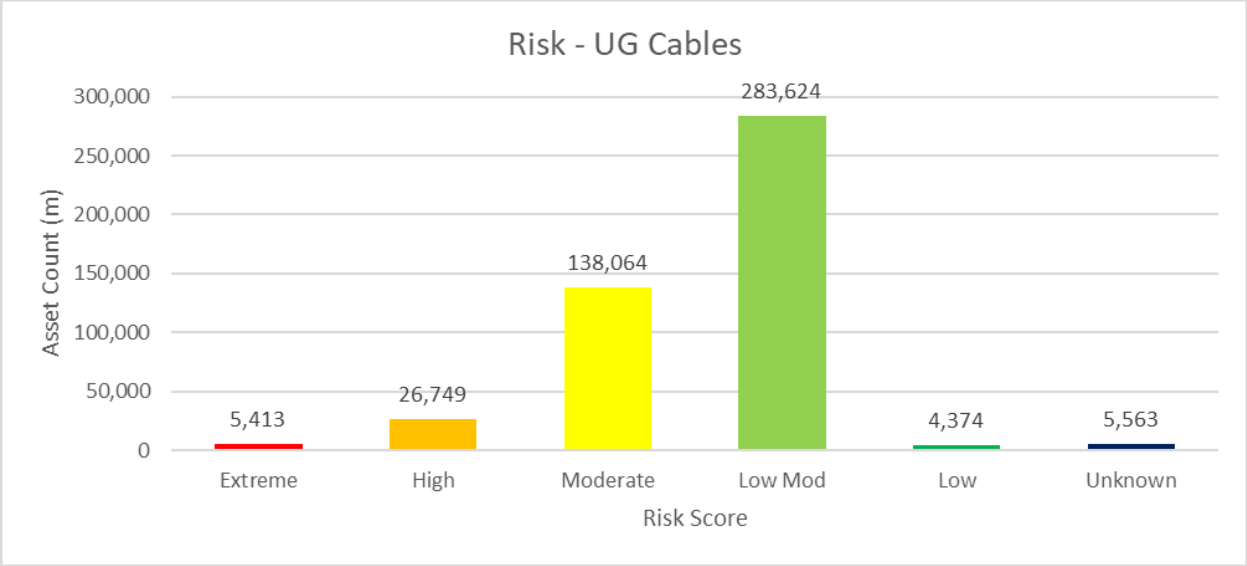


Figure 6-5: UG Cable Risk Assessment Results

6.1.6 Pole-Mount Transformers

Impact Index Formulation

The failure of a distribution transformer would directly affect the customer's connected to it. The transformers size is a proxy for the load of customers connected to it. If the failure effects surrounding assets, it can cause further outages. Transformer type is used to indicate how impactful this type of outage would be.

The impact for pole-mounted transformers is calculated based on the impact assessment criteria summarized in Table 6-6.

Table 6-6: Pole-mount Transformer Impact Formulation

Risk Category	Risk Factor	DAI	Weight	Ranking	Numerical Grade	Max Score
Reliability	Size	100%	4	A,B,C,D,E	4,3,2,1,0	16
	Type: Radial/Loop	99%	2	A,E	4,0	8
Total Score						**24**

Results

A risk score was calculated for 98% pole-mount transformers, all of which have Moderate or lower risk. The risk assessment results are shown in Figure 6-6.

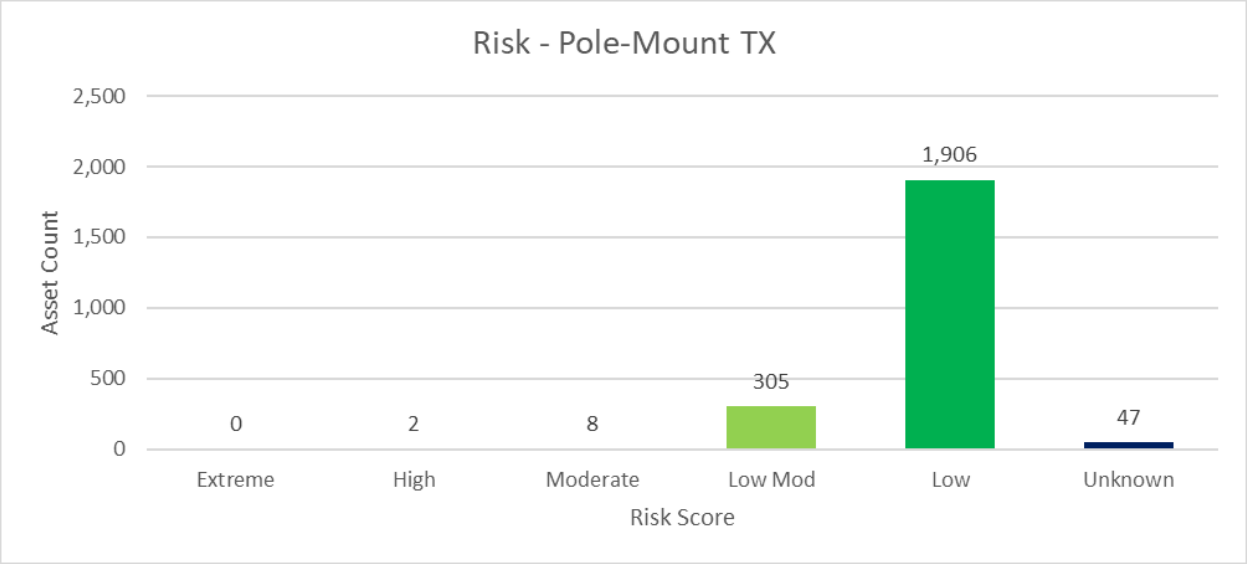


Figure 6-6: Pole-mount Transformer Risk Assessment Results

6.1.7 Pad-Mount Transformers

Risk Index Formulation

The failure of a distribution transformer would directly affect the customer's connected to it. The transformers size is a proxy for the load of customers connected to it. If the failure effects surrounding assets, it can cause further outages. Transformer type is used to indicate how impactful this type of outage would be.

The impact for pad-mounted transformers is calculated based on the impact assessment criteria summarized in Table 6-7.

Table 6-7: Pad-mount Transformer Impact Formulation

Risk Category	Risk Factor	DAI	Weight	Ranking	Numerical Grade	Max Score
Reliability	Size	100%	4	A,B,C,D,E	4,3,2,1,0	16
	Type	100%	2	A,E	4,0	8
Environmental	Oil Leak	56%	3	A,B,C,D,E	4,3,2,1,0	12
Safety	Overgrown	22%	2	A,B,C,D,E	4,3,2,1,0	8
	Lock	56%	2	A,B,C,D,E	4,3,2,1,0	8
	Penta Bolt	52%	2	A,B,C,D,E	4,3,2,1,0	8
Total Score						**60**

Results

A risk score was calculated for 55% of pad-mounted transformers, all of which have Moderate or lower risk. The assessment risk results are shown in Figure 6-7.

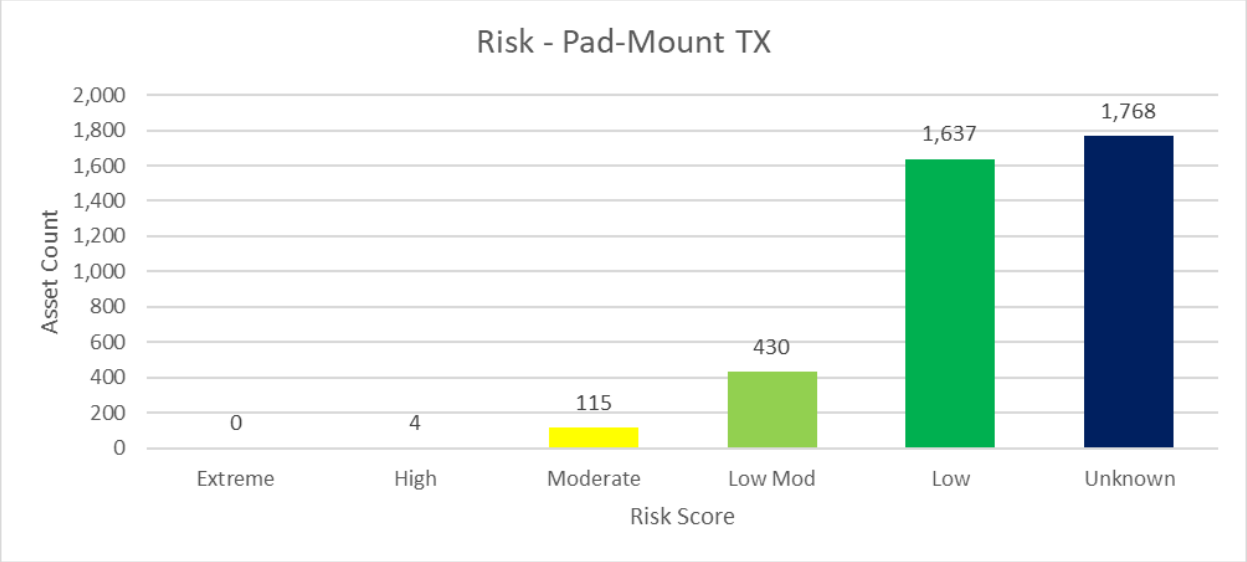


Figure 6-7: Pad-mount Transformer Risk Assessment Results

6.1.8 Vault Transformers

Risk Index Formulation

The failure of a distribution transformer would directly affect the customer's connected to it. The transformers size is a proxy for the load of customers connected to it. If the failure effects surrounding assets, it can cause further outages. Transformer type is used to indicate how impactful this type of outage would be.

The impact for vault transformers is calculated based on the impact assessment criteria summarized in Table 6-8.

Table 6-8: Vault Transformer Impact Formulation

Risk Category	Risk Factor	DAI	Weight	Ranking	Numerical Grade	Max Score
Reliability	Size	100%	4	A,B,C,D,E	4,3,2,1,0	16
	Type	100%	2	A,E	4,0	8
Environmental	Oil Leak	56%	3	A,B,C,D,E	4,3,2,1,0	12
Total Score						**36**

Results

A risk score was calculated for 56% of vault transformers, all of which have Moderate or lower risk. The risk assessment results are shown in Figure 6-8.

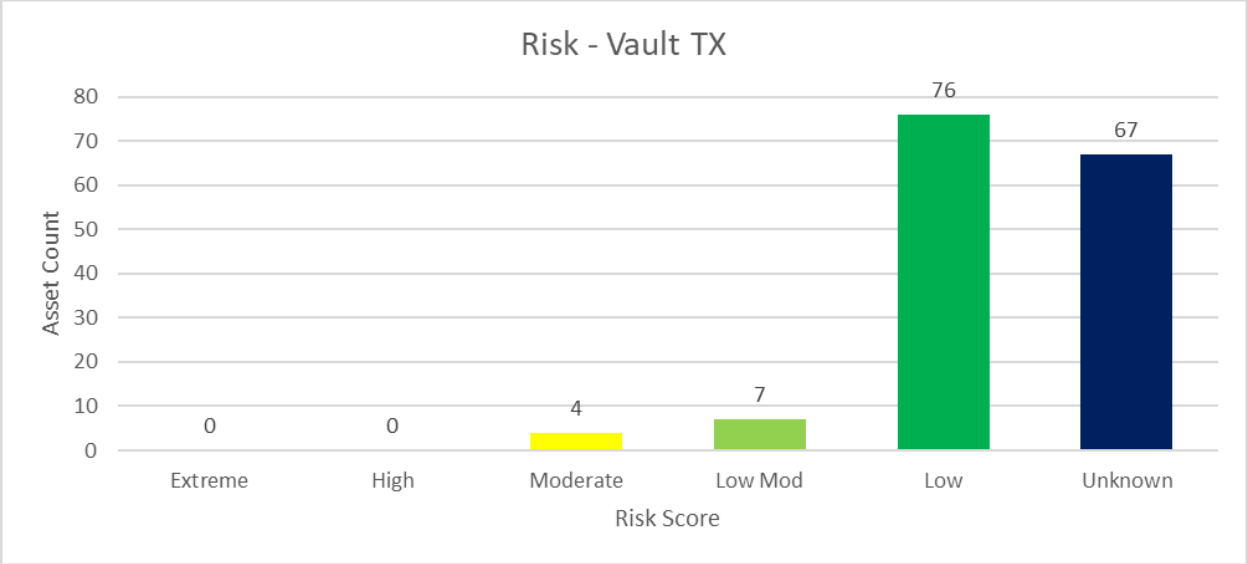


Figure 6-8: Vault Transformer Risk Assessment Results

6.1.9 Overhead Switches

Impact Index Formulation

Switch current rating and phase are used to approximate the OH switches importance within the feeder. The impact for OH switches is calculated based on the impact assessment criteria summarized in Table 6-9.

Table 6-9: OH Switch Impact Formulation

Risk Category	Risk Factor	DAI	Weight	Ranking	Numerical Grade	Max Score
Reliability	Customer Count	71%	1	A,B,C,D,E	4,3,2,1,0	4
	Feeder Loading	71%	1	A,B,C,D,E	4,3,2,1,0	4
	Phase	100%	2	A,E	4,0	8
	Current Rating	5%	2	A,B,C,D,E	4,3,2,1,0	8
Total Score						**24**

Results

A risk score was calculated for 72% of OH switches, of which 99% have Moderate or lower risk. The risk assessment results are shown in Figure 6-9.

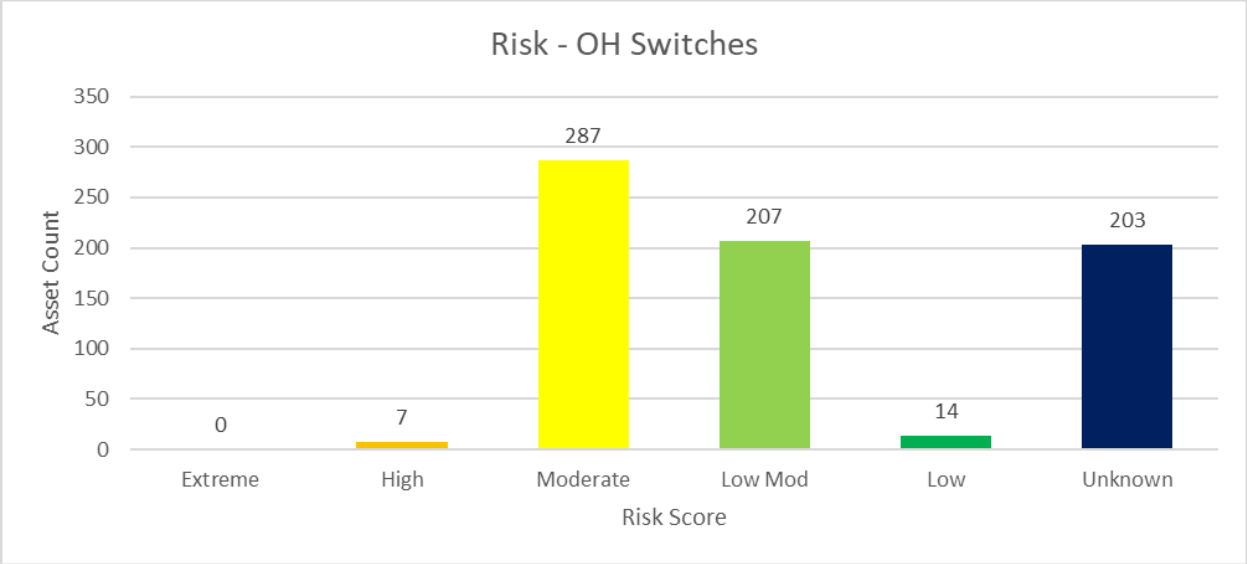


Figure 6-9: OH Switch Risk Assessment Results

6.1.10 Smart Switches

Impact Index Formulation

Smart switch current rating and phase are used to approximate the smart switches importance within the feeder. The impact for smart switches is calculated based on the impact assessment criteria summarized in Table 6-10.

Table 6-10: Smart Switch Impact Formulation

Risk Category	Risk Factor	DAI	Weight	Ranking	Numerical Grade	Max Score
Reliability	Phase	100%	1	A,E	4,0	4
	Current Rating	10%	1	A,B,C,D,E	4,3,2,1,0	4
Total Score						**8**

Results

A risk score was calculated for all smart switches and all of them have Low risk. The risk assessment results are shown in Figure 6-10.

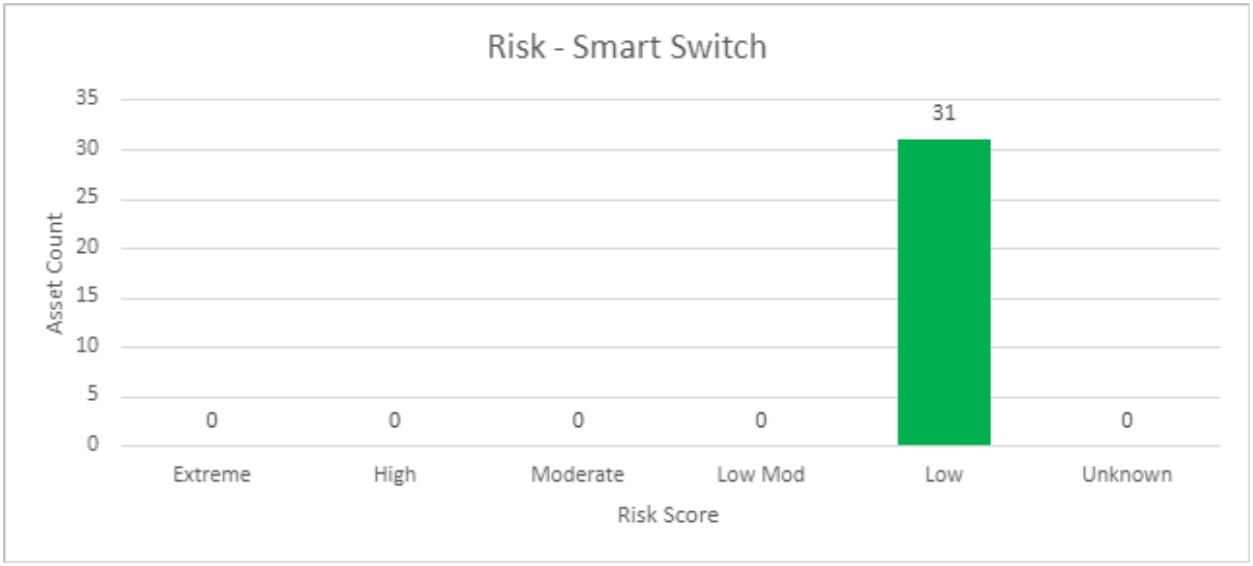


Figure 6-10: Smart Switch Risk Assessment Results

6.1.11 Distribution Switchgear

Impact Index Formulation

Distribution switchgear current rating and phase are used to approximate the distribution switchgears importance within the feeder. The impact for distribution switchgear is calculated based on the impact assessment criteria summarized in Table 6-11.

Table 6-11: Distribution Switchgear Impact Formulation

Risk Category	Risk Factor	DAI	Weight	Ranking	Numerical Grade	Max Score
Reliability	Customer Count	100%	1	A,B,C,D,E	4,3,2,1,0	4
	Feeder Loading	100%	1	A,B,C,D,E	4,3,2,1,0	4
	Phase	100%	3	A,E	4,0	12
	Current Rating	100%	3	A,E	4,0	12
Environmental	SF6 Presence	100%	4	A, E	4,0	16
Total Score						**48**

Results

A risk score was calculated for all distribution switchgear, of which 71% have Moderate or lower risk. The risk results are shown in Figure 6-11.

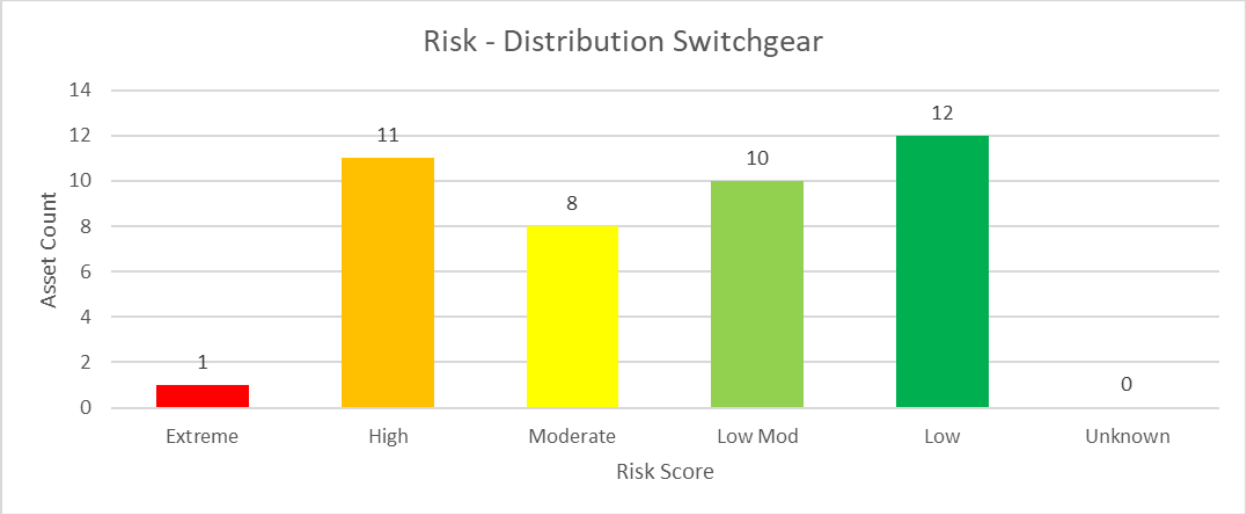


Figure 6-11: Distribution Switchgear Risk Assessment Results

6.1.12 Cut-Out Arrestors

Impact Index Formulation

Cut-out arrestors current rating are used to approximate the cut-out arrestors importance within the feeder. The impact for cut-out arrestors is calculated based on the impact assessment criteria summarized in Table 6-12.

Table 6-12: Cut-out Arrestor Impact Formulation

Risk Category	Risk Factor	DAI	Weight	Ranking	Numerical Grade	Max Score
Reliability	Customer Count	100%	1	A,B,C,D,E	4,3,2,1,0	4
	Feeder Loading	100%	1	A,B,C,D,E	4,3,2,1,0	4
	Current Rating	95%	2	A,B,C,D,E	4,3,2,1,0	8
Total Score						**16**

Results

A risk score was calculated for 89% of cut-out arrestors, of which 96% have Moderate or lower risk. The risk assessment results are shown in Figure 6-12.

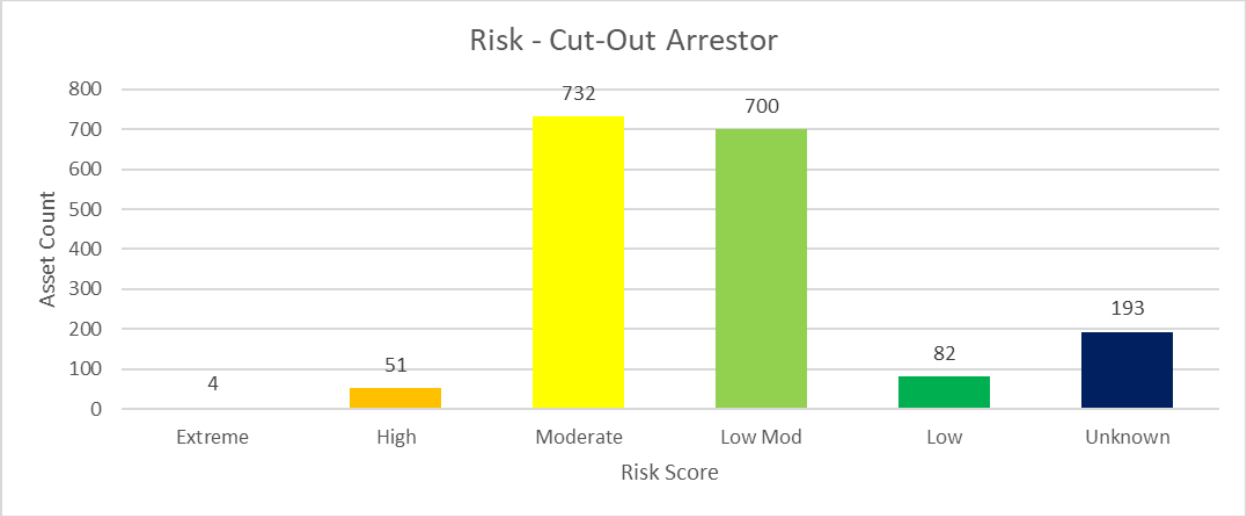


Figure 6-12: Cut-out Arrestor Risk Assessment Results

6.1.13 Elbow Connectors

Impact Index Formulation

The elbow connectors phase is used to approximate the elbow connectors importance within the feeder. The impact for elbow connectors is calculated based on the impact assessment criteria summarized in Table 6-13.

Table 6-13: Elbow Connector Impact Formulation

Risk Category	Risk Factor	DAI	Weight	Ranking	Numerical Grade	Max Score
Reliability	Customer Count	100%	1	A,B,C,D,E	4,3,2,1,0	4
	Feeder Loading	100%	1	A,B,C,D,E	4,3,2,1,0	4
	Phase	100%	2	A,C,E	4,2,0	8
Total Score						**16**

Results

A risk score was calculated for nearly 100% of elbow connectors, all of which have Moderate or lower risk. The risk assessment results can be seen in Figure 6-13.

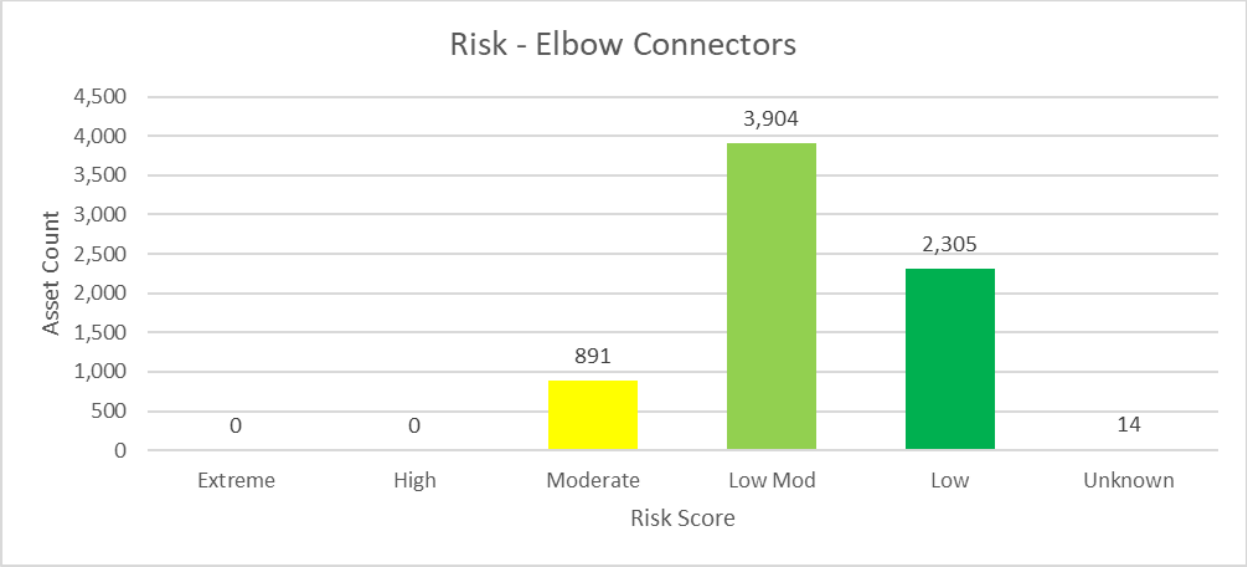


Figure 6-13: Elbow Connector Risk Assessment Results

6.1.14 Reclosers

Impact Index Formulation

The impact for OH reclosers is calculated based on the impact assessment criteria summarized in Table 6-14.

Table 6-14: OH Recloser Impact Formulation

Risk Category	Risk Factor	DAI	Weight	Ranking	Numerical Grade	Max Score
Reliability	Customer Count	100%	1	A,B,C,D,E	4,3,2,1,0	4
	Feeder Loading	100%	1	A,B,C,D,E	4,3,2,1,0	4
Total Score						**8**

Results

A risk score was calculated for all OH reclosers and all of them have Moderate or lower risk. The risk assessment results are shown in Figure 6-14.

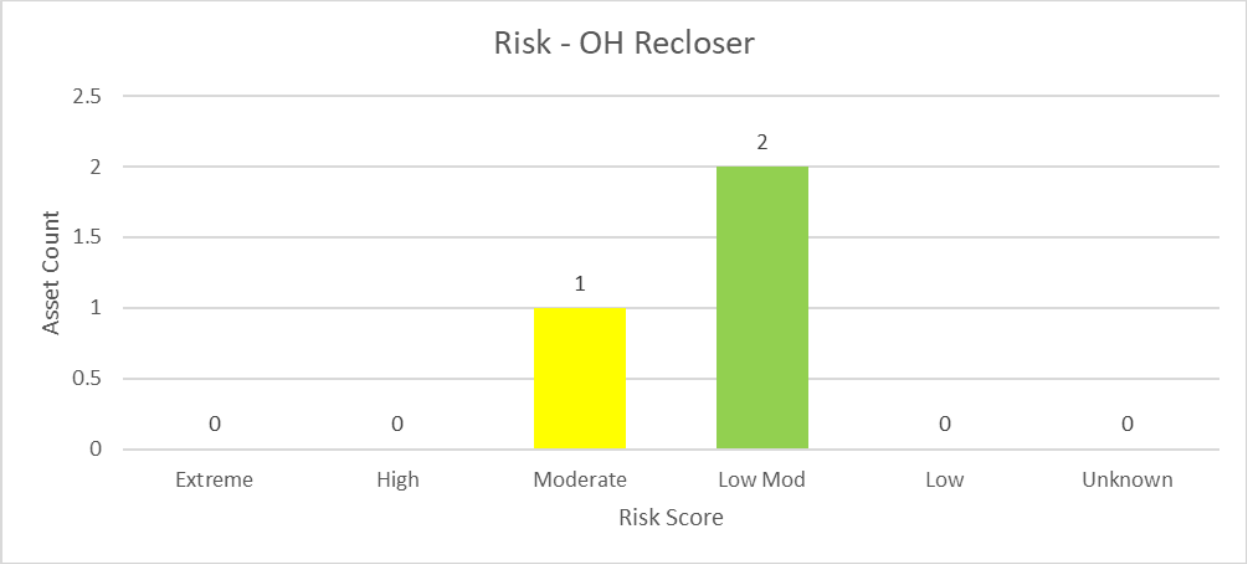


Figure 6-14: OH Recloser Risk Assessment Results

6.1.15 Vaults & Manholes

Impact Index Formulation

In the case that a vault fails the equipment inside determines the impact on the system. The transformer size of the vault transformers associated with each vault are used as a proxy for affected customers in case of a vault failure. The impact for vaults and manholes is calculated based on the impact assessment criteria summarized in Table 6-15 and Table 6-16.

Table 6-15: Vault Impact Formulation

Risk Category	Risk Factor	DAI	Weight	Ranking	Numerical Grade	Max Score
Safety	Trip Hazard/Hatch	100%	2	A,B,C,D,E	4,3,2,1,0	8
	Access	100%	2	A,B,C,D,E	4,3,2,1,0	8
	Vents	83%	2	A,B,C,D,E	4,3,2,1,0	8
	Locks	100%	3	A,B,C,D,E	4,3,2,1,0	12
	Signs	100%	1	A,B,C,D,E	4,3,2,1,0	4
	Lighting	100%	3	A,B,C,D,E	4,3,2,1,0	12
	Drainage	100%	2	A,B,C,D,E	4,3,2,1,0	8
	Grounding	100%	3	A,B,C,D,E	4,3,2,1,0	12
	Clean	100%	1	A,B,C,D,E	4,3,2,1,0	4
Reliability	Customer Count	100%	5	A,B,C,D,E	4,3,2,1,0	20
	Feeder Load	100%	5	A,B,C,D,E	4,3,2,1,0	20
	Transformer Size	83%	9	A,B,C,D,E	4,3,2,1,0	36
Total Score						**152**

Table 6-16: Manhole Impact Formulation

Risk Category	Risk Factor	DAI	Weight	Ranking	Numerical Grade	Max Score
Safety	Lid & Chimney	52%	2	A,B,C,D,E	4,3,2,1,0	8
	Drainage	52%	1	A,B,C,D,E	4,3,2,1,0	4
	Structure/Power Center	52%	3	A,B,C,D,E	4,3,2,1,0	12
Total Score						**24**

Results

A risk score was calculated for all vaults, all of which have Moderate or lower risk. The risk assessment results are shown in Figure 6-15.

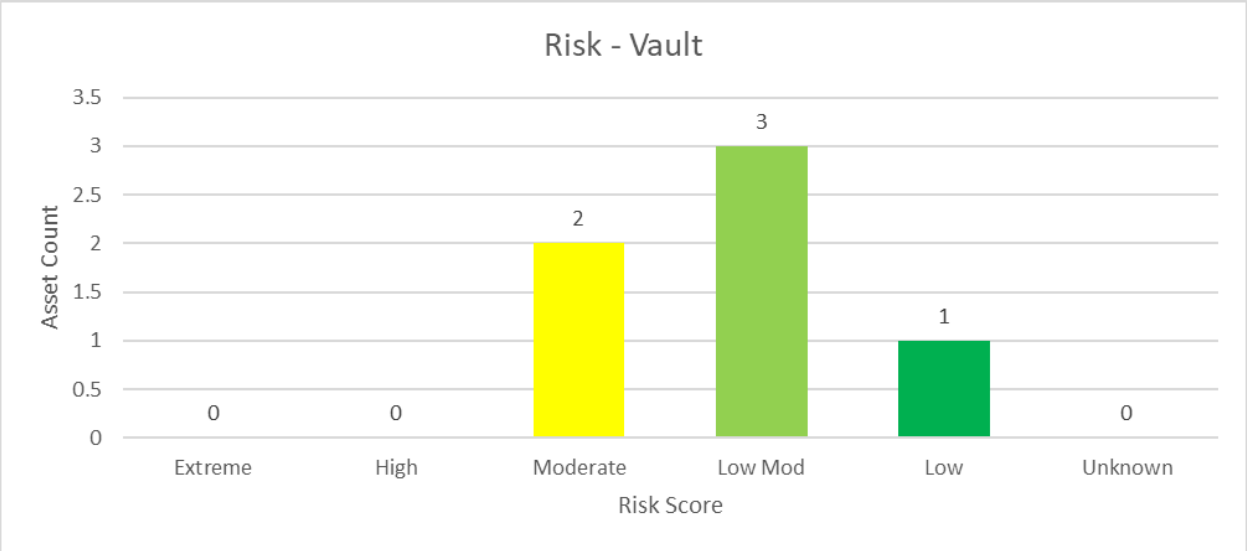


Figure 6-15: Vault Risk Assessment Results

A risk score was calculated for 50% of manholes, all of which have Moderate or lower risk. The risk assessment results are shown in Figure 6-16.

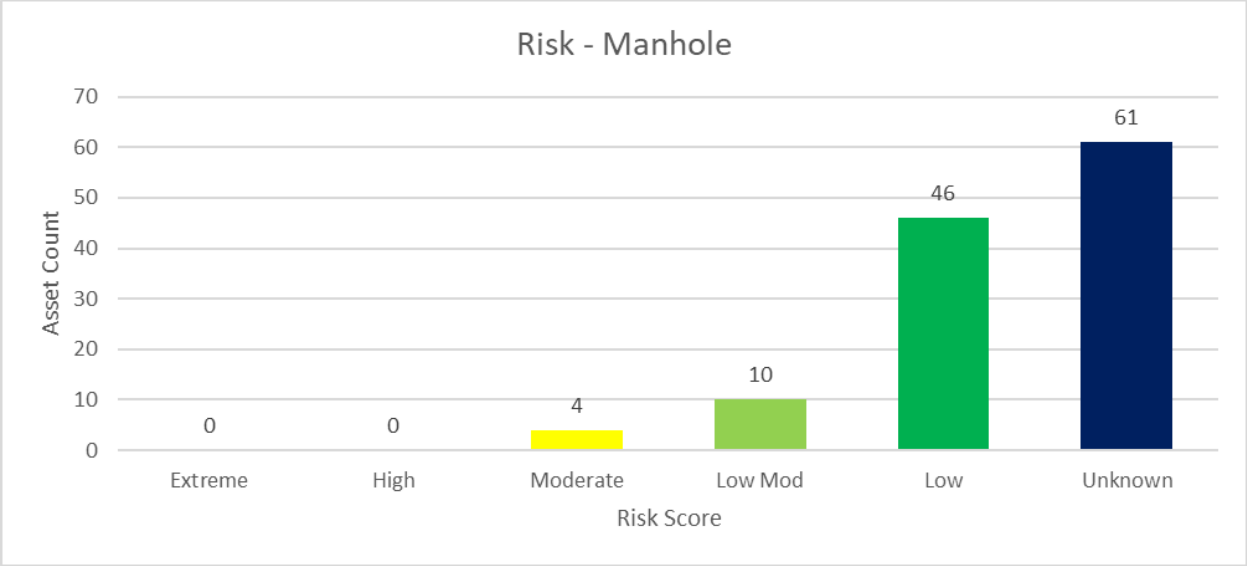


Figure 6-16: Manhole Risk Assessment Results

6.2 Station Assets

6.2.1 Power Transformers

Impact Index Formulation

Power transformers are critical assets for any power utility. In the case of OPUCN the outage of a power transformer would result in the loss of power for three feeders. Power transformers can also pose large environmental risk due to the large volume of oil they contain.

The impact for power transformers is calculated based on the impact assessment criteria summarized in Table 6-17.

Table 6-17: Power Transformer Impact Formulation

Risk Category	Risk Factor	DAI	Weight	Ranking	Numerical Grade	Max Score
Reliability	Customer Count	100%	2	A,B,C,D,E	4,3,2,1,0	8
	Feeder Load	100%	2	A,B,C,D,E	4,3,2,1,0	8
Safety	Grounding	100%	4	A,B,C,D,E	4,3,2,1,0	16
Environmental	Oil Leaks	100%	1	A,B,C,D,E	4,3,2,1,0	4
	Oil Volume (L)	44%	1	A,B,C,D,E	4,3,2,1,0	4
Total Score						**40**

Results

The risk was calculated for all power transformers, all of which have Moderate or lower risk. The risk assessment results are shown in Figure 6-17.

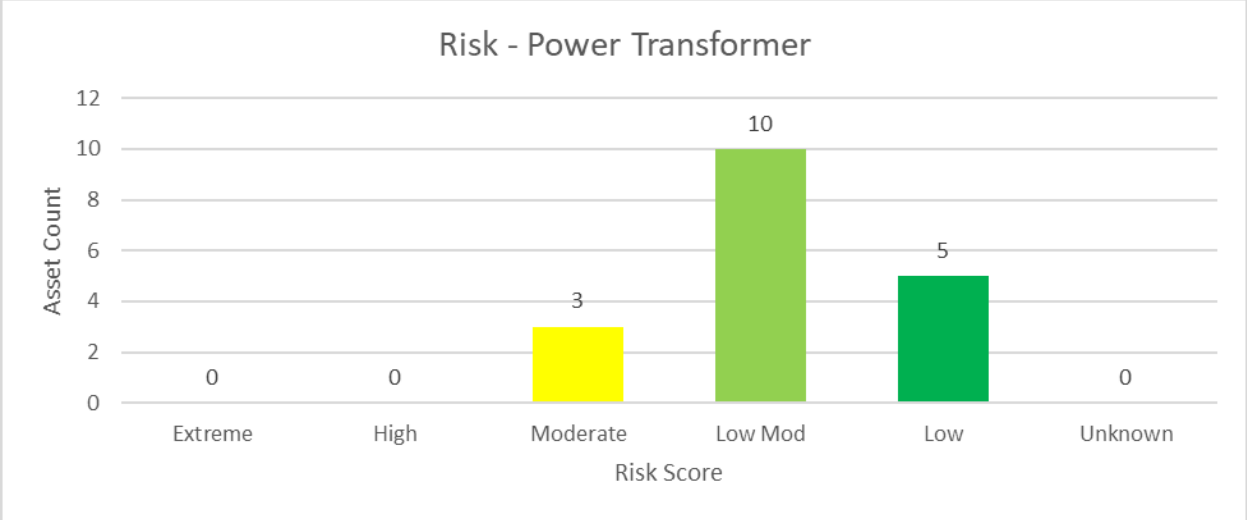


Figure 6-17: Power Transformer Risk Assessment Results

6.2.2 Circuit Breakers

Risk Index Formulation

Circuit breakers are important protective devices for the stations. The failure of a 13.8-kV breaker would impact a single feeder while the failure of a 44-kV circuit breaker would impact three feeders. The impact for 13.8-kV and 44-kV circuit breakers is calculated based on the impact assessment criteria summarized in Table 6-18 and Figure 6-19, respectively.

Table 6-18: 13.8-kV Circuit Breaker Impact Formulation

Risk Category	Risk Factor	DAI	Weight	Ranking	Numerical Grade	Max Score
Reliability	Customer Count	100%	2	A,B,C,D,E	4,3,2,1,0	8
	Feeder Load	100%	2	A,B,C,D,E	4,3,2,1,0	8
Safety	Grounding	99%	4	A,B,C,D,E	4,3,2,1,0	16
Environmental	SF6 Presence	100%	1	A,E	4,0	4
Total Score						**40**

Table 6-19: 44-kV Circuit Breaker Impact Formulation

Risk Category	Risk Factor	DAI	Weight	Ranking	Numerical Grade	Max Score
Reliability	Customer Count	100%	2	A,B,C,D,E	4,3,2,1,0	8
	Feeder Loading	100%	2	A,B,C,D,E	4,3,2,1,0	8
Safety	Grounding	100%	4	A,B,C,D,E	4,3,2,1,0	16
Environmental	SF6 Leaks	67%	1	A,B,C,D,E	4,3,2,1,0	4
Total Score						**40**

Results

A risk score was calculated for 99% of 13.8-kV circuit breakers, of which 99% have Moderate or lower risk. The risk assessment results are shown in Figure 6-18.

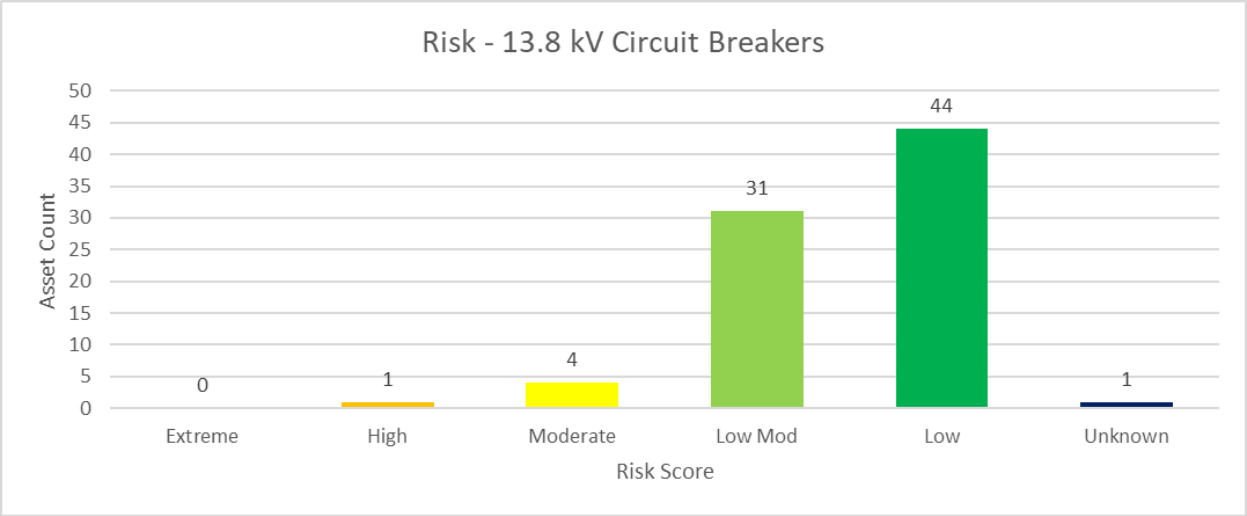


Figure 6-18: 13.8-kV Circuit Breaker Risk Assessment Results

A risk score was calculated for all 44-kV circuit breakers and all of them have Moderate or lower risk. The risk assessment results are shown in Figure 6-19.

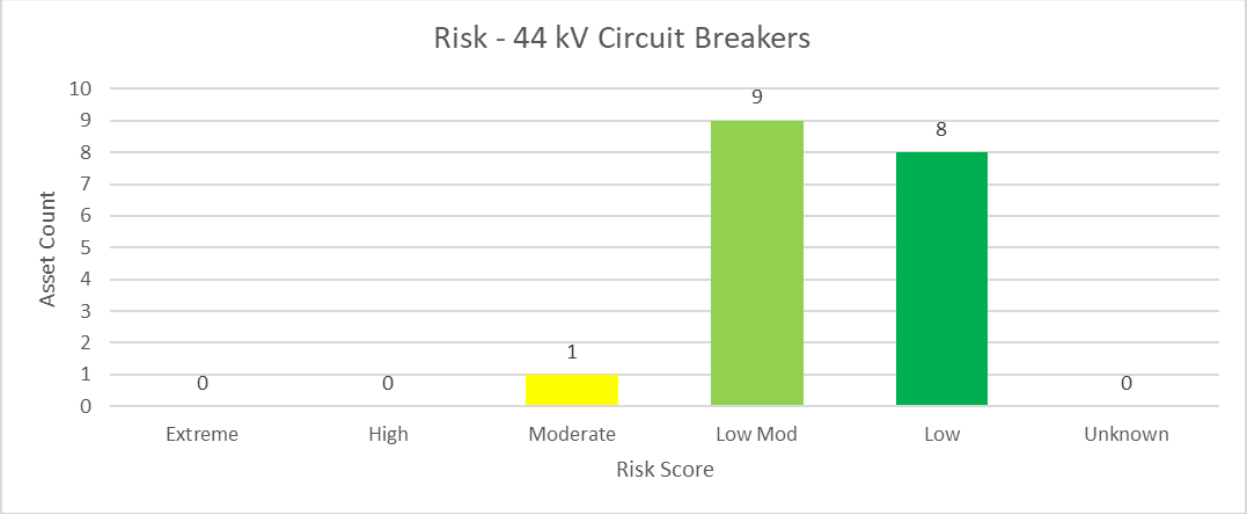


Figure 6-19: 44-kV Circuit Breaker Risk Assessment Results

6.2.3 Switchgears

Risk Index Formulation

In OPUCN's system switchgear buses protect three feeders. The impact for switchgear buses is calculated based on the impact assessment criteria summarized in Table 6-20.

Table 6-20: Station Switchgear Impact Formulation

Risk Category	Risk Factor	DAI	Weight	Ranking	Numerical Grade	Max Score
Reliability	Customer Count	100%	1	A,B,C,D,E	4,3,2,1,0	4
	Feeder Loading	100%	1	A,B,C,D,E	4,3,2,1,0	4
Total Score						**8**

Results

A risk score was calculated for all switchgear busses. Most of the calculated assets have Moderate or lower risk. One asset has high risk. The risk assessment results are shown in Figure 6-20.

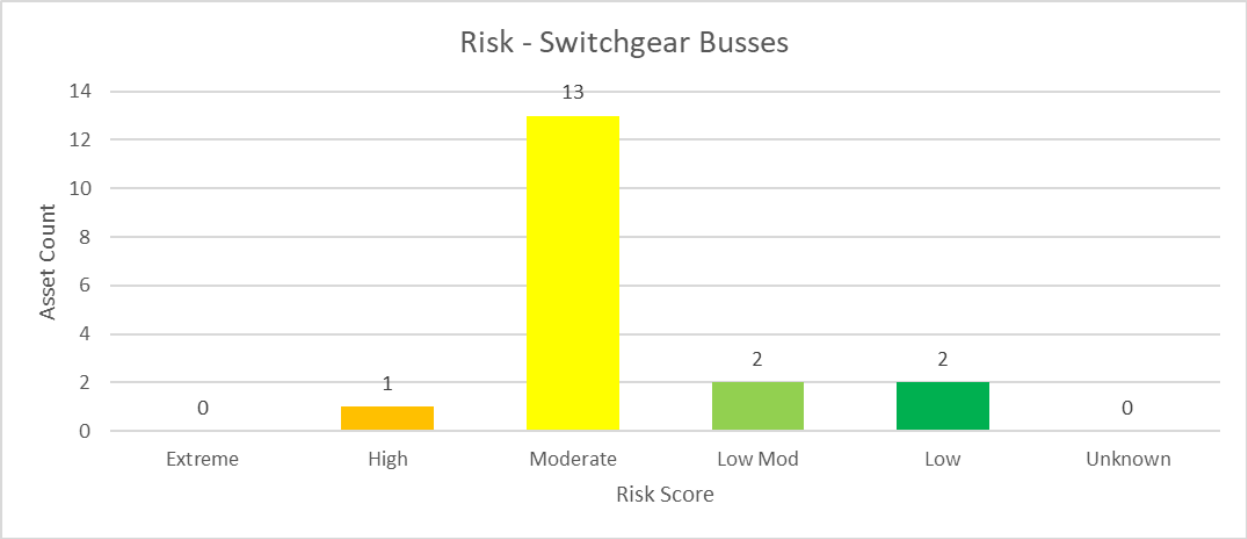


Figure 6-20: Station Switchgear Busses Risk Assessment Results

6.2.4 Relays & RTUs

Risk Index Formulation

Relays are important devices in protecting workers or customers who come into contact with live lines by reducing arc flash hazards. The impact for relays and RTUs is calculated based on the impact assessment criteria summarized in Table 6-21 and Table 6-22, respectively.

Table 6-21: Relay Impact Formulation

Risk Category	Risk Factor	DAI	Weight	Ranking	Numerical Grade	Max Score
Reliability	Customer Count	100%	2	A,B,C,D,E	4,3,2,1,0	8
	Feeder Loading	100%	2	A,B,C,D,E	4,3,2,1,0	8
	Relay Type	89%	1	A,E	4,0	4
Total Score						**20**

Table 6-22: RTU Impact Formulation

Risk Category	Risk Factor	DAI	Weight	Ranking	Numerical Grade	Max Score
Reliability	Customer Count	100%	1	A,B,C,D,E	4,3,2,1,0	4
	Feeder Loading	100%	1	A,B,C,D,E	4,3,2,1,0	4
Total Score						**8**

Results

A risk score was calculated for all relays, 96% of which have Moderate or lower risk. The risk assessment results are shown in Figure 6-21.

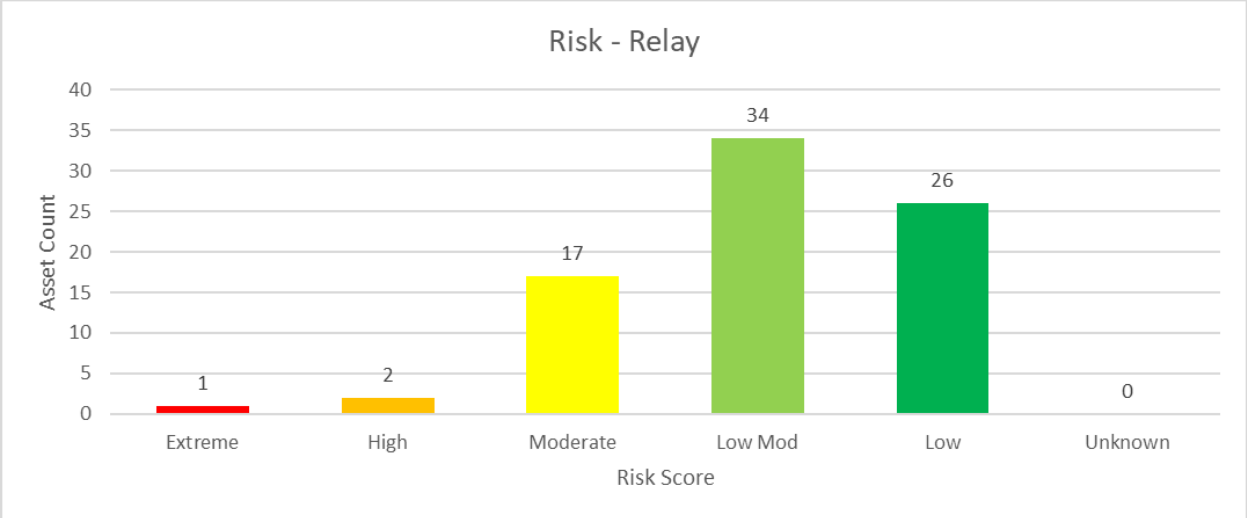


Figure 6-21: Relay Risk Assessment Results

A risk score was calculated for all RTUs; where HI is unavailable, age is used instead for these RTUs. Approximately 56% of the calculated assets have Moderate or lower risk. The risk assessment results are shown in Figure 6-22.

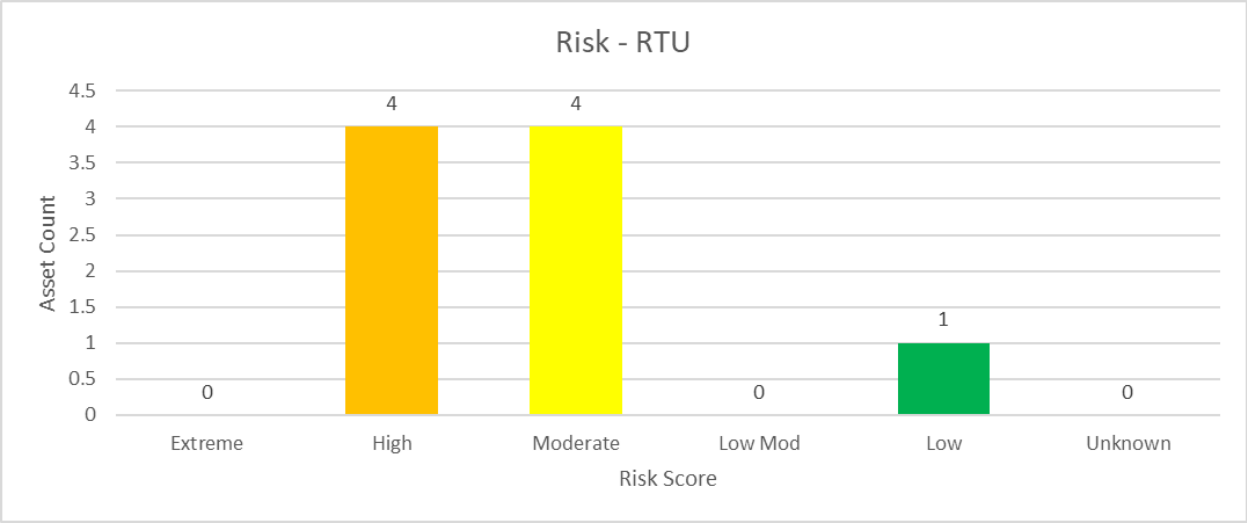


Figure 6-22: RTU Risk Assessment Results

6.2.5 Batteries & Chargers

Risk Index Formulation

Batteries and chargers are used in the case of the station losing power in order to keep the station running. Because of this they are considered to be supporting the entire stations load and customer count. The impact for batteries and chargers is calculated based on the impact assessment criteria summarized in Table 6-23 and Table 6-24, respectively.

Table 6-23: Station Battery Impact Formulation

Risk Category	Risk Factor	DAI	Weight	Ranking	Numerical Grade	Max Score
Reliability	Customer Count	100%	1	A,B,C,D,E	4,3,2,1,0	4
	Feeder Loading	100%	1	A,B,C,D,E	4,3,2,1,0	4
Safety	Grounding	100%	1	A,B,C,D,E	4,3,2,1,0	4
	Excessive Heat	100%	1	A,B,C,D,E	4,3,2,1,0	4
Total Score						**16**

Table 6-24: Station Charger Impact Formulation

Risk Category	Risk Factor	DAI	Weight	Ranking	Numerical Grade	Max Score
Reliability	Customer Count	100%	1	A,B,C,D,E	4,3,2,1,0	4
	Feeder Loading	100%	1	A,B,C,D,E	4,3,2,1,0	4
Total Score						**8**

Results

A risk score was calculated for all station batteries and chargers, all of which have Moderate or lower risk. The risk assessment results are shown in Figure 6-23 and Figure 6-24, respectively.

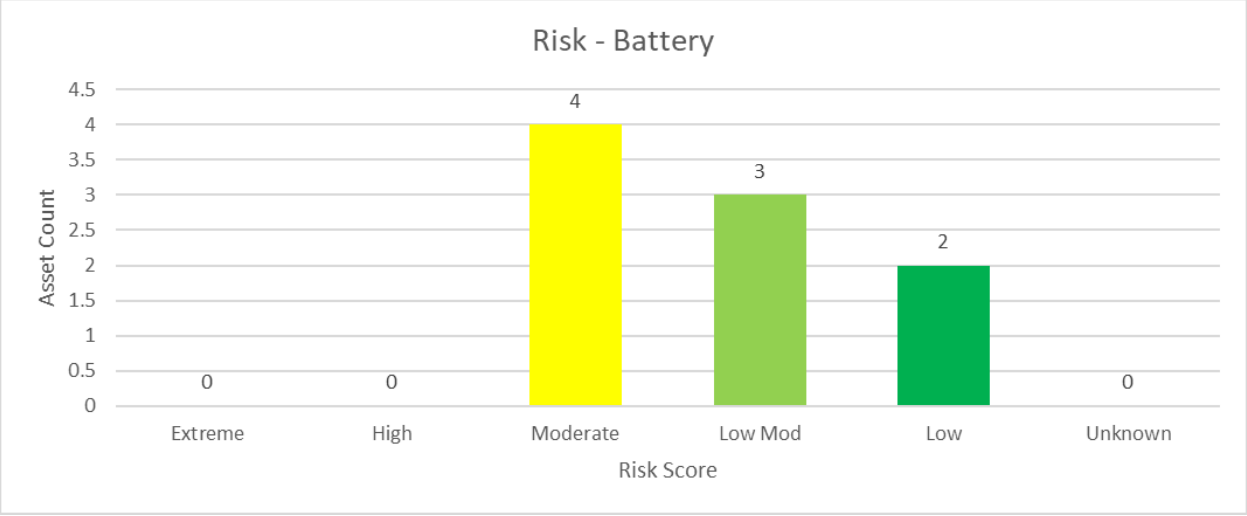


Figure 6-23: Station Battery Risk Assessment Results

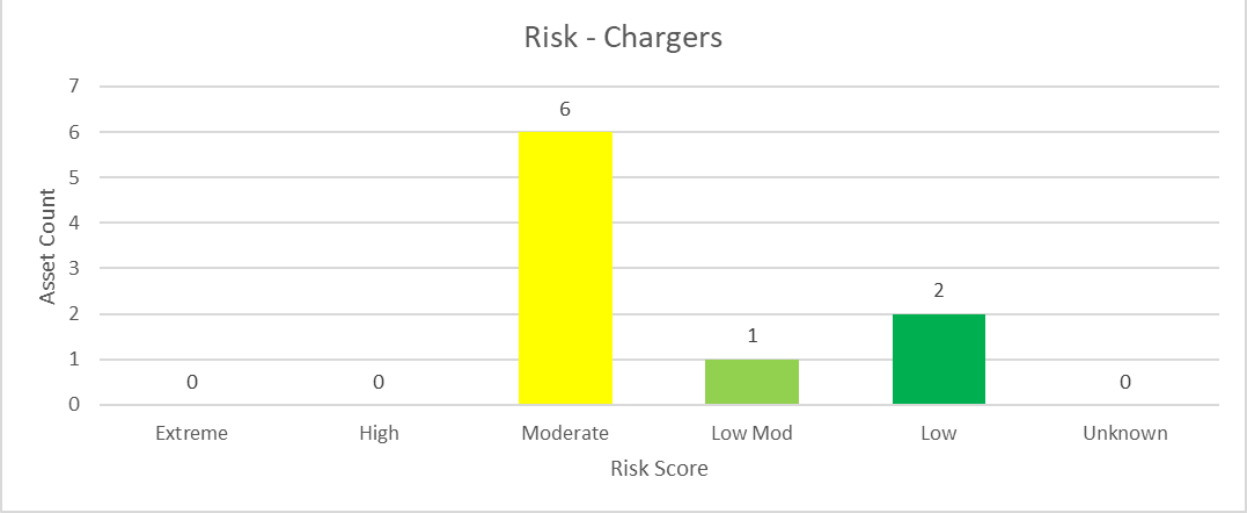


Figure 6-24: Station Charger Risk Assessment Results

6.2.6 Station Egress Cables

Risk Index Formulation

The impact for station egress cables is calculated based on the impact assessment criteria summarized in Table 6-25.

Table 6-25: Station Egress Cable Impact Formulation

Risk Category	Risk Factor	DAI	Weight	Ranking	Numerical Grade	Max Score
Reliability	Customer Count	98%	2	A,B,C,D,E	4,3,2,1,0	8
	Feeder Loading	98%	2	A,B,C,D,E	4,3,2,1,0	8
	Size	93%	1	A,E	4,0	4
Total Score						**20**

Results

A risk score was calculated for 98% of station egress cables. 77% of 13.8kV egress cables and 75% of 44kV egress cables have Moderate or lower risk. The risk assessment results are shown in Figure 6-25 and Figure 6-26.

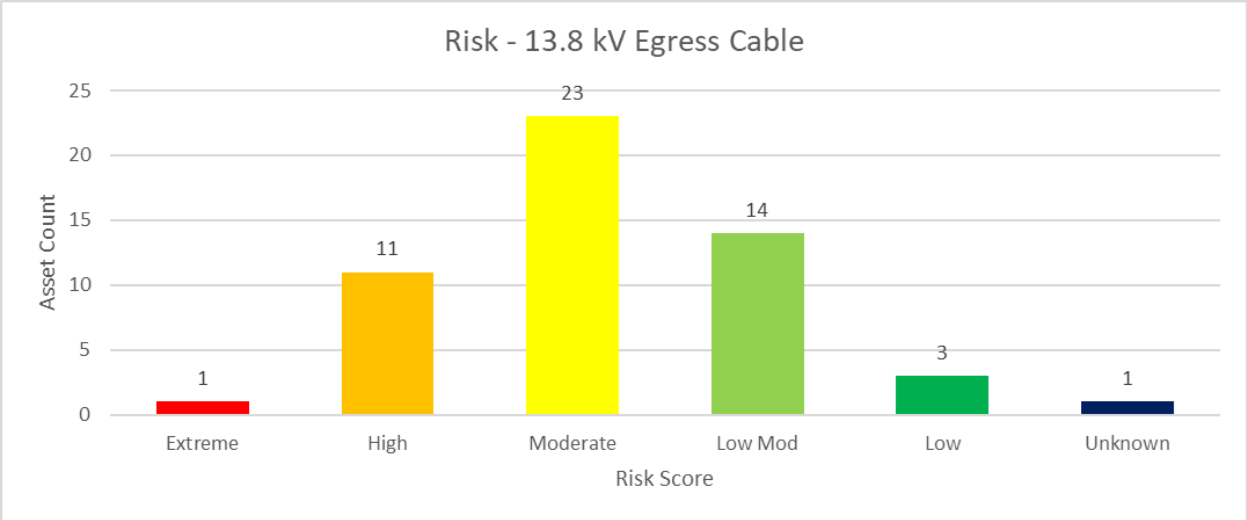


Figure 6-25: 13.8-kV Station Egress Cable Risk Assessment Results

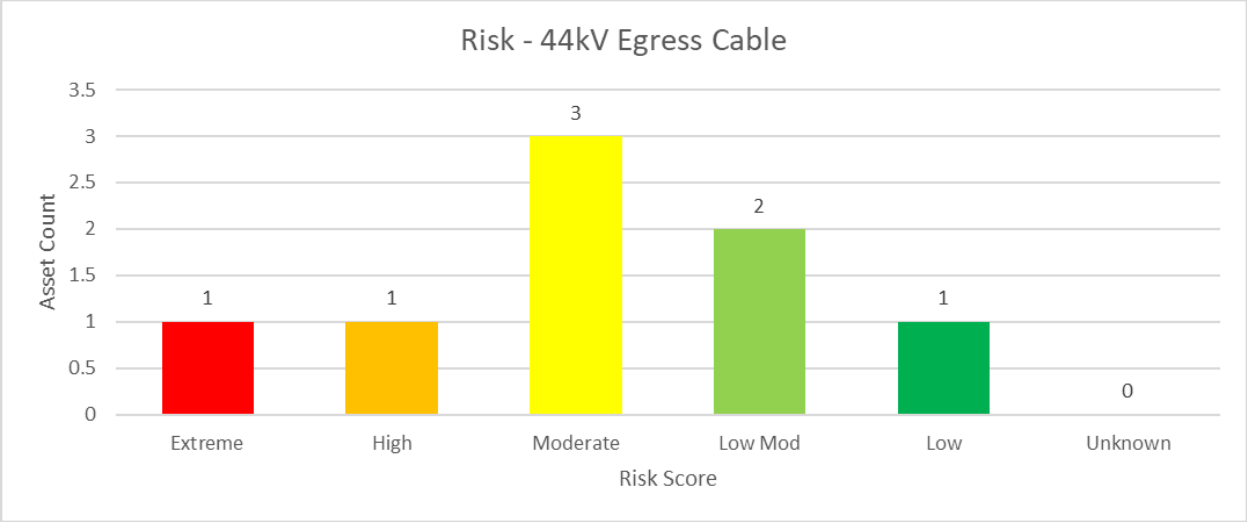


Figure 6-26: 44-kV Station Egress Cable Risk Assessment Results

6.2.7 Station Fences & Yards

Risk Index Formulation

Station fences and yards are important to protect both the public and workers by keeping them away from energized equipment. The impact for station fences and yards is calculated based on the impact assessment criteria summarized in Table 6-26.

Table 6-26: Station Fence & Yard Impact Formulation

Risk Category	Risk Factor	DAI	Weight	Ranking	Numerical Grade	Max Score
Safety	Fence Condition	100%	2	A,B,C,D,E	4,3,2,1,0	8
	Warning Signs	100%	1	A,B,C,D,E	4,3,2,1,0	4
	Debris/Weeds	100%	2	A,B,C,D,E	4,3,2,1,0	8
	Grounding	100%	3	A,B,C,D,E	4,3,2,1,0	12
Total Score						**32**

Results

A risk score was calculated for all station fences and yards, all of which have Low risk. The risk assessment results are shown in Figure 6-27.

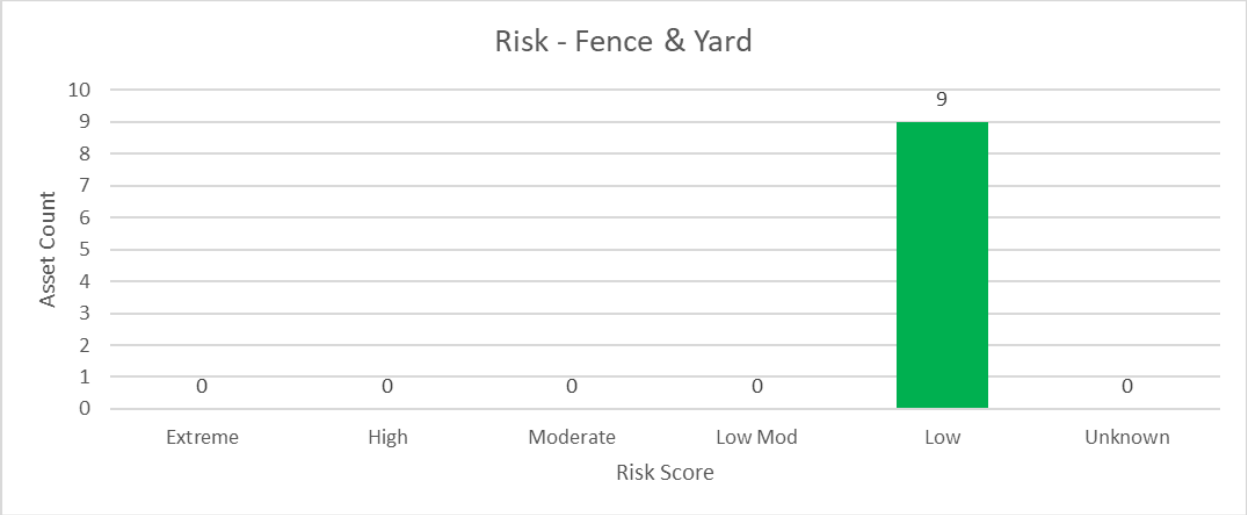


Figure 6-27: Fence & Yard Risk Assessment Results

6.2.8 Station Buildings

Risk Index Formulation

Like fences and yards, buildings are important to protect both the public and workers by keeping them away from critical infrastructure. The impact for station buildings is calculated based on the impact assessment criteria summarized in Table 6-27.

Table 6-27: Station Building Impact Formulation

Risk Category	Risk Factor	DAI	Weight	Ranking	Numerical Grade	Max Score
Safety	Doors/Locks	100%	4	A,B,C,D,E	4,3,2,1,0	16
	Lighting	100%	2	A,B,C,D,E	4,3,2,1,0	8
	Signage	100%	1	A,B,C,D,E	4,3,2,1,0	4
	Grounding	100%	4	A,B,C,D,E	4,3,2,1,0	16
	Emergency Devices	100%	3	A,B,C,D,E	4,3,2,1,0	12
	Ventilation	100%	2	A,B,C,D,E	4,3,2,1,0	8
Environmental	Oil Leaks	100%	8	A,B,C,D,E	4,3,2,1,0	32
Total Score						**96**

Results

A risk score was calculated for all station buildings and all of them have Low risk. The risk assessment results are shown in Figure 6-28.

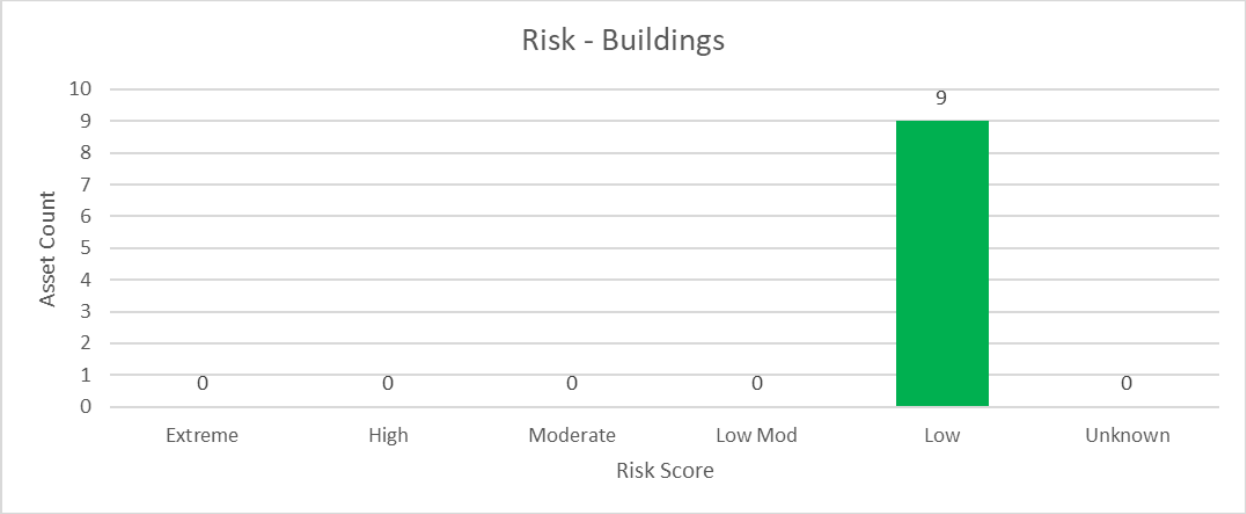


Figure 6-28: Station Building Risk Assessment Results

6.2.9 Bus Structures

Risk Index Formulation

The impact for bus structures is calculated based on the impact assessment criteria summarized in Table 6-28.

Table 6-28: Bus Structure Impact Formulation

Risk Category	Risk Factor	DAI	Weight	Ranking	Numerical Grade	Max Score
Reliability	Customer Count	100%	1	A,B,C,D,E	4,3,2,1,0	4
	Feeder Loading	100%	1	A,B,C,D,E	4,3,2,1,0	4
Safety	Grounding	100%	2	A,B,C,D,E	4,3,2,1,0	8
Total Score						**16**

Results

A risk score was calculated for all bus structures and all of them have Moderate or lower risk. The risk assessment results are shown in Figure 6-29.

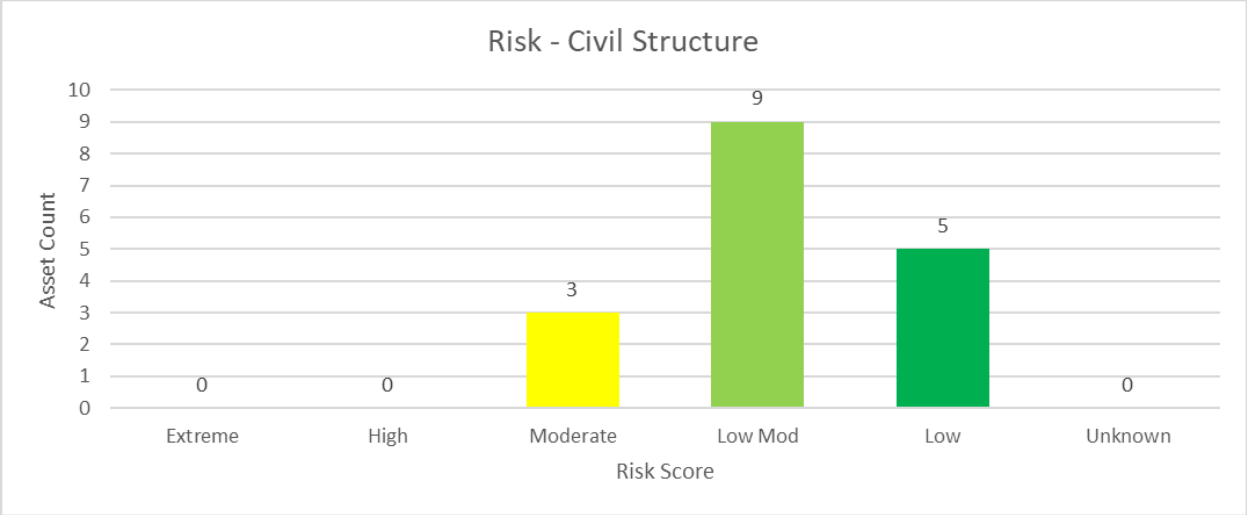


Figure 6-29: Bus Structure Risk Assessment Results

7 Recommendations & Conclusions

7.1 Replacement Plan

The following section outlines the recommended replacement plan for OPUCN between 2026 and 2030. METSCO recommends that replacements in the next five-year planning cycle are targeted at assets which meet any of the following criteria:

- The asset has been classified as High or Extreme risk; and/or
- The asset's HI score is less than 50% indicating that it is in Poor or Very Poor condition; and/or
- The asset is past economic EOL or will pass economic EOL during the planning cycle (see Appendix B).

7.1.1 Distribution

7.1.1.1 Wood Poles

There are 39 wood poles in Very Poor condition and 50 wood poles in Poor condition. METSCO recommends that all of these assets are scheduled for replacement over the five-year period. There are also nine wood poles which are in Fair condition and have been classified as high risk and 308 assets with invalid HI that have been classified as high or extreme risk. In total it is recommended that OPUCN replace 406 wood poles. Table 7-1 shows the recommended replacement rates for each year from 2026 to 2030.

Table 7-1: Wood Pole Five-Year Replacement Program

Year	2026	2027	2028	2026	2030
Pole Replacement Program (#)	82	81	81	81	81

Between now and 2026, OPUCN should verify the condition of poles with invalid HI scores to validate which specific poles require replacement.

7.1.1.2 Concrete Poles

There is one concrete pole in Very Poor condition and another in Poor condition. METSCO recommends that both of these assets are scheduled for replacement over the five-year period. There are also 110 concrete poles which are in Fair condition and have been classified as high risk. In total it is recommended that OPUCN replace 112 concrete poles. Table 7-2 shows the recommended replacement rates for each year from 2026 to 2030.

Table 7-2: Concrete Pole Five-Year Replacement Program

Year	2026	2027	2028	2029	2030
Pole Replacement Program (#)	22	23	22	23	22

7.1.1.3 Steel Poles

No replacement of steel poles is recommended at this time. All the steel poles in OPUCN's system are in Good or better condition. Additionally, there are no high or extreme risk steel poles.

7.1.1.4 Overhead Primary Conductors

There are 10,218 m of OH primary conductor in Very Poor condition and another 2,585 m in Poor condition. METSCO recommends that these conductor segments are scheduled for replacement over the five-year period. There is also 17,602 m of OH primary conductor which is in Fair condition and has been classified as high risk. In total it is recommended that OPUCN replace 30,405 m of OH primary conductor. Table 7-3 shows the recommended replacement rate for each year from 2026 to 2030.

Table 7-3: OH Primary Conductor Five-Year Replacement Program

Year	2026	2027	2028	2029	2030
Conductor Replacement Program (m)	6,081	6,081	6,081	6,081	6,081

7.1.1.5 Underground Primary Cables

There is 4,322 m of UG primary cable in Very Poor condition and another 1,318 m in Poor condition. METSCO recommends that these cable segments are scheduled for replacement over the five-year period. There is also 26,522 m of UG primary cable which is in Fair condition and has been classified as high risk. In total it is recommended that OPUCN replace 32,162 m of UG primary cable. Table 7-4 shows the recommended replacement rate for each year from 2026 to 2030.

Table 7-4: UG Primary Cable Five-Year Replacement Program

Year	2026	2027	2028	2029	2030
Cable Replacement Program (m)	6,432	6,433	6,432	6,433	6,432

7.1.1.6 Pole-Mount Transformers

Pole-mount transformers are replaced proactively based on overloading or customer upgrade requests, or as part of overhead rebuild projects. Besides those situations, pole-mounted transformers are run-to-failure.

Based on the situation where pole-mounted transformers are replaced as part of the overhead rebuild project an average number of transformers per meter was used to determine the recommended replacement rate. Table 7-5 shows the recommended replacement rates for each year from 2026 to 2030.

Table 7-5: Pole-Mount Transformer Five-Year Replacement Program

Year	2026	2027	2028	2029	2030
Transformer Replacement Program (#)	26	26	26	26	26

OPUCN pole-mount transformer loading data from 2018 identified 120 transformers being overloaded. OPUCN should investigate whether these transformers are still overloaded today and plan to replace/upgrade them accordingly.

7.1.1.7 Pad-Mount Transformers

Pad-mount transformers are replaced proactively based on overloading or customer upgrade requests, or as part of underground rebuild projects. Besides those situations, pad-mounted transformers are run-to-failure.

Based on the situation where pad-mounted transformers are replaced as part of the underground rebuild project an average number of transformers per meter was used to determine the recommended replacement rate. Table 7-6 shows the recommended replacement rates for each year from 2026 to 2030.

Table 7-6: Pad-Mount Transformer Five-Year Replacement Program

Year	2026	2027	2028	2029	2030
Transformer Replacement Program (#)	55	55	55	55	55

OPUCN pad-mount transformer loading data from 2018 identified 27 transformers being overloaded. OPUCN should investigate whether these transformers are still overloaded today and plan to replace/upgrade them accordingly.

7.1.1.8 Vault Transformers

Vault transformers are replaced proactively based on overloading or customer upgrade requests, or as part of underground rebuild projects. Besides those situations, vault transformers are run-to-failure.

Based on the situation where vault transformers are replaced as part of the underground rebuild project an average number of transformers per meter was used to determine the recommended replacement rate. Table 7-7 shows the recommended replacement rates for each year from 2026 to 2030.

Table 7-7: Vault Transformer Five-Year Replacement Program

Year	2026	2027	2028	2029	2030
Transformer Replacement Program (#)	2	2	2	2	2

OPUCN vault transformer loading data from 2018 identified 81 transformers being overloaded. OPUCN should investigate whether these transformers are still overloaded today and plan to replace/upgrade them accordingly.

7.1.1.9 Overhead Switches

Although there are no OH switches in Very Poor or Poor condition, there are seven OH switches which are in Fair condition and have been classified as high risk. METSCO recommends that these seven assets be scheduled for replacement. Table 7-8 shows the recommended replacement rates for each year from 2026 to 2030.

Table 7-8: OH Switch Five-Year Replacement Program

Year	2026	2027	2028	2029	2030
Switch Replacement Program (#)	1	2	1	2	1

7.1.1.10 Smart Switches

No replacement of smart switches is recommended at this time. All the smart switches in OPUCN's system are in Very Good condition. Additionally, there are no high or extreme risk smart switches.

7.1.1.11 Distribution Switchgears

There is one distribution switchgear in Very Poor condition and no distribution switchgears in Poor condition. METSCO recommends that this asset is scheduled for replacement over the five-year period. There are also eleven distribution switchgears which are in Fair condition and have been classified as high risk. In total it is recommended that OPUCN replace twelve distribution switchgears. Table 7-9 shows the recommended replacement rates for each year from 2026 to 2030.

Table 7-9: Distribution Switchgear Five-Year Replacement Program

Year	2026	2027	2028	2029	2030
Switchgear Replacement Program (#)	2	3	2	3	2

7.1.1.12 Cut-Out Arrestors

There are three cut-out arrestors in Very Poor condition and two cut-out arrestors in Poor condition. METSCO recommends that all of these assets are scheduled for replacement over the five-year period. There are also 50 cut-out arrestors which are in Fair condition and have been classified as high risk. In total it is recommended that OPUCN replace 55 cut-out arrestors. Table 7-10 shows the recommended replacement rates for each year from 2026 to 2030.

Table 7-10: Cut-Out Arrestor Five-Year Replacement Program

Year	2026	2027	2028	2029	2030
Cut-Out Arrestor Replacement Program (#)	11	11	11	11	11

7.1.1.13 Elbow Connectors

No replacement of elbow connectors is recommended at this time. All the elbow connectors in OPUCN's system are in Fair or better condition. Additionally, there are no High- or Extreme-Risk elbow connectors.

7.1.1.14 Reclosers

No replacement of reclosers is recommended at this time. All the reclosers in OPUCN's system are in Very Good condition. Additionally, there are no high or extreme risk reclosers.

7.1.1.15 Vaults & Manholes

No replacement of vaults or manholes is recommended at this time. All the vaults and manholes in OPUCN's system are in Fair or better condition. Additionally, there are no high or extreme risk vaults or manholes.

7.1.2 Station

7.1.2.1 Power Transformers

No replacement of power transformers is recommended at this time. All the power transformers in OPUCN's system are in Good or better condition. Additionally, there are no high-risk transformers or any transformers past their economic EOL.

OPUCN may also consider obtaining a spare power transformer unit to increase reliability in the system. The spare transformer may be a transformer past the TUL which is taken out of service while still in reasonable working condition.

For all transformers in the system OPUCN should continue their normal maintenance program.

7.1.2.2 Circuit Breakers

METSCO does not recommend any replacements of 44-kV circuit breakers currently. All 44-kV circuit breakers are in Good or better condition. Additionally, there are no high-risk 44-kV circuit breakers.

There is one 13.8-kV circuit breaker that is in Fair condition and is at high risk. METSCO recommends the replacement of this circuit breaker as indicated in Table 7-11. This replacement is currently planned as part of OPUCN's switchgear replacement.

Table 7-11: List of Circuit Breakers Flagged for Intervention between 2023 and 2025

Circuit Breaker ID	Condition Notes	Recommended Replacement Year
MS2-F4	Failed insulation resistance test	2023

In accordance with OPUCN's switchgear replacement program the other circuit breakers in the same switchgear will be replaced at the same time. OPUCN plans to replace the circuit breakers associated with the other switchgears in the switchgear replacement program listed in Table 7-12. METSCO verified the need to replace these switchgears and breakers in the Life-Cycle Risk and Options Analysis report attached as Appendix B.

7.1.2.3 Switchgears

All switchgear buses are in Good or better condition; however, it is recommended that OPUCN replaces their MS2-Y Bus and MS2-B Bus in conjunction with the replacement of the circuit breakers. Additional switchgears that OPUCN plans to replace as part of their switchgear replacement program are shown in Table 7-12. The switchgear bus at high risk, MS7-B Bus, is included in this list.

Table 7-12: List of Switchgears Planned for Replacement Between 2023 to 2025

Switchgear ID	Recommended Replacement Year
MS2	2023
MS5	2024
MS7	2025

Additionally, METSCO recommends the replacement or refurbishment of switchgears that have exceeded their economic EOL or will exceed their economic EOL during the planning period as found in Appendix B. This is detailed in Table 7-13 below. Switchgear refurbishment is recommended when there is disparity between components past their end of life and components that can continue to operate economically. In each case, OPUCN should produce a business case to confirm whether a refurbishment is technically feasible; if so, confirm the

refurbishment approach to be used; and if not, review whether replacement provides a positive NPV as a technically and economically viable alternative to manage risk.

Table 7-13: List of Switchgear Flagged for Intervention between 2026 and 2030

Switchgear ID	Condition Notes	Recommended Intervention	Recommended Intervention Year
MS11	Past economic EOL	Replacement	2026
MS10	Past economic EOL	Refurbishment	2027
MS15	Past economic EOL	Refurbishment	2028
MS13	Past economic EOL	Refurbishment	2029

7.1.2.4 Relays & RTUs

Three relays were found to have high or extreme risk and are therefore recommended for replacement. These relays are outlined in Table 7-14. Additionally, OPUCN plans to replace the relays associated with the switchgears in the switchgear replacement program listed in Table 7-12 as well as replace the 7 relays in MS15 during 2023.

Table 7-14: List of Relays Flagged for Intervention Between 2026 to 2030

Station Relay ID	Recommended Replacement Year
MS7T1	2026
MS5T1	2027
MS5T2	2027

7.1.2.5 Batteries & Chargers

All batteries and chargers are in Fair condition or better with Moderate or lower risk. No replacements are required at this time; continue regular maintenance activities.

7.1.2.6 Station Egress Cables

There are two 44-kV station egress cables that have High or worse risk and Fair or worse HI scores. METSCO recommends the replacement of the cables detailed in Table 7-15.

Table 7-15: List of 44-kV Station Egress Flagged for Intervention Between 2026 to 2030

Station Egress ID	Recommended Replacement Year
10T1	2026
15T2	2027

There are twelve 13.8-kV station egress cables that have High/Extreme risk or Poor/Very Poor HI scores. METSCO recommends the replacement of these assets as detailed in Table 7-16. Additionally, OPUCN plans on replacing the 13.8kV egress cables connected to the switchgears listed in Table 7-12 during their switchgear replacement program. This includes the five cables at MS7 found to be in poor condition, as such they are not included in Table 7-16.

Table 7-16: List of 13.8-kV Station Egress Flagged for Intervention Between 2026 to 2030

Station Egress ID	Recommended Replacement Year
10F3	2026
10F4	2026
10F6	2026
15F1	2027
15F3	2027
15F6	2027
14F1	2028

7.1.2.7 Fences & Yards

All fences and yards are in Very Good condition. No replacements are required at this time; continue regular maintenance.

7.1.2.8 Station Buildings

All buildings are in Very Good condition. OPUCN is planning to replace the eHouses housing the switchgears in Table 7-12 in conjunction with the switchgear replacement program as the eHouses are custom built for each switchgear.

7.1.2.9 Bus Structures

All bus structures are in Good or Very Good condition. No replacements are required at this time; continue regular maintenance.

7.2 Data Collection Improvements

A complete ACA framework for OPUCN 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 OPUCN'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.

OPUCN might also consider expanding the scope of the assets included in future iterations of the ACA. METSCO recommends that OPUCN target demographic, operational, and maintenance data collection for substation ground grids to support the HI formulation.

METSCO also recommends that OPUCN begin transitioning their inspection records to a digital collection format. This will help OPUCN in both standardizing inspection results and quickly identifying and flagging issues within the system.

The following sections target additional condition parameters that OPUCN 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.

7.2.1 Distribution Assets

7.2.1.1 Pole Inspections

It is recommended that OPUCN continue their pole testing program to increase the DAI of all pole asset classes. Additionally, METSCO recommends that a rust or corrosion condition be added to the pole inspection form to account for concrete and steel pole degradation factors.

7.2.1.2 Overhead Primary Conductors

METSCO recommends that OPUCN begin visual inspections on their OH conductors including:

- Conductor condition;
- Suspension clamp condition;
- Damper condition;
- Spacer condition; and
- Sleeve condition.

7.2.1.3 Underground Primary Cables

METSCO recommends that OPUCN begin more detailed preventative maintenance for its primary underground distribution cables including:

- Visual inspection of splices/terminations;
- Very-low-frequency tan-delta measurements;
- Online partial discharge; and
- Time domain reflectometry.

Due to the number of cables across OPUCN's service territory and the cost of cable testing, it is recommended to test a sample of cables rather than the whole population. For example, OPUCN could test 1% of cables each year, stratifying tests based on age, insulation type, burial type, and other demographics. After ten years, OPUCN would have a sample size of 10% of the population and could extrapolate these test results.

In addition, it is also recommended to consider post-mortem analysis following a cable failure or proactive replacement to identify the failure mode and, in the case of a proactive replacement, verify the condition of the replaced cable.

7.2.1.4 Distribution Transformers

It is recommended that OPUCN resume collecting distribution transformers loading data. Additionally, METSCO recommends that IR scans be taken of all transformers. Finally, it is recommended that visual inspections continue on pad-mount and vault transformers to increase DAI and begin on pole-mounted transformers.

7.2.1.5 Switches

METSCO recommends that more detailed visual inspections be performed on OH and smart switches including:

- Insulator condition;
- Operating mechanism condition;
- Bushing condition;
- Blade condition; and
- Enclosure condition.

Additionally, failure rates should be recorded for smart switches.

7.2.1.6 Distribution Switchgear

It is recommended that OPUCN continue their switchgear inspection program by expanding the list of assets that are inspected with the Switchgear Inspection form to provide more detailed visual inspection results.

7.2.1.7 Cut-Out Arrestors

METSCO recommends that OPUCN begin visual inspections on their cut-out arrestors including:

- Insulator condition;
- Operating mechanism condition;
- Bushing condition; and
- Blade condition.

7.2.1.8 Elbow Connectors

METSCO recommends that OPUCN begin visual inspections on their elbow connectors including:

- Operating mechanism condition; and
- Enclosure condition.

7.2.1.9 Reclosers

It is recommended that OPUCN perform more detailed inspections of their reclosers including:

- Termination condition:
- Operating mechanism and control condition;
- Tank/enclosure condition; and
- Oil leaks or vacuum bottle integrity.

If the reclosers are oil reclosers, oil analysis tests can also be performed.

7.2.2 Station Assets

7.2.2.1 Power Transformers

METSCO recommends that OPUCN perform IR scans on their power transformers as part of its routine maintenance process.

7.2.2.2 Circuit Breakers

It is recommended that OPUCN expand their visual inspection and testing programs for circuit breakers be expanded to include type specific factors for all assets including:

- Air breakers
    - Air consumption test;
    - Moisture content test;
    - Air leaks;
    - Switching resistor condition;
    - Pressure vessel condition;
    - Mechanism box condition;
    - Air storage, compressors & distributor lines condition; and
    - Grading capacitor condition.
- SF6 breakers

    - SF6 gas analysis;
    - Recharge time;
    - Coil signature test;
    - SF6 leaks; and
    - Grading capacitor condition.
- Vacuum breakers
    - Enclosure condition; and
    - Vacuum bottle integrity.

7.2.2.3 Switchgears

It is recommended that OPUCN begin visual inspections of their switchgears including:

- Bushings/support insulators condition;
- Operating mechanisms condition;
- Grading capacitors condition;
- Switching resistor condition;
- Foundation/support steel condition;
- Grounding condition; and
- Enclosure condition.

7.2.2.4 Relays

OPUCN should continue its inspections and testing of relays to increase DAI.

7.3 Conclusions

On top of a condition assessment and risk analysis of OPUCN's major distribution and station asset classes, this report provides OPUCN with a broad range of recommendations with respect to specific types of information that it may choose to collect and the metrics it may deploy to enhance it's AM analytics.

Keeping records of 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. METSCO recommends that OPUCN begin transitioning their inspection records to a digital collection format. This will help OPUCN 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.

This concludes METSCO's ACA report for OPUCN's major distribution and substation assets. We thank OPUCN'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 OPUCN.

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: Life-Cycle Risk & Options Analysis

METSCO

MAKING IT POSSIBLE

SUBSTATION TRANSFORMER & SWITCHGEAR LIFECYCLE RISK & OPTIONS ANALYSIS REPORT 2023



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Executive Summary

Following the Asset Condition Assessment and Asset Valuation work that METSCO Energy Solutions Inc. ("METSCO") performed for Oshawa Power and Utilities Corporation Network Inc. ("OPUCN"), OPUCN retained METSCO to carry out an Options Analysis for eighteen power transformers and eighteen station switchgear buses. The purpose of the Options Analysis is to evaluate different asset intervention options and determine the optimal intervention time ("OIT") for the assets in scope. Options to investigate for each asset are:

1. Replace the assets in their entirety;
2. Refurbish the assets/subset of the asset; or
3. Continue to operate as normal without intervention.

For switchgears, refurbishment entails replacement of circuit breakers within the switchgear. For power transformers, refurbishment involves rewinding of the transformer.

The Options Analysis process is outlined below in Figure 0-1.

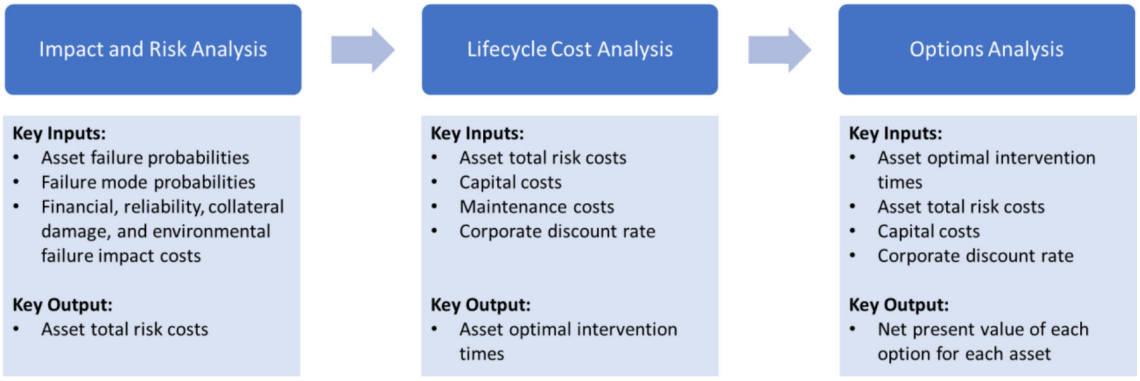


Figure 0-1 Options Analysis Process

The first step of the Options Analysis involved an impact and risk analysis. The objective of the impact and risk analysis is to quantify the risk associated with each asset through:

1. The development of asset end-of-life ("EOL") failure curves to determine the failure probability of each asset;
2. The determination of relative failure mode probabilities; and
3. The quantification of financial, reliability, collateral damage, and environmental failure impacts.

The risk represents the socio-economic cost incurred by the utility through continued operation of the asset. Asset risk costs are further combined with the assets' capital costs in order to carry out the Lifecycle Cost Analysis, which is used to calculate the total cost of ownership ("TCO") for each of the assets in the system. By comparing the equivalent annualized cost of the new asset to be installed, against the annual risk costs curve of the existing asset to be replaced, the point in time at which the future annual risk costs of the

existing asset will exceed an average annual total cost of the new asset if it's replaced is determined. This represents the OIT; in other words, the point in time at which it would be economically viable to install a new asset instead of continued operation of the existing asset. Through this analysis, the TCO can be determined under the three options in scope:

1. Replacing the asset;
2. Refurbishing the asset/subset of the asset; or
3. Running the asset to failure.

Finally, the Options Analysis involved the calculation of net present value ("NPV") for each option for assets with an OIT before 2030, aligned with OPUCN's capital plan. OPUCN's Five-Year Forecast Capital Investment Plan has the scope of 2026-2030 and is part of their Distribution System Plan ("DSP"). The option with the highest NPV is the recommended intervention. The final recommendations are presented in Table 0-1 and Table 0-2. It is recommended that all power transformers operate as normal, and that four switchgears are replaced and three are refurbished. In accordance with OPUCN's switchgear replacement program in which both buses are replaced or refurbished at the same time the switchgear results are presented by switchgear. Assets which fall outside of the current Capital Plan should be reassessed in five years.

Table 0-1 Summary of Power Transformer Results

Asset	OIT	NPV ($'000)			Recommended Intervention
		RTF	Replacement	Refurbishment	
MS 2-T1	Beyond 2040	--	--	--	Operate as Normal
MS 2-T2	Beyond 2040	--	--	--	Operate as Normal
MS 5-T1	Beyond 2040	--	--	--	Operate as Normal
MS 5-T2	Beyond 2040	--	--	--	Operate as Normal
MS 7-T1	2036-2040	--	--	--	Operate as Normal
MS 7-T2	Beyond 2040	--	--	--	Operate as Normal
MS 9-T1	Beyond 2040	--	--	--	Operate as Normal
MS 9-T2	Beyond 2040	--	--	--	Operate as Normal
MS 10-T1	Beyond 2040	--	--	--	Operate as Normal
MS 10-T2	Beyond 2040	--	--	--	Operate as Normal
MS 11-T1	Beyond 2040	--	--	--	Operate as Normal
MS 11-T2	Beyond 2040	--	--	--	Operate as Normal
MS 13-T1	Beyond 2040	--	--	--	Operate as Normal
MS 13-T2	Beyond 2040	--	--	--	Operate as Normal
MS 14-T1	2036-2040	--	--	--	Operate as Normal
MS 14-T2	2036-2040	--	--	--	Operate as Normal
MS 15-T1	Beyond 2040	--	--	--	Operate as Normal
MS 15-T2	Beyond 2040	--	--	--	Operate as Normal

Table 0-2 Summary of Switchgear Results

Asset	OIT	NPV ($'000)			Recommended Intervention
		RTF	Replacement	Refurbishment	
MS2	Within Capital Plan	-708	**673**	-16	**Replacement**
MS5	Within Capital Plan	-708	**976**	197	**Replacement**
MS7	Within Capital Plan	-708	**898**	142	**Replacement**
MS9	Beyond 2040	0	-1040	-506	Operate as Normal
MS10	Within Capital Plan	0	412	**510**	**Refurbish**
MS11	Within Capital Plan	-708	**548**	-103	**Replacement**
MS13	Within Capital Plan	0	434	**525**	**Refurbish**
MS14	Beyond 2040	0	-993	-473	Operate as Normal
MS15	Within Capital Plan	0	289	**424**	**Refurbish**

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List of Abbreviations and Acronyms

The following acronyms are used within the report:

Acronym	Definition
ACA	Asset Condition Assessment
CD	Collateral Damage
CDF	Cumulative Density Function
C&I	Commercial & Industrial
CICs	Customer Interruption Costs
DCF	Discounted Cash Flow
EAC	Equivalent Annualized Cost
EOL	End of Life
ICE	Interruption Cost Estimate
METSCO	METSCO Energy Solutions Inc.
NCF	Net Cash Flow
NPV	Net Present Value
OIT	Optimal Intervention Time
OPUCN	Oshawa Power and Utilities Corporation Network Inc
PDF	Probability Density Function
RTF	Run to Failure
SR	Survival Rate
TCO	Total Cost of Ownership
TUL	Typical Useful life
WACC	Weighted Average Cost of Capital

1 Introduction

1.1 Purpose and Scope

METSCO Energy Solutions' ("METSCO") was asked perform a Lifecycle Risk and Options Analysis study for Oshawa Power and Utilities Corporation Network Inc. ("OPUCN"). The purpose of this study is to determine the asset's optimal intervention time ("OIT") based on a balance of risk and capital spending for the asset to minimize the lifecycle cost. The study was done for OPUCN's station power transformers and switchgears.

Key outputs from the Options Analysis can be used to support the development of asset renewal capital investment plans and other long-term planning activities. The Options Analysis is performed to provide OPUCN investment recommendations to ensure that the utility is making justified decisions that prioritize the assets and mitigate the unacceptable asset risks while minimizing total ownership costs of the assets.

Delivery of the Options Analysis was divided into three phases:

1. Impact and Risk Analysis
2. Lifecycle Cost Analysis
3. Options Analysis

This report contains an introduction, Section 1, which includes details on inputs, assumptions, and basic approach. Section 2 provides detail on the impact and risk analysis. Section 3 provides detail on the lifecycle cost analysis. Section 4 provides detail on the Option Analysis. The results are concluded in Section 5 along with recommended interventions.

1.2 Approach

The Options Analysis was performed to balance operational, capital, and risk costs over the complete lifecycle of each station asset by determining the point in time to replace or refurbish the asset. The general approach taken by METSCO is explained in this Section with further details provided in Sections 2, 3, and 4.

Risk costs were derived based upon the determination of the assets' probability of failure and the quantification of the assets' impact of failure. An Asset Condition Assessment ("ACA"; see Report P-23-165-001) was performed to determine the Health Index for each. An asset's probability of failure is determined through the usage of asset failure curves that were set as a function of the age and health index score. The ACA framework is further discussed in Report P-23-165-0001; the failure curve development and calibration procedure is further explained in Section 2.1.

An asset's impact of failure is determined through the identification of defined failure modes and failure impacts. Failure modes were defined for each asset class. These failure modes were utilized to determine a specific impact for each asset across four risk categories and are documented in Section 2.2.

Failure impacts were defined based upon four categories: Financial, Customer/Reliability, Collateral Damage, and Environmental. All impacts have been monetized. The approach used

to determine these quantified results for individual asset classes is discussed further in Section 2.3.

Following the determination of failure probability and impact for each asset, the risk of asset failure can be determined as part of the risk-based lifecycle calculation. These calculations incorporate input data for each asset, including asset nameplate and connectivity data, as well as impact quantification factors. The results from the ACA, failure curves, failure modes, and impact quantification results were used to compute a quantified risk for each asset at any point in time.

Both the risk and capital costs were annualized across the lifecycle of the asset: where the annualized risks cost increases over time as the failure probability increases and annualized capital costs decreases as assets depreciate over time. Therefore, this risk cost of asset failure must be balanced against the benefit of delaying the capital spending on infrastructure. These two components were summed in order to produce the annualized lifecycle cost, or total operating cost of the evaluated asset. An asset's Equivalent Annualized Cost ("EAC"), which represents the time or age of the minimum annualized lifecycle cost, was cross-referenced against the existing assets' risk cost curve to determine economic end of life. This represents the optimal intervention time. By replacing assets at their optimal intervention time OPUCN can minimize their total cost of ownership. This approach is further discussed in Section 3.

Results from these calculations can be used in deriving the long-term spending plan for OPUCN, on the basis of replacing or refurbishing assets at their respective OIT. The final results and various spending scenarios are further discussed in Section 4.

1.3 Inputs and Assumptions

In order to execute this study, a series of input parameters and assumptions were provided to METSCO by OPUCN between September and October 2023. These parameters were all used to either determine the asset health index result and/or determine the results within the Options Analysis.

A key component within the Options Analysis was the calculation of the risk of failure. Risk was derived based upon the assets' failure probability, failure modes, and impacts of failure. Asset failure probability is a function of an asset's condition and age. Failure mode probabilities were determined through industry research [1]. Associated outage durations were derived based upon discussions with OPUCN system planners and engineers.

OPUCN provided inputs used for determining an asset's impact of failure including material and labour units, emergency costing and corporate discount rate assumptions to be used as financial inputs for investment costs and the financial risk category. OPUCN's historical reliability and customer count data were used within a Interruption Cost Estimate ("ICE") calculator [2] to derive customer interruption costs ("CICs"). These CICs were used in conjunction with individual asset loading values per customer class, measured in kVA, in order to quantify overall customer impacts.

To supplement information available from OPUCN, external studies and METSCO's knowledgebase from working with other utilities were utilized in supporting the quantification of safety impacts [3] [4]. Furthermore, environmental cost factors were determined based upon METSCO's knowledgebase.

The refurbishment benefits used in the Options Analysis were determined based on external studies [5], [6]. Refurbishment costs were derived from OPUCN's vendor estimates and verified by METSCO's equipment experts. Specifically, OPUCN currently has contracts in place for the replacement of four switchgears based on its previous Distribution System Plan ("DSP") filed with the Ontario Energy Board. Some of these replacements were deferred due to delays from COVID-19. In reassessing whether these switchgear should still be replaced or refurbished, the cost of cancelling the contracts was considered.

2 Impact and Risk Analysis

The impact and risk analysis is the first step of the Options Analysis. The purpose of the impact and risk analysis is to quantify the total risk cost of each asset. The process is detailed in the following subsections.

2.1 Failure Curve Development

The failure probability for each asset is produced based upon a time-based failure probability function – otherwise referred to as a "failure curve". A unique failure curve was derived for both power transformers and switchgears.

To develop these failure curves, a two-parameter Weibull distribution was utilized. The Weibull distribution is flexible and can be adapted to a wide range of data, and is by far the most widely utilized mathematical distribution for life data analysis [7], [8], [9].

The two-parameter Weibull distribution function is defined by its Shape (α) and Scale (β). The shape parameter controls the overall shape of the distribution and indicates whether the failure rate is increasing, constant, or decreasing. The scale parameter controls the overall spread of the distribution function. The greater the scale value, the more spread out the distribution will be; smaller scale values, in contrast, will result in a narrower distribution.

When developing the hazard rate function, METSCO derived a probability density function ("PDF") and cumulative density function ("CDF"). The PDF is a function that describes the relative likelihood for a variable to take on a given value. The area as bounded by the PDF represents the probability of the random variable falling within a given range of values. The CDF represents a summation of the sequence of values as defined by the PDF. In addition, METSCO utilized the PDF and CDF equations to derive the survival rate ("SR") function. The SR function is used to evaluate the time-to-event phenomena of a continuous random variable. Essentially, it describes the probability of experiencing an event, which correlates to asset failure. Survival rate curves are strictly decreasing functions that represent the cumulative probability that an asset has survived until a given point in time.

The Weibull PDF, CDF and SR are further detailed in Equations 1, 2 and 3 respectively:

$$f(t) = \frac{\alpha}{\beta}\left(\frac{t}{\beta}\right)^{\alpha-1} e^{-\left(\frac{t}{\beta}\right)^{\alpha}} \qquad \text{(Equation 1)}$$

$$F(t) = 1 - e^{-(\frac{t}{\beta})^{\alpha}} \qquad \text{(Equation 2)}$$

$$S(t) = e^{-(\frac{t}{\beta})^{\alpha}} \qquad \text{(Equation 3)}$$

Where:

- f(t) = probability density function
- F(t) = cumulative density function
- S(t) = survival rate function
- α, β = shape and scale factors, respectively
- t = time, as measured in years.

With shape (α) and scale (β) parameters derived, a Weibull distribution function was established for each asset class. The hazard rate function (also known as the failure probability function), which defines the probability of an asset failing at any given age providing the asset is still in service, was then obtained by utilizing the formulation as declared in Equation 4.

$$h(t) = \frac{f(t)}{1-F(t)} \qquad \text{(Equation 4)}$$

Where:

- h(t) = age-based failure probability function (hazard rate)
- f(t) = probability density function
- F(t) = cumulative density function
- t = time in years

METSCO uses industry-wide definitions for asset-specific typical useful life ("TUL") values that create a basis for planning and depreciation assumptions. According to Kinectrics' Asset Depreciation Study for the Ontario Energy Board, the TUL is 45 years for power transformers and 40 years for switchgears [10]. The TUL value is used to calculate the shape and scale of the Weibull Curve. The following graphs show the Weibull PDF, Hazard Rate, and Survival Rate for power transformers and switchgears.

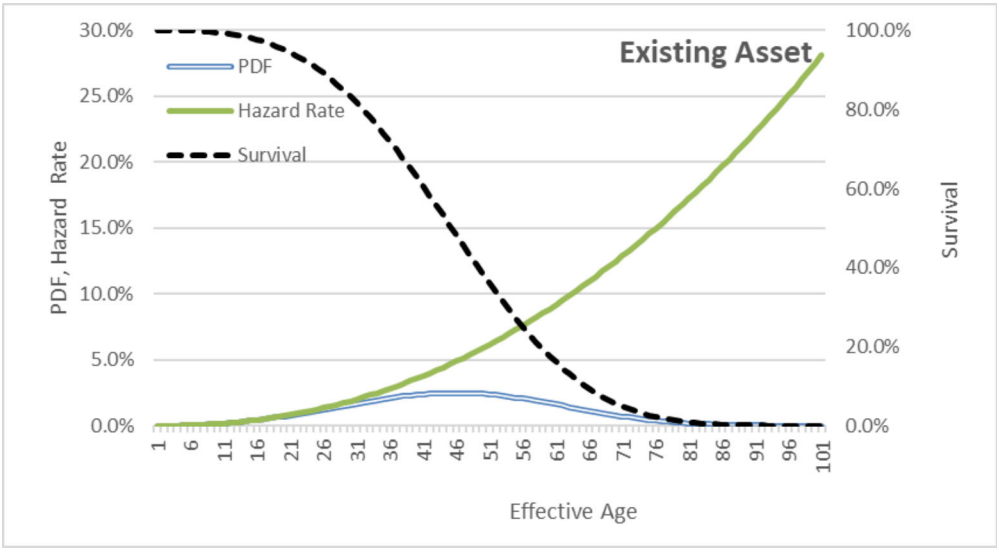


Figure 2-1: Weibull Curve for Main Tank of Transformer

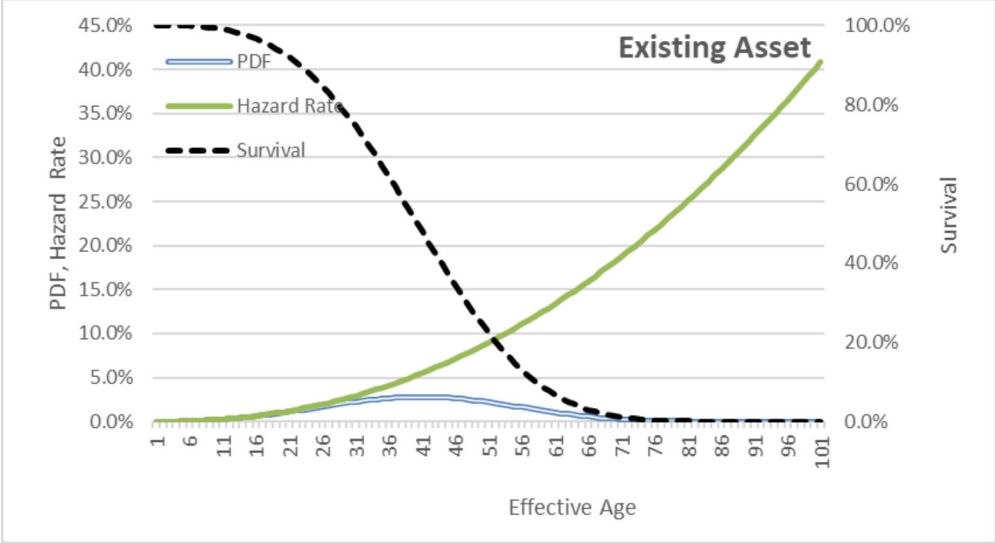


Figure 2-2: Weibull Curve for Switchgear

2.2 Failure Mode Determination

With a failure probability result produced for each asset, the impact and risk analysis also considers the different failure modes that may take place when an asset experiences a failure event. Three categories of failure modes are used in the analysis:

1. **Inspection-Based Failure Mode**

An inspection-based failure mode occurs when the utility has proactively identified that an asset has reached its end-of-life criteria during the inspection and/or testing process. These failure modes can be identified through regular inspection, testing, or maintenance activities.

2. **Normal Failure Mode**

Normal failures are failures that occur over time due to the inherent wear of an asset. These failures are expected as a part of the asset's lifecycle. They typically result from factors such as material fatigue, corrosion, or other gradual degradation processes.

3. **Catastrophic Failure Mode**

Catastrophic failures are severe and sudden failures that can have a significant and immediate impact on safety, the environment, or operations. These failures often result from a critical failure mode, design flaws, or the occurrence of unforeseen extreme conditions.

A combination of industry data [1] and OPUCN's historical failure data were used to determine the relative probabilities for inspection-based, normal, and catastrophic failure modes.

2.3 Failure Impact Quantification

All of the failure impacts were divided into one of four categories:

1. Financial: Direct financial costs to the utility for replacing the assets reactively
2. Reliability: CICs as a measure of the monetary losses for customers due to an interruption of electric service.
3. Collateral Damages: Costs relating to third-party claims and safety events due to a catastrophic asset failure event
4. Environmental: Costs relating to the clean-up and remediation of environmental contaminants due to a catastrophic failure event

2.3.1 Financial Impact Quantification

Direct financial impacts have been accounted for within the impact and risk analysis in the form of reactive costs to the utility when the asset is replaced under emergency situations. For each asset class, a series of asset unit replacement costs have been defined by OPUCN, including material and labour cost factors. These costs are based upon the standardized equipment that OPUCN would install should an existing asset fail and require replacement.

2.3.2 Reliability Impact Quantification

Impacts, as they relate to customers and reliability, have been quantified through the use of CICs, which represent a measure of monetary losses for customers due to an interruption of electric service. CICs were derived in alignment with the following two stages of an outage [11]:

1. The "Event" stage of the outage, where the customer is forced to terminate all activities involving electricity. Due to this termination, this results in an impact to the customer, which can be quantified in the form of an "Event Effect Cost", which is proportional to the customer load measured in kVA.

2. The "Duration" stage of the outage, where the customer readjusts their activities to account for the loss of electricity. Due to the continued interruption, the customer will continue to suffer the associated inconvenience. This stage can be quantified in the form of a "Duration Effect Cost", which is proportional to the customer load as well as the time duration of the outage, as measured in hours.

CICs were derived through the use of the ICE Calculator [2]. The ICE Calculator is an online electric reliability planning tool created by the Lawrence Berkeley National Laboratory and Nexant Inc. which allows utilities to input specific attributes relating to their customer demographics, average loading, and system performance. Final CICs were derived through the usage of these tools for residential, small commercial & industrial ("C&I"), and large & medium C&I customer types. For the context of this study, small C&I customers have a peak demand of less than 50 kW and large & medium C&I customers have a peak demand of 50 kW or greater. The CICs are further detailed in Table 2-1.

Table 2-1: Customer Interruption Costs per Customer Class

Residential Event Cost per kVA	$7.01
Residential Duration Cost per kVA-hour	$1.84
Small C&I Event Cost per kVA	$274.47
Small C&I Duration Cost per kVA-hour	$198.48
Large & Medium C&I Event Cost per kVA	$138.38
Large & Medium C&I Duration Cost per kVA-hour	$73.90

2.3.3 Collateral Damage Impact Quantification

The impact and risk analysis also takes into consideration collateral damages due to catastrophic failure events. Collateral damage costs account for third-party claims which may be filed against the utility in the event of a major asset failure and safety-related impacts. Information derived by METSCO based on its own engineering experience and knowledgebase – as it relates to third-party claims and injuries – were utilized in combination with information from Transport Canada and the Electrical Safety Association [3] [4].

2.3.4 Environmental Impact Quantification

Environmental costs, which account for environmental-related damages due to a catastrophic failure event, were derived based upon METSCO's knowledgebase and industry values. These environmental costs represent the scenario where an oil spill or SF6 leak has resulted in contamination to the surrounding environment and private property.

2.4 Risk Analysis

The concept of risk cost acknowledges that the impact of a failure cannot be assessed in isolation. Rather, it must be considered in conjunction with the probability of occurrence to appropriately represent the overall financial risk posed by a specific asset.

The risk cost is calculated by first defining the impact cost for all failure modes, as described in Section 2.3. The total impact cost of an asset is the sum of its customer impact, financial impact, environmental damage impact, and collateral impact costs. Each impact cost is then multiplied by the failure probability to obtain risk costs which are summed to determine the total risk cost. A high-risk cost can result from a high failure probability even if the asset is in otherwise good condition. This is due to failure probability being driven by both HI and asset age, either of these factors could lead to a higher risk cost associated with the asset. The final risk costs are then used in the subsequent steps of the Options Analysis process, described in Section 3.

3 Lifecycle Cost Analysis

With the calculation of the probability and impact of failure, a quantified monetized risk value can be determined for each power transformer and switchgear in OPUCN's distribution system. This quantified risk represents a key input as part of the lifecycle costing calculation taking place within the Options Analysis. Figure 3-1 provides a typical example of a lifecycle costing calculation for a new asset.

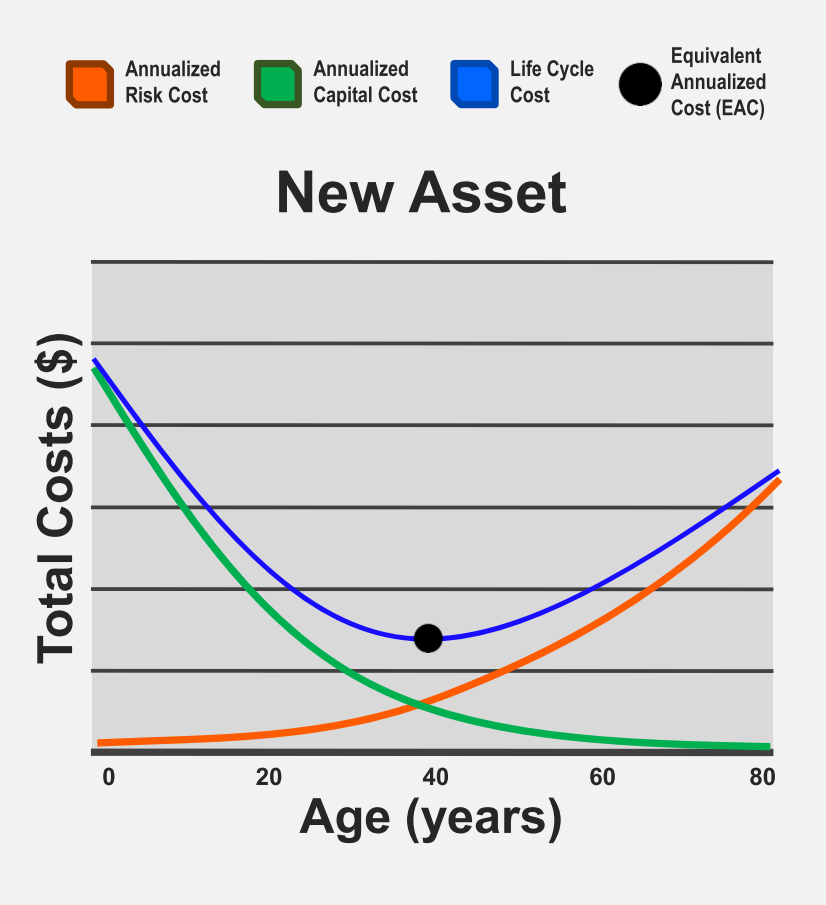


Figure 3-1: Lifecycle Costing Calculation for New Asset

The orange curve in Figure 3-1 is the risk cost annualized across the lifecycle of the new asset for any given age of replacing the asset. Similarly, the green curve represents the capital cost of installing the new asset annualized across the same lifecycle period for any given replacement age. The risk of asset failure must be balanced against the benefit of delaying the capital spending in the infrastructure by extending service life for as long as possible. The total sum of the annualized risk and annualized capital cost produces the annualized lifecycle cost, or total operating cost of the evaluated asset. The asset replacement cycle should be

set to the time or age when the minimum annualized lifecycle cost is achieved, referred to as the EAC.

Figure 3-2 provides a practical example where a new asset will replace an existing asset which possesses elevated risks. The EAC, as determined from the new asset to be installed, must be cross-referenced against the existing asset's risk cost curve, as shown by the red curve to the right of the figure. It is at this point in time that the existing asset will reach its economic end-of-life ("EOL") criteria and require intervention. This intervention time will represent a point when the future annual risk costs of the existing asset will exceed an average annual total cost of the new asset if it's replaced. Thus, by not replacing the existing asset, the risk costs will outweigh the costs of the new asset and will lead to a higher cost of asset ownership. By replacing the existing asset too early, when the annual risks are lower than the annualized costs of the new asset, the utility will sacrifice the economic life of the existing asset and will incur a higher cost of asset ownership. However, if the existing asset is replaced at the intervention time which balances the existing asset risk cost and capital cost of the new asset, the total cost of asset ownership will be minimized. This represents the OIT.

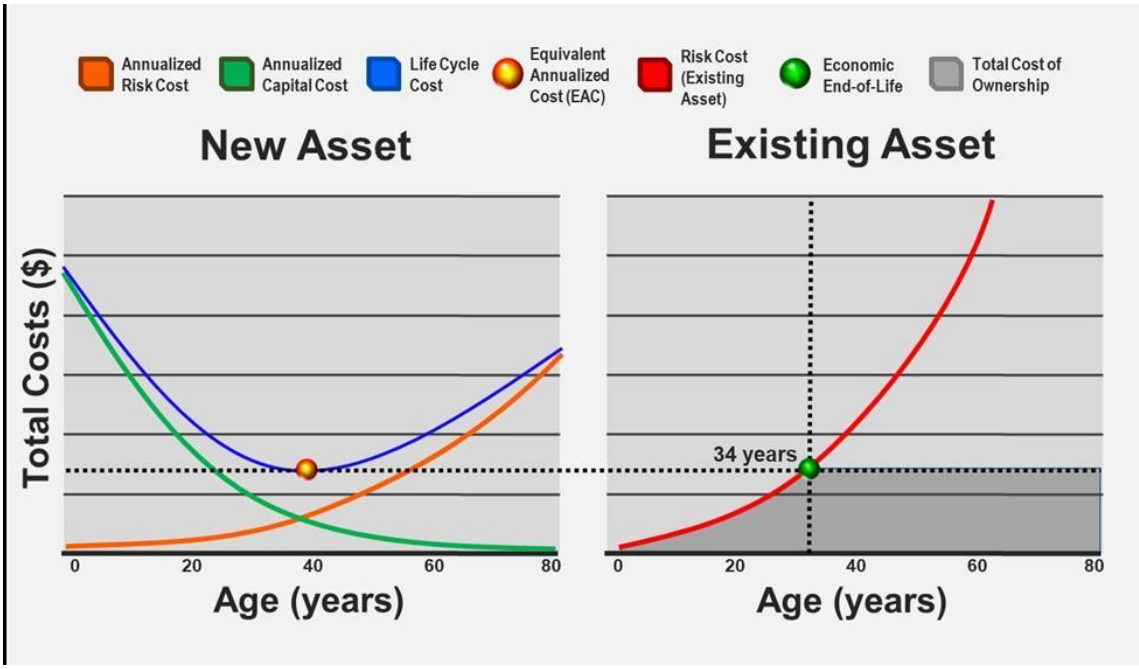


Figure 3-2: Determination of Economic End-of-Life for Existing Asset

3.1 Optimal Intervention Time Results

From the lifecycle cost analysis, it was determined which assets have an OIT that falls before the end of OPUCN's next Five-Year Forecast Capital Investment Plan (2026-2030) as part of their Distribution System Plan ("DSP"). Table 3-1 and Table 3-2 present which power

transformers and switchgear buses, respectively, fall within or outside of this period of time. Assets which fall outside of the current Capital Plan should be reassessed in five years.

Table 3-1: Power Transformer OIT

Asset	OIT
MS 2-T1	Beyond 2040
MS 2-T2	Beyond 2040
MS 5-T1	Beyond 2040
MS 5-T2	Beyond 2040
MS 7-T1	2036-2040
MS 7-T2	Beyond 2040
MS 9-T1	Beyond 2040
MS 9-T2	Beyond 2040
MS 10-T1	Beyond 2040
MS 10-T2	Beyond 2040
MS 11-T1	Beyond 2040
MS 11-T2	Beyond 2040
MS 13-T1	Beyond 2040
MS 13-T2	Beyond 2040
MS 14-T1	2036-2040
MS 14-T2	2036-2040
MS 15-T1	Beyond 2040
MS 15-T2	Beyond 2040

Table 3-2: Switchgear Bus OIT

Asset	OIT
MS2	Within Capital Plan
MS5	Within Capital Plan
MS7	Within Capital Plan
MS9	Beyond 2040
MS10	Within Capital Plan
MS11	Within Capital Plan
MS13	Within Capital Plan
MS14	Beyond 2040
MS15	Within Capital Plan

-

4 Options Analysis

The Options Analysis compares different intervention scenarios for assets reaching OIT within the capital plan. Three scenarios were considered in the Options Analysis;

1. Run to Failure ("RTF")
2. Replacement at OIT
3. Refurbishment at OIT.

RTF represents a scenario where no actions are taken by OPUCN to extend the life of the asset. The replacement scenario represents the proactive removal of the existing asset and the instillation of a brand-new asset before the existing asset fails. The refurbishment scenario represents actions being taken to extend the life of the existing asset. For power transformers, refurbishment involves rewinding of the transformer. For switchgears, refurbishment entails replacement of circuit breakers within the switchgear.

When a utility is able to replace all of their assets at their respective OITs, they are able to minimize the total cost of ownership ("TCO") across their distribution system, thus providing the most beneficial solution to the customers. The TCO represents the total cost of owning the asset over its lifecycle. Figure 4-1 illustrates an example of this minimization of TCO through the replacement of assets at their optimal timing results.

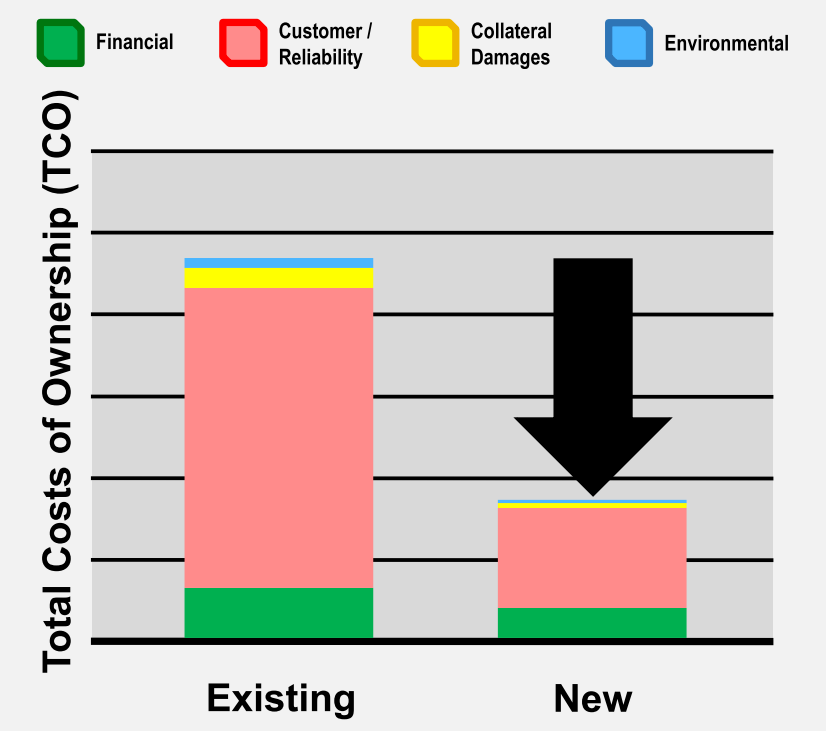


Figure 4-1: Minimization of TCO via Replacement of Assets at Lowest Life-Cycle Costs

For each of the three scenarios a net present value ("NPV") was calculated using OPUCN's discount rate of 5.9% over 25 years.

$$NPV = \frac{R_t}{(1+i)^t}$$

Where:

- *Net Cash Flow at Time t (R_t),*
- *Discount Rate (i),*
- *Time of Cash Flow (t)*

The Net Cash Flow ("NCF") for each year was calculated for each for each scenario using the existing asset's risk as the baseline. For each scenario, the total cash inflow is the difference between the existing annual risk of the asset and the annual risk after intervention as indicated in Figure 4-1 by the black arrow. The cash outflow of each scenario is the cost of the intervention. In cases where OPUCN's switchgear contract would be broken by not replacing the asset and instead refurbishing or letting the asset RTF the cost of breaking the contract was also considered as cash outflow in the initial year. The switchgears covered by this contract are MS2, MS5, MS7, and MS11.

4.1 Options Analysis Results

The Options Analysis was only performed on assets that reach their OIT within the capital planning period (2030 and earlier). No power transformers reach their OIT during this time period. The NPVs of the three scenarios for these switchgear are presented below in Table 4-1. These represent the current value of future risk savings and the cost of the intervention method. The greater the value the greater the benefit to OPUCN. A negative value indicates that the capital cost of the option will exceed the benefit of the option. The highlighted intervention type indicates the option with the most value to OPUCN.

Table 4-1: Switchgear NPV Results

Asset ID	Intervention Type	NPV ($'000)
MS2	RTF	-708
	Replacement	673
	Refurbishment	-16
MS5	RTF	-708
	Replacement	976
	Refurbishment	197
MS7	RTF	-708
	Replacement	898
	Refurbishment	142
MS10	RTF	0
	Replacement	412
	Refurbishment	510
MS11	RTF	-708
	Replacement	548
	Refurbishment	-103
MS13	RTF	0
	Replacement	434
	Refurbishment	525
MS15	RTF	0
	Replacement	289
	Refurbishment	424

5 Conclusions & Recommendations

The power transformers and switchgears results and recommended intervention are summarized in Table 5-1 and Table 5-2 respectively. The NPV results for the RTF, refurbishment, and replacement options are presented for power transformers and switchgears which will reach their OIT within the capital planning period. In accordance with OPUCN's switchgear replacement program in which both buses are replaced or refurbished at the same time the switchgear results are presented by switchgear.

Table 5-1: Summary of Power Transformer Results

Asset	OIT	NPV ($'000)			Recommended Intervention
		RTF	Replacement	Refurbishment	
MS 2-T1	Beyond 2040	--	--	--	Operate as Normal
MS 2-T2	Beyond 2040	--	--	--	Operate as Normal
MS 5-T1	Beyond 2040	--	--	--	Operate as Normal
MS 5-T2	Beyond 2040	--	--	--	Operate as Normal
MS 7-T1	2036-2040	--	--	--	Operate as Normal
MS 7-T2	Beyond 2040	--	--	--	Operate as Normal
MS 9-T1	Beyond 2040	--	--	--	Operate as Normal
MS 9-T2	Beyond 2040	--	--	--	Operate as Normal
MS 10-T1	Beyond 2040	--	--	--	Operate as Normal
MS 10-T2	Beyond 2040	--	--	--	Operate as Normal
MS 11-T1	Beyond 2040	--	--	--	Operate as Normal
MS 11-T2	Beyond 2040	--	--	--	Operate as Normal
MS 13-T1	Beyond 2040	--	--	--	Operate as Normal
MS 13-T2	Beyond 2040	--	--	--	Operate as Normal
MS 14-T1	2036-2040	--	--	--	Operate as Normal
MS 14-T2	2036-2040	--	--	--	Operate as Normal
MS 15-T1	Beyond 2040	--	--	--	Operate as Normal
MS 15-T2	Beyond 2040	--	--	--	Operate as Normal

Table 5-2: Summary of Switchgear Results

Asset	OIT	NPV ($'000)			Recommended Intervention
		RTF	Replacement	Refurbishment	
MS2	Within Capital Plan	-708	**673**	-16	**Replacement**
MS5	Within Capital Plan	-708	**976**	197	**Replacement**
MS7	Within Capital Plan	-708	**898**	142	**Replacement**
MS9	Beyond 2040	0	-1040	-506	Operate as Normal
MS10	Within Capital Plan	0	412	**510**	**Refurbish**
MS11	Within Capital Plan	-708	**548**	-103	**Replacement**
MS13	Within Capital Plan	0	434	**525**	**Refurbish**
MS14	Beyond 2040	0	-993	-473	Operate as Normal
MS15	Within Capital Plan	0	289	**424**	**Refurbish**

The NPV comparison between the replacement vs. refurbishment vs. RTF options determines which intervention type is optimal. There are no recommended interventions for power transformers. There are four switchgear buses recommended for replacement and three switchgear buses recommended for refurbishment. OPUCN should plan on replacing or refurbishing these assets accordingly over the capital planning period (by 2030)

Before the next capital planning period, it is recommended that OPUCN work towards completing this analysis for their other types of distribution and substation assets. Assets which fall outside of the current Capital Plan should be reassessed in five years.

6 References

[1] Office of Gas and Electricity Markets, "DNO Common Network Asset Indices Methodology," 2021.

[2] Lawrence Berkeley National Laboratory; Nexant, Inc., "Interruption Cost Estimate (ICE) Calculator".

[3] A. Zhang, A. E. Boardman, D. Gillen and W. Waters II, "Towards Estimating the Social and Environmental Costs of Transportation in Canada," Centre for Transportation Studies, The University of British Columbia, Vancouver, 2004.

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[6] *Life extension of oil filled transformers and shunt reactors,* Montreal, Quebec: CIGRE, 2022.

[7] "IEC 61649:2008 – Weibull Analysis," IEC, Geneva, 2008.

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[9] W. Luff, "Reliability Model for Linear Assets," University of Toronto, Toronto, 2012.

[10] Kinectrics, "Asset Depreciation Study for the Ontario Energy Board," 2010.

[11] R.-L. Chen, K. Allen and R. Billinton, "Value-Based Distribution Reliability Assessment & Planning," *IEEE Transactions on Power Delivery,* vol. 10, no. 1, pp. 421-429, January 1995.

P-23-165-003-R2-Options Analysis

Final Audit Report 2024-02-17

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Appendix D

Hydro One Planning Status Letter, GTA East Needs Assessment Report, Hydro One List of Station Capacity

October 11th, 2024

Mr. Aiyappa Ganapathy
Manager - Distribution Design & System Planning
Oshawa PUC Networks Inc.
100 Simcoe St S
Oshawa, ON L1H 7M7

Via email: aganapathy@oshawapower.ca

Hydro One Networks Inc.

483 Bay Street
8th Floor South Tower
Toronto, Ontario M5G 2P5

HydroOne.com

Dear Mr. Ganapathy:

Subject: Regional Planning Status – Oshawa PUC Networks Inc. Service Area

This letter is in response to your request for a Regional Planning Status letter. For the purposes of regional planning the province has been divided into 21 regions. A map showing details with respect to the 21 regions[1] and the list of Local Distribution Companies (LDCs) in each region are attached in Appendix A and B respectively. Hydro One Networks Inc. is the lead transmitter in 20 regions and Oshawa PUC Networks Inc.'s (OPUCN) service area belongs to the GTA East Region. OPUCN is connected to Thornton TS, Wilson TS, and Enfield TS within the GTA East Region.

This letter confirms that the second cycle of the Regional Planning process for the GTA East region was completed in February 2020. The findings and the recommendations stemming out of the second cycle RP are provided in detail in the GTA East Regional Infrastructure Planning (RIP) report. The third regional planning cycle is currently underway beginning with the Needs Assessment (NA), which is scheduled for completion in December 2024.

A summary of the regional planning status, including needs and plans currently identified in the GTA East region that affects OPUCN's service area is provided below:

GTA East Region:

The following transmission projects were undertaken by Hydro One to address near-term supply needs that were recommended in the first Regional Planning cycle.

- New Enfield TS, in-serviced May 2019, is a 230/44 kV DESN transformer station to increase supply capacity in the Oshawa-Clarington sub-region and to provide load relief to Wilson TS.
- New Seaton MTS, in-serviced June 2023, is a 230/27.6/27.6 transformer station to increase supply capacity in the Pickering-Ajax-Whitby sub-region and to provide load relief to Whitby TS 27.6 kV system following the development of the new community of Seaton.

OPUCN was required to make the capital contribution for Enfield TS in accordance with the Ontario Energy Board's Transmission System Code. There are no direct cost implications of the new Seaton MTS on OPUCN.

The recommendations in the second RP cycle for the GTA East region include replacement of

[1] Hydro One Regional Planning

some of the major high voltage transmission assets approaching end-of-life as listed below:

- Cherrywood TS 230kV & 500kV breaker replacement (multi-phase)
- Cherrywood TS MV DESN Switchyard Refurbishment
- Wilson TS T1/T2 and Switchyard Refurbishment

As mentioned above, the second cycle Regional Infrastructure Planning report was completed and published in February 2020. The report did not identify any needs requiring further regional co-ordination during OPUCN's planning cycle at this time. No capital contribution is expected to be required by Hydro One Transmission from OPUCN for the projects recommended in the second regional planning cycle.

Hydro One Networks Inc. would like to acknowledge and thank you for your work and effort in support of the Regional Planning process. We look forward to continuing to work with you in the future. If you have any further questions, please feel free to contact me.

Sincerely,



Ajay Garg,
Senior Manager, System Planning & Regional Planning Coordination

Hydro One Networks Inc.
Tel: (647) 242-2105
ajay.garg@HydroOne.com

Appendix A: Map of Ontario's Planning Regions

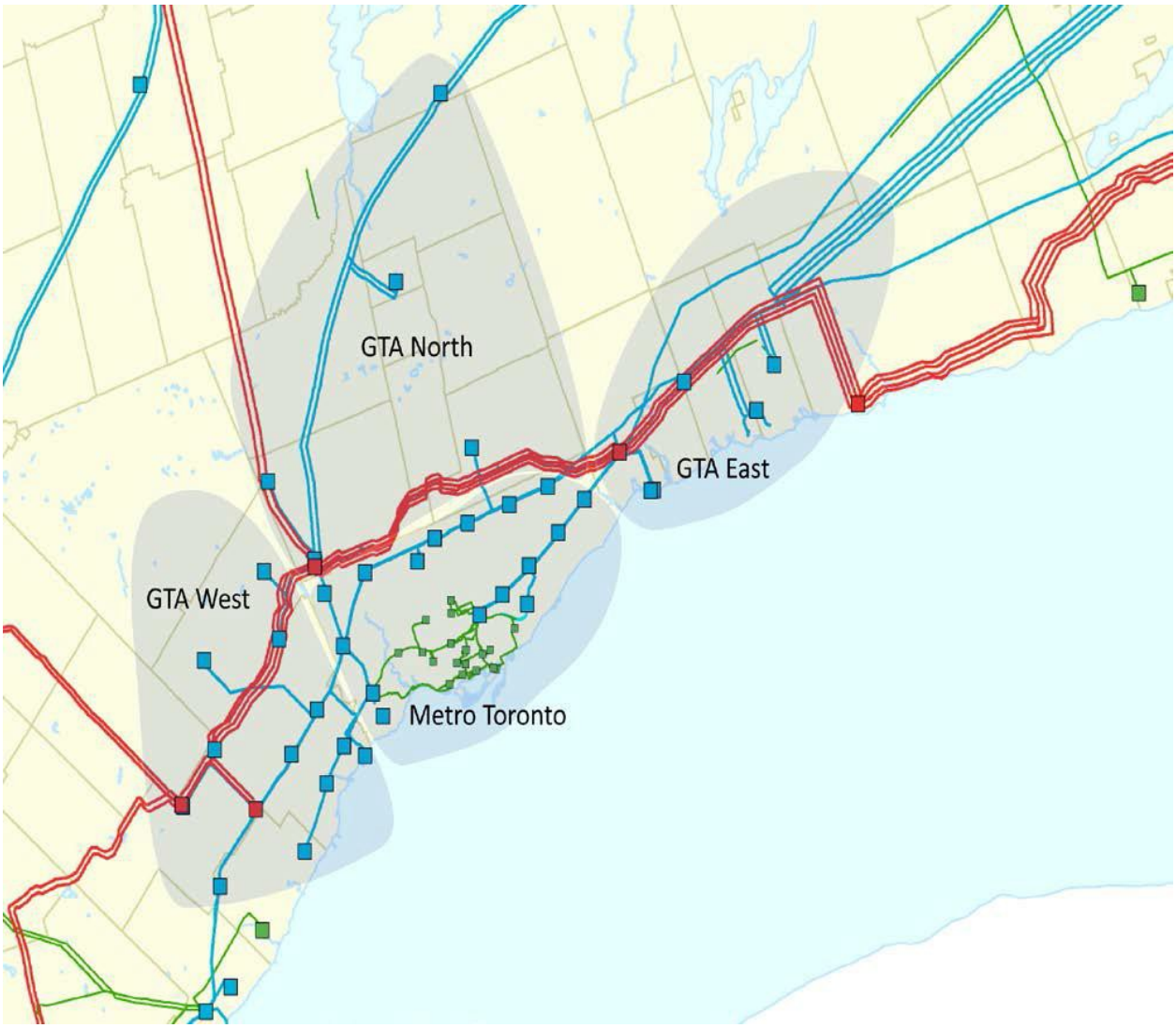
Northern Ontario



Southern Ontario



Greater Toronto Area (GTA)



Appendix B: List of LDCs for Each Region

[Hydro One as Upstream Transmitter]

Region	LDCs
1. Burlington to Nanticoke	• Burlington Hydro Inc. • GrandBridge Energy Inc. (Formerly Energy+ and Brantford Power) • Alectra Utilities Corporation (Formerly Horizon Utilities Inc.) • Hydro One Networks Inc. (Distribution) • Oakville Hydro Electricity Distribution Inc.
2. Greater Ottawa	• Hydro 2000 Inc. • Hydro Ottawa Limited • Hydro Hawkesbury Inc. • Ottawa River Power Corporation • Hydro One Networks Inc. (Distribution) • Renfrew Hydro Inc
3. GTA North	• Alectra Utilities Co. • Hydro One Networks Inc. (Distribution) • Newmarket-Tay Power Distribution Ltd. • Toronto Hydro Electric System Limited
4. GTA West	• Burlington Hydro Inc. • Hydro One Networks Inc. (Distribution) • Alectra Utilities Co. • Milton Hydro Distribution Inc. • Halton Hills Hydro Inc. • Oakville Hydro Electricity Distribution Inc.
5. Kitchener- Waterloo-Cambridge-Guelph ("KWCG")	• Alectra Utilities Corporation. • Enova Power Corporation. • Grandbridge Energy Inc. • Centre Wellington Hydro Ltd. • Hydro One Networks Inc. (Distribution) • Halton Hills Hydro Inc. • Wellington North Power Inc.

6. Toronto	• Alectra Utilities • Elexicon Energy Inc. • Hydro One Networks Inc. (Distribution) • Toronto Hydro Electric System Limited
7. Northwest Ontario	• Atikokan Hydro Inc. • Fort Frances Power Corporation • Hydro One Networks Inc. (Distribution) • Synergy North • Sioux Lookout Hydro Inc.
8. Windsor-Essex	• E.L.K. Energy Inc. • Entegrus Powerlines Inc. (Chatham-Kent) • EnWin Utilities Ltd. • Essex Powerlines Corporation • Hydro One Networks Inc. (Distribution)
9. East Lake Superior [Hydro One Sault Ste. Marie L.P. is the Lead Transmitter for the region]	• Algoma Power Inc. • Hydro One Networks Inc. (Distribution) • PUC Distribution
10. GTA East	• Elexicon Energy Inc. • Oshawa PUC Networks Inc. • Hydro One Networks Inc. (Distribution)
11. London Area	• Entegrus Powerlines Inc. • ERTH Power Inc. • Hydro One Networks Inc. (Distribution) • London Hydro Inc. • Tillsonburg Hydro Inc.

12. Peterborough to Kingston	• Eastern Ontario Power Inc. • Elexicon Energy Inc. • Hydro One Networks Inc. (Distribution) • Kingston Hydro Corporation • Lakefront Utilities Inc.
13. South Georgian Bay/Muskoka	• Hydro One Networks Inc. (Distribution) • Alectra Utilities • InnPower • Orangeville Hydro • Elexicon Energy • Lakeland Power • EPCOR Electricity Dist. Ontario Inc. • Newmarket-Tay Power Distribution Ltd. • Wasaga Distribution Inc.
14. Sudbury/Algoma	• Greater Sudbury Hydro Inc. • North Bay Hydro • Hydro One Networks Inc. (Distribution)
15. Chatham-Kent/Lambton/Sarnia	• Bluewater Power Distribution Corporation • Entegrus Power Lines Inc. (Chatham-Kent) • Hydro One Networks Inc. (Distribution)
16. Greater Bruce/Huron	• Entegrus Powerlines Inc. • ERTH Power Corporation • Hydro One Networks Inc. (Distribution) • Festival Hydro Inc. • Wellington North Power Inc. • Westario Power Inc.

17. Niagara	• Canadian Niagara Power Inc. [Port Colborne] • Hydro One Networks Inc. (Distribution) • Grimsby Power Inc. • Niagara Peninsula Energy Inc. • Niagara-On-The-Lake Hydro Inc. • Alectra Utilities Co. • Welland Hydro-Electric System Corporation
18. North of Moosonee [Five Nations Energy Inc (FNEI) is the Lead Transmitter for the region]	• Distribution in this region is provided by FNEI
19. North/East of Sudbury	• Northern Ontario Wires Inc. • Hearst Power Distribution Company Limited • North Bay Hydro Distribution Ltd. • Hydro One Networks Inc. (Distribution) • Greater Sudbury Hydro Inc.
20. Renfrew	• Hydro One Networks Inc. (Distribution) • Ottawa River Power Corporation
21. St. Lawrence	• Cooperative Hydro Embrun Inc. • Hydro One Networks Inc. (Distribution) • Rideau St. Lawrence Distribution Inc.



NEEDS ASSESSMENT REPORT

Greater Toronto Area East

December 11, 2024

Needs Assessment Report

Greater Toronto Area (GTA) East Region

December 11, 2024

Lead Transmitter:

Hydro One Networks Inc.

Prepared by:

GTA East Technical Working Group

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Disclaimer

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

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Executive Summary

REGION	Greater Toronto Area East (GTA East) Region (the "Region")
LEAD	Hydro One Networks Inc. ("Hydro One")
START DATE: August 13, 2024	**END DATE:** December 11, 2024

1. INTRODUCTION

The second Regional Planning cycle for the GTA East Region was completed in February 2020 with the publication of the Regional Infrastructure Plan ("RIP") report (RIP Report). This is the third cycle of Regional Planning for the region.

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

a) Identify any new needs and reaffirm needs identified in the previous regional planning cycle; and,

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

The planning horizon for this NA assessment is ten years.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. Considering these timelines, the 3rd Regional Planning cycle was triggered for the GTA East Region on August 13th , 2024.

3. SCOPE OF NEEDS ASSESSMENT

The scope of the GTA East Region NA includes:

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

b) Identify any new needs resulting from this assessment,

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

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

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The GTA East Region comprises the municipalities of Pickering, Ajax, Whitby, Oshawa and parts of Clarington, and other parts of the Durham area.

5. INPUTS/DATA

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

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

6. ASSESSMENT METHODOLOGY

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

A technical assessment of needs is undertaken based on:

a) Current and future station capacity and transmission adequacy
b) System reliability needs and operational concerns
c) Major HV transmission equipment requiring replacement with consideration to "right-sizing"

d) Sensitivity analysis to capture uncertainty in the load forecast as well as variability of demand drivers such as electrification.

7. NEEDS

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

The following needs discussed in the GTA East Region second cycle RIP have been completed:

- Increase Transformation Capacity in Pickering-Ajax-Whitby Sub-region: Seaton MTS has been built and placed in-service in 2023.
- Wilson TS – T1, T2 and Switchyard Refurbishment: Wilson TS T1/T2 have been replaced and new T7/T8 were placed in service in early 2024, maintaining station reliability and ensuring continued supply reliability to Oshawa PUC Inc. (OPUC) and Hydro One Distribution (H1DX) customers.

The following needs and projects discussed in the GTA East second cycle RIP are currently underway:

- Cherrywood TS 230kV Breaker Replacement (multi-phase projects): Two phases are underway with currently planned in-service dates of 2033 and 2037 respetively.

II. Newly identified needs in the region

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

a) Asset Renewal for Major HV Transmission Equipment

- Wilson TS - T3/T4 Replacement

b) Station Capacity

- Whitby TS T1/T2 DESN (44kV)
- Thornton TS T3/T4 DESN
- Wilson TS T7/T8 DESN
- Wilson TS T3/T4 DESN

c) Transmission Line Capacity

- No new transmission Line Capacity need identified

d) System Reliability, Operation and Load Restoration

- T23C/T29C corridor may exceed load security limit of 600MW in 2032 if all forecasted loads at the current stations are supplied from original connection points

e) Transmission System Reinforcement

- Major transmission expansion in Oshawa-Clarington sub-region area will be needed to accommodate increasing new large load connection requests. Existing 230kV transmission facilities do not have sufficient capacity to supply the new demand.

8. SENSITIVITY ANALYSIS

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

The impact of the sensitivity analysis for the high and low growth scenarios identified the following updates to need dates and new station capacity needs. These needs will be assessed again during the next phases of this Regional Planning cycle.

No.	Need Identified	Need Date		
		Normal Growth Scenario	High Growth Scenario	Low Growth Scenario
Needs update under high and low load growth scenarios				
1	Whitby TS T1/T2 (44kV) LTR	2032	2030	Beyond 2033
2	Thornton TS T3/T4 LTR	2031	2027	Beyond 2033
3	Wilson TS T7/T8 LTR	2032	2029	Beyond 2033
4	Wilson TS T3/T4 LTR	2024 (2025*)	2024 (2025*)	2024 (Beyond 2033*)
Additional capacity needs under high growth scenario				
5	Cherrywood T7/T8 LTR	Beyond 2033	2031	Beyond 2033
6	Seaton MTS LTR**	Beyond 2033	2032	Beyond 2033
7	Whitby TS T3/T4 LTR	Beyond 2033	2031	Beyond 2033

* If the transformers are replaced with higher LTR rating units as planned.

** Based on the LDC provided LTRs of 153MW (Summer) and 180MW (Winter) for Seaton MTS

9. RECOMMENDATIONS

The TWG recommendations are as follows:

I. Needs that require further assessment and regional coordination

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

a) Integrated Transmission reinforcement at Oshawa-Clarington Sub-region area to accommodate large load connection requests and address T23C/T29C corridor load security issue
b) Station capacity need at Thornton TS in Oshawa area due to load growth
c) Station capacity need at Wilson TS T7/T8 in Oshawa area due to load growth
d) Station capacity need at Wilson TS T3/T4 in Oshawa area due to load growth

II. Needs that do not require further regional coordination

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

a) Cherrywood TS 230kV Breaker Replacement
b) Wilson TS - T3/T4 Transformer Replacement
c) Station capacity need at Whitby TS T1/T2 (44kV) in North Whitby area due to load growth

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

- Elexicon Energy Inc.
- Oshawa PUC Networks Inc.
- Hydro One Networks Inc. (Distribution)

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

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1. Introduction

The second cycle of the Regional Planning process for the GTA East Region was completed in February 2020 with the publication of the Regional Infrastructure Plan ("RIP") Report [1] - (RIP link). The RIP report included a common discussion of all the options and recommended plans for preferred wire infrastructure investments to address the near- and medium-term needs.

This Needs Assessment initiates the third regional planning cycle for the GTA East Region. The purpose of this Needs Assessment ("NA") is to:

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

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

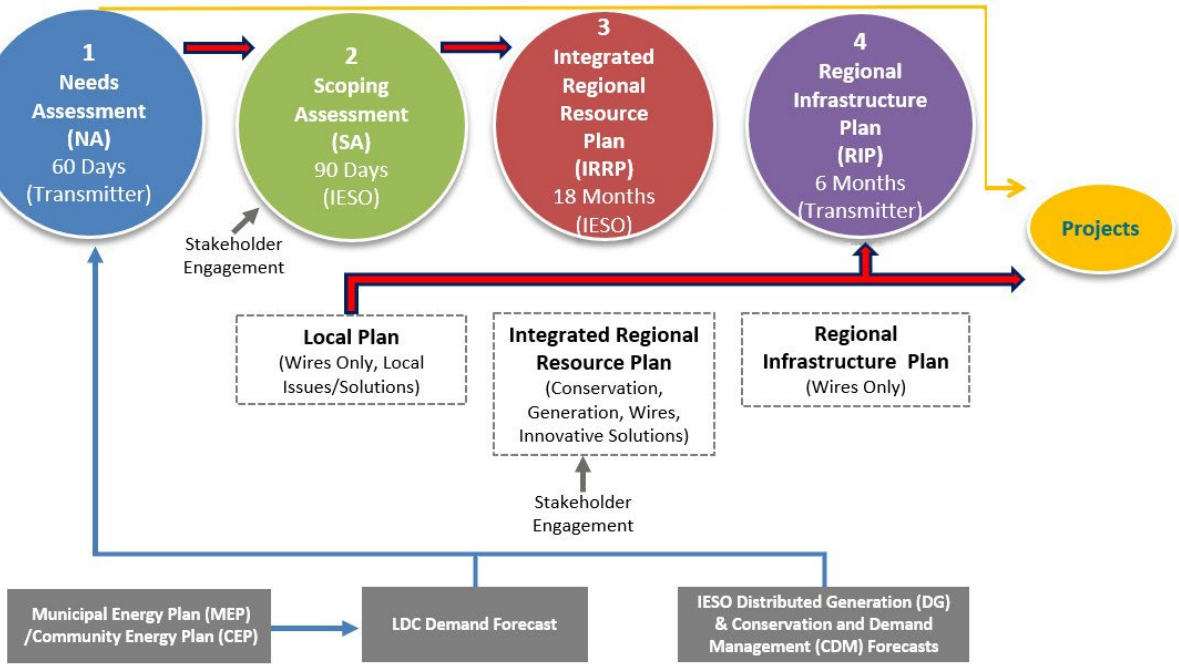


Figure 1: Regional Planning Process

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

Table 1: GTA East Region TWG Participants

No.	Name of TWG Participants
1	Hydro One Networks Inc. (Transmission) - (Lead Transmitter)
2	Independent Electricity System Operator
3	Elexicon Energy Inc.
4	Oshawa PUC Networks Inc.
5	Hydro One Networks Inc. (Distribution)

2. Regional Issue/Trigger

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. As such, the third Regional Planning cycle was triggered for the GTA East Region.

3. Scope of Needs Assessment

The scope of this NA covers the GTA East region and includes:

- Review and update needs and plans identified in the previous cycle RIP,
- Identify any new needs resulting from this assessment,
- Recommend which needs require further assessment and regional coordination in the next phases of the regional planning cycle to develop a preferred plan, and
- Recommend which needs do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDCs to develop a preferred plan and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

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

The planning horizon for this NA assessment is 10 years.

4. Regional Description and Connection Configuration

The GTA East Region comprises the municipalities of Pickering, Ajax, Whitby, Oshawa and parts of Clarington, and other parts of the Durham area.

The geographical boundaries of the Region are shown in Figure 2.

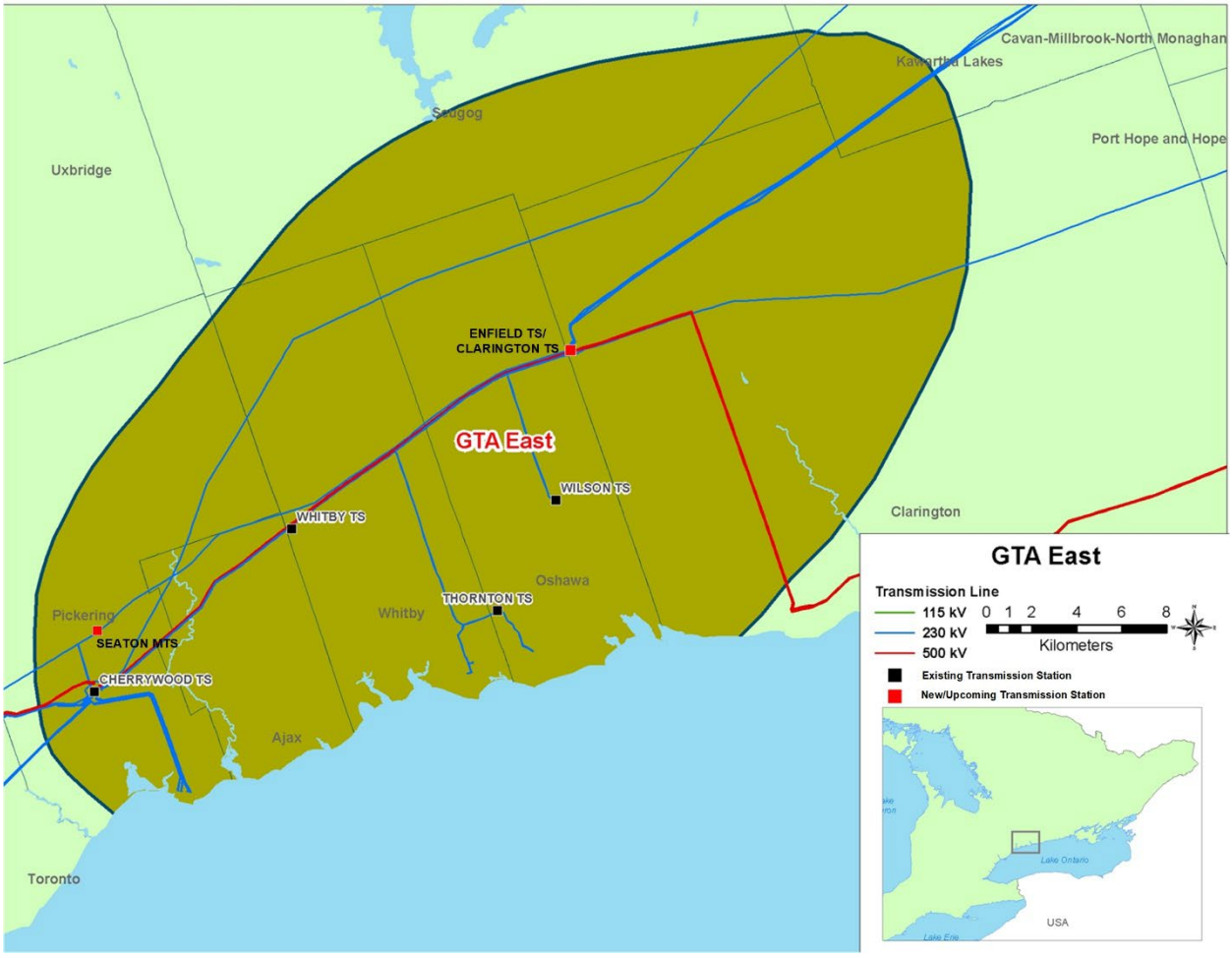


Figure 2: Map of GTA East Regional Planning Area

Electrical supply to the GTA East Region is provided through 500/230kV autotransformers at Cherrywood Transformer Station (TS) and Clarington Transformer Station (TS) and six 230 kV transmission lines connecting Cherrywood to Eastern Ontario. There are six step-down transformer stations (five Hydro One owned and one LDC owned), and three direct transmission connected load customers. Metrolinx Traction Power Substation (TPSS) is proposed to be in service in 2029. The distribution system is at two voltage levels, 44kV and 27.6kV.

The Local Distribution Customers (LDC) in the Region include Elexicon Energy Inc., Oshawa PUC Networks Inc. and Hydro One Networks Inc. (Distribution). An electrical single line diagram for the GTA East Region facilities is shown in Figure 3.

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

Table 2: Transmission Station and Circuits in the GTA East Region

230kV circuits	Transformer Stations	Generation Stations
T23C T24C T26C T28C T29C C10A	Cherrywood TS[1] Seaton MTS Thornton TS Whitby TS Wilson TS Enfield TS CTS A CTS B CTS C Metrolinx TPSS (in-service 2029)	CGS D, 60MW gas-fired cogeneration Pickering Nuclear Generating Station (NGS), approximately 3000 MW

1: 500kV Stations with Autotransformers installed

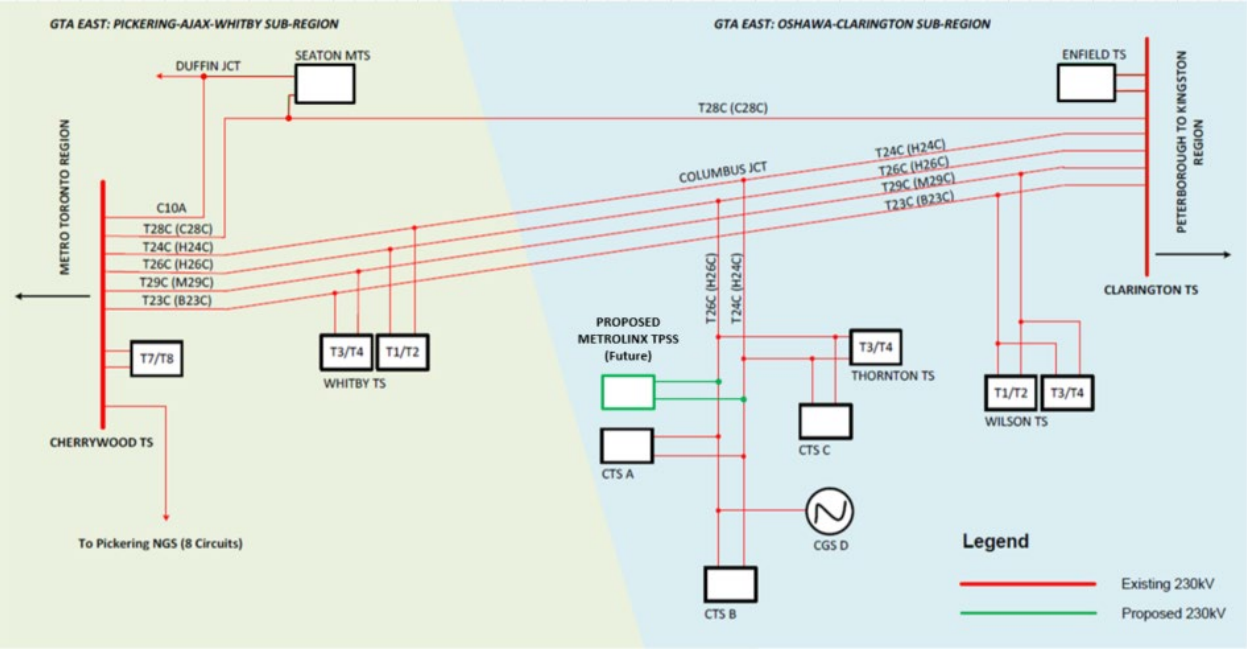


Figure 3: GTA East Transmission Single Line Diagram

5. Inputs and Data

TWG participants, including representatives from LDCs, IESO, and Hydro One provided input for the GTA East NA. With respect to the load forecast information, the OEB Regional Planning Process Advisory Group (RPPAG) recently published a document called "Load Forecast Guideline for Ontario" in Oct. 2022 [2]. The objective of this document is to provide guidance to the TWG in the development of the load forecasts used in the various phases of the regional planning process with a focus on the NA and the IRRP. One of the inputs into the LDC's load forecast that is called for in this guideline is information from Municipal Energy Plans (MEP) and/or Community Energy Plans (CEP). The list of all the Municipalities falling under the geographical boundaries of the region are given in Appendix-E.

The information provided includes the followings:

- GTA East 10-year summer and winter load forecast for all supply stations inclusive of the inputs provided by the municipalities listed in Appendix E
- Known capacity and reliability needs, operating issues, and/or major assets requiring replacement or refurbishment
- Planned transmission and distribution investments that are relevant to Regional Planning for the GTA East
- Captured uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments.

6. Assessment Methodology

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

6.1 Technical Assessments and Study Assumptions

The technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy
- System reliability and operational considerations
- Asset renewal for major high voltage transmission equipment requiring replacement with consideration to "right-sizing"
- Load forecast data requested from industrial customers in the region
- Summer and Winter peak load conditions. Three load forecasts were developed for Summer and Winter respectively, i.e. normal growth scenario, high and low growth scenario. The high and low growth load forecasts are developed to conduct a sensitivity analysis to cover unforeseen developments such as fuel switching, government policies, higher than expected EV charging trend during peak load conditions, etc.

The following assumptions are made in this report:

- The study period for this Needs Assessment is 2024-2033.
- The Region is summer peaking, but will be transitioning to winter peaking for most of transformer stations in this study period, so this assessment is based on both summer and winter peak loads.
- Line capacity adequacy is assessed by using coincident peak loads in the area.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations without low-voltage capacitor banks and 95% lagging power factor for stations with low-voltage capacitor banks.
- Normal planning supply capacity for transformer stations is determined by the Hydro One Summer/Winter 10-Day Limited Time Rating (LTR) at 35 and 10 degree celcius respectively for Summer/Winter of a single transformer at that station.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC)[3] .

6.2 Information Gathering Process

6.2.1 Load forecast

The LDCs provided their summer and winter load forecast for all the stations supplying their loads in the GTA East region for the 10-year study period including the inputs from the Municipalities such as MEPs and CEPs. The IESO provided a Conservation and Demand Management ("CDM") and Distributed Generation ("DG") forecast for the Region. The net extreme summer weather load

forecasts were produced by reducing the gross load forecasts for each station by the percentage CDM and then by the amount of effective DG capacity provided by the IESO for that station. It is to be noted that as contracts for existing DG resources in the region begin to expire, at which point the load forecast has a decreasing contribution from local DG resources, and an increase in net demand. This extreme summer weather corrected net load forecast for the individual stations in the Region is given in Appendix A.

6.2.2 Sensitivity analysis

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

6.2.3 Asset renewal needs for major HV equipment

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

6.2.4 System reliability and operational issues

Relevant information regarding system reliability and operational issues in the region as feedback is provided by the IESO during the NA phase.

7. Needs

This section describes new needs identified in the Region and updates on previously identified needs since the completion of previous regional planning cycle.

Needs that were identified and discussed in the previous regional planning cycle with associated projects that were recently completed and reaffirmed needs that are underway, are briefly described below with relevant updates:

- Increase Transformation Capacity in Pickering-Ajax-Whitby Sub-region: Seaton MTS has been built and placed in-service in 2023.
- Wilson TS – T1, T2 and Switchyard Refurbishment: Wilson TS T1/T2 have been replaced and new T7/T8 were placed inservice in early 2024, maintaining station reliability and ensuring continued supply reliability to Oshawa PUC Inc. (OPUC) and Hydro One Distribution (H1DX) customers.
- Cherrywood TS – 230kV Breaker Replacements (multi-phase projects): Two phases are underway with currently planned in-service dates of 2033 and 2037 respectively.

All near and midterm needs that are discussed as a part of this report are summarized in Table 3. Note the planned in-service year for the projects is tentative and is subject to change.

Table 3: Near/Mid-term Needs Identified in Previous RIP and/or this NA

Need Description	Recommended Plan/Update	Previous RIP Report Section	NA Report Section
Asset Renewal Needs			
Cherrywood TS 230kV Breaker Replacements (multi-phase projects)	Two phases are underway with currently planned in-service dates of 2033 and 2037 respectively.	Sec. 7.2	Sec. 7.1
Wilson TS T3/T4 Transformer Replacement	Replacement of T3/T4 transformers with planned in-service date of 2031.	N/A	Sec. 7.1
Station Capacity Needs			
Whitby TS T1/T2 (44kV) Station Capacity need	Plan a new Transformer Station at North Whitby area, tapping on 230kV circuits of P15C and T28C. TWG agreed to proceed with local planning, no further regional coordination is required.	N/A	Sec. 7.2.1
Thornton TS T3/T4 Station Capacity need	Further regional coordination to address this need along with the identified new needs at Wilson TS T3/T4 and Wilson TS T7/T8 in Oshawa area (see Section 7.2.3 and 7.2.4).	N/A	Sec. 7.2.2

Wilson TS T7/T8 Station Capacity need	Further regional coordination required to address this need along with the identified new needs at Wilson TS T3/T4 (Section 7.2.4), and a new Transformer Station will be required.	N/A	Sec. 7.2.3
Wilson TS T3/T4 Station Capacity need	A new Transformer Station will be required as early as 2028/2029 and further regional coordination to address this need along with the needs at Wilson TS T7/T8 and Thornton TS T3/T4 (Section 7.2.2 and 7.2.3). As a near term solution, the LDCs are encouraged to continue transferring loads to Enfield TS.	N/A	Sec. 7.2.4
System Reliability, Operation and Load restoration Needs			
T23C/T29C corridor exceeds load security limit of 600MW	Further regional coordination required, especially when determining where to connect new Transformer Station to accommodate new needs identified in Section 7.2.2, 7.2.3 and 7.2.4.	N/A	Sec. 7.4
Transmission System Reinforcement Needs			
Oshawa-Clarington Sub-region area transmission reinforcement for load supply	Further regional coordination to address the capacity needs. Coordinated efforts from IESO bulk system planning, Hydro One, LDCs and major customers should continue in developing solutions.	N/A	Sec. 7.5

7.1 Asset Renewal Needs for Major HV Transmission Equipment

In addition to the previously identified asset renewal needs from the second regional planning cycle, Hydro One and TWG has also identified new asset renewal need for major high voltage transmission equipment that are expected to be replaced over the next 10 years in the Region. The complete list of planned major HV transmission equipment requiring replacement is provided in Table 4. Note the in service year is subject to change as the asset renewal planning is a dynamic process.

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

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

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

- 230 load serving step down transformers
- 230kV breakers where:

replacement of six breakers or more than 50% of station breakers, the lesser of the two

- 230kV transmission lines requiring refurbishment where:
  Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like
- 230kV underground cable requiring replacement where:
  Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like

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

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

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

7.1.1 Wilson TS T3/T4

Based on asset condition assessment, Wilson TS T3/T4 transformers are newly identified assets for replacement with currently planned in-service date of 2031. The existing T3 and T4 (75/100/125 MVA) transformers at Wilson TS and associated LV equipment require replacement. It is expected that Wilson TS T3/T4 capacity will increase to approximate 160 MW for Summer and 180 MW for Winter, once being replaced with the new standard 75/100/125 MVA transformers (Section 7.2.4).

No other HV station equipment or transmission lines in the GTA East region have been identified for replacement at this time over the next ten year. If and when new and/or additional information is available, it will be provided during the next regional planning phases.

The needs below in Table 4 do not need further regional coordination.

Table 4: Major HV Transmission Asset Assessed for Replacement in the Region in Next 10 Years

Station/Circuit	Need Description	Planned ISD
Cherrywood TS	230kV Breaker Replacements (multi-phase projects), two phases are underway	2033/2037
Wilson TS T3/T4	Asset condition based replacement with "like for like" standard units	2031

7.2 Station Capacity Needs

A Station Capacity assessment was performed over the study period 2024-2033 for the 230kV Transforming stations in the Region using the summer and winter peak load forecasts. Based on the results, the identified station capacity needs are flagged in Table 5. Comparing with the recommendations in RIP 2022 [1], all Transformer Stations below are newly identified needs in this NA period.

Table 5: Stations with Capacity Need

TS	Season	LTR (MW)	Net Load Forecast (MW)									
			2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Whitby TS T1/T2 (44kV)	Winter	113.2	36.6	47.5	56.9	66.6	76.7	87.1	98.1	107.4	118.2	130.1
Thornton TS T3/T4	Summer	154.9	138.0	138.8	139.5	140.0	141.1	142.4	144.7	147.7	151.5	156.2
	Winter	175.5	154.5	157.8	160.3	162.6	165.6	168.9	173.3	178.0	183.7	190.4
Wilson TS T7/T8	Summer	169.1	139.7	147.5	149.1	150.8	155.7	159.5	163.4	168.2	174.1	181.3
Wilson TS T3/T4	Summer	130.2	144.6	161.2	176.0	187.7	198.8	213.6	232.2	254.6	290.5	311.6
	Winter	152.0	136.1	154.7	171.5	185.1	198.2	214.6	234.6	257.2	293.0	312.8

7.2.1 Whitby TS T1/T2 (44kV)

Whitby TS T1/T2 (44kV) supplies loads from one LDC - Elexicon at 44kV level. Elexicon forecasts rapid annual gross load growth of approximate 6.3% at its 44kV service area in North Whitby in next ten years. With forecasted DG and CDM in place, the forecasted net load at Whitby TS T1/T2 (44kV) is expected to exceed its Winter LTR in 2032/2033 by 5MW or 17 MW respectively. In addition, the LDC has indicated that its 44kV distribution capacity at Whitby area will be exceeded by Summer 2032, and majority of the load growth in North Whitby area, which is currently supplied through Whitby TS T3/T4 and Whitby T1/T2 (27.6kV and 44kV), is highly expected post 2033. Also, in Northeast Pickering, there is projected load in the region that cannot be supplied by Whitby TS due to the long distance of the load center from the station.

In order to accommodate these needs, the LDC is currently consulting with Hydro One Tx to build a new Transformer Station, with preliminary option of tapping on two 230kV transmission circuits in the region, namely T28C and P15C. This new Transformer Station will address future projected load growth from North Whiby and North Pickering area. The TWG recommends LDC and Hydro One to proceed to local planning as no expected network reinforcement is required. No further regional coordination is required.

7.2.2 Thornton TS T3/T4

Thornton TS T3/T4 supplies loads from two LDCs, namely Hydro One Distribution (H1DX, with Elexicon's load embedded in) and Oshawa PUC Networks Inc. (OPUC), at 44kV level. OPUC forecasts rapid annual load growth of approximate 4.6% at Thornton TS T3/T4 in next ten years, while Elexicon load forecast remains flat in the study period. With forecasted DG and CDM in place, the net forecasted load at

Thornton TS T3/T4 is expected to exceed its LTRs as early as 2031 for Winter, or 2033 for Summer. The TWG recommends further regional coordination to address this need along with the identified new needs at Wilson TS T7/T8 and Wilson TS T3/T4 in Oshawa area (see Section 7.2.3 and 7.2.4 below).

7.2.3 Wilson TS T7/T8

Wilson TS T7/T8 serves loads from two LDCs, including OPUC and Hydro One Distribution (H1DX) at 44kV level. The two transformers have recently been replaced in early 2024 with largest size as per Hydro One standard transformer specification. Both LDCs forecast similar moderate annual gross load growth of approximate 3.2-3.7% at Wilson TS T7/T8 in next ten years. The net forecasted load at Wilson TS T7/T8 is expected to exceed its LTR as early as 2032 for Summer. The TWG recommends further regional coordination to address this need along with the identified new needs at Wilson TS T3/T4 (Section 7.2.4), and acknowledges that a new Transformer Station will be required for these needs.

7.2.4 Wilson TS T3/T4

Wilson TS T3/T4 serves loads from LDCs OPUC and Hydro One Distribution (H1DX) at 44kV level, with Elexicon's load embedded in H1DX. H1DX (including Elexicon) forecasts approximate 12% annual load growth at Wilson TS T3/T4 in next ten years, while OPUC forecasts moderate growth of approximate 3.6% annually in next ten years. The net forecasted load at Wilson TS T3/T4 is expected to exceed its LTR as early as 2024 for Summer, and 2025 for Winter.

As mentioned in Section 7.1.1, based on asset condition assessment, the T3 and T4 transformers at Wilson TS and associated LV equipment have been identified for replacement. Hydro One has identified the replacement of Wilson TS T3/T4 with planned in-service date of 2031. As the existing transformers have substandard LTRs, it is expected that Wilson TS T3/T4 will be replaced with standard 75/100/125 MVA transformers, and the capacity will increase from the current 130 MW for Summer and 152 MW for Winter to approximately 160 MW for Summer and 180 MW for Winter.

However, even with higher ratings of the new transformers, Wilson TS T3/T4 LTRs will still be exceeded based on load forecast. As a near term solution, the LDCs are encouraged to continue transferring loads to Enfield TS which can accommodate the additional loads that exceed Wilson TS T3/T4 station capacity. By doing so, the station capacity need could potentially be deferred for a few years. The TWG acknowledges that a new station will be required as early as 2028/2029 even with load transfers, and recommends further regional coordination to address this need along with the need in Section 7.2.2 and 7.2.3.

7.3 Transmission Lines Capacity Needs

All line and equipment loads shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings. A

Transmission Lines Capacity Assessment was performed over the study period 2024-2033 for the 230kV Transmission line circuits in the Region by assessing thermal limits of the circuit and the voltage range as per ORTAC[3].

Based on the results, there is no new transmission line capacity need identified.

7.4 System Reliability, Operation and Restoration Needs

The transmission system must be planned to satisfy demand levels up to the extreme weather, median-economic forecast for an extended period with any one transmission element out of service. The system should also meet load security and load restoration criteria as defined in ORTAC[3]. Based on input from the IESO and LDCs, the following system reliability, operational and restoration issues were identified:

- The new load forecast suggests T23C/T29C corridor will exceed load security limit of 600MW[3] in 2032. Table 6 shows load growth of all double-circuit corridors in the Region (assuming all forecasted loads were supplied from original connection points). The TWG recommends further regional coordination to address the T23C/T29C corridor load security issue, especially when determining where to connect the new Transformer Station to accommodate new needs identified in Section 7.2.3 and 7.2.4. The other T24C/T28C corridor will not have more than 600MW net loads in the assessment window.

Table 6: Double-circuit Corridor Non-coincident Load

Circuits		Non-coincident Load served by the double circuits (MW)									
		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
T23C/T29C	Summer	442.6	468.3	486.1	500.7	518.2	538.2	562.8	592.4	638.0	671.0
	Winter	362.1	395.3	420.3	442.1	466.3	493.1	524.0	557.0	605.3	639.5
T24C/T26C	Summer	412.9	418.5	424.1	429.5	435.7	472.5	480.9	489.8	501.5	515.4
	Winter	399.0	414.9	428.3	441.7	456.4	501.6	518.7	534.2	552.6	573.3

- All double-circuit corridor loads will exceed 250MW in this assessment timeframe. The ORTAC[3] requires the amount of load interruption in excess of 250MW must be restored within 30 minutes (and within 4 hours for load loss more than 150MW). The TWG surveyed transmission load interruption performance data from 2014 to 2024 for the Region. The results show that delivery points supplied by the circuits in Table 6 did not log load loss of more than 250MW for longer than 30 minutes, or loss of more than 150MW for longer than 4 hours in the past 10 years. Based on past performance data, the TWG would not recommends capital investment for load restoration at this point. Hydro One shall proactively monitor load restoration data and identify opportunities to reduce risk of prolonged load restoration.

7.5 Transmission System Reinforcement Needs

Oshawa-Clarington Sub-region area transmission reinforcement:

In addition to the rapid organic load growth forecasted in T23C/T29C/T24C/T26C corridors, multiple proponents have requested to connect large-scale loads in Oshawa-Clarington Sub-region area. Majority of the requests are large data centers. It is not feasible for the existing 230kV transmission infrastructure in Oshawa-Clarington Sub-region area to accommodate such sizeable loads. Due to the scale and complexity of such connections, the TWG recommends further regional coordination to address these potential capacity needs. Coordinated efforts from IESO bulk system planning, Hydro One, LDCs and major customers should continue in developing solutions.

8. Sensitivity Analysis

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

The TWG reviewed EV scenarios and any unforeseen electrification needs to develop high demand growth forecasts by applying 50% additional growth to the growth rate on the extreme summer/winter corrected Normal Growth net load forecasts. The low growth scenario was obtained by reducing the growth rate by 50%.

The impact of sensitivity analysis for the high and low growth scenario is shown in Table 7. The additional capacity needs identified towards the end of the study period will be assessed again during the next phases of the Regional Planning cycle where another sensitivity anaylyis will be undertaken based on updated information.

Table 7: Impact of Sensitivity Analysis on Capacity Needs in the Region

No.	Need Identified	Need Date		
		Normal Growth Scenario	High Growth Scenario	Low Growth Scenario
Needs update under high and low load growth scenarios				
1	Whitby TS T1/T2 (44kV) LTR	2032	2030	Beyond 2033
2	Thornton TS T3/T4 LTR	2031	2027	Beyond 2033
3	Wilson TS T7/T8 LTR	2032	2029	Beyond 2033
4	Wilson TS T3/T4 LTR	2024 (2025*)	2024 (2025*)	2024 (Beyond 2033*)
Additional capacity needs under high growth scenario				
5	Cherrywood T7/T8 LTR	Beyond 2033	2031	Beyond 2033
6	Seaton MTS LTR**	Beyond 2033	2032	Beyond 2033
7	Whitby TS T3/T4 LTR	Beyond 2033	2031	Beyond 2033
* If the transformers are replaced with higher LTR rating units as planned. ** Based on the LDC provided LTRs of 153MW (Summer) and 180MW (Winter) for Seaton MTS				

9. Conclusion and Recommendation

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

Table 8: Needs that Do Not Require Further Regional Coordination

No.	Need	Recommendation
1	Cherrywood TS 230kV Breaker Replacement	Replace 230kV Breaker in multi phases. Two phases are underway with currently planned in-service dates of 2033 and 2037 respectively.
2	Wilson TS T3/T4 Transformer Replacement	Replace Wilson TS T3/T4 transformers with "like for like" standard units with currently planned in service date of 2031.
3	Station capacity need at Whitby TS T1/T2 (44kV) due to load growth	Plan a new Transformer Station at North Whitby area, tapping on 230kV circuits of P15C and T28C. TWG agreed to proceed with local planning and no further regional coordination is required.

Table 9: Needs Requiring Further Regional Coordination

No.	Need
1	Transmission reinforcement at Oshawa-Clarington Sub-region area to accommodate large load connection requests and address potential load security issue
2	Station capacity need at Thornton TS T3/T4 due to load growth
3	Station capacity need at Wilson TS T7/T8 due to load growth
4	Station capacity need at Wilson TS T3/T4 due to load growth

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

- Elexicon Energy Inc.
- Oshawa PUC Networks Inc.
- Hydro One Networks Inc. (Distribution)

10. References

[1] Hydro One, RIP Report GTA East 2020 (hydroone.com) (issue February 29, 2020)

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

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

[4] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. August 2, 2023)

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

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

Table A.1: GTA East Region – Summer Non-coincident Normal Growth Net Load Forecast

Transformer Station		Summer LTR (MW)	Summer Non-Coincident NET Forecast (MW) - Normal Growth									
Name	DESN ID		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Cherrywood TS	T7/T8	167.2	143.4	145.8	148.3	150.8	153.5	156.2	159.3	162.8	163.6	163.1
Seaton MTS	T1/T2	N/A	4.1	10.1	17.0	25.6	36.9	47.0	56.8	66.7	76.7	86.7
Thornton TS	T3/T4	154.9	138.0	138.8	139.5	140.0	141.1	142.4	144.7	147.7	151.5	156.2
Whitby TS	T3/T4	182.4	158.2	159.5	161.0	162.2	163.6	165.1	167.1	169.6	173.4	178.1
Whitby TS	T1/T2 (27.6kV)	99.9	51.8	52.1	52.4	52.6	52.9	53.2	53.7	54.3	55.4	56.8
Whitby TS	T1/T2 (44kV)	100.8	46.1	50.6	55.2	59.9	64.7	69.8	75.5	80.8	87.6	95.4
Wilson TS	T7/T8	169.1	139.7	147.5	149.1	150.8	155.7	159.5	163.4	168.2	174.1	181.3
Wilson TS	T3/T4	130.2	144.6	161.2	176.0	187.7	198.8	213.6	232.2	254.6	290.5	311.6
Enfield TS	T5/T6	161.5	91.7	96.4	99.7	104.0	107.3	110.7	113.5	117.0	121.4	126.5
CTS A	N/A		40	40	40	40	40	40	40	40	40	40
CTS B			97	97	97	97	97	97	97	97	97	97
CTS C			40	40	40	40	40	40	40	40	40	40
Metrolinx TPSS			0	0	0	0	0	30	30	30	30	30

Note:
1. All LTRs are based on 35C for Summer and 10C for Winter.
2. Cherrywood TS DESN LTR is limited by outdoor AL tube, decreasing summer LTR by 8MW.
3. Wilson TS T3/T4 will be replaced by 2031 with higher rating of approximate 160MW for Summer and 180MW for Winter.

Table A.2: GTA East Region – Summer Coincident Normal Growth Net Load Forecast

Transformer Station		Summer LTR (MW)	Summer Non-Coincident NET Forecast (MW) - Normal Growth									
Name	DESN ID		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Cherrywood TS	T7/T8	167.2	136.2	138.5	140.9	143.3	145.8	148.4	151.4	154.7	155.5	154.9
Seaton MTS	T1/T2	N/A	2.7	6.8	11.4	17.1	24.8	31.5	38.1	44.7	51.4	58.1
Thornton TS	T3/T4	154.9	127.0	127.7	128.3	128.8	129.8	131.0	133.1	135.9	139.4	143.7
Whitby TS	T3/T4	182.4	150.3	151.5	152.9	154.0	155.5	156.9	158.8	161.1	164.7	169.2
Whitby TS	T1/T2 (27.6kV)	99.9	49.2	49.5	49.8	50.0	50.3	50.6	51.0	51.6	52.6	53.9
Whitby TS	T1/T2 (44kV)	100.8	43.8	48.1	52.4	56.9	61.4	66.3	71.7	76.8	83.2	90.7
Wilson TS	T7/T8	169.1	125.8	132.8	134.2	135.8	140.2	143.5	147.1	151.4	156.7	163.2
Wilson TS	T3/T4	130.2	130.2	145.1	158.4	168.9	178.9	192.2	209.0	229.1	261.4	280.5
Enfield TS	T5/T6	161.5	85.3	89.7	92.7	96.8	99.8	102.9	105.5	108.8	112.9	117.7
CTS A	N/A		30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
CTS B			46.6	46.6	46.6	46.6	46.6	46.6	46.6	46.6	46.6	46.6
CTS C			38.8	38.8	38.8	38.8	38.8	38.8	38.8	38.8	38.8	38.8
Metrolinx TPSS			0	0	0	0	0	30	30	30	30	30

Table A.3: GTA East Region – Winter Non-coincident Normal Growth Net Load Forecast

Transformer Station		Winter LTR (MW)	Winter Non-Coincident NET Forecast (MW) - Normal Growth									
Name	DESN ID		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Cherrywood TS	T7/T8	204.5	127.8	134.8	140.9	147.0	153.6	160.0	167.1	170.9	170.2	169.6
Seaton MTS	T1/T2	N/A	4.2	10.4	17.5	26.5	38.3	48.8	59.0	69.3	79.7	90.1
Thornton TS	T3/T4	175.5	154.5	157.8	160.3	162.6	165.6	168.9	173.3	178.0	183.7	190.4
Whitby TS	T3/T4	206.2	111.0	117.0	122.3	127.4	132.9	138.3	144.3	149.6	156.1	163.4
Whitby TS	T1/T2 (27.6kV)	112.5	30.9	32.6	34.1	35.5	37.1	38.6	40.3	41.8	43.7	45.8
Whitby TS	T1/T2 (44kV)	113.2	36.6	47.5	56.9	66.6	76.7	87.1	98.1	107.4	118.2	130.1
Wilson TS	T7/T8	184.3	114.9	123.6	126.5	129.6	135.3	140.2	145.1	150.2	156.3	163.4
Wilson TS	T3/T4	152.0	136.1	154.7	171.5	185.1	198.2	214.6	234.6	257.2	293.0	312.8
Enfield TS	T5/T6	183.4	94.7	101.0	105.7	111.3	116.0	120.7	124.7	129.3	134.7	140.9
CTS A	N/A		40	40	40	40	40	40	40	40	40	40
CTS B			97	97	97	97	97	97	97	97	97	97
CTS C			40	40	40	40	40	40	40	40	40	40
Metrolinx TPSS			0	0	0	0	0	30	30	30	30	30

Note:
1. All LTRs are based on 35C for Summer and 10C for Winter.
2. Cherrywood TS DESN LTR is limited by outdoor AL tube, decreasing summer LTR by 8MW.
3. Wilson TS T3/T4 will be replaced by 2031 with higher rating of approximate 160MW for Summer and 180MW for Winter.

Table A.4: GTA East Region – Winter Coincident Normal Growth Net Load Forecast

Transformer Station		Winter LTR (MW)	Winter Non-Coincident NET Forecast (MW) - Normal Growth									
Name	DESN ID		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Cherrywood TS	T7/T8	204.5	125.2	132.1	138.1	144.1	150.5	156.8	163.7	167.5	166.8	166.2
Seaton MTS	T1/T2	N/A	2.6	6.4	10.9	16.4	23.8	30.2	36.6	43.0	49.4	55.9
Thornton TS	T3/T4	175.5	140.6	143.6	145.9	148.0	150.7	153.7	157.7	162.0	167.2	173.3
Whitby TS	T3/T4	206.2	108.8	114.7	119.8	124.8	130.2	135.6	141.4	146.6	153.0	160.1
Whitby TS	T1/T2 (27.6kV)	112.5	30.2	31.9	33.4	34.8	36.3	37.8	39.5	41.0	42.8	44.8
Whitby TS	T1/T2 (44kV)	113.2	35.9	46.6	55.8	65.3	75.1	85.4	96.1	105.2	115.8	127.5
Wilson TS	T7/T8	184.3	108.0	116.2	118.9	121.8	127.2	131.8	136.4	141.2	146.9	153.6
Wilson TS	T3/T4	152.0	128.0	145.4	161.2	174.0	186.3	201.7	220.5	241.8	275.4	294.0
Enfield TS	T5/T6	183.4	87.1	92.9	97.2	102.4	106.7	111.1	114.7	118.9	123.9	129.6
CTS A	N/A		35.2	35.2	35.2	35.2	35.2	35.2	35.2	35.2	35.2	35.2
CTS B			86.3	86.3	86.3	86.3	86.3	86.3	86.3	86.3	86.3	86.3
CTS C			34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0
Metrolinx TPSS			0	0	0	0	0	30	30	30	30	30

Appendix B: Lists of Step-Down Transformer Stations

No.	Transformer Station		Voltage (kV)	Supply Circuits
1	Cherrywood TS	T7/T8	230/44	Cherrywood TS, DK Bus
2	Seaton MTS	N/A	230/27.6	C10A/T28C
3	Thornton TS	T3/T4	230/44	T24C/T26C
4	Whitby TS	T1/T2	230/27.6	T24C/T26C
			230/44	
		T3/T4	230/44	T23C/T29C
5	Wilson TS	T1/T2	230/44	T23C/T29C
		T3/T4	230/44	
6	Enfield TS	T5/T6	230/44	Clarington TS, PK Bus
7	CTS A	N/A	N/A	T24C/T26C
8	CTS B	N/A	N/A	T24C/T26C
9	CTS C	N/A	N/A	T24C/T26C

Appendix C: Lists of Transmission Circuits

No.	Circuit ID	From Station	To Station	Voltage (kV)
1	C10A	Cherrywood TS	Seaton MTS	230
2	T23C	Cherrywood TS	Clarington TS	230
3	T24C	Cherrywood TS	Clarington TS	230
4	T26C	Cherrywood TS	Clarington TS	230
5	T28C	Cherrywood TS	Clarington TS	230
6	T29C	Cherrywood TS	Clarington TS	230

Appendix D: List of LDC's

No.	Name of LDC	Connection Type (TX/DX)
1	Elexicon Energy Inc.	TX / DX
2	Oshawa PUC Networks Inc.	TX / DX
3	Hydro One Networks Inc. (Distribution)	TX

Appendix E: List of Municipalities in the region

No.	Name of Municipality
1	City of Pickering
2	Town of Ajax
3	Town of Whitby
4	City of Oshawa
5	Municipality of Clarington
6	Township of Scugog
7	Township of Uxbridge
8	Regional Municipality of Durham

Appendix F: Acronyms

Acronym	Description
CDM	Conservation and Demand Management
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating 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
KOP	Key Operating Point
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LP	Local Plan
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
MVGIS	Medium Voltage Gas Insulated Switchgear
NA	Needs Assessment
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
SS	Switching Station
TS	Transformer Station

Hydro One List of Station Capacity

This document lists the estimated thermal and short circuit capacities for generation connections to distribution system supplied by Hydro One stations in the province of Ontario. Capacity on those stations constrained by limits on the transmission system is shown as Transmission Constraints (TC). For more information, please refer to the glossary of terms at the end.

The Thermal Capacity represents the estimated total name plate amount of generation that can be connected to the distribution system supplied by the subject bus or station. The Short Circuit capacity represents the estimated total acceptable short circuit contribution by generation connected to the distribution system supplied by the subject bus or station. Estimated short circuit capacity is not applicable to all Hydro One stations and buses depending on their type and configuration. Estimated short circuit capacity for those stations is shown as “N/A”.

The listed capacity values in this document are estimates only and are based on the maximum permissible thermal and short circuit levels at Hydro One stations. This list does not reflect the capacity on Hydro One transmission network or indicate the condition of any Hydro One equipment. These estimated thermal and short circuit capacities are calculated without considering any existing or allocated generation capacity listed in Hydro One’s List of Applications.

Please refer to the online station capacity calculator to determine preliminary connection availability. Note that capacity allocation will be determined when the generator applies for a Connection Impact Assessment (CIA) excluding microFIT applicants.

This document will be updated regularly. For any questions, please contact the Dx Generation Connections Group at dxgenerationconnections@hydroone.com or 1-877-447-4412. An accompanying document titled “List of Applications” provides information regarding applications to connect at Hydro One-owned transformer stations. This document can be found on Hydro One’s website www.HydroOne.com under the Distribution-Connected Generators section. The potential capacity of a feeder is described in that section as well.

The list was updated on March 31st, 2025

Notes:

Station Name	Bus Name	Feeder Name	Voltage (kV)	Minimum Load (MW)	Short Circuit Capacity (MVA)	Thermal Capacity (MW)	Upstream TS	Upstream TS feeder
ABBEY DS	Total	F1,F2,F3	8.32	1.6	N/A	4.0	FRONTENAC TS	M1
ABERDEEN DS	Total	F1,F2,F3	8.32	1.3	N/A	3.7	HANOVER TS	H1E
ABERFOYLE DS	Total	F1,F2,F3,F4	8.32	1.2	N/A	4.8	PUSLINCH DS	F3
ABITIBI CANYON DS	Total	F1,F2	4.16	0.2	N/A	2.6	N/A	N/A
ACTON CORNERS DS	Total	F1,F2,F3	8.32	1.1	N/A	3.5	SMITHS FALLS TS	M23
ADAMS POINT DS	Total	F1	8.32	0.3	N/A	1.7	AWENDA DS	F2
ADDISON DS	Total	F1,F2,F3	8.32	1.0	N/A	3.4	BROCKVILLE TS	M6
AGIMAK DS	Total	F2	24.9	1.0	133.9	7.0		
AGINCOURT TS	B	M1,M3,M5,M7,M11	27.6	14.4	125.9	30.4		
AGINCOURT TS	Y	M2,M4,M6,M8,M10,M12	27.6	13.2	125.2	29.2		
AGINCOURT TS	Total	M2,M4,M6,M8,M10,M12,M1,M3,M5,M7,M11	27.6	27.4	N/A	Sum of Buses		
AGUASABON DS	T2	F1	12.5	0.5	N/A	3.4	N/A	N/A
AGUASABON DS	Total	F1,F2	12.5	1.3	N/A	2.7	N/A	N/A
AGUASABON DS	T3	F2	12.5	0.8	N/A	4.4	N/A	N/A
AILSA CRAIG DS	Total	F1,F2,F3	8.32	0.3	N/A	2.7	CENTRALIA TS	M2
ALBAN DS	Total	F1,F2,F3	12.5	0.8	N/A	2.3	MARTINDALE TS	M5
ALBION TS	BQ	For any information or inquiries please contact Hydro Ottawa	12.5	20.9	52.2	20.9		
ALBION TS	JY	For any information or inquiries please contact Hydro Ottawa	12.5	14.3	51.3	14.3		
ALBION TS	Total	For any information or inquiries please contact Hydro Ottawa	12.5	35.8	N/A	Sum of Buses		
Albuna PDS	Total	F1	8.32	0.9	N/A	2.1	Leamington TS	M4
ALEX EAST BOUNDARY DS	Total	F1,F2,F3	4.16	0.6	N/A	3.0	ST ISIDORE TS	M4
ALEX INDUSTRIAL DS	Total	F1,F2	4.16	0.7	N/A	3.1	ST ISIDORE TS	M4
ALEX KENYON WEST DS	Total	F1	4.16	0.3	N/A	1.2	ST ISIDORE TS	M4
ALEX MARGARET DS	Total	F1,F2	4.16	0.3	N/A	1.8	ST ISIDORE TS	M4
ALEX WEST BOUNDARY DS	Total	F1,F2	4.16	0.5	N/A	2.9	ST ISIDORE TS	M4
ALEXANDER DS	Total	F1,F2,F3,F4	27.6	7.1	N/A	15.1	SOUTH MARCH TS	M5
ALEXANDER DS	T1	F1,F3	27.6	3.3	N/A	11.3	SOUTH MARCH TS	M5
ALEXANDER DS	T2	F2,F4	27.6	3.8	N/A	11.8	SOUTH MARCH TS	M5
ALFRED DS	Total	F1,F2,F3	8.32	1.8	N/A	5.0	LONGUEUIL TS	M26
ALLANBURG TS	BY	M6, M7, M8	27.6	9.8	63.5	24.8		
ALLISTON TS	BY	M1, M2, M3, M4, M5, M6	44	21.6	460.9	61.6		
ALLISTON TS	T2	M11, M12	44	8.1	916.5	48.1		
ALMA DS	Total	F1,F2,F3	8.32	0.8	N/A	3.2	FERGUS TS	M1
ALMONTE TS	J	M25	44	1.8	980.7	41.8		
ALMONTE TS	Total	M25,M26,M28	44	9.5	N/A	49.5		
ALMONTE TS	Q	M26, M28	44	7.7	982.8	47.7		
ALVINSTON DS	Total	F1,F2,F3	8.32	0.7	N/A	3.1	WANSTEAD TS	M1
AMHERSTVIEW DS	Total	F1,F2,F3	8.32	1.1	N/A	3.5	KINGSTON GARDINER TS DESN1	M14
AMULREE DS	Total	F1,F2	8.32	0.6	N/A	3.0	STRATFORD TS	M1
ANCASTER WEST DS	Total	F1,F2,F3	8.32	1.1	N/A	3.5	DUNDAS TS	M6
ANDERDON DS	Total	F1,F2	8.32	0.5	N/A	1.4	MALDEN TS	M8
ANDREWS TS	T4	For any information or inquiries please contact Hydro One Sault St Marie Inc	24.9	0.0	699.2	2.4		
ANGUS DS	Total	F1,F2	8.32	1.5	N/A	3.9	ALLISTON TS	M5
ANJIGAMI TS	T1	Anjigami1	44	0.0	944.7	25.6		
APPIN DS	Total	F1,F2	8.32	0.6	N/A	2.4	LONGWOOD TS	M26
APSLEY WEST DS	Total	F1,F2,F3	12.5	1.1	N/A	4.0	HAVELOCK TS	M1
ARDOCH DS	Total	F1, F2	12.5	0.5	50.8	8.5		
ARDTREA DS	Total	F1,F2,F3	8.32	1.5	N/A	3.9	ORILLIA TS	M2
ARGYLE DS	Total	F1,F2,F3	8.32	1.0	N/A	3.4	BEAVERTON TS	M23
ARMITAGE TS DESN1	JQ	M11, M12, M13, M14, M21, M22, M23, M24	44	59.6	357.7	119.6		
ARMITAGE TS DESN2	EY	M31, M32, M33, M34, M41, M42, M43, M44	44	60.4	331.2	120.4		
ARMOW DS	Total	F1,F2,F3	8.32	1.2	N/A	3.6	DOUGLAS POINT TS	M6
ARNPRI AIRPORT DS	Total	F1	4.16	0.1	N/A	1.1	ARNPRIOR TS	M1
ARNPRI ELGIN DS	Total	F1,F2,F3,F4	4.16	0.7	N/A	1.6	ARNPRIOR TS	M1
ARNPRI MADAWASKA DS	Total	F1,F3	4.16	0.6	N/A	1.5	ARNPRIOR TS	M1
ARNPRI MCLACHLIN DS	Total	F7,F8,F9	4.16	0.3	N/A	1.3	ARNPRIOR TS	M1
ARNPRI REID ST DS	Total	F1,F2	4.16	0.6	N/A	3.0	ARNPRIOR TS	M1
ARNPRI ZERVOS DS	Total	F1,F2	4.16	0.5	N/A	5.3	ARNPRIOR TS	M1

Station Name	Bus Name	Feeder Name	Voltage (kV)	Minimum Load (MW)	Short Circuit Capacity (MVA)	Thermal Capacity (MW)	Upstream TS	Upstream TS feeder
ARNPRIOR TS	BJ	M1, M2	44	15.4	885.9	35.4		
ARVA DS	Total	F1,F2,F3	8.32	0.8	N/A	3.2	CLARKE TS	M2
ASPDIN DS	Total	F1,F2,F3	12.5	2.3	N/A	5.0	MUSKOKA TS	M9
ATHENS DS	Total	F1,F2,F3	8.32	1.1	N/A	3.5	BROCKVILLE TS	M6
ATWOOD SOUTH DS	Total	F1,F2,F3	8.32	1.6	N/A	4.0	PALMERSTON TS	M1
AUBURN DS	Total	F1,F2,F3	8.32	0.7	N/A	3.1	GODERICH TS	M10
AVONMORE DS	Total	F1,F2,F3	8.32	1.2	N/A	3.6	ST LAWRENCE TS	M26
AWENDA DS	Total	F1,F2	27.6	2.3	N/A	5.0	WAUBAUSHENE TS	M7
AYLMER TS	JQ	M1, M2, M3, M4	27.6	9.3	399.6	29.3		
AZILDA DS	Total	F1,F2,F3	12.5	1.3	N/A	4.2	CLARABELLE TS	M8
BAILEYS CORNER DS	Total	F1,F2	12.5	1.1	N/A	4.0	MARTINDALE TS	M6
BAINSVILLE DS	Total	F1,F2	8.32	1.0	N/A	3.4	ST LAWRENCE TS	M25
BALA RIVER DS	Total	F1,F2,F3	12.5	1.4	N/A	4.3	MUSKOKA TS	M1
BALLANTRAE DS	Total	F1,F2,F3,F4	8.32	1.6	N/A	4.0	ARMITAGE TS DESN2	M32
BALLANTRAE DS	T2	F1,F4	8.32	1.0	N/A	3.4	ARMITAGE TS DESN2	M32
BALLANTRAE DS	T1	F2,F3	8.32	0.7	N/A	3.1	ARMITAGE TS DESN2	M32
BALLYDUFF DS	Total	F1,F2,F3	8.32	0.9	N/A	3.3	ENFIELD TS DESN1	M4
BALMER DS	Total	F1,F2	24.9	1.5	N/A	4.4	RED LAKE TS	M4
BALTIMORE DS	T1	F1,F2,F3	8.32	0.7	N/A	3.1	PORT HOPE TS DESN1	M17
BALTIMORE DS	Total	F1,F2,F3,F4	8.32	1.0	N/A	2.4	PORT HOPE TS DESN1	M17
BALTIMORE DS	T2	F4	8.32	0.3	N/A	1.7	PORT HOPE TS DESN1	M17
BANCROFT DS #2	Total	F1,F2,F3,F4	12.5	1.3	N/A	4.2	WALLACE TS	M1
BANCROFT HERITAGE DS	Total	F1,F2,F3,F4	12.5	1.2	N/A	5.0	WALLACE TS	M1
BANDA DS	Total	F1,F2,F3	8.32	1.4	N/A	3.8	STAYNER TS	M2
BARRIE TS	BY	M1, M2, M3, M4, M5, M6, M7	44	24.5	362.7	68.5		
BARRYS BAY DS #1	Total	F1,F2	4.16	0.5	N/A	1.5	WALLACE TS	M6
BARRYS BAY DS #2	Total	F1,F2,F3	12.5	1.2	N/A	4.1	WALLACE TS	M6
BARWICK DS	Total	F1,F2	12.5	0.6	N/A	4.2	BARWICK TS	M2
BARWICK TS	BY	M1,M2	44	5.0	1,240.7	25.2		
BASIN TS	A5A6	For any information or inquiries please contact Toronto Hydro	13.8	10.7	62.3	10.7		
BASIN TS	A7A8	For any information or inquiries please contact Toronto Hydro	13.8	9.5	62.3	9.5		
BASIN TS	Total	For any information or inquiries please contact Toronto Hydro	13.8	21.5	N/A	Sum of Buses		
BASS LAKE DS	Total	F1,F2,F3	8.32	1.1	N/A	3.5	ORILLIA TS	M7
BATH DS	Total	F1,F2,F3	8.32	1.4	N/A	3.8	NAPANEE TS	M3
BATHURST TS DESN1	Y	M1,M2,M3,M7,M9	27.6	11.8	109.5	36.8		
BATHURST TS DESN1	Total	M1,M2,M3,M7,M9,M10,M4,M5, M6, M8	27.6	26.6	N/A	Sum of Buses		
BATHURST TS DESN1	B	M10,M4,M5, M6, M8	27.6	14.9	95.8	39.9		
BATHURST TS DESN2	Q	M23,M25,M27,M31	27.6	12.3	97.1	12.3		
BATHURST TS DESN2	Total	M23,M25,M27,M31,M24,M26,M30,M32	27.6	24.0	N/A	Sum of Buses		
BATHURST TS DESN2	J	M24,M26,M30, M32	27.6	17.7	96.5	17.7		
BATTERSEA DS	B1	F1,F2	12.5	1.1	46.2	7.1		
BATTERSEA DS	Total	F1,F2,F3	12.5	2.0	46.7	8.0		
BATTERSEA DS	B2	F3	12.5	1.0	42.2	7.7		
BAXTER DS	Total	F1,F2,F3,F4	8.32	1.3	N/A	5.0	ALLISTON TS	M4
BAYFIELD DS	Total	F1,F2,F3	8.32	1.1	N/A	3.5	GODERICH TS	M9
BAYRIDGE DS	T1	F1,F2,F3	8.32	0.6	N/A	3.0	KINGSTON GARDINER TS DESN1	M15
BAYRIDGE DS	Total	F1,F2,F3,F4,F5,F6	8.32	1.4	N/A	3.8	KINGSTON GARDINER TS DESN1	M15
BAYRIDGE DS	T2	F4,F5,F6	8.32	0.8	N/A	4.4	KINGSTON GARDINER TS DESN1	M15
BAYSIDE DS	Total	F1,F2,F3	8.32	1.3	N/A	4.9	BELLEVILLE TS	M7
BAYSVILLE DS	Total	F1,F2,F3	12.5	1.2	N/A	4.1	MUSKOKA TS	M3
BEACH TS DESN1	B1B2	M11, M12, M13, M14, M21, M22, M23, M24	13.8	0.4	134.3	29.4		
BEACH TS DESN1	Y1Y2	M51,M52,M53,M54,M61,M62,M63,M64	13.8	6.7	137.0	6.7		
BEACH TS DESN2	Q1Q2	M41,M42,M43, M44, M31,M32,M33,M34	13.8	8.2	40.6	8.2		
BEACH TS DESN2	J1J2	M71,M72,M73,M74,M81,M82,M83,M84	13.8	9.2	47.8	38.2		
BEACHBURG DS	Total	F1,F2,F3	12.5	1.9	N/A	TC	COBDEN TS	M2
BEAMSVILLE TS	BY	M1, M2, M3, M4	27.6	12.4	374.7	32.4		
BEARDMORE DS #2	Total	F1,F2,F3,F4	24.9	0.4	179.6	7.1		
BEAUMARIS DS	Total	F1,F2	12.5	1.8	N/A	4.7	MUSKOKA TS	M7

Station Name	Bus Name	Feeder Name	Voltage (kV)	Minimum Load (MW)	Short Circuit Capacity (MVA)	Thermal Capacity (MW)	Upstream TS	Upstream TS feeder
BEAVERTON TS	JQ	M23, M24, M25, M26, M27, M28, M29, M30	44	16.6	503.1	76.6		
BECKWITH DS	Total	F1,F2,F3	27.6	1.4	N/A	5.0	ALMONTE TS	M28
BEECHWOOD DS	Total	F1,F2,F3	8.32	1.3	N/A	3.7	NAPANEE TS	M1
BELLE RIVER DS #1	Total	F1,F2	8	0.5	N/A	2.2	BELLE RIVER TS	M2
BELLE RIVER TS	BQ	M1, M2, M3, M4	27.6	6.8	212.1	26.9		
BELLEVILLE DS #2	Total	F1,F2	8.32	1.4	N/A	3.8	BELLEVILLE TS	M2
BELLEVILLE TS	BY	M1, M2, M3, M4, M5, M6, M7, M8, M9, M10	44	57.0	102.7	117.0		
BELMONT DS	Total	F1,F2	8.32	1.0	N/A	2.7	BUCHANAN TS	M21
BENSFORT BRIDGE DS	Total	F1,F2,F3	8.32	1.7	N/A	4.1	OTONABEE TS DESN2	M28
BERKELEY DS	Total	F1,F2	8.32	0.9	N/A	1.8	OWEN SOUND TS	M26
BERMONDSEY TS DESN1	J	M23,M25,M27	27.6	0.6	113.7	0.6		
BERMONDSEY TS DESN1	Total	M23,M25,M27,M24,M26,M28	27.6	5.7	N/A	Sum of Buses		
BERMONDSEY TS DESN1	Q	M24,M26,M28	27.6	5.1	113.4	5.1		
BERMONDSEY TS DESN2	B	M1,M3,M5,M7,M9,M11	27.6	11.1	120.2	11.1		
BERMONDSEY TS DESN2	Total	M1,M3,M5,M7,M9,M11,M2,M4,M6,M8,M10,M12	27.6	31.7	N/A	Sum of Buses		
BERMONDSEY TS DESN2	Y	M2,M4,M6,M8,M10,M12	27.6	20.6	95.1	20.6		
BERWICK DS	Total	F1,F2	8.32	1.0	N/A	TC	CHESTERVILLE TS	M4
BEST DS	Total	F1,F2,F3	8.32	1.1	N/A	3.5	DOBBIN TS	M2
BETHANY DS	Total	F1,F2,F3	8.32	1.0	N/A	3.4	DOBBIN TS	M1
BICKFORD DS	Total	F1,F2,F3	8.32	0.7	N/A	3.1	LAMBTON TS	M3
BIG CHUTE DS	Total	F1,F2	12.5	1.2	N/A	4.0	WAUBAUSHENE TS	M1
BILBERRY CREEK TS	BY	M1, M2, M3, M4, M5, M6	27.6	19.4	176.3	59.4		
BIRCH ISLAND DS	Total	F1,F2	12.5	0.6	N/A	3.5	MANITOULIN TS	M26
BIRCH TS	BY	M1, M2, M3, M4, M5, M6, M7, M8	24.9	25.1	216.2	65.1		
BIRMINGHAM TS DESN1	JQ	M1,M2,M3,M4,M5,M6,M7,M8	13.8	3.1	83.3	3.1		
BIRMINGHAM TS DESN1	Total	M1,M2,M3,M4,M5,M6,M7,M8,M21,M22	13.8	5.0	N/A	Sum of Buses		
BIRMINGHAM TS DESN1	BY	M21,M22	13.8	1.9	83.0	1.9		
BIRMINGHAM TS DESN2	EZ	M10,M11,M12,M13,M14	13.8	0.0	62.3	15.0		
BIRMINGHAM TS DESN2	Total	M10,M11,M12,M13,M14,M71,M81	13.8	22.2	N/A	Sum of Buses		
BIRMINGHAM TS DESN2	DK	M71,M81	13.8	22.2	0.0	37.2		
BIRR DS	Total	F1,F2,F3	8.32	1.0	N/A	3.4	CLARKE TS	M2
BISMARK DS	Total	F1,F2,F3	8.32	1.1	N/A	4.7	BEAMSVILLE TS	M2
BLACK CORNERS DS	Total	F1,F3	8.32	1.4	N/A	3.8	ALMONTE TS	M28
BLACKSTOCK DS	Total	F1,F2,F3	8.32	0.6	N/A	3.0	ENFIELD TS DESN1	M4
BLENHEIM DS	Total	F1,F2	8.32	0.9	N/A	2.6	KENT TS DESN1	M18
BLIND RIVER DS	Total	F1,F3	4.16	0.3	N/A	1.7	STRIKER DS	F1
BLOOMSBURG DS	QJ	M1, M2, M3	27.6	11.0	852.0	31.0		
BLUE CHURCH DS	Total	F1,F2,F3	8.32	0.9	N/A	3.3	BROCKVILLE TS	B1R
BLUE MOUNTAIN DS	Total	F1,F2	27.6	1.4	N/A	5.0	STAYNER TS	M6
BLYTH DS	T1	F1	8.32	0.4	N/A	2.1	CONSTANCE DS	F1
BLYTH DS	Total	F1,F3,F4	8.32	0.9	N/A	2.4	CONSTANCE DS	F1
BLYTH DS	T2	F3,F4	8.32	0.5	N/A	2.0	CONSTANCE DS	F1
BLYTHESWOOD DS	Total	F1,F2	8.32	1.2	N/A	3.6	LEAMINGTON TS DESN1	M21
BOBCAYGEON ANNE DS	Total	F1,F2,F3	4.16	0.7	N/A	3.1	LINDSAY TS	M6
BOBCAYGEON BOYD DS	Total	F1,F2,F3	4.16	0.3	N/A	2.7	LINDSAY TS	M6
BOBCAYGEON DUKE DS	Total	F1,F2,F3	4.16	0.5	N/A	4.1	LINDSAY TS	M6
BOBCAYGEON WEST DS	Total	F1,F2,F3	12.5	1.1	N/A	4.0	LINDSAY TS	M7
BOLSOVER DS	Total	F1,F2	8.32	0.8	N/A	4.4	BEAVERTON TS	M24
BOLTON HARDWICK DS	Total	M1,M2,M3	8.32	1.2	N/A	5.0	KLEINBURG TS 44 KV	M25
BOLTON KING DS	Total	F1,F2,F3,F4	8.32	1.3	N/A	5.0	KLEINBURG TS 44 KV	M25
BONDHEAD DS	Total	F1,F2,F3	8.32	1.2	N/A	3.6	HOLLAND TS	M4
BONFIELD DS	T1	F2	24.9	1.2	N/A	4.0	TROUT LAKE TS	M8
BONFIELD DS	Total	F2,F3	24.9	1.6	N/A	4.4	TROUT LAKE TS	M8
BONFIELD DS	T2	F3	24.9	0.4	N/A	3.3	TROUT LAKE TS	M8
BOSTON MILLS DS	Total	F1,F3	12.5	1.0	N/A	3.9	ORANGEVILLE TS DESN2	M3
BOTANY DS	Total	F1,F2,F3	8.32	0.6	N/A	3.0	KENT TS DESN1	M15
BOTHWELL CORNERS DS	Total	F1,F2,F3	8.32	1.5	N/A	3.9	OWEN SOUND TS	M26
BOTHWELL DS #2	Total	F1,F2,F3	8.32	0.6	N/A	2.4	KENT TS DESN2	M24

Station Name	Bus Name	Feeder Name	Voltage (kV)	Minimum Load (MW)	Short Circuit Capacity (MVA)	Thermal Capacity (MW)	Upstream TS	Upstream TS feeder
BOURGET DS	Total	F1,F2,F3	8.32	1.4	N/A	3.8	ST ISIDORE TS	M1
BOWEN CORNERS DS	Total	F1,F2,F3	12.5	0.6	N/A	2.1	WALLACE TS	M1
BOWMANTON DS	Total	F1,F2,F3	8.32	1.1	N/A	3.5	PORT HOPE TS DESN1	M15
BRACEBRIDGE TS	T1	M20, M21	44	10.0	1,005.4	49.8		
BRADFORD DS	Total	F1,F2,F3	8.32	1.0	N/A	3.4	HOLLAND TS	M3
BRAMALEA TS DESN1	B	M1,M3,M5,M7,M9,M11	27.6	11.2	37.9	27.2		
BRAMALEA TS DESN1	Total	M1,M3,M5,M7,M9,M11,M2,M4,M6,M8,M10,M12	27.6	27.4	N/A	Sum of Buses		
BRAMALEA TS DESN1	Y	M2,M4,M6,M8,M10,M12	27.6	16.2	41.2	32.2		
BRAMALEA TS DESN2	JQ	M23,M25,M27,M29,M24,M26,M28	44	11.6	316.8	51.6		
BRAMALEA TS DESN3	EZ	M44,M46,M48,M50,M43,M45,M47	44	53.8	276.9	113.8		
BRANT TS	BY	M11, M12, M13, M14, M21, M22, M23, M24	27.6	21.0	183.4	61.0		
BRANTFORD TS	Y	M21,M23,M25,M27,M29	27.6	21.0	69.7	37.0		
BRANTFORD TS	Total	M21,M23,M25,M27,M29,M22,M24,M26,M28,M30	27.6	40.5	N/A	Sum of Buses		
BRANTFORD TS	Z	M22,M24,M26,M28,M30	27.6	19.5	73.1	35.5		
BRIDGENORTH DS	Total	F1,F2,F3	8.32	0.8	N/A	3.2	DOBBIN DS	F2
BRIDGMAN TS DESN1	A1A2	For any information or inquiries please contact Toronto Hydro	13.8	12.4	62.6	12.4		
BRIDGMAN TS DESN2	LA1&LA2	For any information or inquiries please contact Toronto Hydro	13.8	17.5	69.8	17.5		
BRIDGMAN TS DESN3	LA5&LA6	For any information or inquiries please contact Toronto Hydro	13.8	7.4	63.3	7.4		
BRIDGMAN TS DESN4	LA7&LA8	For any information or inquiries please contact Toronto Hydro	13.8	18.8	71.4	18.8		
BRIGDEN DS	Total	F1,F2,F3	8.32	0.6	N/A	2.3	WANSTEAD TS	M4
BRIGHTON DIVISION DS	Total	F1,F2,F3	4.16	0.6	N/A	2.0	SIDNEY TS	M7
BRIGHTON DS #2	Total	F1,F2	8.32	0.7	N/A	1.7	SIDNEY TS	M7
BRIGHTON PINNACLE DS	Total	F1,F2,F3	4.16	0.6	N/A	3.0	SIDNEY TS	M7
BRIGHTON SHARPE DS	Total	F1,F2,F3	4.16	0.6	N/A	3.0	SIDNEY TS	M7
BROCKS BEACH DS	Total	F1,F2	8.32	1.0	N/A	3.4	STAYNER TS	M8
BROCKVIL CEDAR DS	Total	F31,F32,F33	4.16	0.6	N/A	3.8	BROCKVILLE TS	M3
BROCKVIL CENTENNI DS	Total	F81,F82,F83,F84	8.32	1.3	N/A	9.3	BROCKVILLE TS	M7
BROCKVIL GEORGE DS	Total	F71,F72,F73,F74	4.16	1.2	N/A	7.2	BROCKVILLE TS	M3
BROCKVIL PARK DS	Total	F21,F22,F23,F24	4.16	0.5	N/A	1.4	BROCKVILLE TS	M3
BROCKVIL PARKDALE DS	Total	F61,F62,F63	8.32	1.5	N/A	5.0	BROCKVILLE TS	M1
BROCKVIL SCHOFLD DS	Total	F41,F42,F43	4.16	0.9	N/A	3.3	BROCKVILLE TS	M3
BROCKVIL WATER DS	T3	F1,F2	27.6	0.0	N/A	4.8	BROCKVILLE TS	M3
BROCKVIL WATER DS	T1	F11,F12,F13,F14	4.16	0.6	N/A	3.8	BROCKVILLE TS	M3
BROCKVILLE TS	BQ	M1, M2, M3, M4, M5, M6, M7,B1R	44	38.6	374.0	98.6		
BRONTE TS	Q	M23,M24,M25,M26,M27,M28	27.6	14.0	421.4	54.0		
BRONTE TS DESN1	EZ	M1,M2,M3,M4,M5,M6,M7,M8	27.6	19.2	120.9	63.9		
BROOKHOLM DS	Total	F1,F2,F3	8.32	1.3	N/A	3.7	OWEN SOUND TS	M23
BROOKSIDE DS	Total	F1,F2,F3	8.32	0.5	N/A	2.9	PORT HOPE TS DESN1	M17
BROWN HILL DS	Total	F1,F2,F3	8.32	1.2	N/A	5.0	BROWN HILL TS	M5
BROWN HILL TS	BY	M1, M2, M3, M4, M5, M11, M12	44	22.5	451.8	82.5		
BRUNELLE DS	Total	F1,F2,F3	8.32	0.8	N/A	3.5	WAUBAUSHENE TS	M3
BRUSSELS DS	Total	F1,F2,F3	8.32	1.7	N/A	5.0	SEAFORTH TS	M4
BUCHANAN TS	B	M21,M23,M25,M27,M29,M37	27.6	24.4	102.9	49.4		
BUCHANAN TS	Total	M21,M23,M25,M27,M29,M37,M22,M24,M26,M28,M30,M38	27.6	38.5	N/A	Sum of Buses		
BUCHANAN TS	Y	M22,M24,M26,M28,M30,M38	27.6	35.9	103.8	60.9		
BUCKHORN DS	Total	F1,F2,F3,F4	12.5	1.8	N/A	4.7	OTONABEE TS DESN2	M27
BUCKHORN DS	T1	F1,F3	12.5	1.0	N/A	3.8	OTONABEE TS DESN2	M27
BUCKHORN DS	T2	F2,F4	12.5	0.8	N/A	3.7	OTONABEE TS DESN2	M27
BUNTING TS	J1J2	M55,M56,M57,M61,M62,M63	13.8	5.0	112.5	5.0		
BUNTING TS	Total	M55,M56,M57,M61,M62,M63,M75,M76,M77,M81,M82	13.8	14.6	N/A	Sum of Buses		
BUNTING TS	Q1Q2	M75,M76,M77,M81,M82	13.8	7.6	112.0	7.6		
BURFORD DS	Total	F1,F2	8.32	0.4	N/A	2.2	BRANT TS	M21
BURKS FALLS SOUTH DS	Total	F1,F2,F3	12.5	1.2	N/A	5.0	MUSKOKA TS	M2
BURLEIGH DS	B	F1,F2	12.5	0.7	183.5	6.7		
BURLINGTON TS	BY	M1,M2,M3,M4,M5,M6	27.6	21.8	86.8	46.8		
BURLINGTON TS	Total	M1,M2,M3,M4,M5,M6,M31,M32,M33,M34,M35,M36	27.6	46.2	N/A	Sum of Buses		
BURLINGTON TS	JQ	M31,M32,M33,M34,M35,M36	27.6	22.7	87.7	47.7		
BURNHAM DS	Total	F1,F2,F3	8.32	1.5	N/A	3.9	OTONABEE TS DESN2	M28

Station Name	Bus Name	Feeder Name	Voltage (kV)	Minimum Load (MW)	Short Circuit Capacity (MVA)	Thermal Capacity (MW)	Upstream TS	Upstream TS feeder
BUTTERNUT DS	Total	F1,F2,F3	27.6	2.5	N/A	10.5	FRONTENAC TS	M3
BUTTONVILLE TS	Q	M1,M3,M5,M7,M9,M11	27.6	22.8	109.1	38.8		
BUTTONVILLE TS	Total	M1,M3,M5,M7,M9,M11,M2,M4,M6,M8,M10,M12	27.6	46.4	N/A	Sum of Buses		
BUTTONVILLE TS	Z	M2,M4,M6,M8,M10,M12	27.6	18.0	108.9	34.0		
CACHE BAY DS	Total	F1,F2,F3	12.5	0.8	N/A	3.6	CRYSTAL FALLS TS	M1
CAINTOWN DS	Total	F1,F2,F3	8.32	0.6	N/A	3.0	BROCKVILLE TS	M2
CALABOGIE DS	Total	F1,F2	12.5	1.2	N/A	2.6	STEWARTVILLE TS	M1
CALEDON DS	Total	F1,F2,F3	12.5	1.8	N/A	4.7	ORANGEVILLE TS DESN2	M3
CALEDONIA ARGYLE DS	Total	F1,F2	8.32	0.5	N/A	1.9	CALEDONIA TS	M6
CALEDONIA TS	BY	M3, M4, M5, M6	27.6	15.1	154.8	55.1		
CALLANDER DS	Total	F1,F2	12.5	1.7	N/A	4.6	TROUT LAKE TS	M3
CALSTOCK DS	Total	F1,F2	24.9	0.8	445.2	4.9		
CAMERON DS	Total	F1,F3	12.5	1.9	N/A	4.7	LINDSAY TS	M8
CAMILLA DS	Total	F1,F2,F3	12.5	1.5	N/A	4.3	ORANGEVILLE TS DESN2	M4
CAMLACHIE DS	Total	F1,F2	8.32	0.8	N/A	3.2	FOREST JURA DS	F3
CAMPBELFD ALMA DS	Total	F1,F2	4.16	0.6	N/A	2.0	HAVELOCK TS	M4
CAMPBELFD FRONT N DS	Total	F1,F2	4.16	0.6	N/A	3.0	HAVELOCK TS	M4
CAMPBELFD INDUST DS	T1	F1	4.16	0.2	N/A	1.7	HAVELOCK TS	M4
CAMPBELFD INDUST DS	Total	F1,F2	4.16	0.3	N/A	1.7	HAVELOCK TS	M4
CAMPBELFD INDUST DS	T2	F2	4.16	0.1	N/A	1.5	HAVELOCK TS	M4
CAMPBELFD KING DS	Total	F1,F2	4.16	0.3	N/A	1.8	HAVELOCK TS	M4
CAMPBELL TS DESN1	BY	M11,M12,M13,M14,M21,M22,M23,M24	13.8	13.4	144.0	61.4		
CAMPBELL TS DESN1	Total	M11,M12,M13,M14,M21,M22,M23,M24,M31,M32,M33,M34,M41,M42,M43,M44	13.8	28.7	N/A	Sum of Buses		
CAMPBELL TS DESN1	JQ	M31,M32,M33,M34,M41,M42,M43,M44	13.8	15.3	133.1	63.3		
CAMPBELL TS DESN2	EZ	M51,M52,M53,M54,M61,M62,M63,M64	13.8	15.0	54.4	15.0		
CAMPBELLCROFT DS	Total	F1,F2,F3	8.32	1.4	N/A	3.8	PORT HOPE TS DESN1	M15
CANFIELD DS	Total	F1,F2,F3	8.32	0.7	N/A	3.1	CALEDONIA TS	M4
CARDIFF TS	BQ	M1, M2, M3, M4, M5, M6, M7, M8, M9, M10	27.6	30.1	19.9	70.1		
CARLAW TS	A6A7	For any information or inquiries please contact Toronto Hydro	13.8	6.1	100.5	6.1		
CARLAW TS	A8A9	For any information or inquiries please contact Toronto Hydro	13.8	13.0	100.6	13.0		
CARLAW TS	Total	For any information or inquiries please contact Toronto Hydro	13.8	19.4	N/A	Sum of Buses		
CARLETON PLACE DS #2	Total	F1,F2	8.32	1.0	N/A	3.4	ALMONTE TS	M26
CARLEY DS	Total	F1,F2,F3	8.32	1.3	N/A	3.7	ORILLIA TS	M3
CARLING DS	Total	F1,F3	12.5	0.8	N/A	2.3	PARRY SOUND TS	M1
CARLING TS	KY	For any information or inquiries please contact Hydro Ottawa	12.5	14.8	95.4	34.8		
CARLING TS	QZ	For any information or inquiries please contact Hydro Ottawa	12.5	13.5	95.8	33.5		
CARLING TS	Total	For any information or inquiries please contact Hydro Ottawa	12.5	28.3	N/A	Sum of Buses		
CARLISLE DS	Total	F1,F2,F3	8.32	1.1	N/A	3.5	DUNDAS TS	M5
CARLT PL BRIDGE DS	Total	F1,F2,F4	4.16	0.6	N/A	3.3	ALMONTE TS	M26
CARLT PL EDMUND DS	Total	F1,F2,F3,F5	4.16	0.4	N/A	2.8	ALMONTE TS	M26
CARLT PL FRANCIS DS	Total	F1,F2,F3,F4,F5	4.16	0.8	N/A	3.2	ALMONTE TS	M28
CARLT PL NAPOLEON DS	Total	F2,F3,F4,F5,F6,F7,F8	4.16	1.0	N/A	4.6	ALMONTE TS	M28
CARLTON TS DESN2	BY	M12,M20,M25,M11,M10,M21	13.8	8.6	85.4	23.6		
CARLTON TS DESN2	Total	M12,M20,M25,M11,M10,M21, M17,M18, M7	13.8	20.4	N/A	Sum of Buses		
CARLTON TS DESN2	HK	M7,M17,M18	13.8	11.8	77.2	26.8		
CARP DS	Total	F1,F2,F3,F4	12.5	1.4	N/A	4.3	SOUTH MARCH TS	M6
CARP DS	T1	F1,F3	12.5	1.0	N/A	3.9	SOUTH MARCH TS	M6
CARP DS	T2	F2,F4	12.5	0.4	N/A	3.3	SOUTH MARCH TS	M6
CARRYING PLACE DS	Total	F1,F2,F3	8.32	1.3	N/A	3.7	PICTON TS	M5
CASS BRIDGE DS	Total	F1,F2,F3	8.32	1.6	N/A	TC	MORRISBURG TS	M26
CASSELMAN DS	Total	F1,F2,F3	8.32	0.4	N/A	2.8	ST ISIDORE TS	M2
CASTLETON DS	Total	F1,F2,F3	8.32	1.0	N/A	3.4	PORT HOPE TS DESN1	M16
CATARACT DS	Total	F1,F2,F3	12.5	0.7	N/A	3.5	ORANGEVILLE TS DESN2	M46
CATARAQUI DS	Total	F1,F2,F3	8.32	1.7	N/A	5.0	KINGSTON GARDINER TS DESN1	M13
CAVAN DS	Total	F1,F2,F3	8.32	0.9	N/A	3.3	DOBBIN TS	M5
CECIL TS DESN1	A1A2	For any information or inquiries please contact Toronto Hydro	13.8	17.5	47.6	17.5		
CECIL TS DESN1	A3A4	For any information or inquiries please contact Toronto Hydro	13.8	12.9	47.5	12.9		
CECIL TS DESN1	Total	For any information or inquiries please contact Toronto Hydro	13.8	30.4	N/A	Sum of Buses		

Station Name	Bus Name	Feeder Name	Voltage (kV)	Minimum Load (MW)	Short Circuit Capacity (MVA)	Thermal Capacity (MW)	Upstream TS	Upstream TS feeder
CECIL TS DESN2	A5A6	For any information or inquiries please contact Toronto Hydro	13.8	15.8	40.8	15.8		
CECIL TS DESN2	A7A8	For any information or inquiries please contact Toronto Hydro	13.8	22.6	41.7	22.6		
CECIL TS DESN2	Total	For any information or inquiries please contact Toronto Hydro	13.8	38.3	N/A	Sum of Buses		
CEDAR MILLS DS	T1	F1	27.6	3.3	N/A	11.3	KLEINBURG TS 44 KV	M27
CEDAR MILLS DS	Total	F1,F2,F3	27.6	6.6	N/A	14.6	KLEINBURG TS 44 KV	M27
CEDAR MILLS DS	T2	F2,F3	27.6	3.3	N/A	11.3	KLEINBURG TS 44 KV	M27
CEDAR TS DESN1	BY	M11,M12,M13,M14, M21,M22,M23,M24	13.8	17.3	71.1	17.3		
CEDAR TS DESN1	Total	M11,M12,M13,M14, M21,M22,M23,M24,M61,M62,M63,M64	13.8	23.7	N/A	Sum of Buses		
CEDAR TS DESN1	EZ	M61,M62,M63,M64	13.8	6.4	73.3	6.4		
CEDAR TS DESN2	JQ	M71, M72, M73, M74, M81, M82, M83, M84	13.8	17.3	67.1	35.3		
CENTRALIA DS	Total	F1,F3	8.32	0.3	N/A	1.2	CENTRALIA TS	M3
CENTRALIA TS	QZ	M1, M2, M3, M4	27.6	11.4	429.1	31.5		
CEYLON DS	Total	F1,F3	8.32	1.2	N/A	3.6	HANOVER TS	H1E
CHAPLEAU DS	Total	F3,F4	24.9	3.2	451.6	9.2		
CHARLES TS DESN1	A5A6	For any information or inquiries please contact Toronto Hydro	13.8	15.6	53.8	15.6		
CHARLES TS DESN1	A7A8	For any information or inquiries please contact Toronto Hydro	13.8	11.3	61.1	11.3		
CHARLES TS DESN1	Total	For any information or inquiries please contact Toronto Hydro	13.8	26.9	N/A	Sum of Buses		
CHARLES TS DESN2	A1A2	For any information or inquiries please contact Toronto Hydro	13.8	11.8	98.2	11.8		
CHARLES TS DESN2	A3A4	For any information or inquiries please contact Toronto Hydro	13.8	12.9	87.0	12.9		
CHARLES TS DESN2	Total	For any information or inquiries please contact Toronto Hydro	13.8	24.7	N/A	Sum of Buses		
CHATHAM HARWICH DS	Total	F1,F2	8.32	0.5	N/A	2.2	KENT TS DESN1	M6
CHATHAM RALEIGH DS	Total	F1,F2	8.32	0.7	N/A	2.4	KENT TS DESN2	M23
CHATSWORTH DS	Total	F1,F2,F3,F4	8.32	1.6	N/A	4.0	OWEN SOUND TS	M26
CHELMSFORD DS	Total	F1,F2,F3	12.5	1.2	N/A	4.1	CLARABELLE TS	M8
CHELMSFORD MORGAN DS	Total	F1,F2,F3	12.5	1.0	N/A	3.9	CLARABELLE TS	M8
CHEMUNG DS	Total	F1,F2,F3	8.32	0.9	N/A	3.3	DOBBIN TS	M2
CHERRYWOOD TS	BY	M1, M2, M3, M4, M5, M6, M7, M8	44	57.9	170.0	117.9		
CHESLEY HAWKINS DS	Total	F1,F2,F3	4.16	0.6	N/A	3.0	HANOVER TS	M4
CHESTERS CORNERS DS	Total	F1,F2,F3	12.5	0.8	N/A	3.7	DYMOND TS	M4
CHESTERVILLE BRAN DS	Total	F1,F2,F3	4.16	0.2	N/A	TC	CHESTERVILLE TS	M2
CHESTERVILLE DS #2	Total	F1,F2	4.16	0.2	N/A	TC	CHESTERVILLE TS	M2
CHESTERVILLE FRD DS	Total	F1,F2,F3	8.32	1.2	N/A	TC	CHESTERVILLE TS	M2
CHESTERVILLE TS	BY	M1, M2, M4	44	12.1	868.0	TC		
CHURCHILL MEADOWS TS	BY	M1, M2, M3, M4, M5, M6, M7, M8	44	0.0	230.0	60.0		
CLARABELLE TS	BY	M4, M5, M6, M7, M8	44	29.1	370.3	89.1		
CLARENCE DS	Total	F1,F2	8.32	0.6	62.9	6.6		
CLARKE TS	BY	M1, M2, M3, M4, M5, M6, M7, M8	27.6	30.8	170.0	70.8		
CLARKSBURG DS	Total	F1,F2,F3	8.32	1.9	N/A	7.9	MEAFORD TS	M1
CLAYTON DS	Total	F1,F2,F3	12.5	1.2	N/A	4.0	ALMONTE TS	M25
CLEAR LAKE DS	Total	F1,F2,F3	12.5	1.1	N/A	3.9	MUSKOKA TS	M10
CLEARWATER BAY DS	Total	F1,F2	24.9	0.9	108.0	4.2		
COBALT DS	Total	F1,F2,F3	12.5	0.7	N/A	2.1	DYMOND TS	M2
COBDEN DS	Total	F1,F2,F3,F4	12.5	1.6	46.8	TC		
COBDEN TS	T2	M2	44	2.0	1,218.8	TC		
COBDEN TS	Total	M2,M6	44	4.6	N/A	TC		
COBDEN TS	T1	M6	44	2.5	1,215.8	TC		
COBOCONK DS	Total	F1,F2,F3	12.5	1.9	N/A	5.0	LINDSAY TS	M7
COCHRANE WEST DS	Total	F1,F2	12.5	0.9	25.4	3.8		
COE HILL DS	Total	F2,F3	12.5	1.3	N/A	4.2	HAVELOCK TS	M1
COLBORNE DS #2	Total	F3,F4	8.32	0.7	N/A	2.1	PORT HOPE TS DESN1	M16
COLDSTREAM DS	Total	F1,F2,F3	8.32	0.8	N/A	3.2	LONGWOOD TS	M24
COLDWATER DS	Total	F1,F2,F3	8.32	1.1	N/A	3.5	ORILLIA TS	M3
COLGAN DS	Total	F1,F2	27.6	2.5	N/A	5.0	EVERETT TS	M5
COLLINS BAY DS	Total	F1,F2	8.32	0.6	N/A	2.1	KINGSTON GARDINER TS DESN1	M14
COLPOYS BAY DS	Total	F1,F2,F3	12.5	2.6	N/A	5.0	OWEN SOUND TS	M24
COMBERMERE DS	Total	F1,F2,F3	12.5	1.4	N/A	4.2	WALLACE TS	M6
COMET DS	Total	F1,F2	8.32	0.5	N/A	2.0	KINGSVILLE TS	M7
COMMANDA DS	Total	F1	12.5	0.2	N/A	0.6	NORTH BAY TS	M1

Station Name	Bus Name	Feeder Name	Voltage (kV)	Minimum Load (MW)	Short Circuit Capacity (MVA)	Thermal Capacity (MW)	Upstream TS	Upstream TS feeder
COMMERCE WAY TS	BY	M1,M2,M3,M4	27.6	11.4	132.1	51.4		
CONCORD DS	Total	F1,F2,F3	8.32	1.6	N/A	4.0	BEAVERTON TS	M26
CONSECON DS	Total	F1,F2	8.32	0.6	N/A	3.0	PICTON TS	M5
CONSTANCE DS	T1	F1	27.6	1.7	225.2	13.7		
CONSTANCE DS	Total	F1,F2,F4	27.6	5.7	227.4	17.7		
CONSTANCE DS	T2	F2,F4	27.6	4.1	226.7	16.1		
COOKSTOWN WEST DS	Total	F1,F2,F3,F4	8.32	1.2	N/A	4.8	EVERETT TS	M6
COOKSVILLE TS DESN1	JQ	M10,M12,M14,M11,M13,M9	27.6	17.1	16.2	57.1		
COOKSVILLE TS DESN2	EZ	M17,M19,M21,M18,M20,M22	27.6	19.2	119.1	59.2		
CORBEIL DS	Total	F1	12.5	0.7	N/A	1.7	TROUT LAKE TS	M8
CORBETTON DS	Total	F1,F2,F3	8.32	1.0	N/A	3.4	ORANGEVILLE TS DESN2	M45
CORUNNA DS	Total	F1,F2	8.32	1.1	N/A	3.5	LAMBTON TS	M5
COTTAM DS	Total	F1,F2,F3,F4	8.32	1.6	N/A	4.0	KINGSVILLE TS	M10
COURTICE DS	Total	F1,F2,F3	8.32	0.8	N/A	3.2	WILSON TS DESN2	M15
COURTLAND DS	Total	F1,F2,F3	8.32	1.0	N/A	3.4	TILLSONBURG TS	M4
COUTSVILLE DS	Total	F1,F2,F3	12.5	0.9	N/A	3.8	DYMOND TS	M1
CRAIG DS	Total	F1,F2,F3,F4,F5	12.5	2.0	42.2	10.0		
CRAIGHURST DS	Total	F1,F2,F3	8.32	1.3	N/A	3.7	MIDHURST TS - DESN1	M9
CRAIGLEITH DS	Total	F1,F2,F3	8.32	1.6	N/A	4.0	STAYNER TS	M1
CRAMPTON DS	Total	F1,F2,F3	8.32	0.9	N/A	3.3	INGERSOLL TS	M45
CRANBERRY LAKE DS	Total	F1,F2,F3	12.5	0.9	N/A	3.8	MINDEN TS	M4
CRAWFORD TS	EY	M5, M6, M7, M8, M8, M9, M10, M11, M12, M13, M14	27.6	25.1	47.7	65.1		
CREEMORE DS	Total	F1,F2,F3	8.32	1.3	N/A	3.7	STAYNER TS	M2
CRILLY DS	Total	F1	24.9	0.2	N/A	0.9	N/A	N/A
CROSBY TS	Q	M1,M2	44	2.0	961.8	46.8		
CROSBY TS DESN1	Total	M3, M4, M5, M6	27.6	2.9	N/A	22.9		
CROSBY TS DESN1	B	M3,M5	27.6	1.4	284.2	21.4		
CROSBY TS DESN1	Y	M4,M6	27.6	1.4	286.3	21.5		
CROW RIVER DS	Total	F1,F2	24.9	0.5	180.9	6.5		
CROWLAND TS	QY	M13, M14, M15, M16, M17, M18, M19, M20, M21, M22	27.6	27.6	179.3	67.6		
CROWN HILL DS	Total	F1,F2,F3	8.32	1.2	N/A	3.6	MIDHURST TS - DESN1	M4
CROYDON DS	Total	F1,F2	8.32	1.0	N/A	3.4	NAPANEE TS	M2
CROZIER DS	Total	F1,F2	24.9	0.3	N/A	3.2	BARWICK TS	M1
CRYSLER DS	Total	F1,F2,F3	8.32	1.2	N/A	3.6	ST ISIDORE TS	M2
CRYSTAL FALLS TS	EZ	M1, M2	44	5.3	672.0	25.3		
CULTUS DS	Total	F1,F2	8.32	0.3	N/A	1.3	TILLSONBURG TS	M2
CUMBERLAND DS	Total	F1, F2, F3, F4	8.32	2.0	16.1	4.9		
CUMBERLAND DS	T2	F1,F3	8.32	0.3	16.0	5.1		
CUMBERLAND DS	T1	F2,F4	8.32	1.7	15.5	4.6		
CUMBERLAND TS	Q	M21,M23,M25,M27,M29	27.6	19.2	50.2	44.2		
CUMBERLAND TS	Total	M21,M23,M25,M27,M29,M22,M24,M26,M28,M30	27.6	43.7	N/A	Sum of Buses		
CUMBERLAND TS	B	M22,M24,M26,M28,M30	27.6	16.7	51.5	41.7		
CURRIE DS	Total	F1,F2	8.32	0.6	N/A	4.2	COMMERCE WAY TS	M1
CURVE INN DS	B1	F1,F2,F3	8.32	0.6	N/A	3.0	ENFIELD TS DESN1	M3
CURVE INN DS	B2	F5	27.6	0.3	N/A	6.1	ENFIELD TS DESN1	M3
DA WATSON TS	B1	For any information or inquiries please contact Algoma Power Inc	34.5	0.0	370.7	36.0		
DA WATSON TS	B2	For any information or inquiries please contact Algoma Power Inc	34.5	0.0	370.7	36.0		
DA WATSON TS	Total	For any information or inquiries please contact Algoma Power Inc	34.5	0.0	N/A	36.0		
DACK DS	Total	F1,F2	12.5	0.5	N/A	1.9	KIRKLAND LAKE TS	M62
DARTFORD DS	Total	F2,F3	8.32	1.2	N/A	3.6	SIDNEY TS	R8S
DECEWSVILLE DS	Total	F2,F3	8.32	0.5	N/A	2.9	CALEDONIA TS	M4
DEEP RIVER DS	T1	F1	12.5	0.6	7.3	6.6		
DEEP RIVER DS	Total	F1,F2,F3,F5	12.5	2.7	7.4	8.7		
DEEP RIVER DS	T2	F2,F3	12.5	1.4	7.1	7.4		
DEEP RIVER DS	T3	F5	12.5	0.7	7.1	6.7		
DEERHURST DS	Total	F1,F2,F3	12.5	1.8	N/A	4.6	MUSKOKA TS	M4
DELAWARE DS	Total	F1,F2,F3,F4	8.32	1.3	N/A	3.7	LONGWOOD TS	M23
DELHI ANN DS	Total	F1, F2, F3	8.32	0.8	N/A	2.7	NORFOLK TS	M1

Station Name	Bus Name	Feeder Name	Voltage (kV)	Minimum Load (MW)	Short Circuit Capacity (MVA)	Thermal Capacity (MW)	Upstream TS	Upstream TS feeder
DELHI DS #2	Total	F1,F2	8.32	0.7	N/A	3.1	NORFOLK TS	M1
DELHI INDUSTRIAL DS	Total	F1, F2, F3	8.32	0.3	N/A	2.7	NORFOLK TS	M1
DELORO DS #1	Total	F1,F2,F3	12.5	1.3	N/A	4.1	HAVELOCK TS	M2
DEMORESTVILLE DS	Total	F1,F2	8.32	0.9	N/A	2.3	PICTON TS	M5
DES JOACHIMS DS	Total	F1,F2,F3	12.5	0.6	11.0	6.6		
DESERONTO DS	Total	F1,F2	4.16	0.6	N/A	2.1	NAPANEE TS	M4
DEVLIN DS	Total	F1,F2	12.5	0.7	N/A	1.6	BARWICK TS	M1
DEWITT CORNERS DS	Total	F1,F2,F3,F4	8.32	1.4	N/A	5.0	SMITHS FALLS TS	M21
DICKENSON ROAD DS	Total	F1,F2,F3	8.32	0.9	N/A	3.3	NEBO TS DESN1	M5
DIRLETON DS	Total	F1,F2,F3	12.5	1.4	N/A	4.3	ARNPRIOR TS	M2
DIXONS CORNERS DS	Total	F1,F2,F3	8.32	1.6	N/A	TC	MORRISBURG TS	M25
DOANE DS	T1	F1,F2	27.6	1.9	N/A	9.9	BROWN HILL TS	M3
DOANE DS	Total	F1,F2,F3	27.6	1.9	N/A	7.7	BROWN HILL TS	M3
DOANE DS	T2	F3	27.6	0.1	N/A	5.8	BROWN HILL TS	M3
DOBBIN DS	T1	F1	27.6	1.4	424.6	13.4		
DOBBIN DS	Total	F1,F2	27.6	2.6	425.0	14.6		
DOBBIN DS	T2	F2	27.6	1.2	424.9	13.2		
DOBBIN TS	BY	M1, M2, M3, M4, M5, M6, M7, M8	44	30.1	610.8	90.1		
DOMINION DRIVE DS	Total	F1,F2,F3	12.5	1.5	N/A	5.0	MARTINDALE TS	M6
DOMVILLE DS	Total	F1,F2	8.32	0.6	N/A	2.0	BROCKVILLE TS	B1R
DORCAS BAY DS	Total	F1,F2	12.5	1.2	N/A	4.1	OWEN SOUND TS	M24
DORCHESTER DS	Total	F1,F2	8.32	0.2	N/A	0.5	HIGHBURY TS	M11
DORCHESTER POND DS	Total	F1,F2,F3	8.32	0.6	N/A	4.2	BUCHANAN TS	M21
DORSET DS	Total	F1,F2	12.5	1.1	N/A	4.0	MINDEN TS	M2
DOUGLAS POINT TS	DJ	M1, M2, M3, M4, M6, M8	44	12.4	392.7	52.4		
DOVER CENTRE DS	Total	F1,F2,F3	8.32	1.1	N/A	3.5	WALLACEBURG TS	M3
DRAYTON DS	Total	F1,F2,F3	8.32	1.6	N/A	6.4	PALMERSTON TS	M2
DRESDEN DS	Total	F1,F2	8.32	0.5	N/A	1.4	WALLACEBURG TS	M1
DRUMBO DS	Total	F1,F2	8.32	0.4	N/A	1.3	WOLVERTON DS	F2
DRUMMOND DS - 27.6 kV	T2	F4	27.6	0.6	N/A	8.6	SMITHS FALLS TS	M26
DRUMMOND DS - 8.32 kV	T1	F1,F2	8.32	0.8	N/A	2.2	SMITHS FALLS TS	M26
DRYDEN COLONIZATN DS	Total	F1,F2,F3	12.5	0.4	N/A	3.3	DRYDEN TS	M1
DRYDEN GOVERNMENT DS	Total	F1,F2	12.5	0.7	N/A	2.1	DRYDEN TS	M3
DRYDEN RURAL DS	Total	F1,F2,F3	24.9	1.1	N/A	4.0	DRYDEN TS	M1
DRYDEN TS	BY	M1, M3	44	6.0	955.9	26.1		
DRYDEN WILDE DS	Total	F1,F2,F3	12.5	2.1	N/A	5.0	DRYDEN TS	M1
DUART TS DESN1	B	M5	27.6	1.0	84.8	26.0		
DUART TS DESN1	Total	M5, M6	27.6	4.0	N/A	Sum of Buses		
DUART TS DESN1	Y	M6	27.6	2.0	81.5	27.0		
DUBLIN DS	Total	F1,F2	8.32	1.0	N/A	2.4	SEAFORTH TS	M2
DUFF DS	Total	F1,F2	8.32	0.8	N/A	3.2	NEBO TS DESN1	M6
DUFFERIN TS DESN1	A1A2	For any information or inquiries please contact Toronto Hydro	13.8	9.4	83.4	9.4		
DUFFERIN TS DESN1	A3A4	For any information or inquiries please contact Toronto Hydro	13.8	4.7	82.2	4.7		
DUFFERIN TS DESN1	Total	For any information or inquiries please contact Toronto Hydro	13.8	14.1	N/A	Sum of Buses		
DUFFERIN TS DESN2	A5A6	For any information or inquiries please contact Toronto Hydro	13.8	13.9	73.4	13.9		
DUFFERIN TS DESN2	A7A8	For any information or inquiries please contact Toronto Hydro	13.8	8.1	72.1	8.1		
DUFFERIN TS DESN2	Total	For any information or inquiries please contact Toronto Hydro	13.8	22.0	N/A	Sum of Buses		
DUNBOYNE DS	Total	F1,F2,F3	8.32	0.8	N/A	3.2	AYLMER TS	M1
DUNCHURCH DS	Total	F1,F2,F3	12.5	0.9	N/A	3.8	PARRY SOUND TS	M3
DUNDALK VICTORIA DS	Total	F1,F2,F3,F4	4.16	0.7	N/A	3.1	ORANGEVILLE TS DESN2	M45
DUNDAS SYDENHAM DS	Total	F1,F2	8.32	0.5	N/A	1.9	DUNDAS TS	M3
DUNDAS TS	BY	M1, M2, M3, M4, M5, M6, M7, M8	27.6	30.6	41.2	70.6		
DUNDAS TS #2	JQ	M11, M12, M13, M14, M15, M16	27.6	11.8	68.7	51.8		
DUNEDIN DS	Total	F1,F2,F3	8.32	1.4	N/A	3.8	STAYNER TS	M2
DUNLOP DS	Total	F1,F2	8.32	0.8	N/A	2.2	GODERICH TS	M10
DUNNVILLE DS	Total	F1	8.32	0.5	N/A	2.9	DUNNVILLE TS	M1
DUNNVILLE TS	EQ	M1, M2, M4	27.6	7.2	460.4	26.9		
DUNSFORD DS	Total	F1,F2,F3	12.5	1.5	N/A	4.4	LINDSAY TS	M6

Station Name	Bus Name	Feeder Name	Voltage (kV)	Minimum Load (MW)	Short Circuit Capacity (MVA)	Thermal Capacity (MW)	Upstream TS	Upstream TS feeder
DUNTROON DS	Total	F1,F2,F3	8.32	1.5	N/A	3.9	STAYNER TS	M8
DUPLEX TS DESN1	A1A2	For any information or inquiries please contact Toronto Hydro	13.8	10.2	95.4	10.2		
DUPLEX TS DESN1	A3A4	For any information or inquiries please contact Toronto Hydro	13.8	8.6	95.3	8.6		
DUPLEX TS DESN1	Total	For any information or inquiries please contact Toronto Hydro	13.8	18.8	N/A	Sum of Buses		
DUPLEX TS DESN2	A5A6	For any information or inquiries please contact Toronto Hydro	13.8	13.3	64.2	13.3		
DURHAM ELGIN DS	Total	F1,F2,F3,F4	4.16	0.6	N/A	3.0	HANOVER TS	H1E
DURHAM ROAD DS	T1	F1,F2	8.32	0.1	N/A	2.5	ARMITAGE TS DESN2	M32
DURHAM ROAD DS	T2	F4,F5	27.6	1.3	N/A	5.0	ARMITAGE TS DESN2	M32
DUTTON DS	Total	F1,F2,F3	8.32	1.0	N/A	4.6	DUART TS DESN1	M6
DWIGHT DS	Total	F1,F2,F3	12.5	1.2	N/A	4.1	MUSKOKA TS	M4
DYMOND TS	BY	M1, M2, M3, M4	44	18.5	388.3	40.1		
EAMER DS	Total	F1,F2,F3	8.32	1.0	N/A	3.4	ST LAWRENCE TS	M24
EAR FALLS DS	Total	F1,F2,F3	12.5	1.4	N/A	N/A	EAR FALLS TS	M1
EAR FALLS TS	T5	M1	44	1.5	1,348.0	11.5		
EARLTON DS	Total	F1,F2	12.5	0.6	N/A	2.0	DYMOND TS	M1
EAST LUTHER DS	Total	F1,F2,F3	12.5	1.1	N/A	4.0	ORANGEVILLE TS DESN2	M2
EDGEWARE TS	Total	M1, M2, M3, M4, M5, M6, M7, M8, M10	27.6	33.7	N/A	Sum of Buses		
EDGEWARE TS	B	M1, M3, M5, M7	27.6	13.6	165.9	13.6		
EDGEWARE TS	Y	M2, M4, M6, M8, M10	27.6	20.1	167.2	20.1		
EGANVILLE BRUCE DS	Total	F1,F2	4.16	0.5	N/A	TC	COBDEN TS	M6
EGREMONT ROAD PDS	Total	F1	8.32	0.2	N/A	1.4	WANSTEAD TS	M2
ELGIN DS	Total	F1,F2,F3,F4	8.32	0.8	N/A	3.2	CROSBY TS DESN1	M6
ELGIN DS	T1	F1,F3	8.32	0.3	N/A	2.7	CROSBY TS DESN1	M6
ELGIN DS	T2	F2,F4	8.32	0.5	N/A	2.9	CROSBY TS DESN1	M6
ELGIN TS	J1J2Q1Q2	M11,M12,M13,M21,M22,M23,M31,M32,M33,M41,M42,M43	13.8	16.0	86.2	16.0		
ELGIN TS	Total	,M12,M13,M21,M22,M23,M31,M32,M33,M41,M42,M43,M51,M52,M53,M61,M62,M63,M71,M72,M73,M81,M82,	13.8	32.0	N/A	Sum of Buses		
ELGIN TS	B1B2E1E2	M51,M52,M53,M61,M62,M63,M71,M72,M73,M81,M82,M83	13.8	16.0	131.5	16.0		
ELGINBURG DS	Total	F1,F2,F3	8.32	1.2	N/A	3.6	KINGSTON GARDINER TS DESN1	M3
ELK LAKE DS	Total	F1	4.16	0.2	N/A	1.1	KIRKLAND LAKE TS	G3K
ELLESMERE TS	J	M21,M23,M25,M27,M29,M31	27.6	19.5	51.5	44.5		
ELLESMERE TS	Total	M21,M23,M25,M27,M29,M31,M22,M24,M26,M28,M30,M32	27.6	35.9	N/A	Sum of Buses		
ELLESMERE TS	Q	M22,M24,M26,M28,M30,M32	27.6	16.4	50.0	41.4		
ELLIOT LAKE DS	Total	F1,F2	12.5	0.9	N/A	4.9	ELLIOT LAKE TS	M3
ELLIOT LAKE MISS DS	T1	F1,F3	12.5	0.3	N/A	4.3	ELLIOT LAKE TS	M3
ELLIOT LAKE MISS DS	Total	F1,F3,F4,F5	12.5	1.0	N/A	3.9	ELLIOT LAKE TS	M3
ELLIOT LAKE MISS DS	T2	F4,F5	12.5	0.7	N/A	3.6	ELLIOT LAKE TS	M3
ELLIOT LAKE TS	B1B3	M1, M3	44	5.0	371.6	25.0		
ELMHURST DS	T1	F1,F2,F3	8.32	0.5	N/A	2.9	BROWN HILL TS	M2
ELMHURST DS	T2	F4,F5	27.6	1.6	N/A	5.0	BROWN HILL TS	M2
ELMIRA TS	BY	M1, M2, M3	27.6	11.0	381.6	31.0		
ELMVALE DS	Total	F1,F2	8.32	0.8	N/A	2.2	MIDHURST TS - DESN1	M10
ELORA UNION DS	Total	F1,F2,F4	8.32	0.6	N/A	3.0	FERGUS TS	M7
ELSINORE DS	Total	F1,F2,F3	8.32	1.1	N/A	3.5	OWEN SOUND TS	M25
EMBRUN DS	Total	F2,F3,F4,	8.32	0.9	N/A	TC	CHESTERVILLE TS	M1
EMO DS	Total	F1,F2	12.5	0.7	N/A	2.1	BARWICK TS	M1
EMSDALE DS	Total	F1,F2,F3	12.5	1.7	N/A	4.6	MUSKOKA TS	M10
ENFIELD TS DESN1	BY	M3,M4,M5,M6,M7,M8	44	31.9	257.9	91.9		
ENGLEHART NORTH DS	Total	F1,F2,F3	12.5	0.7	N/A	3.6	KIRKLAND LAKE TS	M62
ENNISMORE DS	Total	F1,F2,F3	8.32	0.9	N/A	3.3	DOBBIN TS	M2
ERAMOSA DS	Total	F4,F5,F6	8.32	0.8	N/A	3.2	FERGUS TS	M8
ERIEAU DS	Total	F1,F2,F3	8.32	0.8	N/A	3.2	KENT TS DESN1	M18
ERIN DS	Total	F1,F2,F3	12.5	1.8	N/A	5.0	ORANGEVILLE TS DESN2	M1
ERINDALE TS DESN1	Q	M31,M33,M35,M37,M39,M41	27.6	21.0	109.2	21.0		
ERINDALE TS DESN1	E	M32,M34,M36,M38,M40,M42	27.6	25.8	110.0	25.8		
ERINDALE TS DESN1	Total	M32,M34,M36,M38,M40,M42,M31,M33,M35,M37,M39,M41	27.6	46.8	N/A	Sum of Buses		
ERINDALE TS DESN2	YZ	M23, M24, M25, M26, M27, M28, M29, M30	44	33.6	199.7	93.6		
ERINDALE TS DESN3	BJ	M1, M2, M3, M4, M5, M6, M7, M8	44	42.9	187.5	102.9		
ESPANOLA DS	Total	F1,F2	12.5	0.7	N/A	3.6	ESPANOLA TS	M1

Station Name	Bus Name	Feeder Name	Voltage (kV)	Minimum Load (MW)	Short Circuit Capacity (MVA)	Thermal Capacity (MW)	Upstream TS	Upstream TS feeder
ESPANOLA TS	BY	M1, M2	44	3.7	1,141.6	10.9		
ESPLANADE TS	A1A2	For any information or inquiries please contact Toronto Hydro	13.8	18.3	58.8	18.3		
ESPLANADE TS	J1J2	M1,M2,M3,M4	13.8	24.4	61.9	24.4		
ESPLANADE TS	Total	M1,M2,M3,M4,M11,M12,M13,M14	13.8	61.1	N/A	Sum of Buses		
ESPLANADE TS	Q1Q2	M11,M12,M13,M14	13.8	18.5	59.6	18.5		
ESSEX DS	Total	F1,F2	8.32	0.5	N/A	2.9	LAUZON TS DESN2	M24
ESSEX TS	JQ	M5, M6, M7, M8, M10, M11	27.6	14.3	103.0	54.3		
ETON DS	Total	F1,F2,F3	12.5	0.9	9.9	7.6		
EVERETT DS	Total	F1,F2,F3	8.32	1.8	N/A	5.0	EVERETT TS	M5
EVERETT TS	BY	M5, M6, M7, M8	44	23.8	477.3	63.8		
EVERSLEY DS	T1	F1,F2,F3	13.8	1.4	N/A	9.4	KLEINBURG TS 44 KV	M23
EVERSLEY DS	Total	F1,F2,F3,F5,F6	13.8	2.7	N/A	10.7	KLEINBURG TS 44 KV	M23
EVERSLEY DS	T2	F5,F6	13.8	1.2	N/A	9.2	KLEINBURG TS 44 KV	M23
EVERTON DS	Total	F1,F2	8.32	0.7	N/A	3.1	FERGUS TS	M2
EXETER DS #2	Total	F1,F2	8.32	0.6	N/A	1.6	CENTRALIA TS	M1
EXETER ROSEMOUNT DS	Total	F1,F2,F3	4.16	0.6	N/A	3.0	CENTRALIA TS	M1
EXETER SANDERS DS	Total	F1,F2,F3	4.16	0.5	N/A	2.9	CENTRALIA TS	M1
EXETER WELLINGTON DS	Total	F1,F2	4.16	0.4	N/A	1.8	CENTRALIA TS	M1
FAIRBANK TS DESN1	YZ	M11,M12,M7,M3,M5,M8	27.6	22.9	90.5	62.9		
FAIRBANK TS DESN2	BQ	M1,M10,M2,M23,M24,M4,M6,M9	27.6	21.5	91.4	61.5		
FAIRCHILD TS DESN1	B	M1,M3,M5,M7,M9,M11	27.6	18.0	74.5	18.0		
FAIRCHILD TS DESN1	Total	M1,M3,M5,M7,M9,M11,M2,M4,M6,M8,M10,M12	27.6	36.1	N/A	Sum of Buses		
FAIRCHILD TS DESN1	Y	M2,M4,M6,M8,M10,M12	27.6	18.8	68.8	18.8		
FAIRCHILD TS DESN2	J	M21,M23,M25,M27,M29,M31	27.6	11.2	115.0	27.2		
FAIRCHILD TS DESN2	Total	M21,M23,M25,M27,M29,M31,M22,M24,M26,M28,M30,M32	27.6	32.6	N/A	Sum of Buses		
FAIRCHILD TS DESN2	Q	M22,M24,M26,M28,M30,M32	27.6	20.5	116.5	36.5		
FAIRFIELD DS	Total	F1,F2,F3	8.32	1.2	N/A	3.6	KINGSTON GARDINER TS DESN1	M14
FARLAIN LAKE DS	Total	F1,F2,F3	8.32	0.6	N/A	3.0	WAUBAUSHENE TS	M7
FAUQUIER DS	Total	F1,F2	12.5	0.5	94.0	2.0		
FENELON F CLIFTON DS	Total	F1,F2,F3,F4	4.16	0.5	N/A	2.9	BEAVERTON TS	M23
FENELON F ELLIOTT DS	Total	F1,F2,F3,F4	4.16	0.4	N/A	1.8	BEAVERTON TS	M23
FENELON FALLS DS	Total	F1,F2,F3	12.5	1.3	N/A	2.8	BEAVERTON TS	M23
FERGUS EAST DS	Total	F1,F2,F3	8.32	1.2	N/A	3.6	FERGUS TS	M6
FERGUS TS	BY	M1, M2, M3, M4, M7, M8	44	36.1	325.8	96.1		
FERGUSONVALE DS	Total	F1,F2,F3	8.32	1.6	N/A	4.0	MIDHURST TS - DESN1	M10
FERNDALE DS	Total	F1,F2,F3	12.5	2.3	N/A	5.0	OWEN SOUND TS	M24
FIDDLERS GREEN DS	Total	F1,F2	8.32	0.9	N/A	3.3	NEBO TS DESN1	M8
FINCH TS DESN1	B	M1,M3,M5,M7,M9,M11	27.6	15.1	89.5	15.1		
FINCH TS DESN1	Total	M1,M3,M5,M7,M9,M11,M2,M4,M6,M8,M10,M12	27.6	37.9	N/A	Sum of Buses		
FINCH TS DESN1	Y	M2,M4,M6,M8,M10,M12	27.6	25.6	89.9	25.6		
FINCH TS DESN2	J	M21,M23,M25,M27,M29,M31	27.6	20.3	46.4	45.3		
FINCH TS DESN2	Total	M21,M23,M25,M27,M29,M31,M22,M24,M26,M28,M30,M32	27.6	39.3	N/A	Sum of Buses		
FINCH TS DESN2	Q	M22,M24,M26,M28,M30,M32	27.6	18.8	44.7	43.8		
FIRTHS CORNERS DS	Total	F1,F2,F3	8.32	1.5	N/A	3.9	WAUBAUSHENE TS	M7
FLYNNS CORNERS DS	Total	F1,F2,F3	12.5	1.2	N/A	4.1	OTONABEE TS DESN2	M27
FOOTES BAY DS	Total	F1,F2,F3	12.5	1.7	N/A	4.6	PARRY SOUND TS	M2
FOREST JEFFERSON DS	Total	F1,F2,F3	2.4	0.3	N/A	1.3	FOREST JURA DS	F2
FOREST JURA DS	Total	F1,F2,F3	27.6	6.7	245.2	19.5		
FOREST JURA DS	B1	F1,F3	27.6	3.8	208.3	15.8		
FOREST JURA DS	B2	F2	27.6	2.9	206.4	14.9		
FOREST LEA DS	T1	F1,F2	12.5	1.4	21.5	7.4		
FOREST LEA DS	Total	F1,F2,F3,F4	12.5	2.3	21.6	8.3		
FOREST LEA DS	T2	F3,F4	12.5	0.8	21.5	6.8		
FOREST MCNAB DS	Total	F1,F2	4.16	0.4	N/A	2.8	FOREST JURA DS	F2
FOREST UNION DS	Total	F1,F3	8.32	0.3	N/A	1.7	FOREST JURA DS	F2
FORKS RD PDS	Total	F1	8.32	0.2	N/A	1.4	CROWLAND TS	M13
FORT WILLIAM TS	JQ	M1, M2, M3, M4, M5, M6, M7, M8, M9, M10	24.9	29.7	126.1	69.7		
FRANKFORD DS #2	Total	F1,F2,F3	8.32	0.7	N/A	3.1	SIDNEY TS	M1

Station Name	Bus Name	Feeder Name	Voltage (kV)	Minimum Load (MW)	Short Circuit Capacity (MVA)	Thermal Capacity (MW)	Upstream TS	Upstream TS feeder
FRANKFORD PATRICK DS	Total	F1,F2	8.32	0.6	N/A	4.2	SIDNEY TS	M1
FREELTON DS	Total	F1,F2,F3	8.32	1.0	N/A	3.4	DUNDAS TS	M5
FROGMORE DS	Total	F1,F2,F3	8.32	0.6	N/A	3.0	TILLSONBURG TS	M2
FRONTENAC TS	BY	M1, M2, M3, M4, M5, M8	44	46.9	817.0	86.9		
GAGE TS DESN2	YZ	For any information or inquires please contact Alectra Utilities	13.8	7.0	97.7	33.9		
GAGE TS DESN3	DJ	For any information or inquires please contact Alectra Utilities	13.8	3.8	96.8	30.7		
GAGE TS DESN4	EK	For any information or inquires please contact Alectra Utilities	13.8	22.1	0.0	79.7		
GALETTA DS	Total	F1,F2,F3	12.5	1.6	N/A	4.5	ARNPRIOR TS	M2
GALT TS	J	M11,M13,M15,M17,M19,M21	27.6	14.3	97.8	39.3		
GALT TS	Total	M11,M13,M15,M17,M19,M21,M12,M14,M16,M18,M20,M22	27.6	28.7	N/A	Sum of Buses		
GALT TS	Y	M12,M14,M16,M18,M20,M22	27.6	14.3	98.6	39.3		
GANANOQUE DS	Total	F1,F2	27.6	0.9	N/A	5.0	FRONTENAC TS	M8
GARDINER DS	T1	F1,F2,F3	8.32	1.0	N/A	3.4	KINGSTON GARDINER TS DESN2	M23
GARDINER DS	Total	F1,F2,F3,F4,F5	8.32	2.2	N/A	4.6	KINGSTON GARDINER TS DESN2	M23
GARDINER DS	T2	F4,F5	8.32	1.1	N/A	3.5	KINGSTON GARDINER TS DESN2	M23
GARSON DS	Total	F1,F2,F3	12.5	1.5	N/A	4.4	MARTINDALE TS	M6
GEORGINA BURKE DS	Total	F4,F5	8.32	0.6	N/A	3.0	BROWN HILL TS	M12
GERALDTON NORTH DS	Total	F1,F2	12.5	0.8	N/A	3.7	LONGLAC TS	M2
GERALDTON SOUTH DS	Total	F1,F2	12.5	0.6	N/A	2.0	LONGLAC TS	M2
GERRARD TS DESN1	A1A2	For any information or inquiries please contact Toronto Hydro	13.8	3.3	41.6	27.3		
GERRARD TS DESN1	A4A5	For any information or inquiries please contact Toronto Hydro	13.8	8.2	57.0	32.2		
GLEN ALLAN DS	Total	F1,F2,F3	8.32	1.2	N/A	3.6	ELMIRA TS	M2
GLEN BECKER DS	Total	F1,F2,F3	8.32	1.0	N/A	TC	MORRISBURG TS	M26
GLEN SANDFIELD DS	Total	F1,F2,F3	8.32	1.0	N/A	3.4	LONGUEUIL TS	M23
GLENARM DS	Total	F1,F2,F3	12.5	0.9	N/A	3.8	BEAVERTON TS	M23
GLENCOE DS	Total	F1,F2,F3	8.32	0.9	N/A	3.3	LONGWOOD TS	M25
GLENDALE TS	BJ	M31,M32,M33,M34	13.8	6.4	89.0	6.4		
GLENDALE TS	Total	M31,M32,M33,M34,M5,M8,M23,M24	13.8	14.8	N/A	Sum of Buses		
GLENDALE TS	DQ	M5,M8,M23,M24	13.8	9.0	88.0	9.0		
GLENDALE TS DESN2	EY	M16, M9	13.8	3.7	143.8	10.9		
GLENGARRY DS	Total	F1,F2	27.6	1.3	N/A	9.3	ST ISIDORE TS	M4
GLENGROVE TS DESN1	A3A4	For any information or inquiries please contact Toronto Hydro	13.8	8.2	76.4	24.2		
GLENGROVE TS DESN2	A7A8	For any information or inquiries please contact Toronto Hydro	13.8	7.7	81.7	23.7		
GODERICH TS	QZ	M3,M4,M5,M6,M8,M9,M10	27.6	12.0	411.1	51.8		
GOLDEN BEACH DS	Total	F1,F2	12.5	1.9	N/A	4.7	MUSKOKA TS	M7
GOLDEN LAKE DS	Total	F1,F2,F3	12.5	1.5	N/A	TC	COBDEN TS	M6
GOLDEN VALLEY DS	Total	F1,F2	24.9	1.0	N/A	3.8	TROUT LAKE TS	M7
GOODFISH DS	Total	F8,F9,F10	4.16	0.9	N/A	3.3	KIRKLAND LAKE TS	M61
GOODWOOD DS	Total	F1,F2,F3	8.32	0.9	N/A	3.3	ARMITAGE TS DESN2	M32
GORE BAY DS	Total	F1,F2,F3	12.5	1.0	N/A	3.9	MANITOULIN TS	M25
GOREWAY TS DESN1	B	M41,M43,M45,M47,M49,M51	27.6	25.1	96.4	50.1		
GOREWAY TS DESN1	Total	M41,M43,M45,M47,M49,M51,M42,M44,M46,M48,M50,M52	27.6	57.2	N/A	Sum of Buses		
GOREWAY TS DESN1	Y	M42,M44,M46,M48,M50,M52	27.6	26.4	95.7	51.4		
GOREWAY TS DESN2	Q	M1,M3,M5,M7,M9,M17	27.6	0.0	43.2	25.0		
GOREWAY TS DESN2	Total	M1,M3,M5,M7,M9,M17,M2,M4,M6,M8,M10,M18	27.6	0.0	N/A	Sum of Buses		
GOREWAY TS DESN2	J	M2,M4,M6,M8,M10,M18	27.6	0.0	44.5	25.0		
GORMLEY DS	Total	F3	8.32	0.5	N/A	2.9	ARMITAGE TS DESN2	M31
GORRIE DS	Total	F1,F2,F3	8.32	1.2	N/A	3.6	WINGHAM TS	M4
GOULAIS BAY TS	T1	For any information or inquiries please contact Algoma Power Inc	12	0.0	65.1	2.4		
GOUROCK DS	Total	F1,F2	8.32	1.0	N/A	3.4	PUSLINCH DS	F2
GRAFTON DS	Total	F1,F2,F3	8.32	1.3	N/A	3.7	PORT HOPE TS DESN1	M16
GRAND BEND DS	Total	F1,F2,F3	8.32	1.0	N/A	3.4	GRAND BEND EAST DS	F2
GRAND BEND EAST DS	T1	F1	27.6	1.7	458.7	13.7		
GRAND BEND EAST DS	Total	F1,F2	27.6	5.0	459.6	17.0		
GRAND BEND EAST DS	T2	F2	27.6	3.3	454.4	15.3		
GRAND BEND MUNI DS	Total	F1,F2,F3	8.32	0.8	N/A	3.2	GRAND BEND EAST DS	F2
GRAND VALLEY DS #2	Total	F2,F3	12.5	0.4	N/A	1.9	ORANGEVILLE TS DESN2	M2
GRASSMERE DS	Total	F1,F2,F3	12.5	1.2	N/A	4.0	MUSKOKA TS	M4

Station Name	Bus Name	Feeder Name	Voltage (kV)	Minimum Load (MW)	Short Circuit Capacity (MVA)	Thermal Capacity (MW)	Upstream TS	Upstream TS feeder
GRAVENHURST DS	Total	F1,F2,F3	12.5	1.5	N/A	4.3	BRACEBRIDGE TS	M21
GREELY DS	Total	F2,F3,F4	27.6	4.7	382.5	20.7		
GREELY DS	T2	F2,F4	27.6	2.6	380.3	18.6		
GREELY DS	T1	F3	27.6	2.1	381.8	18.1		
GREEN PARK DS	Total	F1,F2,F3	12.5	1.1	N/A	4.0	FERGUS TS	M1
GREEN VALLEY DS	Total	F1,F2,F3	8.32	1.0	N/A	3.4	ST ISIDORE TS	M4
GREENBANK DS	Total	F1,F2,F3	8.32	0.5	N/A	2.9	BEAVERTON TS	M29
GREENLAND DS	Total	F1,F2,F3	12.5	1.3	N/A	4.1	ARNPRIOR TS	M2
GREENOCK DS	Total	F1,F2,F3	8.32	1.4	N/A	3.8	HANOVER TS	M2
GREENS CORNER DS	Total	F1,F2,F3	8.32	1.1	N/A	3.5	NORFOLK TS	M1
GREENSVILLE DS	Total	F1,F2,F3	8.32	3.0	N/A	5.0	DUNDAS TS	M3
GREENWOOD DS	Total	F1,F2,F3	12.5	1.3	N/A	TC	PEMBROKE TS	M2
GRENFEL DS	Total	F1,F2,F3	8.32	1.2	N/A	2.6	MIDHURST TS - DESN1	M3
GRETNA DS	Total	F1,F2	8.32	0.9	N/A	3.3	NAPANEE TS	M3
GUELPH DS	Total	F1,F2,F3	8.32	0.9	N/A	3.3	FERGUS TS	M8
GULL RIVER DS	Total	F1,F2,F3	12.5	0.8	N/A	3.6	MINDEN TS	M3
GUTHRIE DS	Total	F1,F2,F3	8.32	0.7	N/A	2.1	MIDHURST TS - DESN1	M4
HAILEYBURY DS	Total	F1,F2,F3	4.16	0.4	N/A	1.8	DYMOND TS	M2
HALIBURTON DS	Total	F1,F2,F3	12.5	1.1	N/A	4.0	MINDEN TS	M1
HALLS LAKE DS	Total	F1,F2,F3	12.5	1.9	N/A	4.8	MINDEN TS	M2
HALTON TS	Q	M21,M23,M25,M27,M29,M31	27.6	20.4	103.0	45.4		
HALTON TS	Total	M21,M23,M25,M27,M29,M31,M22,M24,M26,M28,M30,M32	27.6	40.0	N/A	Sum of Buses		
HALTON TS	J	M22,M24,M26,M28,M30,M32	27.6	20.3	97.1	45.3		
HAMPTON DS	Total	F1,F2,F3	8.32	0.8	N/A	3.2	WILSON TS DESN2	M13
HANLON TS	BY	M11, M12, M13, M14, M21, M22, M23, M24	13.8	13.8	84.6	29.6		
HANMER DS	Total	F1,F2	12.5	1.0	N/A	3.9	MARTINDALE TS	M7
HANMER KENNETH DS	Total	F1,F2,F3	12.5	1.2	N/A	4.1	CLARABELLE TS	M7
HANOVER TS	BY	M1, M2, M3, M4, M5, H1E	44	29.1	575.3	69.1		
HARCOURT DS	Total	F1,F2,F3	12.5	0.9	N/A	3.7	WALLACE TS	M4
HARRISTON DS #2	Total	F1,F2,F3	8.32	1.4	N/A	3.8	PALMERSTON TS	M4
HARROWSMITH DS	T1	F2,F3	12.5	1.8	153.8	7.8		
HARROWSMITH DS	Total	F2,F3,F4,F5	12.5	3.7	155.0	9.7		
HARROWSMITH DS	T2	F4,F5	12.5	1.8	154.2	7.8		
HASTINGS DS	Total	F1,F2,F3	8.32	0.5	N/A	1.9	OTONABEE TS DESN2	M28
HASTINGS ELGIN DS	Total	F1,F2	8.32	0.6	N/A	3.0	OTONABEE TS DESN2	M28
HAVELK INDUSTRIAL DS	Total	F1,F2	12.5	0.4	N/A	2.8	HAVELOCK TS	M3
HAVELOCK TS	BY	M1, M2, M3, M4, M6	44	24.6	823.7	69.4		
HAWKESTONE DS	Total	F1,F2,F3	8.32	0.9	N/A	3.3	ORILLIA TS	M7
HAWLEY DS	Total	F1,F2,F3	8.32	1.0	N/A	2.0	NAPANEE TS	M3
HAWTHORNE TS	BJ	M1, M2, M3, M4, M5	44	35.6	356.1	75.6		
HAYCROFT DS	Total	F1,F2,F3	8.32	1.3	N/A	3.7	BELLE RIVER TS	M2
HEARST TS	BY	M1, M2, M3	24.9	4.9	248.8	24.9		
HECKSTON DS	Total	F1,F2,F3	8.32	1.4	N/A	TC	MORRISBURG TS	M25
HEPWORTH DS	Total	F1,F2,F3	8.32	1.2	N/A	3.6	OWEN SOUND TS	M25
HERRIDGE LAKE DS	Total	F1, F2	12.5	0.6	93.3	2.1		
HIGHBURY TS	JY	M11, M12, M13, M14, M15, M16, M17, M18	27.6	27.0	66.2	67.0		
HIGHGATE DS	Total	F1,F2	8.32	0.4	N/A	2.8	DUART TS DESN1	M5
HILLSBURGH DS	Total	F1,F2,F3	12.5	1.2	N/A	4.1	ORANGEVILLE TS DESN2	M1
HINCHEY TS	BY	For any information or inquiries please contact Hydro Ottawa	13.8	0.0	81.2	18.0		
HINCHEY TS	QZ	For any information or inquiries please contact Hydro Ottawa	13.8	17.7	82.6	35.7		
HINCHEY TS	Total	For any information or inquiries please contact Hydro Ottawa	13.8	17.7	N/A	Sum of Buses		
HINCHINBROOKE DS	Total	F1, F2, F3	12.5	1.3	53.1	4.6		
HOCKLEY DS	Total	F1,F2,F3	12.5	1.1	N/A	4.0	ORANGEVILLE TS DESN2	M6
HOLLAND DS	Total	F1,F2	27.6	0.2	N/A	5.0	HOLLAND TS	M3
HOLLAND LANDING DS	Total	F1,F2,F3	8.32	1.2	N/A	3.6	BROWN HILL TS	M3
HOLLAND TS	BY	M3,M4,M5,M6,M7,M8,M9,M10	44	36.6	376.8	96.6		
HOLLINGWORTH TS	T1	Limer1	44	0.0	39.4	12.0		
HOLSTEIN DS	Total	F1,F2,F3	8.32	1.1	N/A	3.5	HANOVER TS	M5

Station Name	Bus Name	Feeder Name	Voltage (kV)	Minimum Load (MW)	Short Circuit Capacity (MVA)	Thermal Capacity (MW)	Upstream TS	Upstream TS feeder
HOMESTEAD DS	Total	F1,F2	27.6	2.9	N/A	5.0	BROWN HILL TS	M1
HONEY HARBOUR DS	Total	F1,F2	12.5	1.3	N/A	4.2	WAUBAUSHENE TS	M1
HORNEPAYNE DS	Total	F1,F2,F3	4.16	0.7	N/A	3.1	MANITOUWADGE TS	M2
HORNER TS	B	M1,M3,M5,M7,M9, M11	27.6	19.8	88.5	19.8		
HORNER TS	Total	M1,M3,M5,M7,M9,M2,M4,M6,M8,M10	27.6	40.2	N/A	Sum of Buses		
HORNER TS	Y	M2,M4,M6,M8,M10, M12	27.6	26.7	88.9	26.7		
HORNING MILLS DS	Total	F1,F2,F3	8.32	1.4	N/A	3.8	ORANGEVILLE TS DESN2	M4
HORNING TS	Total	M2,M3,M4,M5,M6,M7,M8,M9,M10,M11,M45,M46,M47,M48,M49,M50	13.8	13.2	N/A	Sum of Buses		
HORNING TS	YZ	M2,M4,M5,M6,M7,M8,M9,M10	13.8	10.6	116.8	34.6		
HORNING TS	EJ	M3,M11,M45,M46,M47,M48,M49,M50	13.8	2.5	114.8	26.4		
HORSESHOE LAKE DS	Total	F1,F2,F3	12.5	1.3	N/A	4.2	PARRY SOUND TS	M2
HORSEY BAY DS	T1	F1,F2	8.32	1.1	N/A	3.5	KINGSTON GARDINER TS DESN1	M11
HORSEY BAY DS	Total	F1,F2,F3,F4	8.32	2.1	N/A	4.5	KINGSTON GARDINER TS DESN1	M11
HORSEY BAY DS	T2	F3,F4	8.32	1.0	N/A	3.4	KINGSTON GARDINER TS DESN1	M11
HOYLE DS	Total	F1, F2	27.6	1.3	226.8	13.3		
HUNTSVILLE DS	T1	F2,F3	12.5	0.4	N/A	3.3	MUSKOKA TS	M9
HUNTSVILLE DS	T2	F4,F6	27.6	0.4	N/A	5.0	MUSKOKA TS	M9
HURON PARK DS	Total	F1,F3	4.16	0.1	N/A	1.6	CENTRALIA TS	M3
HURONDALE PDS	Total	F1,F2	8.32	0.3	N/A	1.6	SEAFORTH TS	M5
INDUSTRIAL ROAD DS	Total	F1,F2	12.5	1.6	N/A	5.0	CLARABELLE TS	M7
INGERSOLL TS	Total	M43,M44,M45,M46,M49,M50,M51,M52	27.6	28.0	N/A	Sum of Buses		
INGERSOLL TS	E	M43,M45,M49,M51	27.6	14.5	104.2	44.5		
INGERSOLL TS	Z	M44,M46,M50,M52	27.6	12.2	104.6	42.2		
INGLESIDE DS	Total	F1,F2	8.32	0.6	N/A	2.0	ST LAWRENCE TS	M26
INGLESIDE WEST DS	Total	F1,F2,F3	8.32	0.9	N/A	3.3	ST LAWRENCE TS	M26
IROQUOIS FALLS DS	Total	F1, F2, F3	12.5	2.0	35.0	5.6		
ISLAND GROVE DS	Total	F1,F2,F3	8.32	0.7	N/A	3.1	BROWN HILL TS	M11
IVY LEA DS	Total	F1,F2,F3	8.32	1.6	N/A	4.0	BROCKVILLE TS	M2
JARVIS DS	Total	F3	8.32	0.2	N/A	2.6	JARVIS TS	M4
JARVIS TS	BY	M1, M2, M3, M4, M5, M6, M7	27.6	27.6	35.4	67.6		
JASPER DS	Total	F1,F2	27.6	0.8	N/A	5.0	SMITHS FALLS TS	M28
JELLICOE DS	Total	F1	12.5	0.2	20.3	0.9		
JOHN TS DESN1	A17A18	For any information or inquiries please contact Toronto Hydro	13.8	29.2	85.8	29.2		
JOHN TS DESN1	A4A6	For any information or inquiries please contact Toronto Hydro	13.8	35.0	65.4	35.0		
JOHN TS DESN1	Total	For any information or inquiries please contact Toronto Hydro	13.8	64.2	N/A	Sum of Buses		
JOHN TS DESN2	A13A14	For any information or inquiries please contact Toronto Hydro	13.8	24.6	74.6	24.6		
JOHN TS DESN2	A3A5	For any information or inquiries please contact Toronto Hydro	13.8	34.0	65.4	34.0		
JOHN TS DESN2	Total	For any information or inquiries please contact Toronto Hydro	13.8	58.6	N/A	Sum of Buses		
JOHN TS DESN3	A11A12	For any information or inquiries please contact Toronto Hydro	13.8	45.3	95.2	45.3		
JOHN TS DESN3	A15A16	For any information or inquiries please contact Toronto Hydro	13.8	36.9	95.2	36.9		
JOHN TS DESN3	Total	For any information or inquiries please contact Toronto Hydro	13.8	82.2	N/A	Sum of Buses		
JOHNSTOWN DS	Total	F1,F2	8.32	1.0	N/A	TC	MORRISBURG TS	M23
JONES CREEK DS	Total	F1,F2,F3	8.32	1.2	N/A	3.6	BELLEVILLE TS	M7
JONES ROAD DS	Total	F1,F2,F3	12.5	1.6	N/A	4.5	BRACEBRIDGE TS	M21
JOYCEVILLE DS	Total	F1,F3	12.5	1.4	N/A	4.3	FRONTENAC TS	M1
KAKABEKA DS	Total	F1,F2	12.5	1.3	N/A	4.1	MURILLO DS	K3_4F
KAMREG DS	Total	F1	12.5	0.6	N/A	2.0	TIMMINS TS	M8
KAPUSKASING TS	EZ	M1, M2, M3, M4	24.9	6.2	148.7	TC		
KARS DS	Total	F1,F3	8.32	0.9	N/A	3.3	HAWTHORNE TS	M1
KEEWATIN DS	Total	F1, F2	12.5	0.6	182.1	6.6		
KEITH TS DESN1	BY	M1, M2, M3, M4, M5, M6	27.6	20.2	156.7	60.2		
KEMBLE DS	T2	F2	12.5	0.6	N/A	4.2	OWEN SOUND TS	M23
KEMBLE DS	T1	F5	8.32	0.7	N/A	4.3	OWEN SOUND TS	M23
KEMPTVIL HARRIET DS	Total	F1,F2,F3	4.16	0.6	N/A	3.0	SMITHS FALLS TS	M23
KEMPTVIL V BUREN DS	Total	F1,F2,F3	4.16	0.5	N/A	1.9	SMITHS FALLS TS	M23
KEMPTVILLE KING DS	Total	F1,F2,F3,F5	4.16	0.4	N/A	4.0	SMITHS FALLS TS	M23
KEMPTVILLE WEST DS	Total	F1,F2,F3	8.32	1.4	N/A	3.8	SMITHS FALLS TS	M23
KENILWORTH DS	Total	F1,F2	8.32	1.1	N/A	2.6	PALMERSTON TS	M2

Station Name	Bus Name	Feeder Name	Voltage (kV)	Minimum Load (MW)	Short Circuit Capacity (MVA)	Thermal Capacity (MW)	Upstream TS	Upstream TS feeder
KENILWORTH TS DESN1	EJ	M20, M21, M22, M23, M24, M25, M26, M27, M28, M29, M30	14.2	10.6	73.3	10.6		
KENILWORTH TS DESN2	B1Y1	M51, M52, M53, M54, M61, M62, M63, M64	14.2	26.6	74.1	74.6		
KENNISIS LAKE DS	Total	F1,F2,F3	12.5	1.2	N/A	4.1	MINDEN TS	M4
KENOGAMI DS	Total	F1,F2	12.5	0.3	N/A	5.1	KIRKLAND LAKE TS	G3K
KENORA DS	Total	F1, F2, F3, F4	12.5	2.1	23.3	8.1		
KENT TS DESN1	Total	M3,M4,M5,M6,M7,M8,M15,M16,M17,M18	27.6	30.2	N/A	Sum of Buses		
KENT TS DESN1	B	M3,M5,M7,M15,M17	27.6	13.5	124.1	29.5		
KENT TS DESN1	Y	M4,M6,M8,M16,M18	27.6	16.7	124.7	32.7		
KENT TS DESN2	EZ	M21,M22,M23,M24	27.6	12.8	174.1	32.8		
KERWOOD DS	Total	F1,F2,F3	8.32	0.9	N/A	2.6	STRATHROY TS	M1
KESWICK DS	Total	F1,F2,F3	8.32	1.9	N/A	5.0	BROWN HILL TS	M1
KILLALOE DS	Total	F1,F2,F3	12.5	1.1	N/A	TC	COBDEN TS	M6
KILLBEAR DS	Total	F1,F2,F3	12.5	1.0	N/A	3.9	PARRY SOUND TS	M1
KIMBERLEY DS	Total	F1,F2,F3	8.32	1.3	N/A	3.7	MEAFORD TS	M1
KINCARDINE DS #2	Total	F1,F2	8.32	0.4	N/A	1.8	DOUGLAS POINT TS	M6
KING EDWARD TS	JY	For any information or inquiries please contact Hydro Ottawa	12.5	15.8	97.2	15.8		
KING EDWARD TS	QZ	For any information or inquiries please contact Hydro Ottawa	12.5	12.1	96.9	12.1		
KING EDWARD TS	Total	For any information or inquiries please contact Hydro Ottawa	12.5	31.0	N/A	Sum of Buses		
KINGSTON GARDINER TS DESN1	BY	M3, M7, M8, M9, M10, M11, M12, M13, M14, M15	44	40.4	308.3	100.4		
KINGSTON GARDINER TS DESN2	JQ	M23,M24,M25,M26	44	24.2	510.7	64.2		
KINGSTON MILLS DS	Total	F1,F2	8.32	0.5	N/A	1.9	FRONTENAC TS	M3
KINGSVIL PULFORD DS	Total	F1,F2	8.32	1.0	N/A	3.4	KINGSVILLE TS	M5
KINGSVILLE TS	BY	M1,M2,M3,M4,M5,M6, M7, M8, M9, M10	27.6	34.3	367.1	74.3		
KINMOUNT DS	Total	F1,F2,F3	12.5	1.4	N/A	4.2	MINDEN TS	M3
KINTORE DS	Total	F1,F2,F3	8.32	0.7	N/A	3.1	INGERSOLL TS	M45
KIRBY DS	Total	F1,F2,F3	8.32	0.7	N/A	3.1	ENFIELD TS DESN1	M3
KIRKFIELD DS	Total	F1,F2,F3	8.32	1.6	N/A	4.0	BEAVERTON TS	M24
KIRKLAND LAKE DS #1	Total	F1,F2,F3	4.16	0.7	N/A	3.1	KIRKLAND LAKE TS	M61
KIRKLAND LAKE TS	EJ	M61,M62,G3K	44	8.2	487.0	28.2		
KIRKTON DS	Total	F1,F2,F3	8.32	0.7	N/A	3.1	CENTRALIA TS	M3
KLEINBURG TS	JQ	M23,M24,M25,M26,M27,M28	44	21.0	575.5	46.0		
KLEINBURG TS	BY	M3,M4,M5,M6,M7,M8	27.6	12.1	0.0	37.1		
KOMOKA DS	Total	F1,F2,F3	8.32	0.8	N/A	3.2	WONDERLAND TS	M2
LAFOREST ROAD DS	Total	F1, F2	27.6	3.4	176.6	TC		
LAGOON CITY DS	Total	F1,F2,F3	8.32	1.1	N/A	3.5	BEAVERTON TS	M26
LAKE ST.GEORGE DS	Total	F1,F2,F3	8.32	1.1	N/A	4.7	ORILLIA TS	M2
LAKE TS DESN1	BY	M1, M2, M3, M4, M5, M6	27.6	17.1	0.0	57.1		
LAKE TS DESN2	J1J2	M31, M32, M33, M41, M42, M43	13.8	7.4	36.2	7.4		
LAKE TS DESN2	Total	M31,M32,M33,M41,M42,M43,M71,M72,M73,M81,M82,M83	13.8	14.9	N/A	Sum of Buses		
LAKE TS DESN2	Q1Q2	M71, M72, M73, M81, M82, M83	13.8	8.9	28.2	8.9		
LAKE VERNON DS	Total	F1,F2,F3	12.5	1.8	N/A	4.7	MUSKOKA TS	M8
LAKEFIELD DS #1	Total	F1,F2	12.5	1.1	N/A	4.0	OTONABEE TS DESN2	M27
LAKEFIELD DS #2	T1	F1,F2,F3	4.16	0.6	N/A	3.0	OTONABEE TS DESN2	M27
LAKEFIELD DS #2	Total	F1,F2,F3,F4,F5,F6,F7	4.16	1.0	N/A	3.4	OTONABEE TS DESN2	M27
LAKEFIELD DS #2	T2	F4,F5,F6,F7	4.16	0.4	N/A	4.4	OTONABEE TS DESN2	M27
LAMBTON TS	Total	M1,M2,M3,M4,M5,M6	27.6	58.2	N/A	102.9		
LAMBTON TS	J	M1,M3,M5	27.6	12.4	325.0	57.2		
LAMBTON TS	Q	M2,M4,M6,M8	27.6	45.7	322.9	90.5		
LANARK DS	Total	F1,F2,F3	8.32	1.3	N/A	3.7	SMITHS FALLS TS	M26
LANCASTER DS	Total	F1,F2,F3	8.32	0.9	N/A	3.3	ST LAWRENCE TS	M25
LARCHWOOD DS	Total	F1,F2,F3	12.5	1.7	N/A	4.6	LARCHWOOD TS	M4
LARCHWOOD TS	Y	M3, M4	44	3.6	1,214.5	13.6		
LARDER LAKE DS	Total	F1,F2	4.16	0.3	N/A	1.9	KIRKLAND LAKE TS	M64
LAUZON TS DESN1	BQ	M1, M2, M3, M4, M5, M6, M7, M8	27.6	24.1	27.2	64.1		
LAUZON TS DESN2	EJ	M23, M24, M25, M26, M27, M28, M29	27.6	22.4	194.2	62.4		
LEAMINGTON DS #2	Total	F1,F2,F3	8.32	0.8	N/A	3.2	LEAMINGTON TS DESN1	M23
LEAMINGTON TS DESN1	Total	M21,M22,M23,M24,M26,M27,M28,M29,M30,M31,M32	27.6	21.0	N/A	Sum of Buses		
LEAMINGTON TS DESN1	B	M21,M23,M25,M27,M29,M31	27.6	9.5	136.1	a		

Station Name	Bus Name	Feeder Name	Voltage (kV)	Minimum Load (MW)	Short Circuit Capacity (MVA)	Thermal Capacity (MW)	Upstream TS	Upstream TS feeder
LEAMINGTON TS DESN1	Y	M22,M24,M26,M28,M30,M32	27.6	11.5	140.1	41.5		
LEAMINGTON TS DESN2	Total	M1,M2,M3,M4,M5,M6,M7,M8,M9,M10,M11,M12	27.6	0.0	N/A	Sum of Buses		
LEAMINGTON TS DESN2	J	M1,M3,M5,M7,M9,M11,	27.6	0.0	135.2	30.0		
LEAMINGTON TS DESN2	Q	M2,M4,M6,M8,M10,M12	27.6	0.0	138.0	30.0		
LEASIDE TS DESN1	A1A2Q1Q2	For any information or inquiries please contact Toronto Hydro	13.8	15.9	0.0	15.9		
LEASIDE TS DESN2	BY	M1,M2,M3,M4,M5,M6,M7,M8	27.6	18.0	67.4	18.0		
LEBEL DS	Total	F1	12.5	0.2	N/A	0.6	KIRKLAND LAKE TS	M64
LESLIE TS DESN1	H1	For any information or inquiries please contact Toronto Hydro	13.8	0.0	250.9	25.0		
LESLIE TS DESN1	H2	For any information or inquiries please contact Toronto Hydro	13.8	0.0	247.9	25.0		
LESLIE TS DESN1	BY	M2,M3,M4,M5,M6,M7,M8	27.6	18.4	69.2	18.4		
LESLIE TS DESN1	Total	M2,M3,M4,M5,M6,M7,M8	27.6	0.0	N/A	Sum of Buses		
LESLIE TS DESN2	J	M21,M23,M25,M27,M29,M31	27.6	17.0	62.9	33.0		
LESLIE TS DESN2	Total	M21,M23,M25,M27,M29,M31,M22,M24,M26,M28,M30,M32	27.6	37.2	N/A	Sum of Buses		
LESLIE TS DESN2	Q	M22,M24,M26,M28,M30,M32	27.6	20.8	66.0	36.8		
LILY LAKE DS	Total	F1,F2,F3	8.32	0.7	N/A	1.7	DOBBIN TS	M2
LIMOGES DS	Total	F1,F2,F3	8.32	1.2	N/A	TC	CHESTERVILLE TS	M1
LINCOLN HEIGHTS TS	B	For any information or inquiries please contact Hydro Ottawa	12.5	6.6	83.0	6.6		
LINCOLN HEIGHTS TS	Y	For any information or inquiries please contact Hydro Ottawa	12.5	9.8	82.3	9.8		
LINCOLN HEIGHTS TS	Total	For any information or inquiries please contact Hydro Ottawa	12.5	16.4	N/A	Sum of Buses		
LINDSAY ANGELIN S DS	Total	F80,F81,F82,F83	4.16	0.9	N/A	4.9	LINDSAY TS	M5
LINDSAY COLBORNE DS	Total	F40,F41,F42,F43	4.16	0.9	N/A	4.9	LINDSAY TS	M5
LINDSAY DENNISTON DS	Total	F70,F71,F72,F73	4.16	0.6	N/A	3.0	LINDSAY TS	M4
LINDSAY DURHAM W DS	T2	F50,F51,F52,F53	4.16	0.6	N/A	3.0	LINDSAY TS	M3
LINDSAY DURHAM W DS	Total	F20,F21,F22,F23,F50,F51,F52,F53	4.16	1.2	N/A	3.6	LINDSAY TS	M3
LINDSAY DURHAM W DS	T1	F20,F21,F22,F23	4.16	0.6	N/A	3.0	LINDSAY TS	M3
LINDSAY EASTVIEW DS	Total	F62,F63	4.16	0.4	N/A	1.9	LINDSAY TS	M4
LINDSAY EGLINGTON DS	T2	F10,F12,F13	4.16	0.7	N/A	2.6	LINDSAY TS	M4
LINDSAY EGLINGTON DS	Total	F10,F12,F13,F31,F35	4.16	1.1	N/A	4.7	LINDSAY TS	M4
LINDSAY EGLINGTON DS	T1	F31,F35	4.16	0.4	N/A	4.0	LINDSAY TS	M4
LINDSAY TS	BY	M3,M4,M5,M6,M7,M8	44	28.0	595.4	88.0		
LISGAR TS	JY	For any information or inquiries please contact Hydro Ottawa	12.5	14.0	111.3	14.0		
LISGAR TS	QZ	For any information or inquiries please contact Hydro Ottawa	12.5	11.5	112.0	11.5		
LISGAR TS	Total	For any information or inquiries please contact Hydro Ottawa	12.5	16.8	N/A	Sum of Buses		
LISTOWEL BRIGHT DS	Total	F1,F2,F3,F4	4.16	1.0	N/A	3.4	WINGHAM TS	M3
LISTOWEL DAVIDSON DS	Total	F1,F2,F3,F4	4.16	0.5	N/A	2.9	WINGHAM TS	M3
LISTOWEL ELMA DS	Total	F1,F2,F3,F4	4.16	0.8	N/A	3.2	WINGHAM TS	M3
LITTLE BRITAIN DS	Total	F1,F2,F3	8.32	0.9	N/A	3.3	LINDSAY TS	M8
LITTLE CURRENT DS	Total	F1,F2,F3	12.5	1.1	N/A	4.7	MANITOULIN TS	M26
LIVELY DS	Total	F1,F2,F3	12.5	1.9	N/A	5.0	CLARABELLE TS	M7
LODGEROOM DS	T2	F1,F2	12.5	1.1	11.1	7.1		
LODGEROOM DS	Total	F1,F2,F3,F4	12.5	2.4	12.2	8.4		
LODGEROOM DS	T1	F3,F4	12.5	1.4	10.8	8.1		
LONG SAULT NORTH DS	Total	F1,F2,F3	8.32	1.3	N/A	3.7	ST LAWRENCE TS	M26
LONGLAC EAST DS	Total	F1,F2	12.5	0.9	N/A	2.3	LONGLAC TS	M1
LONGLAC TS	Z	M1, M2	44	4.3	1,291.2	24.3		
LONGLAC WEST DS	Total	F1	12.5	0.4	N/A	5.2	LONGLAC TS	M1
LONGUEUIL DS	Total	F2,F3,F4,	27.6	2.9	N/A	5.0	LONGUEUIL TS	M25
LONGUEUIL TS	JQ	M23, M24, M25, M26	44	16.1	826.2	60.7		
LONGWOOD TS	JQ	M23, M24, M25, M26	27.6	8.5	169.2	48.5		
L'ORIGNAL DS	Total	F1,F2,F3	8.32	0.8	N/A	3.2	LONGUEUIL TS	M25
LORNE PARK TS	B	M1,M3,M5,M7,M9	27.6	23.2	100.0	39.2		
LORNE PARK TS	Total	M1,M3,M5,M7,M9,M2,M4,M6,M8,M10	27.6	40.6	N/A	Sum of Buses		
LORNE PARK TS	J	M2,M4,M6,M8,M10	27.6	17.2	101.5	33.2		
LUCAN DUCHESS PDS	Total	F1	4.16	0.2	N/A	1.4	CENTRALIA TS	M2
LUCAN MARKET DS - 8.32 KV	T1	F1,F2,F3	8.32	0.5	N/A	2.2	CENTRALIA TS	M2
LUCAN MARKET PDS	Total	F1,F2	4.16	0.4	N/A	1.6	CENTRALIA TS	M2
LUCKNOW DS	Total	F1,F2,F3	8.32	0.7	N/A	3.1	WINGHAM TS	M5
LYN DS	Total	F1,F2	8.32	0.9	N/A	2.3	BROCKVILLE TS	M2

Station Name	Bus Name	Feeder Name	Voltage (kV)	Minimum Load (MW)	Short Circuit Capacity (MVA)	Thermal Capacity (MW)	Upstream TS	Upstream TS feeder
LYNDHURST DS	Total	F1,F2	8.32	1.4	N/A	3.8	BROCKVILLE TS	M6
LYTHMORE DS	Total	F1,F2,F3	8.32	1.0	N/A	3.4	CALEDONIA TS	M3
MACKAY TS	T1	For any information or inquiries please contact Algoma Power Inc	23	0.0	655.6	2.4		
MACVILLE DS	Total	F1,F2,F3	8.32	1.0	N/A	3.4	KLEINBURG TS 44 KV	M27
MADAWASKA DS	Total	F1,F2	12.5	0.5	N/A	1.5	WALLACE TS	M6
MADOC DS #2	Total	F1,F2,F3	12.5	1.7	N/A	4.6	HAVELOCK TS	M2
MADOC MADAWASKA DS	Total	F1,F2,F3	12.5	0.6	N/A	3.5	HAVELOCK TS	M2
MADSEN DS	Total	F1,F2	4.16	0.3	N/A	3.1	RED LAKE TS	M4
MAIDSTONE DS	Total	F1,F2	8.32	0.8	N/A	3.2	LAUZON TS DESN2	M29
MAIN TS	A1A2	For any information or inquiries please contact Toronto Hydro	13.8	9.7	35.8	9.7		
MAIN TS	A3A4	For any information or inquiries please contact Toronto Hydro	13.8	13.4	66.9	13.4		
MAIN TS	Total	For any information or inquiries please contact Toronto Hydro	13.8	21.1	N/A	Sum of Buses		
MAIR MILLS DS	Total	F1,F2,F3	8.32	1.1	N/A	3.5	STAYNER TS	M6
MAITLAND DS	Total	F1,F2	8.32	0.7	N/A	2.2	BROCKVILLE TS	M5
MALDEN TS	B	M1, M3, M5, M7, M9, M11	27.6	25.4	83.4	50.4		
MALDEN TS	Total	M1, M3, M5, M7, M9, M11,M2, M4, M6, M8, M10, M12	27.6	41.4	N/A	Sum of Buses		
MALDEN TS	Y	M2, M4, M6, M8, M10, M12	27.6	16.2	80.2	41.2		
MALLORYTOWN DS	Total	F1,F2,F3	8.32	1.2	N/A	3.6	BROCKVILLE TS	M2
MALVERN TS	J	M21,M31,M33,M35	27.6	18.2	111.2	18.2		
MALVERN TS	Total	M21,M31,M33,M35,M22,M32,M34,M36	27.6	39.3	N/A	Sum of Buses		
MALVERN TS	Q	M22,M32,M34,M36	27.6	13.8	110.2	13.8		
MANBY TS DESN1	BY	M1,M3,M5,M7,M9,M12	27.6	13.9	146.8	33.9		
MANBY TS DESN2	QZ	M13,M16,M17,M20,M21,M24	27.6	20.5	173.9	40.5		
MANBY TS DESN3	VF	M4,M6,M8,M10,M23,M25,M27,M29	27.6	30.1	42.1	74.9		
MANITOULIN TS	J	M25	44	3.4	745.9	23.4		
MANITOULIN TS	Total	M25,M26	44	7.8	N/A	27.8		
MANITOULIN TS	Q	M26	44	4.3	741.8	24.3		
MANITOUWADGE DS	Total	F3	12.5	0.3	64.3	3.1		
MANITOUWADGE DS #2	T2	F2,F4	12.5	1.1	N/A	4.0	MANITOUWADGE TS	M3
MANITOUWADGE DS #2	T3	F2,F4	12.5	1.1	N/A	4.0	MANITOUWADGE TS	M3
MANITOUWADGE DS #2	Total	F2,F4	12.5	1.1	N/A	4.0	MANITOUWADGE TS	M3
MANITOUWADGE TS	B1B2	M1, M2, M3	44	6.6	220.5	26.6		
MANITOUWANING DS	Total	F1,F2,F3	12.5	1.3	N/A	5.0	MANITOULIN TS	M26
MANOTICK DS	T1	F1,F2	8.32	2.0	2.7	8.0		
MANOTICK DS	Total	F1,F2,F4,F5	8.32	2.0	6.7	8.0		
MANOTICK DS	T2	F4,F5	8.32	0.0	6.6	6.0		
MANSFIELD DS	Total	F1,F2,F3	8.32	1.1	N/A	3.5	STAYNER TS	M2
MARATHON DS	Total	F2, F3	24.9	0.4	396.9	10.0		
MARGACH DS	Total	F1, F2, F3	24.9	1.7	87.8	5.3		
MARIONVILLE DS	Total	F1, F2	27.6	3.7	239.3	15.7		
MARKDALE MCDUFF DS	Total	F1,F2,F3	4.16	0.4	N/A	2.8	OWEN SOUND TS	M26
MARKDALE TORONTO DS	Total	F1,F2,F3,F4	4.16	0.7	N/A	3.1	OWEN SOUND TS	M26
MARMION DS	Total	F1,F2	8.32	0.9	N/A	3.3	HANOVER TS	M4
MARMORA REGINALD DS	T1	F1,F2	12.5	0.4	N/A	3.2	HAVELOCK TS	M2
MARTHAVILLE DS	Total	F1,F2,F3	8.32	0.9	N/A	3.3	WANSTEAD TS	M2
MARTINDALE TS	BQ	M1, M2, M3, M4, M5, M6, M7	44	25.7	350.2	85.6		
MARTINTOWN DS	Total	F1,F2,F3	8.32	0.5	N/A	1.5	ST LAWRENCE TS	M25
MARYSVILLE DS	Total	F1,F2,F3	8.32	1.3	N/A	3.7	NAPANEE TS	M4
MASSEY DS	Total	F1, F3	12.5	1.1	26.2	4.0		
MATACHEWAN DS	Total	F1, F2	12.5	0.2	N/A	5.0	KIRKLAND LAKE TS	G3K
MATHESON DS	Total	F1,F2	12.5	0.4	N/A	2.1	RAMORE TS	M5
MATTAWA DS	B	F1,F2	24.9	1.6	434.8	7.6		
MAXVILLE GEORGE DS	Total	F1,F2	8.32	0.4	N/A	4.0	ST ISIDORE TS	M4
MAXVILLE PRINCE DS	Total	F1,F2	4.16	0.3	N/A	1.2	ST ISIDORE TS	M4
MAYNOOTH DS	Total	F1,F2,F3	12.5	0.9	N/A	2.4	WALLACE TS	M4
MAZINAW DS	Total	F1, F2	12.5	0.8	187.8	TC		
MCCRACKENS DS	Total	F1,F2,F3	12.5	1.8	N/A	4.7	HAVELOCK TS	M6
MCCRIMMON DS	Total	F1,F2,F3	8.32	1.5	N/A	3.9	ST ISIDORE TS	M3

Station Name	Bus Name	Feeder Name	Voltage (kV)	Minimum Load (MW)	Short Circuit Capacity (MVA)	Thermal Capacity (MW)	Upstream TS	Upstream TS feeder
MCCUE DS	Total	F1,F2,F3	8.32	0.7	N/A	3.1	SMITHS FALLS TS	M25
MCGOWAN LAKE DS	Total	F1,F2	12.5	1.3	N/A	4.2	PARRY SOUND TS	M3
MCGREGOR DS	Total	F1,F2,F3	8.32	1.1	N/A	3.5	MALDEN TS	M12
MCKELLAR DS	Total	F1,F2	12.5	0.8	N/A	3.7	PARRY SOUND TS	M3
MCNAB DS	Total	F1,F2,F3	12.5	1.6	N/A	4.5	STEWARTVILLE TS	M1
MEADOWVALE TS	EZ	M3, M4, M5, M6, M7, M8	44	69.2	313.0	129.2		
MEAFORD DS #2	Total	F1,F2	8.32	0.9	N/A	2.3	MEAFORD TS	M2
MEAFORD EDWIN DS	Total	F1,F2,F3	4.16	0.4	N/A	2.8	MEAFORD TS	M2
MEAFORD LOUISA DS	Total	F1	4.16	0.1	N/A	1.1	MEAFORD TS	M2
MEAFORD THOMPSON DS	Total	F1,F2,F3	4.16	0.8	N/A	3.2	MEAFORD TS	M2
MEAFORD TS	BY	M1, M2	44	14.3	991.2	34.3		
MEAFORD VINCENT DS	Total	F1,F2,F3	4.16	0.6	N/A	3.0	MEAFORD TS	M2
MEDONTE DS	Total	F1,F2	27.6	1.5	N/A	5.0	MIDHURST TS - DESN1	M9
MERLIN DS	Total	F1,F2	8.32	0.3	N/A	2.7	KENT TS DESN2	M23
MERRICKVILLE DS	Total	F1,F2,F3	8.32	1.3	N/A	3.7	SMITHS FALLS TS	M22
METCALFE DS	Total	F1,F2,F3	8.32	0.9	N/A	3.3	HAWTHORNE TS	M1
MIDHURST DS	Total	F1,F2,F3,F4	8.32	2.1	N/A	5.0	MIDHURST TS - DESN1	M9
MIDHURST TS DESN1	BY	M3, M4, M5, M6, M7, M8, M9, M10	44	59.4	362.6	119.4		
MIDHURST TS DESN2	JQ	M21,M22,M23, M24,M25,M26,M27,M28	44	11.5	357.5	71.5		
MILDMAY DS	Total	F1,F2,F3	8.32	1.3	N/A	3.7	HANOVER TS	M2
MILFORD DS	Total	F1,F2	8.32	0.7	N/A	1.7	PICTON TS	M5
MILLBROOK DS	Total	F1,F2,F3	8.32	1.6	N/A	4.0	DOBBIN TS	M5
MILLGROVE DS	Total	F1,F2,F3	8.32	0.7	N/A	3.1	DUNDAS TS	M1
MILLINGTON DS	Total	F1,F2,F3	8.32	1.0	N/A	3.4	BEAVERTON TS	M26
MILSAP DS	Total	F1,F2,F3	8.32	0.9	N/A	3.3	NAPANEE TS	M2
MILVERTON DS #1	Total	F1,F2,F3,F4	4.16	0.7	N/A	3.1	PALMERSTON TS	M3
MILVERTON DS #2	Total	F1,F2,F3	8.32	1.3	N/A	3.7	PALMERSTON TS	M3
MINAKI DS	Total	F1,F2	24.9	0.3	32.2	6.3		
MINDEMOYA DS	Total	F1,F2	12.5	0.9	N/A	3.8	MANITOULIN TS	M25
MINDEN DS	Total	F1,F2,F3	12.5	0.9	N/A	3.8	MINDEN TS	M3
MINDEN TS	JQ	M1,M2,M3,M4	44	26.8	565.0	66.6		
MINETT DS	Total	F1,F2,F3	12.5	1.7	N/A	4.6	MUSKOKA TS	M1
MITCHELL DS	Total	F1,F2	8.32	0.9	N/A	3.3	STRATFORD TS	M6
MODELAND TS	Total	M23,M24,M25,M26,M27,M28,M29,M30,M31	27.6	38.6	N/A	Sum of Buses		
MODELAND TS	J	M23,M25,M27,M29,M31	27.6	19.4	82.6	44.4		
MODELAND TS	Q	M24,M26,M28,M30	27.6	19.3	83.8	44.3		
MOHAWK TS	B1B2	M51,M52,M53,M61,M62,M63,M64	13.8	11.7	98.9	11.7		
MOHAWK TS	Total	M51,M52,M53,M61,M62,M63,M64,M71,M72,M73,M81,M82,M83	13.8	20.7	N/A	Sum of Buses		
MOHAWK TS	Y1Y2	M71,M72,M73,M81,M82,M83	13.8	8.9	97.9	8.9		
MONKTON DS	Total	F1,F2	8.32	0.8	N/A	3.2	PALMERSTON TS	M1
MONO MILLS DS	Total	F1,F2,F3	12.5	1.1	N/A	4.0	ORANGEVILLE TS DESN2	M6
MONTEITH DS	Total	F1, F2	12.5	0.7	46.5	6.7		
MOONSTONE DS	Total	F1,F2,F3	8.32	1.0	N/A	3.4	WAUBAUSHENE TS	M5
MOOSE LAKE TS	Total	M2,M3,M5,M6	44	1.8	N/A	5.7		
MOOSE LAKE TS	B2	M2,M5	44	0.8	1,147.6	4.6		
MOOSE LAKE TS	B3	M3,M6	44	1.1	1,083.3	8.3		
MOOSONEE DS	Total	F1, F2, F3	24.9	2.0	216.1	5.6		
MORRISBURG TS	JQ	M23, M24, M25, M26	44	17.9	746.8	TC		
MORRISH CHURCH DS	Total	F1,F2,F3	8.32	0.6	N/A	3.0	PORT HOPE TS DESN1	M18
MOUNT ALBERT DS	Total	F1,F2,F3	8.32	1.9	N/A	5.0	BROWN HILL TS	M5
MOUNT BRYDGES DS	Total	F1,F2,F3	8.32	1.1	N/A	4.7	LONGWOOD TS	M23
MOUNT CARMEL DS	Total	F2,F3	8.32	0.7	N/A	3.1	CENTRALIA TS	M4
MOUNT FOREST DS #2	Total	F1,F2,F3	8.32	1.1	N/A	3.5	HANOVER TS	M5
MOUNT HOPE DS	Total	F1,F3	8.32	0.9	N/A	3.3	NEBO TS DESN1	M11
MOUNTAIN CHUTE DS	Total	F1, F2	12.5	0.1	181.7	6.1		
MOUNTAIN LAKE DS	Total	F1,F2,F3	12.5	1.3	N/A	4.2	HAVELOCK TS	M6
MOUNTAIN VIEW NTH DS	Total	F1,F2,F3	8.32	1.3	N/A	3.7	BELLEVILLE TS	M6
MOUNTJOY DS	Total	F1,F2	12.47	0.4	N/A	1.9	TIMMINS TS	M7

Station Name	Bus Name	Feeder Name	Voltage (kV)	Minimum Load (MW)	Short Circuit Capacity (MVA)	Thermal Capacity (MW)	Upstream TS	Upstream TS feeder
MURILLO DS	Total	F1,F2,F3,F4,F5,F6,F7,F8	24.9	5.0	170.3	18.4		
MURILLO DS	T1	F1,F3,F5,F7	24.9	2.5	144.0	9.2		
MURILLO DS	T2	F2,F4,F6,F8	24.9	2.5	137.2	9.2		
MURRAY HILLS DS	Total	F1,F2	27.6	1.2	N/A	5.0	SIDNEY TS	R8S
MURRAY TS DESN1	Y1Y2	M25,M26,M27,M28,M29,M30	13.8	12.4	88.9	12.4		
MURRAY TS DESN1	QZ	M51,M52,M53,M54,M55,M56	13.8	12.0	84.6	12.0		
MURRAY TS DESN1	Total	M51,M52,M53,M54,M55,M56,M25,M26,M27,M28,M29,M30	13.8	24.3	N/A	Sum of Buses		
MURRAY TS DESN2	J	M10,M11,M13	13.8	1.4	119.2	1.4		
MURRAY TS DESN2	Total	M10,M11,M13,M14,M15,M16,M17,M18	13.8	16.6	N/A	Sum of Buses		
MURRAY TS DESN2	K	M14,M15,M16,M17,M18	13.8	9.4	119.2	9.4		
MUSKOKA FALLS DS	Total	F1,F2,F3	12.5	1.7	N/A	4.6	MUSKOKA TS	M7
MUSKOKA TS	BY	M1, M2, M3, M4, M5, M6, M7, M8, M9, M10	44	39.1	659.2	99.1		
NAKINA DS	Total	F1,F2	12.5	0.6	N/A	2.0	LONGLAC TS	M2
NAPANEE DS #2	Total	F1,F2,F3	8.32	1.1	N/A	3.5	NAPANEE TS	M1
NAPANEE INDUSTRIAL DS	Total	F1,F2,F3	4.16	0.9	N/A	3.3	NAPANEE TS	M1
NAPANEE MILL DS	Total	F4,F5,F6	4.16	0.6	N/A	3.0	NAPANEE TS	M3
NAPANEE NORTH DS	Total	F7,F8,F9	4.16	0.5	N/A	2.9	NAPANEE TS	M2
NAPANEE TS	Total	M1,M2,M3,M4	44	32.0	N/A	72.0		
NAPANEE TS	B	M1,M3	44	12.6	975.4	52.6		
NAPANEE TS	Y	M2,M4	44	14.0	970.5	54.0		
NAVAN DS	T1	F1,F2,F3	8.32	0.5	21.4	3.4		
NAVAN DS	T2	F4	27.6	0.6	131.9	7.8		
NEBO TS DESN1	Total	M1,M2,M3,M4,M5,M6,M7,M8,M9,M10,M11,M12	27.6	23.0	N/A	Sum of Buses		
NEBO TS DESN1	B	M1,M3,M5,M7,M9,M11	27.6	11.5	48.6	41.5		
NEBO TS DESN1	Y	M2,M4,M6,M8,M10,M12	27.6	11.5	50.0	41.5		
NEBO TS DESN2	JQ	M51, M52, M53, M54, M61, M62, M63, M64	13.8	15.0	48.3	15.0		
NELSON TS DESN1	BQ	M21,M22,M23,M24,M25,M26,M27,M28	27.6	20.0	68.4	59.8		
NEPEAN TS	JQ	M23, M24, M25, M26, M27, M28	44	40.7	389.0	100.7		
NESTLETON DS	Total	F1,F2,F3	8.32	0.9	N/A	3.3	ENFIELD TS DESN1	M4
NESTOR FALLS DS	Total	F1, F2	12.5	0.7	53.2	6.7		
NEUSTADT DS	Total	F1,F2,F3	8.32	1.1	N/A	3.5	HANOVER TS	M5
NEW LISK HALIBTON DS	Total	F1,F2,F3	12.5	1.8	N/A	3.2	DYMOND TS	M4
NEW LISK NIPISSNG DS	Total	F1,F2,F3	12.5	1.7	N/A	4.5	DYMOND TS	M2
NEWBORO DS	Total	F1,F2,F3	8.32	1.5	N/A	5.0	CROSBY TS DESN1	M5
NEWINGTON DS	Total	F1, F2	27.6	0.4	428.5	TC		
NEWPORT DS	Total	F1	8.32	0.4	N/A	1.3	BRANTFORD TS	M27
NEWTON TS	Total	M1,M2,M3,M4,M5,M6,M7,M8,M9,M10	13.8	14.4	N/A	Sum of Buses		
NEWTON TS	B	M1,M3,M6,M8,M10	13.8	8.5	81.7	26.5		
NEWTON TS	Y	M2,M4,M5,M7,M9	13.8	5.7	81.8	23.7		
NEWTONVILLE DS	Total	F1,F2	8.32	0.8	N/A	3.2	PORT HOPE TS DESN1	M18
NIPIGON DS	Total	F1, F2	12.5	0.8	180.8	6.8		
NOBLETON DS 27.6 kV	T1	F1,F2	27.6	1.9	N/A	7.7	KLEINBURG TS 44 KV	M24
NOBLETON DS 8.32 kV	T2	F5,F6	8.32	0.9	N/A	3.3	KLEINBURG TS 44 KV	M24
NOELVILLE DS	Total	F1,F2	12.5	1.1	N/A	2.6	MARTINDALE TS	M5
NORFOLK TS	BY	M1, M2, M3, M4, M5, M6	27.6	15.9	25.0	55.9		
NORTH AUGUSTA DS	Total	F2,F3	8.32	0.8	N/A	2.3	BROCKVILLE TS	M5
NORTH AUGUSTA DS #2	T1	F51,F52,F53	8.32	1.4	N/A	7.4	BROCKVILLE TS	M4
NORTH AUGUSTA DS #2	Total	F51,F52,F53,F56,F57	8.32	2.4	N/A	8.4	BROCKVILLE TS	M4
NORTH AUGUSTA DS #2	T2	F56,F57	8.32	1.0	N/A	7.0	BROCKVILLE TS	M4
NORTH BAY TS	BY	M1, M3	44	5.7	1,076.2	25.7		
NORTH COBALT DS	Total	F1,F2,F3	12.5	1.0	N/A	3.9	DYMOND TS	M2
NORTH PORCUPINE DS	Total	F2	4.16	0.2	N/A	1.7	HOYLE DS	F2
NORTH SHORE DS	Total	F1, F2	24.9	1.8	439.7	7.8		
NORTHBROOK DS	Total	F1, F2, F3	12.5	1.7	57.0	7.7		
NORTHCOTE DS	Total	F1,F2,F3	12.5	1.3	N/A	TC	COBDEN TS	M2
NORTHERN AVENUE TS	T1	For any information or inquiries please contact Algoma Power Inc	34.5	0.0	490.7	9.6		
NORWICH NORTH DS	Total	F1,F2,F3	8.32	1.0	N/A	3.4	TILLSONBURG TS	M3
NORWOOD DS	Total	F1,F2,F3	8.32	1.3	N/A	3.7	OTONABEE TS DESN2	M28

Station Name	Bus Name	Feeder Name	Voltage (kV)	Minimum Load (MW)	Short Circuit Capacity (MVA)	Thermal Capacity (MW)	Upstream TS	Upstream TS feeder
NOTTAWAGA DS	Total	F1,F2,F3	8.32	0.8	N/A	3.2	WAUBAUSHENE TS	M7
OAKVILLE TS	E	M43,M45,M47,M49,M51	27.6	28.1	75.1	53.1		
OAKVILLE TS	Total	M43,M45,M47,M49,M51,M44,M46,M48,M50,M52	27.6	52.5	N/A	Sum of Buses		
OAKVILLE TS	Z	M44,M46,M48,M50,M52	27.6	24.4	73.2	49.4		
OAKWOOD DS	Total	F1,F2,F3	8.32	1.3	N/A	3.7	LINDSAY TS	M8
ODESSA DS	Total	F1,F2,F3	8.32	1.3	N/A	3.7	KINGSTON GARDINER TS DESN1	M14
OIL SPRINGS DS	Total	F1,F2	8.32	0.5	N/A	2.4	WANSTEAD TS	M4
OLD SCHOOL DS	T1	F1, F2	27.6	2.9	N/A	10.6	Pleasant TS DESN1	M21
OLD SCHOOL DS	Total	F1,F2,F3,F4	27.6	4.4	N/A	12.1	Pleasant TS DESN1	M21
OLD SCHOOL DS	T2	F3, F4	27.6	1.5	N/A	9.2	Pleasant TS DESN1	M21
OMEMEE CHURCH DS	Total	F1,F2	8.32	0.5	N/A	2.9	DOBBIN TS	M2
OMEMEE DS	Total	F1,F2,F3	8.32	1.1	N/A	3.5	DOBBIN TS	M2
ONAPING DS	Total	F1,F2,F3	12.5	0.9	N/A	3.8	LARCHWOOD TS	M3
OPS DS	Total	F1,F2,F3	12.5	1.2	N/A	4.1	LINDSAY TS	M6
ORANGEVILLE DS #3	Total	F1,F2,F3	12.5	0.9	N/A	3.8	ORANGEVILLE TS DESN2	M3
ORANGEVILLE TS DESN1	EZ	M23,M24,M25,M26	27.6	9.2	0.0	25.2		
ORANGEVILLE TS DESN2	BY	M1,M2,M3,M4,M5,M6,M45,M46	44	34.1	355.5	74.1		
ORILLIA CENTRAL DS	Total	F1,F2,F3,F4	4.16	1.0	N/A	4.6	ORILLIA TS	M5
ORILLIA COUCHACHING DS	Total	F1,F2,F3	13.8	1.4	N/A	7.4	ORILLIA TS	M8
ORILLIA JAMES	Total	F1,F2,F3	13.8	1.5	N/A	5.0	ORILLIA TS	M5
ORILLIA JARVIS DS	Total	F1,F2,F3	4.16	0.6	N/A	4.6	ORILLIA TS	M8
ORILLIA LAKEVIEW DS	Total	F1,F2,F3	4.16	0.5	N/A	2.9	ORILLIA TS	M8
ORILLIA NORTH DS	Total	F1,F2,F3	4.16	0.6	N/A	3.0	ORILLIA TS	M8
ORILLIA PROGRESS PARK DS	Total	F1,F2,F3	13.8	0.6	N/A	3.0	ORILLIA TS	M1
ORILLIA TS	BY	M1,M2,M3,M4,M5,M6, M7, M8	44	40.4	451.4	100.4		
ORILLIA UHTHOFF DS	T1	F1	13.8	0.9	N/A	6.9	ORILLIA TS	M4
ORILLIA UHTHOFF DS	Total	F1,F2,F3	13.8	2.6	N/A	8.6	ORILLIA TS	M4
ORILLIA UHTHOFF DS	T2	F2,F3	13.8	1.7	N/A	7.7	ORILLIA TS	M4
ORILLIA WESTMOUNT DS	T1	F1,F2	13.8	1.6	N/A	7.6	ORILLIA TS	M4
ORILLIA WESTMOUNT DS	Total	F1,F2,F3,F4	13.8	3.1	N/A	9.1	ORILLIA TS	M4
ORILLIA WESTMOUNT DS	T2	F3,F4	13.8	1.5	N/A	7.5	ORILLIA TS	M4
ORLEANS TS	JQ	M1, M2, M3, M4, M5, M6, M7, M8	27.6	0.0	412.5	40.0		
ORO DS	Total	F1,F2,F3	8.32	1.5	N/A	3.9	MIDHURST TS - DESN1	M4
ORONO DS	Total	F1,F2,F3	8.32	0.9	N/A	3.3	ENFIELD TS DESN1	M3
OSGOODE DS	T2	F4	27.6	0.9	N/A	8.9	HAWTHORNE TS	M1
OSGOODE DS	Total	F4,F5,F7	27.6	3.0	N/A	11.0	HAWTHORNE TS	M1
OSGOODE DS	T3	F5,F7	27.6	2.1	N/A	10.1	HAWTHORNE TS	M1
OSLER DS	Total	F1,F2,F3	8.32	1.2	N/A	3.6	STAYNER TS	M6
OSPRINGE DS	Total	F1,F2,F3	8.32	0.6	N/A	3.0	FERGUS TS	M2
OSTRANDER DS	Total	F1,F2,F3	8.32	1.3	N/A	4.9	TILLSONBURG TS	M3
OTONABEE DS	Total	F1,F2,F3	8.32	0.9	N/A	2.3	OTONABEE TS DESN2	M28
OTONABEE TS DESN1	JQ	M8,M9,M10,M11,M12	27.6	14.3	22.0	39.3		
OTONABEE TS DESN2	BY	M25,M26,M27,M28	44	12.2	679.3	37.2		
OTTER LAKE DS	Total	F1,F2,F3	8.32	0.8	N/A	3.2	SMITHS FALLS TS	M25
OTTERVILLE DS	Total	F1,F2	8.32	0.9	N/A	3.3	TILLSONBURG TS	M1
OTTO HOLDEN TS	Y	M1	13.8	1.1	0.1	1.1		
OUSTIC DS	Total	F1,F2,F3	8.32	0.5	N/A	2.9	FERGUS TS	M2
OVERBROOK TS	J	For any information or inquiries please contact Hydro Ottawa	12.5	11.0	97.3	11.0		
OVERBROOK TS	Q	For any information or inquiries please contact Hydro Ottawa	12.5	16.4	96.2	16.4		
OVERBROOK TS	Total	For any information or inquiries please contact Hydro Ottawa	12.5	27.5	N/A	Sum of Buses		
OWEN SND 12 ST E DS	T1	F1,F2,F3,F4	4.16	0.8	N/A	4.8	OWEN SOUND TS	M22
OWEN SND 12 ST E DS	Total	F1,F2,F3,F4,F5,F6,F7,F8	4.16	1.5	N/A	5.5	OWEN SOUND TS	M22
OWEN SND 12 ST E DS	T2	F5,F6,F7,F8	4.16	0.6	N/A	4.6	OWEN SOUND TS	M22
OWEN SND 12 ST W DS	Total	F1,F2,F3,F4,F5	4.16	1.1	N/A	5.9	OWEN SOUND TS	M28
OWEN SND 16 AVE E DS	Total	F2,F3,F4,F5	13.8	0.9	N/A	5.7	OWEN SOUND TS	M21
OWEN SND 2 AVE E DS	Total	F1,F2,F3,F4	4.16	0.8	N/A	4.8	OWEN SOUND TS	M28
OWEN SND 24 ST W DS	Total	F2,F3	4.16	0.6	N/A	4.6	OWEN SOUND TS	M22
OWEN SND 3 AVE E DS	Total	F1,F2,F3	4.16	0.7	N/A	3.1	OWEN SOUND TS	M22

Station Name	Bus Name	Feeder Name	Voltage (kV)	Minimum Load (MW)	Short Circuit Capacity (MVA)	Thermal Capacity (MW)	Upstream TS	Upstream TS feeder
OWEN SND 6 ST E DS	Total	F1,F2,F3,F4	4.16	0.9	N/A	3.3	OWEN SOUND TS	M22
OWEN SOUND DS #2	Total	F1,F2	8.32	0.6	N/A	1.5	OWEN SOUND TS	M23
OWEN SOUND TS	JQ	M21, M22, M23, M24, M25, M26, M28	44	45.4	544.4	105.4		
OXFORD MILLS DS	Total	F1,F2,F3	8.32	1.2	N/A	3.6	SMITHS FALLS TS	M23
OXLEY DS	Total	F1,F2,F3	8.32	0.7	N/A	2.5	KINGSVILLE TS	M1
OXMEAD DS	Total	F1,F2,F3	8.32	1.8	N/A	5.0	MEAFORD TS	M2
PAISLEY DS #2 - 4.16 kV	T2	F3,F4,F5	4.16	0.3	N/A	2.7	HANOVER TS	M4
PAISLEY DS #2 - 8.32 kV	T1	F1,F2,	8.32	0.3	N/A	2.7	HANOVER TS	M4
PAKENHAM DS	Total	F1,F2,F3	12.5	1.1	N/A	4.0	ALMONTE TS	M25
PALERMO TS	BY	M1, M2, M3, M4, M5, M6, M7, M8	27.6	31.2	29.6	71.0		
PALMERSTON TS	QZ	M1, M2, M3, M4	44	15.8	1,071.0	55.6		
PARK ROAD DS	Total	F1,F2,F3,F4	27.6	6.1	N/A	10.9	WILSON TS DESN2	M16
PARK ROAD DS	T1	F1,F3	27.6	3.7	N/A	8.5	WILSON TS DESN2	M16
PARK ROAD DS	T2	F2,F4	27.6	2.4	N/A	10.4	WILSON TS DESN2	M16
PARKHILL DS	Total	F1,F2,F3	8.32	0.7	N/A	2.4	CENTRALIA TS	M4
PARRY SOUND TS	BY	M1, M2, M3, M4	44	14.0	761.0	34.1		
PAUDASH DS	Total	F1,F3	12.5	1.1	N/A	4.0	HAVELOCK TS	M1
PEARL LAKE DS	Total	F1,F2,F3	8.32	1.4	N/A	3.8	HANOVER TS	M4
PEFFERLAW DS	Total	F1,F2	8.32	0.8	N/A	1.7	BEAVERTON TS	M27
PELEE ISLAND DS	Total	F1,F2,F3	7.2	0.3	N/A	1.5	KINGSVILLE TS	M9
PELHAM CENTRE DS	Total	F1,F2	8.32	1.4	N/A	5.0	ALLANBURG TS	M7
PEMBROKE DS	Total	F1,F2,F3	12.5	1.2	N/A	TC	PEMBROKE TS	M2
PEMBROKE TS	BY	M1, M2, M3	44	5.3	1,126.7	TC		
PERRAULT FALLS DS	Total	F1,F2	12.5	0.1	51.6	6.1		
PERTH DS	Total	F1,F2,F3	8.32	0.8	N/A	2.3	SMITHS FALLS TS	M21
PERTH HALTON DS	Total	F1,F2,F3	4.16	0.3	N/A	1.7	SMITHS FALLS TS	M25
PERTH NORTH DS	Total	F1,F2,F3,F4,F5	4.16	0.6	N/A	4.6	SMITHS FALLS TS	M25
PERTH SCOTCH LINE DS	Total	F1,F2,F3,F4	4.16	0.4	N/A	4.4	SMITHS FALLS TS	M25
PERTH SUNSET DS	Total	F1,F2,F3,F4	4.16	0.5	N/A	2.9	SMITHS FALLS TS	M25
PERTH WILSON DS	Total	F1,F2,F3,F4	4.16	0.4	N/A	4.4	SMITHS FALLS TS	M26
PETAWAWA DS	Total	F1,F2,F3,F4,F5,F6	12.5	3.8	60.0	9.8		
PETAWAWA DS	T1	F1,F4,F5	12.5	2.0	51.0	8.0		
PETAWAWA DS	T2	F2,F3,F6	12.5	1.8	35.1	7.8		
PETERBOROUGH ASHBURNHAM DS	Total	F1,F3	4.16	0.1	N/A	2.5	OTONABEE TS DESN2	M26
PETERBOROUGH AYLMER DS	T3	F10,F11	4.16	0.4	N/A	1.8	DOBBIN TS	M8
PETERBOROUGH AYLMER DS	T1	F2,F7	4.16	0.4	N/A	1.9	DOBBIN TS	M8
PETERBOROUGH AYLMER DS	Total	F2,F7,F8,F9,F10,F11	4.16	1.2	N/A	2.6	DOBBIN TS	M8
PETERBOROUGH AYLMER DS	T2	F8,F9	4.16	0.4	N/A	1.8	DOBBIN TS	M8
PETERBOROUGH BELLEVUE DS	Total	F1,F2,F3,F4	4.16	0.6	N/A	4.2	DOBBIN TS	M7
PETERBOROUGH CLIFTON	Total	F1,F2,F4	4.16	0.6	N/A	3.3	DOBBIN TS	M7
PETERBOROUGH ERSKINE DS	T1	F1,F2	4.16	0.4	N/A	1.8	OTONABEE TS DESN2	M25
PETERBOROUGH ERSKINE DS	Total	F1,F2,F3,F6	4.16	0.8	N/A	2.2	OTONABEE TS DESN2	M25
PETERBOROUGH ERSKINE DS	T2	F3,F6	4.16	0.4	N/A	2.3	OTONABEE TS DESN2	M25
PETERBOROUGH FRANCIS STEWART DS	Total	F1,F2,F3	4.16	0.0	N/A	2.7	DOBBIN TS	M7
PETERBOROUGH HIGH DS	Total	F1,F2,F3	4.16	0.6	N/A	3.0	DOBBIN TS	M8
PETERBOROUGH HILLIARD DS	Total	F1,F2	27	2.5	N/A	20.9	DOBBIN TS	M7
PETERBOROUGH LANGTON DS	T1	F2,F4	4.16	0.2	N/A	2.6	DOBBIN TS	M7
PETERBOROUGH LANGTON DS	Total	F2,F4,F5,F6	4.16	0.3	N/A	2.7	DOBBIN TS	M7
PETERBOROUGH LANGTON DS	T2	F5,F6	4.16	0.3	N/A	2.7	DOBBIN TS	M7
PETERBOROUGH LANSDOWNE DS	T1	F1,F2,F3	8.32	0.8	N/A	3.2	DOBBIN TS	M6
PETERBOROUGH LANSDOWNE DS	Total	F1,F2,F3,F4,F5,F6	8.32	1.5	N/A	3.0	DOBBIN TS	M6
PETERBOROUGH LANSDOWNE DS	T2	F4,F5,F6	8.32	0.7	N/A	2.2	DOBBIN TS	M6
PETERBOROUGH MCDONNEL DS	T1	F1,F2	4.16	0.4	N/A	6.4	DOBBIN TS	M4
PETERBOROUGH MCDONNEL DS	Total	F1,F2,F4,F5	4.16	1.1	N/A	3.8	DOBBIN TS	M4
PETERBOROUGH MCDONNEL DS	T2	F4,F5	4.16	0.7	N/A	3.4	DOBBIN TS	M4
PETERBOROUGH ROMAINE DS	Total	F1,F2	4.16	0.4	N/A	3.1	OTONABEE TS DESN2	M25
PETERBOROUGH SHERBROOKE DS	Total	F1,F2	4.16	0.6	N/A	3.0	DOBBIN TS	M8
PETERBOROUGH SIMCOE DS	T1	F1,F2	4.16	0.3	N/A	2.2	OTONABEE TS DESN2	M26

Station Name	Bus Name	Feeder Name	Voltage (kV)	Minimum Load (MW)	Short Circuit Capacity (MVA)	Thermal Capacity (MW)	Upstream TS	Upstream TS feeder
PETERBOROUGH SIMCOE DS	Total	F1,F2,F5,F6	4.16	0.6	N/A	2.5	OTONABEE TS DESN2	M26
PETERBOROUGH SIMCOE DS	T2	F5,F6	4.16	0.3	N/A	2.2	OTONABEE TS DESN2	M26
PETERBOROUGH WALLIS DS	Total	F1,F3	4.16	0.5	N/A	3.2	DOBBIN TS	M4
PETERS CORNERS DS	Total	F1,F2,F3	8.32	0.3	N/A	2.7	BROWN HILL TS	M2
PETHERICKS CORNRS DS	Total	F1,F2,F3	12.5	1.1	N/A	4.0	HAVELOCK TS	M4
PIC DS	Total	F1,F2	24.9	1.1	88.2	7.1		
PICTON BARKER DS	Total	F1,F2,F3,F4	4.16	0.6	N/A	3.0	PICTON TS	M6
PICTON DISRAELI DS	Total	F5,F6,F7	4.16	0.5	N/A	2.9	PICTON TS	M6
PICTON DS	Total	F1,F2,F3	8.32	1.0	N/A	3.4	PICTON TS	M6
PICTON TS	BY	M5,M6,M7,M8	44	17.2	595.8	57.2		
PICTON UPPER LAKE DS	Total	F8,F9,F10,F11	4.16	0.4	N/A	2.8	PICTON TS	M6
PIGEON LAKE DS	Total	F1,F2,F3	8.32	1.1	N/A	3.5	DOBBIN TS	M2
PINE RIVER DS	Total	F1,F2,F3	8.32	1.5	N/A	3.9	DOUGLAS POINT TS	M6
PINEGROVE DS	Total	F1,F2,F3	12.5	1.0	N/A	3.9	ARNPRIOR TS	M1
PINELANDS DS	Total	F1,F2,F3	12.5	1.8	N/A	4.7	MUSKOKA TS	M1
PINESTONE DS	Total	F1,F2,F3	12.5	1.5	N/A	5.0	MINDEN TS	M4
PLAINFIELD DS	Total	F1,F2,F3	8.32	1.7	N/A	4.1	BELLEVILLE TS	M2
PLANTAGENET DS	Total	F1,F2,F3	8.32	0.7	N/A	3.1	LONGUEUIL TS	M26
PLATTSVILLE DS	Total	F1,F2	8.32	0.8	N/A	2.5	WOLVERTON DS	F1
PLEASANT POINT DS	Total	F1,F2,F3	12.5	1.2	N/A	4.1	LINDSAY TS	M6
PLEASANT TS DESN1	JQ	M21,M22,M23,M24,M25,M26,M27,M28	44	40.9	236.5	100.9		
PLEASANT TS DESN2	EZ	M43, M44, M45, M46, M47, M48	27.6	26.7	110.2	51.7		
PLEASANT TS DESN2	BY	M7, M8, M9,M10, M11, M12, M13, M14	27.6	12.2	109.1	37.2		
PLEASANT TS DESN2	Total	M7, M8, M9,M10, M11, M12, M13, M14,M43, M44, M45, M46, M47, M48	27.6	38.9	N/A	Sum of Buses		
PLEASANT TS DESN3	F	M61, M63, M65, M67, M69, M71	27.6	2.7	60.1	27.7		
PLEASANT TS DESN3	Total	M61, M63, M65, M67, M69, M71,M62, M64, M66, M68, M70, M72	27.6	6.3	N/A	Sum of Buses		
PLEASANT TS DESN3	V	M62, M64, M66, M68, M70, M72	27.6	3.6	62.9	28.6		
PLEASANTVILLE DS	Total	F1,F2,F3	8.32	0.8	N/A	3.2	HOLLAND TS	M9
POINTE AU BARIL DS	Total	F1,F2	12.5	0.8	N/A	3.2	PARRY SOUND TS	M1
PONSONBY DS	Total	F1,F2,F3	8.32	1.1	N/A	3.5	FERGUS TS	M7
POONAMALIE DS	Total	F1,F2,F3	8.32	1.4	N/A	3.8	SMITHS FALLS TS	M26
PORRIDGE LAKE DS	Total	F1,F2,F3,F4	12.5	1.0	N/A	3.9	ELLIOT LAKE TS	M3
PORT ALBERT DS	Total	F2,F3	8.32	0.6	N/A	3.0	GODERICH TS	M10
PORT ARTHUR TS #1	B1B2	M2,M3,M4,M5,M6,M1,M27	24.9	10.9	8.4	31.0		
PORT BOLSTER DS	Total	F1,F2,F3	8.32	1.4	N/A	3.8	BEAVERTON TS	M27
PORT COLBORNE TS	QZ	M9,M10,M11,M12	27.6	24.6	175.7	47.0		
PORT DOVER SCOTT DS	Total	F1, F2	8.32	0.1	N/A	2.5	BLOOMSBURG DS	M3
PORT DOVER ST. ANDREWS DS	Total	F1, F2, F3	8.32	0.4	N/A	2.8	BLOOMSBURG DS	M3
PORT ELGIN DS	Total	F1,F2,F3	8.32	1.1	N/A	2.5	DOUGLAS POINT TS	M1
PORT HOPE TS DESN1	JQ	M15,M16,M17,M18	44	17.0	895.4	57.0		
PORT HOPE TS DESN2	BY	M1,M2,M3,M4	44	27.2	341.0	67.2		
PORT LAMBTON DS	Total	F1,F2,F3	8.32	0.6	N/A	3.0	LAMBTON TS	M3
PORT PERRY DS	Total	F1,F2,F3	8.32	1.5	N/A	6.3	WILSON TS DESN2	M14
PORT SEVERN DS	Total	F1,F2	12.5	0.5	N/A	4.1	WAUBAUSHENE TS	M1
PORTELANCE DS	Total	F1	7.2	0.0	N/A	0.1	MARTINDALE TS	M7
POST CREEK DS	Total	F1	12.5	0.1	N/A	1.5	MARTINDALE TS	M7
POWASSAN DS	Total	F1,F2,F3	24.9	1.6	N/A	4.5	TROUT LAKE TS	M7
PRECIOUS CORNERS DS	Total	F1,F2,F3	8.32	1.1	N/A	3.5	PORT HOPE TS DESN1	M17
PRENEVEAU DS	Total	F1,F2,F3	12.5	1.2	N/A	4.1	HAVELOCK TS	M3
PRESTON TS	Q	M23,M25,M27,M29	27.6	10.1	121.6	10.1		
PRESTON TS	J	M24,M26,M28,M30	27.6	14.5	139.3	14.5		
PRESTON TS	Total	M24,M26,M28,M30,M23,M25,M27,M29	27.6	24.6	N/A	Sum of Buses		
PRINCETON DS	Total	F1,F2	8	0.5	N/A	1.4	BRANT TS	M22
PROSPECT DS	Total	F1,F2,F3	8.32	0.9	N/A	3.3	WILSON TS DESN2	M14
PROSPECT HILL DS	Total	F1,F2	8.32	0.7	N/A	3.1	CLARKE TS	M2
PUNKIDOODLES DS	Total	F1,F3,F4	8.32	0.5	N/A	2.9	STRATFORD TS	M7
PUSLINCH DS	Total	F1,F2,F3,F4	27.6	7.8	419.5	19.8		
PUSLINCH DS	T1	F1,F3	27.6	3.3	414.1	15.3		

Station Name	Bus Name	Feeder Name	Voltage (kV)	Minimum Load (MW)	Short Circuit Capacity (MVA)	Thermal Capacity (MW)	Upstream TS	Upstream TS feeder
PUSLINCH DS	T2	F2,F4	27.6	4.5	417.0	16.5		
RAINY RIVER DS	Total	F1,F2	4.16	0.3	N/A	1.8	BARWICK TS	M2
RAMA DS	Total	F1,F2,F3	8.32	1.3	N/A	4.9	ORILLIA TS	M7
RAMORE TS	B	M3,M5	27.6	1.1	452.3	9.2		
RED LAKE DS	Total	F1,F2,F3,F4	14.4	3.1	N/A	5.0	RED LAKE TS	M6
RED LAKE TS	BY	M3,M4,M6	44	10.0	1,231.4	17.1		
RED ROCK DS	Total	F1, F2, F3	12.5	1.1	64.7	3.9		
REDBRIDGE DS	Total	F1	12.5	0.6	N/A	3.5	TROUT LAKE TS	M8
REDDENDALE DS	Total	F1,F2,F3	8.32	1.1	N/A	3.5	KINGSTON GARDINER TS DESN2	M24
REDNERSVILLE DS	Total	F1,F2,F3	8.32	1.3	N/A	3.7	BELLEVILLE TS	M6
REID CORNERS DS	Total	F1,F2	8.32	1.0	N/A	2.4	DOUGLAS POINT TS	M6
RENFREW PUCKER DS	Total	F1,F2,F3	12.5	1.0	N/A	3.9	STEWARTVILLE TS	M1
REXDALE TS	BY	M1, M2, M3, M4, M5, M6	27.6	23.9	78.3	48.9		
REXDALE TS	Total	M1, M2, M3, M4, M5, M6,M31, M32, M33, M34, M35, M36	27.6	41.7	N/A	Sum of Buses		
REXDALE TS	QJ	M31, M32, M33, M34, M35, M36	27.6	17.8	73.2	42.8		
RICE DS	Total	F1	7.2	0.0	N/A	0.1	DYMOND TS	M3
RICE LAKE DS	Total	F1,F2,F3	8.32	0.9	N/A	3.3	PORT HOPE TS DESN1	M15
RICHVIEW TS DESN1	E	M11, M13, M15, M17	27.6	11.1	36.3	31.1		
RICHVIEW TS DESN1	Total	M11, M13, M15, M17,M12, M14, M16, M18	27.6	29.9	N/A	Sum of Buses		
RICHVIEW TS DESN1	J	M12, M14, M16, M18	27.6	18.8	36.9	48.8		
RICHVIEW TS DESN2	Q	M41, M43, M45, M47	27.6	19.1	79.9	44.1		
RICHVIEW TS DESN2	Total	M41, M43, M45, M47,M42,M44,M46,M48	27.6	29.9	N/A	Sum of Buses		
RICHVIEW TS DESN2	Z	M42,M44,M46,M48	27.6	11.1	73.5	36.1		
RICHVIEW TS DESN3	BY	M1,M2,M3,M4,M5,M6,M7,M8	27.6	24.2	0.0	64.2		
RINGWOOD DS - 27.6 kV	Total	F5, F6, F7, F8	27.6	4.7	N/A	10.4	ARMITAGE TS DESN2	M31
RINGWOOD DS - 27.6 kV	T2	F5,F6	27.6	2.1	N/A	10.1	ARMITAGE TS DESN2	M31
RINGWOOD DS - 27.6 kV	T3	F7,F8	27.6	2.5	N/A	5.0	ARMITAGE TS DESN2	M31
RINGWOOD DS - 8.32 kV	T1	F1,F2	8.32	0.4	N/A	2.8	ARMITAGE TS DESN2	M31
RIPLEY DS	Total	F1,F2,F3	8.32	0.7	N/A	3.1	WINGHAM TS	M5
RIVERDALE TS	JY	For any information or inquiries please contact Hydro Ottawa	12.5	13.1	99.5	13.1		
RIVERDALE TS	QZ	For any information or inquiries please contact Hydro Ottawa	12.5	11.5	100.4	11.5		
RIVERDALE TS	Total	For any information or inquiries please contact Hydro Ottawa	12.5	24.7	N/A	Sum of Buses		
ROCK MILLS DS	Total	F1,F2,F3	8.32	1.8	N/A	4.2	HANOVER TS	H1E
ROCKLAND DS	Total	F1, F2, F3	8.32	1.9	60.0	7.9		
ROCKLAND EAST DS	T2	F2, F3	8.32	1.6	6.7	7.6		
ROCKLAND EAST DS	Total	F2,F3,F4,F5,F6	8.32	2.6	7.5	8.6		
ROCKLAND EAST DS	T1	F4, F5, F6	8.32	0.9	7.4	6.9		
ROCKWOOD DS	Total	F1,F2,F3,F4	8.32	0.9	N/A	3.8	FERGUS TS	M4
RODNEY WEST DS	Total	F1,F2,F3	8.32	0.9	N/A	3.3	DUART TS DESN1	M6
RONDEAU DS	Total	F1,F2	8.32	0.6	N/A	2.0	KENT TS DESN1	M16
ROSE CORNERS DS	Total	F1,F2,F3	8.32	1.4	N/A	3.8	ST ISIDORE TS	M2
ROSEDALE DS	Total	F1,F2	12.5	0.9	N/A	2.9	BEAVERTON TS	M23
ROSENEATH DS	Total	F1,F2,F3	8.32	0.9	N/A	3.3	PORT HOPE TS DESN1	M15
ROSEVILLE DS	Total	F1,F2,F3	8.32	1.3	N/A	3.7	ARMITAGE TS DESN1	M22
ROSSEAU DS	Total	F1,F2,F3	12.5	1.6	N/A	5.2	MUSKOKA TS	M1
ROTHSAY DS	Total	F1,F2,F3	8.32	1.3	N/A	3.7	PALMERSTON TS	M2
ROWS DS	Total	F1,F2	8.32	1.0	N/A	3.4	BROCKVILLE TS	B1R
RUGBY DS	Total	F1,F2	8.32	0.7	N/A	2.2	ORILLIA TS	M7
RUNNYMEDE TS DESN1	EZ	M21,M22,M23,M24,M25,M26,M27,M28	27.6	35.5	92.0	80.3		
RUNNYMEDE TS DESN2	JQ	M10,M11,M12,M13,M14,M15,M16,M17,M18,M19	27.6	0.0	86.9	39.8		
RUSSELL DS	Total	F1, F2, F3, F4	8.32	0.3	6.3	1.8		
RUSSELL DS #2	Total	F1,F2,F3	8.32	0.6	N/A	TC	CHESTERVILLE TS	M1
RUSSELL TS	BY	For any information or inquiries please contact Hydro Ottawa	12.5	13.3	129.4	13.3		
RUSSELL TS	QZ	For any information or inquiries please contact Hydro Ottawa	12.5	10.7	129.4	10.7		
RUSSELL TS	Total	For any information or inquiries please contact Hydro Ottawa	12.5	24.0	N/A	Sum of Buses		
RUTHERFORD DS	Total	F1,F2	8.32	0.4	N/A	2.8	WALLACEBURG TS	M1
RUTHERGLEN DS	Total	F1,F2	12.5	0.7	N/A	1.7	TROUT LAKE TS	M8
RUTHVEN DS	Total	F1,F2,F3	8.32	1.4	N/A	4.9	LEAMINGTON TS DESN1	M10

Station Name	Bus Name	Feeder Name	Voltage (kV)	Minimum Load (MW)	Short Circuit Capacity (MVA)	Thermal Capacity (MW)	Upstream TS	Upstream TS feeder
RYLSTONE DS	Total	F1,F2,F3	12.5	0.8	N/A	3.7	HAVELOCK TS	M4
SAM LAKE DS	Total	F1, F2, F3, F4	24.9	4.0	137.7	16.0		
SAPAWE DS	Total	F1, F2	12.5	0.3	60.6	1.7		
SAUBLE BEACH DS	Total	F1,F2,F3	8.32	1.3	N/A	3.7	OWEN SOUND TS	M25
SAUBLE RIVER DS	Total	F2,F3	8.32	1.0	N/A	3.4	OWEN SOUND TS	M25
SCARBORO TS DESN1	J	M21, M23, M25, M27, M29, M31	27.6	20.8	109.6	20.8		
SCARBORO TS DESN1	Total	M21, M23, M25, M27, M29, M31,M22, M24, M26, M28, M30, M32	27.6	36.1	N/A	Sum of Buses		
SCARBORO TS DESN1	Q	M22, M24, M26, M28, M30, M32	27.6	15.3	106.9	15.3		
SCARBORO TS DESN2	B	M1, M3, M5, M9	27.6	6.9	127.6	6.9		
SCARBORO TS DESN2	Total	M1, M3, M5, M9,M2, M4, M6, M8, M10	27.6	23.6	N/A	Sum of Buses		
SCARBORO TS DESN2	Y	M2, M4, M6, M8, M10	27.6	16.7	127.6	16.7		
SCHOMBERG DS - 27.6 kV	T2	F3,F4	27.6	3.0	N/A	11.0	KLEINBURG TS 44 KV	M24
SCHOMBERG DS - 8.32 kV	T1	F1,F2	8.32	0.4	N/A	5.2	KLEINBURG TS 44 KV	M24
SCHREIBER WINNIPG DS	Total	F1,F2	12.5	0.8	18.6	3.7		
SCIENCE HILL DS	Total	F1,F2,F3	8.32	0.7	N/A	2.1	ST MARYS TS	M5
SCOTLAND DS	Total	F1,F2,F3	8.32	1.0	N/A	3.4	BRANT TS	M21
SCUGOG ISLAND DS	Total	F1,F2,F3	8.32	1.1	N/A	3.5	ENFIELD TS DESN1	M4
SEAFORTH DS	Total	F1,F2	8.32	1.0	N/A	3.4	SEAFORTH TS	M4
SEAFORTH TS	BQ	M2,M3,M4,M5	27.6	11.8	187.4	31.8		
SEAGRAVE DS	Total	F1,F2,F3	8.32	1.2	N/A	3.6	BEAVERTON TS	M30
SEBRIGHT DS	Total	F1,F2	8.32	0.9	N/A	2.3	BEAVERTON TS	M26
SHABAQUA DS	Total	F1, F2, M2	12.5	0.4	64.3	3.3		
SHANNONVILLE DS	Total	F1,F2	8.32	0.9	N/A	2.4	BELLEVILLE TS	M6
SHARBOT DS	Total	F1,F2,F3	12.5	1.0	33.1	3.8		
SHARON DS	Total	F1,F2,F3	8.32	1.5	N/A	3.9	BROWN HILL TS	M4
SHEDDEN DS	Total	F1,F2	8.32	0.8	N/A	2.6	EDGEWARE TS	M4
SHEFFIELD DS	Total	F1,F2,F3,F4	8.32	0.7	N/A	3.1	GALT TS	M12
SHELBURN ANDREW DS	Total	F1,F2	4.16	0.6	N/A	3.0	ORANGEVILLE TS DESN2	M45
SHELBURN FIDDLEPK DS	Total	F1,F2	4.16	0.5	N/A	2.9	ORANGEVILLE TS DESN2	M45
SHELBURNE DS - 4.16 KV	T2	F1,F2	4.16	0.3	N/A	1.7	ORANGEVILLE TS DESN2	M45
SHELBURNE DS - 8.32 KV	T1	F1,F2	8.32	0.6	N/A	2.1	ORANGEVILLE TS DESN2	M45
SHEPPARD TS DESN1	JQ	M13, M14, M15, M16, M17, M18	27.6	19.5	91.2	44.5		
SHEPPARD TS DESN2	EZ	M1, M2, M3, M4, M5, M6, M7, M8	27.6	32.5	7.5	72.5		
SHININGTREE DS	Total	F1	24.9	0.8	454.6	6.8		
SIBBALD DS	Total	F1,F2,F3	8.32	0.5	N/A	2.9	BROWN HILL TS	M12
SIDNEY TS	BQ	M1,M3,M4,M5,M6,M7,R8S,R9S	44	50.7	912.3	90.7		
SILVER CREEK DS	Total	F1,F2,F3	8.32	1.1	N/A	3.5	ORILLIA TS	M2
SIMCOE BLUELINE DS	Total	F1, F2	8.32	0.6	N/A	3.0	NORFOLK TS	M5
SIMCOE EVERGREEN DS	Total	F1, F2, F3, F4	4.16	0.4	N/A	2.8	BLOOMSBURG DS	M1
SIMCOE IRELAND DS	Total	F1, F2, F3	8.32	0.6	N/A	3.0	NORFOLK TS	M2
SIMCOE WELLINGTON DS	Total	F1, F2	4.16	0.2	N/A	2.3	BLOOMSBURG DS	M1
SIOUX NARROWS DS	Total	F1, F2	12.5	0.9	51.7	6.9		
SLATE FALLS DS	Total	F1	24.9	0.1	220.7	1.5		
SLATER TS	B1B2	For any information or inquiries please contact Hydro Ottawa	12.5	14.8	97.3	14.8		
SLATER TS	J1J2	For any information or inquiries please contact Hydro Ottawa	12.5	16.7	97.0	16.8		
SLATER TS	Q1Q2	For any information or inquiries please contact Hydro Ottawa	12.5	17.7	94.9	17.7		
SLATER TS	Total	For any information or inquiries please contact Hydro Ottawa	12.5	47.9	N/A	Sum of Buses		
SLEEMAN DS	Total	F1,F2,F4	12.5	0.0	N/A	1.4	BARWICK TS	M2
SLESWICK DS	Total	F1,F2,F3	12.5	1.1	N/A	3.9	ORANGEVILLE TS DESN2	M6
SMITHFIELD DS	Total	F1,F2,F3	8.32	1.5	N/A	3.9	SIDNEY TS	M7
SMITHS FALLS DS	Total	F1,F3	8.32	0.6	N/A	3.0	SMITHS FALLS TS	M26
SMITHS FALLS TS	JY	M21,M22,M23,M24,M25,M26,M27,M28	44	41.9	557.7	101.9		
SMITHS FLS ELMSLY DS	Total	F1,F2,F3,F4	4.16	0.4	N/A	2.8	SMITHS FALLS TS	M27
SMITHS FLS JAMES DS	Total	F1,F2,F3	4.16	0.6	N/A	3.0	SMITHS FALLS TS	M27
SMITHS FLS LORNE DS	Total	F1,F2,F3	4.16	0.5	N/A	1.9	SMITHS FALLS TS	M24
SMITHS FLS MARKET DS	Total	F1,F2,F3,F4	4.16	0.9	N/A	2.6	SMITHS FALLS TS	M27
SMITHS FLS PEARL DS	Total	F1,F2,F3	4.16	0.5	N/A	1.9	SMITHS FALLS TS	M27
SMITHS FLS PERCY DS	Total	F1,F2,F3,F4	4.16	0.6	N/A	3.0	SMITHS FALLS TS	M27

Station Name	Bus Name	Feeder Name	Voltage (kV)	Minimum Load (MW)	Short Circuit Capacity (MVA)	Thermal Capacity (MW)	Upstream TS	Upstream TS feeder
SMOOTH ROCK FALLS DS	T1	F1	12.5	0.5	50.8	2.9		
SMOOTH ROCK FALLS DS	Total	F1,F2	12.5	0.8	50.8	3.2		
SMOOTH ROCK FALLS DS	T2	F2	12.5	0.3	50.8	2.7		
SNELGROVE DS	T2	F1,F3	8.32	0.3	N/A	2.7	PLEASANT TS DESN1	M21
SNELGROVE DS	T1	F4,F5	27.6	1.9	N/A	7.6	PLEASANT TS DESN1	M21
SNOW ROAD DS	Total	F1,F2	12.5	1.2	N/A	2.6	SMITHS FALLS TS	M26
SNOW VALLEY DS	T1	F1,F2	27.6	1.6	N/A	7.4	MIDHURST TS - DESN1	M3
SOLINA DS	Total	F1,F2	27.6	2.1	N/A	5.0	WILSON TS DESN2	M17
SOUTH GLOUCESTER DS	Total	F1,F2, F3	8.32	1.1	17.4	4.0		
SOUTH GOWER DS	Total	F1,F2,F3	8.32	1.2	N/A	TC	MORRISBURG TS	M25
SOUTH MARCH TS	QY	M1,M2,M3,M4,M5,M6	44	27.9	549.0	67.9		
SOUTH MIDDLE ROAD TS	J	M61, M63, M65,M67,M69,M71	27.6	0.0	104.8	30.0		
SOUTH MIDDLE ROAD TS	Total	M61,M62,M63,M64,M65,M66,M67,M68,M69,M70,M71,M72	27.6	0.0	N/A	60.0		
SOUTH MIDDLE ROAD TS	Q	M62, M64, M66, M68, M70,M72	27.6	0.0	105.9	30.0		
SOUTH PORCUPINE DS	Total	F1,F2,F3	4.16	0.6	N/A	2.4	TIMMINS TS	M6
SOUTHWOLD DS	Total	F1	8.32	0.3	N/A	1.5	EDGEWARE TS	M4
SOWERBY DS	Total	F1, F2	24.9	0.5	442.9	6.5		
SPANISH DS	Total	F1, F2	12.5	0.7	49.2	7.4		
SPARROW LAKE DS	Total	F1,F2,F3	8.32	1.0	N/A	3.4	ORILLIA TS	M2
SPENCERVILLE DS	Total	F1,F2,F3	8.32	1.3	N/A	3.7	BROCKVILLE TS	B1R
SPINE DS	T1	F2	12.5	0.6	N/A	3.5	ELLIOT LAKE TS	M3
SPINE DS	Total	F2,F3	12.5	1.3	N/A	4.2	ELLIOT LAKE TS	M3
SPINE DS	T2	F3	12.5	0.7	N/A	3.5	ELLIOT LAKE TS	M3
SPRINGFIELD DS	Total	F1,F2	8.32	0.7	N/A	3.1	AYLMER TS	M2
SPRINGVALE DS	Total	F1,F2,F3	8.32	1.3	N/A	3.7	FOREST JURA DS	F1
SPRINGVILLE DS	Total	F1,F2,F3	8.32	1.3	N/A	3.7	DOBBIN TS	M1
SQUIRE DS	Total	F1,F2,F3	8.32	1.0	N/A	3.4	OWEN SOUND TS	M25
ST ANDREWS TS	QZ	M9,M10,M11,M12,M13,M14,M15,M16	27.6	43.1	80.8	87.9		
ST GEORGE DS	Total	F1,F2,F3	8.32	1.5	N/A	5.0	BRANT TS	M14
ST ISIDORE DS	Total	F1,F2,F3	8.32	1.2	N/A	3.6	ST ISIDORE TS	M1
ST ISIDORE TS	JQ	M1,M2,M3,M4,M5	44	11.8	654.4	51.6		
ST LAWRENCE TS	JQ	M24,M25,M26,M27,M28	44	12.7	324.3	72.7		
ST MARYS DS	Total	F1,F2,F3	8.32	0.5	N/A	2.9	ST MARYS TS	M6
ST MARYS TS	BY	M1,M2,M3,M4,M5,M6	13.8	8.9	156.1	28.9		
ST ONGE DS	Total	F1,F2,F3	8.32	0.9	N/A	TC	CHESTERVILLE TS	M1
ST THOMAS UNION DS	Total	F1,F2,F3	8.32	1.0	N/A	3.4	EDGEWARE TS	M3
ST WILLIAMS DS	Total	F1,F2	8.32	0.6	N/A	4.2	NORFOLK TS	M3
STANLEY TS	EZ	M1, M2, M3, M4, M5, M6	13.8	7.1	59.5	7.1		
STANLEY TS	QJ	M31, M32, M33, M41, M42, M43	13.8	10.3	63.2	10.3		
STANLEY TS	Total	M31, M32, M33, M41, M42, M43,M1, M2, M3, M4, M5, M6	13.8	18.1	N/A	Sum of Buses		
STARDALE DS	Total	F2,F3	8.32	0.7	N/A	3.1	LONGUEUIL TS	M23
STAYNER TS	BY	M1,M2,M3,M4,M5,M6,M7,M8	44	29.7	448.1	89.7		
STEWARTVILLE TS	QZ	M1,M3,M4	44	9.2	895.5	29.2		
STIRLING BAKER DS	Total	F1,F2	4.16	0.7	N/A	2.1	BELLEVILLE TS	M5
STIRLING DS	Total	F1,F2,F3	8.32	1.5	N/A	3.9	BELLEVILLE TS	M5
STIRTON TS	QZ	M51, M52, M53, M54, M61, M62, M63, M64	13.8	9.0	90.6	9.0		
STIRTON TS	BY	M71, M72, M75, M76, M81, M82, M83, M84, M85, M86	13.8	11.8	62.0	11.8		
STIRTON TS	Total	M71, M72, M75, M76, M81, M82, M83, M84, M85, M86,M51, M52, M53, M54, M61, M62, M63, M64	13.8	18.6	N/A	Sum of Buses		
STOUFFVIL 10 LINE DS 27.6 kV	T2	F1	27.6	1.5	N/A	6.3	ARMITAGE TS DESN1	M12
STOUFFVIL 10 LINE DS 27.6 kV	Total	F1, F4	27.6	2.7	N/A	7.5	ARMITAGE TS DESN1	M12
STOUFFVIL 10 LINE DS 27.6 kV	T3	F4	27.6	1.2	N/A	6.9	ARMITAGE TS DESN1	M12
STOUFFVIL 10 LINE DS 8.32 kV	T1	F2,F3	8.32	0.5	N/A	4.1	ARMITAGE TS DESN1	M12
STRACHAN TS DESN1	A15A16	For any information or inquiries please contact Toronto Hydro	13.8	10.7	100.2	10.7		
STRACHAN TS DESN1	A11A12	For any information or inquiries please contact Toronto Hydro	13.8	10.5	100.6	10.5		
STRACHAN TS DESN1	Total	For any information or inquiries please contact Toronto Hydro	13.8	21.3	N/A	Sum of Buses		
STRACHAN TS DESN2	A1A2	For any information or inquiries please contact Toronto Hydro	13.8	11.3	87.6	11.3		
STRACHAN TS DESN2	A9A10	For any information or inquiries please contact Toronto Hydro	13.8	12.7	87.6	12.7		
STRACHAN TS DESN2	Total	For any information or inquiries please contact Toronto Hydro	13.8	23.9	N/A	Sum of Buses		

Station Name	Bus Name	Feeder Name	Voltage (kV)	Minimum Load (MW)	Short Circuit Capacity (MVA)	Thermal Capacity (MW)	Upstream TS	Upstream TS feeder
STRAFFORDVILLE DS	Total	F2,F3	8.32	0.5	N/A	2.9	TILLSONBURG TS	M4
STRATFORD DS	Total	F1,F2	8.32	0.4	N/A	1.9	STRATFORD TS	M6
STRATFORD EASTHP DS	Total	F1,F2	8.32	0.3	N/A	1.8	STRATFORD TS	M1
STRATFORD TS	BY	M1,M2,M3,M4,M5,M6,M7,M8	27.6	27.5	122.3	67.5		
STRATHROY DS	Total	F1,F2,F3	8.32	1.1	N/A	3.5	STRATHROY TS	M3
STRATHROY TS	BQ	M1,M2,M3,M4	27.6	14.3	427.4	34.3		
STRIKER DS	Total	F1, F2	24.9	2.0	440.6	8.0		
STURGEON FALLS DS	Total	F1,F2,F3	12.5	1.8	N/A	4.6	CRYSTAL FALLS TS	M2
SUNDERLAND DS	Total	F1,F2,F3	8.32	1.6	N/A	4.0	BEAVERTON TS	M29
SUNDRIDGE DS	Total	F1,F3	12.5	0.7	N/A	2.1	MUSKOKA TS	M2
SUNDRIDGE NORTH DS	Total	F2,F3	12.5	1.2	N/A	4.1	MUSKOKA TS	M2
SUNNIDALE CORNERS DS	Total	F1,F2,F3	8.32	1.0	N/A	3.4	STAYNER TS	M5
SUTTON BASE LN DS #1	T2	F1	8.32	0.5	N/A	2.9	BROWN HILL TS	M12
SUTTON BASE LN DS #1	T1	F2,F3	8.32	0.2	N/A	2.6	BROWN HILL TS	M12
SUTTON BASE LN DS #1	Total	Field Check	8.32	0.7	N/A	3.1	BROWN HILL TS	M12
SUTTON DS #2	Total	F1,F2,F3	8.32	0.9	N/A	3.3	BROWN HILL TS	M12
SWANSON DS	Total	F1,F2,F3	12.5	0.2	N/A	3.1	KIRKLAND LAKE TS	G3K
TALBOT TS DESN1	BY	M11,M12,M13,M14,M21,M22,M23,M25	27.6	21.3	0.0	61.3		
TALBOT TS DESN2	J1J2	M41, M42, M43, M46, M47, M48	27.6	17.7	134.1	33.7		
TALBOT TS DESN2	Total	M41, M42, M43, M46, M47, M48,M51, M52, M53, M54, M55, M56	27.6	36.3	N/A	Sum of Buses		
TALBOT TS DESN2	Q1Q2	M51, M52, M53, M54, M55, M56	27.6	17.5	131.0	33.5		
TAMWORTH DS	Total	F1,F2,F3	12.5	0.8	N/A	3.7	NAPANEE TS	M2
TARA DS #2	Total	F1,F2,F3	8.32	0.9	N/A	2.4	OWEN SOUND TS	M25
TAUNTON DS	Total	F1,F2	27.6	3.0	N/A	5.0	WILSON TS DESN2	M11
TAYLOR DS	Total	F1,F2,F3	12.5	1.7	N/A	4.6	BRACEBRIDGE TS	M21
TAYLOR KIDD DS	T1	F1,F2,F3	8.32	1.0	N/A	5.0	KINGSTON GARDINER TS DESN1	M13
TAYLOR KIDD DS	Total	F1,F2,F3,F4,F5,F6	8.32	2.3	N/A	6.3	KINGSTON GARDINER TS DESN1	M13
TAYLOR KIDD DS	T2	F4,F5,F6	8.32	1.3	N/A	5.3	KINGSTON GARDINER TS DESN1	M13
TEMAGAMI DS	Total	F1, F2	12.5	0.4	32.9	3.3		
TERAULEY TS DESN1	A1A2	For any information or inquiries please contact Toronto Hydro	13.8	18.4	60.7	18.4		
TERAULEY TS DESN1	A9A10	For any information or inquiries please contact Toronto Hydro	13.8	14.2	58.5	14.2		
TERAULEY TS DESN1	Total	For any information or inquiries please contact Toronto Hydro	13.8	32.7	N/A	Sum of Buses		
TERAULEY TS DESN2	A3A4	For any information or inquiries please contact Toronto Hydro	13.8	13.7	98.7	13.7		
TERAULEY TS DESN2	A5A6	For any information or inquiries please contact Toronto Hydro	13.8	19.1	98.7	19.1		
TERAULEY TS DESN2	Total	For any information or inquiries please contact Toronto Hydro	13.8	34.4	N/A	Sum of Buses		
TESSIER DS	Total	F1,F2	12.5	0.3	N/A	1.7	LONGUEUIL TS	M24
THAMESVILLE NORTH DS	Total	F1,F2,F3	8.32	0.7	N/A	3.1	KENT TS DESN2	M24
THEDFORD DS	Total	F1,F2,F3	8.32	0.9	N/A	1.9	FOREST JURA DS	F1
THESSALON PEACHY DS	Total	F1,F2,F3	2.4	0.2	N/A	1.7	WHARNCLIFFE DS	F2
THORAH DS	Total	F1,F2,F3	8.32	1.0	N/A	3.4	BEAVERTON TS	M24
THORNDALE DS	Total	F1,F2,F3	8.32	0.8	N/A	3.2	HIGHBURY TS	M11
THORNTON DS	Total	F1,F2,F3	8.32	0.9	N/A	3.3	ALLISTON TS	M4
THORNTON TS	BY	M1,M2,M3,M4,M5,M6,M7,M8	44	31.0	348.6	98.2		
THOROLD ALLANPORT DS	Total	F1,F2	4.16	0.4	N/A	3.0	ALLANBURG TS	M8
THOROLD CLEVELAND DS	Total	F1,F2	4.16	0.3	N/A	2.7	THOROLD TS	M1
THOROLD DEFOE DS	Total	F1,F2	13.8	0.5	N/A	5.0	ALLANBURG TS	M8
THOROLD FRONT DS	Total	F1,F2	4.16	0.6	N/A	3.2	THOROLD TS	M1
THOROLD ORMOND DS	Total	F1,F2	4.16	0.5	N/A	2.9	THOROLD TS	M1
THOROLD PT ROBINS DS	Total	F2	4.16	0.2	N/A	1.2	ALLANBURG TS	M6
THOROLD SOUTH DS	Total	F1,F2	8.32	0.7	N/A	1.7	ALLANBURG TS	M8
THOROLD TS	EQ	M1,M2,M3	13.8	6.1	60.1	6.1		
THOROLD TS	Total	M1,M2,M3,M5,M6	13.8	12.0	N/A	Sum of Buses		
THOROLD TS	BY	M5,M6	13.8	5.9	4.1	5.9		
THOROLD TURNER DS	Total	F1,F2,F3,F4	8.32	0.6	N/A	2.3	ALLANBURG TS	M6
THRASHERS CORNERS DS	Total	F1,F2	27.6	2.2	N/A	5.0	BELLEVILLE TS	M2
THUNDER BEACH DS	Total	F1,F2,F3	8.32	1.1	N/A	3.5	WAUBAUSHENE TS	M7
TILBURY PELTIER DS	Total	F1,F2	8.32	0.5	N/A	2.9	TILBURY WEST DS	F2
TILBURY WEST DS	T1	F1, F3	27.6	2.3	429.5	14.3		

Station Name	Bus Name	Feeder Name	Voltage (kV)	Minimum Load (MW)	Short Circuit Capacity (MVA)	Thermal Capacity (MW)	Upstream TS	Upstream TS feeder
TILBURY WEST DS	Total	F1,F2, F3, F4	27.6	5.8	443.2	18.8		
TILBURY WEST DS	T2	F2, F4	27.6	3.5	434.0	15.5		
TILLSONBURG DS	Total	F1,F2,F3	8.32	0.6	N/A	2.5	TILLSONBURG TS	M2
TILLSONBURG TS	BY	M1,M2,M3,M4,M5,M6,M7,M8,M10	27.6	26.4	415.4	66.4		
TIMMINS TS	QZ	M5,M6,M7,M8,M9,M10,M11	27.6	19.6	172.3	66.5		
TINCAP DS	Total	F1,F2,F3	8.32	1.2	N/A	3.6	BROCKVILLE TS	M6
TIVERTON DS	Total	F1,F2,F3	8.32	1.0	N/A	3.4	DOUGLAS POINT TS	M6
TOMKEN TS DESN1	BY	M1,M2,M3,M4,M5,M6,M7,M8	44	41.2	163.9	101.2		
TOMKEN TS DESN2	EZ	M23,M24,M25,M26,M27,M28,M29,M30	44	42.6	260.9	102.6		
TORY HILL DS	Total	F1,F2,F3	12.5	1.0	N/A	3.9	MINDEN TS	M1
TOTTENHAM NORTH DS	Total	F1,F2	8.32	1.1	N/A	3.5	EVERETT TS	M5
TRAFALGAR TS	BY	M4,M5,M6,M7,M8	27.6	23.1	0.0	63.1		
TRALEE DS	Total	F1,F2,F3	8.32	1.6	N/A	4.0	PALMERSTON TS	M3
TREMAINE TS	Total	M1, M2, M3, M4, M5, M6, M7, M8, M9, M10, M11, M12	27.6	0.0	N/A	Sum of Buses		
TREMAINE TS	B	M1, M3, M5, M7, M9, M11	27.6	0.0	45.2	25.0		
TREMAINE TS	Y	M2, M4, M6, M8, M10, M12	27.6	0.0	47.6	25.0		
TRENTON BAY DS	Total	F1,F2,F3	4.16	0.7	N/A	4.3	SIDNEY TS	M5
TRENTON DIXON DS	Total	F1,F2,F3,F4	4.16	1.2	N/A	3.6	SIDNEY TS	M5
TRENTON DS	Total	F1,F2	8.32	0.8	N/A	2.3	SIDNEY TS	M6
TRENTON DUFFERIN DS	Total	F1,F2,F3,F4	4.16	0.7	N/A	3.1	SIDNEY TS	M3
TRENTON DUNDAS W DS	Total	F1,F2,F3,F4	4.16	0.1	N/A	2.5	SIDNEY TS	M3
TRENTON FRANKFORD DS	Total	F1,F2	4.16	0.4	N/A	2.2	SIDNEY TS	M3
TRENTON MCAULEY DS	Total	F1,F2,F3	4.16	0.4	N/A	1.8	SIDNEY TS	M3
TRENTON MCNICHOL DS	Total	F1,F2,F3,F4	4.16	0.7	N/A	3.1	SIDNEY TS	M5
TRENTON OAK DS	Total	F1,F2	27.6	0.2	N/A	3.1	SIDNEY TS	M5
TRENTON PELHAM DS	Total	F1,F2,F3,F4	4.16	0.9	N/A	3.3	SIDNEY TS	M3
TROUT CREEK DS	Total	F1,F2	24.9	2.0	N/A	4.9	TROUT LAKE TS	M7
TROUT LAKE TS	BY	M1,M2,M3,M4,M5,M6,M7,M8	44	39.2	320.1	99.2		
TROY DS	Total	F1,F2,F3	8.32	1.1	N/A	3.5	DUNDAS TS	M8
UFFORD DS	Total	F1,F2	12.5	1.2	N/A	2.7	MUSKOKA TS	M1
ULLSWATER DS	Total	F1,F2	12.5	1.0	N/A	3.4	MUSKOKA TS	M5
UTOPIA DS	Total	F1,F2	27.6	2.6	N/A	5.0	MIDHURST TS - DESN1	M3
UTTERSON DS	Total	F1,F2,F3	12.5	1.6	N/A	4.5	MUSKOKA TS	M9
UXBRIDGE DS #1	Total	F5,F6	27.6	0.8	N/A	5.6	ARMITAGE TS DESN1	M22
UXBRIDGE DS #2	Total	F1,F2,F3	8.32	1.5	N/A	3.9	ARMITAGE TS DESN1	M22
VAL CARON DS	Total	F1,F2,F3	12.5	1.8	N/A	4.6	MARTINDALE TS	M6
VALLEY EAST DS	Total	F1,F2,F3	12.5	1.5	N/A	4.4	CLARABELLE TS	M7
VALORA DS	Total	F1	24.9	0.2	74.4	1.6		
VANASTRA DS	Total	F1,F2	8.32	0.8	N/A	2.5	CONSTANCE DS	F4
VANDELEUR DS	Total	F1,F2,F3	8.32	1.3	N/A	2.7	OWEN SOUND TS	M26
VANKLEEK HILL DS	Total	F1,F2,F3	8.32	0.8	N/A	4.4	LONGUEUIL TS	M23
VANKLEEK TERRY FOX DS	Total	F1,F2,F3	8.32	0.6	N/A	3.5	LONGUEUIL TS	M23
VANSICKLE TS	BY	M41,M42,M43,M51,M52,M53	13.8	7.8	53.5	23.7		
VANSICKLE TS	JQ	M71,M72,M73,M81,M82,M83	13.8	0.0	53.1	15.8		
VERMILION BAY DS	Total	F1, F2, F3	12.5	3.8	70.0	6.7		
VERNER DS	Total	F1, F2, F3	12.5	1.2	54.6	7.2		
VICTORIA HARBOUR DS	Total	F1,F2,F3	8.32	0.3	N/A	2.7	WAUBAUSHENE TS	M6
VIENNA DS	Total	F1,F2	8.32	0.7	N/A	2.6	TILLSONBURG TS	M4
VINELAND DS	T1	F1	27.6	2.5	426.2	14.5		
VINELAND DS	Total	F1, F2	27.6	5.0	431.0	17.0		
VINELAND DS	T2	F2	27.6	2.5	425.6	14.5		
VIOLET HILL DS	Total	F1,F2,F3	8.32	1.2	N/A	3.6	ORANGEVILLE TS DESN2	M4
VIRGINIA BEACH DS	Total	F1,F2,F3	8.32	1.5	N/A	3.9	BEAVERTON TS	M27
VIRGINIATOWN DS	Total	F1,F2	4.16	0.2	N/A	1.2	KIRKLAND LAKE TS	M64
VITTORIA DS	Total	F1,F2,F3	8.32	1.0	N/A	3.4	NORFOLK TS	M3
WAINFLEET PDS	T4	F1	8.32	0.3	N/A	1.5	DUNNVILLE TS	M2
WAINFLEET PDS	Total	F1,F2	8.32	0.4	N/A	1.6	DUNNVILLE TS	M2
WAINFLEET PDS	T2	F2	8.32	0.1	N/A	1.3	DUNNVILLE TS	M2

Station Name	Bus Name	Feeder Name	Voltage (kV)	Minimum Load (MW)	Short Circuit Capacity (MVA)	Thermal Capacity (MW)	Upstream TS	Upstream TS feeder
WALKER TS #1	QE	M1,M2,M3,M5,M6	27.6	35.3	195.1	75.3		
WALKERS POINT DS	Total	F1,F2,F3	12.5	1.3	N/A	4.2	MUSKOKA TS	M1
WALKERTON DS #2	Total	F1,F2	8.32	0.6	N/A	2.1	HANOVER TS	M3
WALLACE DS	Total	F1,F2,F3	8.32	1.3	N/A	3.7	PALMERSTON TS	M3
WALLACE TS	Q	M1	44	3.5	972.7	23.5		
WALLACE TS	Total	M1,M4,M6	44	9.7	N/A	29.7		
WALLACE TS	Y	M4, M6	44	6.1	1,163.9	28.6		
WALLACEBURG DS	Total	F1,F2,F3	8.32	0.4	N/A	2.1	WALLACEBURG TS	M3
WALLACEBURG TS	BY	M1,M2,M3,M5,M6	27.6	14.2	441.7	35.8		
WALLBRIDGE DS	Total	F1,F2,F3	27.6	2.3	N/A	10.4	BELLEVILLE TS	M5
WANAPITEI DS	Total	F1,F2	12.5	0.5	N/A	5.3	MARTINDALE TS	M6
WANSTEAD TS	JQ	M1,M2,M3,M4	27.6	15.7	0.0	55.5		
WANUP DS	Total	F1,F2,F3	12.5	0.9	N/A	3.8	MARTINDALE TS	M5
WARDEN TS	J	M21, M23, M25, M27, M29, M31	27.6	16.2	108.6	41.2		
WARDEN TS	Total	M21,M23,M25,M27,M29,M31,M24, M26, M28, M30, M32	27.6	33.9	N/A	Sum of Buses		
WARDEN TS	Q	M24, M26, M28, M30, M32	27.6	17.0	106.8	42.0		
WARDSVILLE DS	Total	F2	8.32	0.5	N/A	1.4	LONGWOOD TS	M25
WARKWORTH DS	Total	F1,F2	8.32	1.0	N/A	2.4	SIDNEY TS	R8S
WARREN DS	T1	F1, F2	12.5	0.5	121.4	4.6		
WARREN DS	Total	F1,F2,F3,F4	12.5	1.6	122.0	5.7		
WARREN DS	T2	F3, F4	12.5	1.1	121.4	5.2		
WARTBURG DS	Total	F1,F2,F3	8.32	1.0	N/A	2.7	STRATFORD TS	M6
WARWICK DS	Total	F1,F2,F3	8.32	1.1	N/A	3.5	WANSTEAD TS	M1
WASHAGO DS	Total	F1,F2,F3	8.32	1.3	N/A	3.7	ORILLIA TS	M2
WASHBURN ISLAND DS	Total	F1,F2,F3	8.32	1.1	N/A	3.5	LINDSAY TS	M8
WATERFORD JAMES DS	Total	F1,F2,F3	8.32	0.9	N/A	3.3	NORFOLK TS	M6
WAUBAMIK DS	Total	F1	12.5	1.3	N/A	4.2	PARRY SOUND TS	M1
WAUBAUSHENE NORTH DS	Total	F1,F2,F3	8.32	1.1	N/A	3.5	WAUBAUSHENE TS	M1
WAUBAUSHENE TS	JQ	M1,M2,M3,M4,M5,M6,M7	44	35.9	602.5	75.9		
WAUPOOS DS	Total	F1,F2,F3	8.32	1.4	N/A	3.8	PICTON TS	M5
WELCOME DS	Total	F1,F2,F3	8.32	0.8	N/A	3.2	PORT HOPE TS DESN1	M18
WELLAND EFFINGHAM DS	Total	F1,F2,F3	8.32	1.0	N/A	3.4	CROWLAND TS	M13
WELLINGTON DS	Total	F1,F2,F3	8.32	0.8	N/A	3.2	PICTON TS	M5
WELLINGTON WHARF DS	Total	F1,F2	8.32	0.6	N/A	3.0	PICTON TS	M6
WENDOVER DS	T1	F1	27.6	1.9	215.6	13.9		
WENDOVER DS	Total	F1,F3	27.6	3.5	233.6	15.5		
WENDOVER DS	T2	F3	27.6	1.6	233.0	15.2		
WESLEY DS	T1	F1,F2	27.6	0.4	N/A	5.0	ARMITAGE TS DESN1	M34
WESLEY DS	T2	F3,F4	8.32	0.4	N/A	2.8	ARMITAGE TS DESN1	M34
WEST BAY DS # 2	Total	F1,F2,F3	12.5	0.0	N/A	4.8	MANITOULIN TS	M25
WEST FLAMBORO DS	Total	F1,F2	8.32	0.6	N/A	2.3	DUNDAS TS	M8
WEST LAKE DS	Total	F1,F2,F3	8.32	0.9	N/A	3.3	PICTON TS	M5
WEST LORNE DS	Total	F1,F2,F3	8.32	0.7	N/A	3.1	DUART TS DESN1	M6
WESTBROOK DS	Total	F1,F2,F3	8.32	0.9	N/A	3.3	KINGSTON GARDINER TS DESN1	M14
WESTON LAKE DS	Total	F1, F2	24.9	0.7	444.5	6.7		
WESTWOOD DS	Total	F1,F2,F3	8.32	1.3	N/A	3.7	OTONABEE TS DESN2	M28
WHARNCLIFFE DS	Total	F1, F2	24.9	1.3	45.8	3.7		
WHEATLEY DS #2	Total	F1,F2,F3	8.32	1.7	N/A	4.1	LEAMINGTON TS DESN1	M22
WHITBY TS DESN1	BY	M43, M44, M45, M46, M47, M48	27.6	0.4	4.7	25.4		
WHITBY TS DESN1	EZ	M5, M6, M7, M8	44	10.9	529.5	35.9		
WHITBY TS DESN2	JQ	M21,M22,M23,M24,M25,M26,M27,M28	44	50.0	277.3	110.0		
WHITE RIVER DS	Total	F1, F2, F3	24.9	10.0	106.5	13.6		
WHITEDOG DS	Total	F1	12.5	0.5	N/A	1.5	WHITEDOG FALLS GS	FP3
WHITEFISH DS	Total	F1, F2, F3	12.5	1.6	19.1	4.8		
WHITNEY DS	Total	F1,F2	12.5	0.5	N/A	2.0	WALLACE TS	M6
WIARTON CLAUDE DS	Total	F1,F2,F3,F4,F5,F6	4.16	0.7	N/A	3.1	OWEN SOUND TS	M23
WILHAVEN DS	T1	F1, F2, F3	27.6	4.1	374.6	20.1		
WILHAVEN DS	Total	F1,F2,F3,F4,F5	27.6	8.6	374.7	24.6		

Station Name	Bus Name	Feeder Name	Voltage (kV)	Minimum Load (MW)	Short Circuit Capacity (MVA)	Thermal Capacity (MW)	Upstream TS	Upstream TS feeder
WILHAVEN DS	T2	F4, F5	27.6	4.5	374.4	20.5		
WILLIAMSTOWN DS	Total	F1,F2,F3	8.32	1.0	N/A	3.4	ST LAWRENCE TS	M25
WILLOW BEACH DS	Total	F1,F2,F3	8.32	0.7	N/A	3.1	BROWN HILL TS	M11
WILLS RD PDS	Total	F1	8.32	0.3	N/A	1.5	DUNNVILLE TS	M2
WILSON TS DESN1	BY	M1,M2,M3,M4,M5,M6,M7,M8	44	52.1	273.2	112.1		
WILSON TS DESN2	JQ	M11,M12,M13,M14,M15,M16,M17,M18	44	46.3	263.8	106.3		
WILSONVILLE DS	Total	F1,F2,F3	8.32	1.1	N/A	2.8	NORFOLK TS	M6
WILTSHIRE TS DESN1	A5A6	For any information or inquiries please contact Toronto Hydro	13.8	21.5	85.3	41.7		
WILTSHIRE TS DESN2	A1A2	For any information or inquiries please contact Toronto Hydro	13.8	13.8	85.9	37.8		
WILTSHIRE TS DESN2	A3A4	For any information or inquiries please contact Toronto Hydro	13.8	13.8	87.8	37.8		
WILTSHIRE TS DESN2	Total	For any information or inquiries please contact Toronto Hydro	13.8	27.7	N/A	Sum of Buses		
WINCHESTER DUFFRN DS	Total	F1,F2,F3	8.32	0.4	N/A	TC	CHESTERVILLE TS	M2
WINCHESTER ST LAW DS	Total	F1,F2,F3	8.32	0.6	N/A	TC	MORRISBURG TS	M26
WINGHAM DS	Total	F1,F2	8.32	0.9	N/A	2.4	WINGHAM TS	M5
WINGHAM TS	BY	M3,M4,M5,M6	44	17.0	577.6	57.0		
WINONA TS	JQ	M11,M12,M13,M14,M15,M16	27.6	13.3	170.3	53.3		
WOLSEY LAKE DS	Total	F1,F2	12.5	0.5	N/A	3.3	MANITOULIN TS	M25
WOLVERTON DS	T1	F1	27.6	3.3	587.5	15.3		
WOLVERTON DS	Total	F1,F2	27.6	6.5	587.7	18.5		
WOLVERTON DS	T2	F2	27.6	3.2	583.7	15.2		
WONDERLAND TS	BY	M1,M2,M3,M4,M5,M6,M7,M8	27.6	28.3	22.8	68.3		
WOODBINE DS	Total	F1,F2,F3,F4,F5,F6	8.32	0.0	N/A	4.8	KINGSTON GARDINER TS DESN1	M14
WOODBRIDGE TS DESN1	BY	M1, M2, M3, M4, M5, M6	27.6	23.6	38.8	23.6		
WOODBRIDGE TS DESN1	QE	M12,M13,M15,M16	44	10.3	538.1	10.3		
WOODBURN DS	Total	F1,F2,F3	8.32	0.7	N/A	3.1	NEBO TS DESN1	M5
WOODLAND BEACH DS	Total	F1,F2,F3	8.32	1.1	N/A	3.5	WAUBAUSHENE TS	M5
WOODLAWN DS	Total	F1,F2,F3	12.5	1.1	N/A	3.9	ARNPRIOR TS	M2
WOODROFFE TS	BJ	For any information or inquiries please contact Hydro Ottawa	12.5	5.3	79.1	21.3		
WOODROFFE TS	QZ	For any information or inquiries please contact Hydro Ottawa	12.5	5.1	79.6	21.1		
WOODS DS	Total	F5,F6,F7	4.16	0.7	N/A	5.5	KIRKLAND LAKE TS	M61
WOODSTOCK BURTCH DS	Total	F333,F632,F618,F617	4.16	0.3	N/A	2.7	WOODSTOCK TS	10M8
WOODSTOCK DEVONSHIRE DS	Total	F926,F925,F930,F931	4.16	0.5	N/A	2.9	WOODSTOCK TS	10M3
WOODSTOCK EAST DS	Total	F1,F2,F3	8.32	2.1	N/A	4.5	COMMERCE WAY TS	M1
WOODSTOCK SPRINGBANK DS	Total	F1343,F1344,F1345	4.16	0.6	N/A	3.0	WOODSTOCK TS	10M3
WOODSTOCK TS	BY	M3,M4,M6,M7,M8,M9,M10	27.6	29.0	124.7	69.0		
WOODVILLE DS	Total	F1,F2,F3	8.32	1.5	N/A	3.9	BEAVERTON TS	M30
WOOLER DS	Total	F1,F2,F3	8.32	1.2	N/A	3.6	SIDNEY TS	R8S
WROXETER DS	Total	F1,F2,F3	8.32	0.8	N/A	2.3	WINGHAM TS	M4
WYEVALE DS	Total	F1,F2	27.6	1.9	N/A	5.0	WAUBAUSHENE TS	M5
WYOMING CHURCHILL DS	T1	F1	8.32	0.3	N/A	1.2	WANSTEAD TS	M2
WYOMING CHURCHILL DS	Total	F1,F2	8.32	0.5	N/A	1.5	WANSTEAD TS	M2
WYOMING CHURCHILL DS	T2	F2	8.32	0.2	N/A	1.2	WANSTEAD TS	M2
WYOMING NORTH DS	Total	F1,F2,F3	8.32	0.7	N/A	3.1	WANSTEAD TS	M1
YARMOUTH CENTRE DS	Total	F1,F2,F3	8.32	0.8	N/A	3.2	EDGEWARE TS	M3
YONGES MILLS DS	Total	F1,F2,F3	8.32	1.0	N/A	3.4	BROCKVILLE TS	M2
YOUNGSVILLE DS	Total	F1,F2,F3	8.32	1.1	N/A	3.5	INGERSOLL TS	M46
ZORRA DS	Total	F1,F2,F3	8.32	0.7	N/A	3.1	COMMERCE WAY TS	M2
ZURICH DS	Total	F1,F2	8.32	0.5	N/A	2.9	GRAND BEND EAST DS	F1

Glossary

Bus Name – The name of the distribution bus connected to the associated Hydro One transformer station.

Feeder Name – The Hydro One designation for the feeder connected to the associated distribution bus.

Minimum Load – The lowest load that we can reasonably expect to experience on the bus.

Short Circuit Capacity – The maximum amount of short circuit contribution that a generator can add to a station bus before short circuit limits are exceeded.

Station Name – The name of the Hydro One-owned transformer station.

Sum of Buses – This is a term used at a Dual Element Spot Network (DESN) station to define the amount of overall capacity available at the station. It is determined by adding the capacity available on each individual bus.

Thermal Capacity – The estimated amount of generation that can be connected to a bus before exceeding the reverse flow limits of the transformer.

Upstream TS – The name of the Hydro One-owned, transmission-connected transformer station that supplies the identified distribution station.

Upstream TS Feeder – The Hydro One designation for the feeder that connects the identified distribution station to the Upstream TS.

Voltage – The nominal voltage level of the distribution feeder.

TC – Capacity Allocation Required projects are restricted at these stations due to Transmission Constraints for Exporting Distributed Energy Resources (DER). This does not apply to Non-Exporting DER. This does not apply to Non-Exporting DER and Micro-generation.

Appendix E

IESO Comment Letter

IESO response to Oshawa PUC Networks Inc. REG Investments Plan 2026 - 2030

As part of the OEB's Filing Requirements for Electricity Distribution Rate Applications, a distributor must submit a letter of comment from the Independent Electricity System Operator (IESO) on its Renewable Energy Generation (REG) Investments Plan, which is part of its Distribution System Plan.

On October 3, 2024, Oshawa PUC Networks Inc. ("OPUCN") sent its REG Investments Plan (Plan) to the IESO for comment. The IESO has reviewed OPUCN's Plan and reports that it contains no investments specific to connecting REG for the Plan period 2026 – 2030.

The IESO notes that OPUCN's service territory is within the GTA East region. The Needs Assessment for GTA East is expected to be completed by Hydro One Networks Inc in December 2024.

On Page 8 of 10 of its Plan, under the heading Investments to Facilitate Distributed Energy Resources, OPUCN states that "OPUCN is not proposing any immediate planned capital expansions or enhancements investments related to these connections for the 2026- 2030 planning period".

As OPUCN has determined it requires no system investments to connect REG over the 2026-2030 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[1].

The IESO appreciates the opportunity provided to review the REG Investments Plan of OPUCN and looks forward to working together in further regional planning processes.

[1] 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 F

Oshawa Power Renewable Energy Generation Investment Plan

Oshawa PUC Networks Inc.

Renewable Energy Generation Investment Plan

October 02, 2024

Executive Summary

Oshawa PUC Networks Inc. (OPUCN) is a licensed electricity distributor serving more than 62,000 customers in the City of Oshawa. OPUCN is filing a Cost of Service Rate Application for rates to be in effect January 1st, 2026. In accordance with the Ontario Energy Board's (Board) Filing Requirements for Electricity Distribution Rate Applications-2023 Edition for 2024 Rate Applications ; Chapter 5 – Distribution System Plan – 5.2 , OPUCN has prepared the Renewable Energy Generation (REG) Investment Plan for its service territory for the five (5) year period 2026-2030.

The REG Investment Plan outlines the readiness of OPUCN's distribution system to connect distributed energy resources (DER), including any expansion or reinforcement necessary to accommodate the connection of DERs over the period 2026-2030.

Presently connected onto OPUCN's distribution system are renewable energy installations with capacity totaling 5005.45 kW under the FIT, microFIT and net-metering program as follows:

- 322 micro-FIT solar photovoltaic (PV) installations with micro-FIT generation capacity of 2562.74kW;
- 6 FIT solar photovoltaic (PV) installation with FIT generation capacity of 940 kW;
- 74 net-metering solar photovoltaic (PV) installation with net-metering generation capacity of 1502.71kW;

Additionally, the following generation projects are connected onto OPUCN's distribution system with capacity totaling to 5150 kW:

- 1 Combined Heat and Power (CHP) system with generation capacity of 1600kW
- 1 Combined Heat and Power (CHP) system with generation capacity of 600kW
- 1 microgrid system consisting of 2400kW CHP and 50kW solar photovoltaic (PV) installation – 2450kW total generation capacity
- 500kW of Battery Energy Storage System

Based on current generation applications received by OPUCN, there are potentially 2 small generation installations with proposed generation of 504.42kW and 5 micro-embedded generation installation with proposed generation of 42.96kW that is being proposed to be connected to the distribution system.

In addition, OPUCN have submitted a request to HydroOne in order to increase capacity threshold allocation on its respective 44KV buses at HydroOne Transformer station. This is in regards to accommodate more DER connections in our network.

Table 1 and Table 2 summarizes the total generation capacity and number of DERs connected and awaiting connection onto the OPUCN distribution system, respectively.

	Micro Generation	Small Generation	Mid-Sized Generation	Large Generation	Comments
Connected to OPUCN (kW)	3082.6	3022.9	4050	0	No constraints
Pending Connections (kW)	42.96	504.42	0	0	No constraints

Table 1 – Total Generation Capacity Connected and Pending Connection on OPUCN Distribution System

	Micro Generation	Small Generation	Mid-Sized Generation	Large Generation	Comments
Connected to OPUCN	392	12	2	0	No constraints
Pending Connections	5	2	0	0	No constraints

Table 2 – Total Number of DERs Connected and Pending Connection on OPUCN Distribution System

As part of the Regional Planning process, OPUCN is currently participating in GTA East Regional Planning group meetings in identifying potential needs within the GTA east region including investments required to accommodate DER connections. A Needs Assessment report is expected to be completed by December 2024. A Planning Status Letter has been requested from the Regional Planning coordinator (Hydro One) to further support this.

With respect to future potential investments related to DER connections, OPUCN presently does not anticipate any need for immediate investments, however, depending on the size of future distributed generation applications and Connection Impact Assessments (CIA), there may be other constraints that warrant the need for additional investments either on the distribution and/or transmission system.

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Introduction

Oshawa PUC Networks Inc. (OPUCN) is a licensed electricity distributor serving approximately 62,000 customers in the City of Oshawa. OPUCN is filing a Cost of Service Rate Application for rates to be in effect January 1st, 2026. In accordance with the Ontario Energy Board's (Board) Filing Requirements for Electricity Distribution Rate Applications-2023 Edition for 2024 Rate Applications ; Chapter 5 – Distribution System Plan – 5.2 , OPUCN has prepared the Renewable Energy Generation (REG) Investment Plan for its service territory for the five (5) year period 2026-2030.

The REG Investment Plan outlines the readiness of OPUCN's distribution system to connect distributed energy resources (DER), including any expansion or reinforcement necessary to accommodate the connection of DERs over the period 2026-2030.

Assessment of OPUCN's Existing Distribution System

OPUCN is a local distribution company that is responsible for the distribution of electricity to the City of Oshawa. This territory is currently serviced from 3 Hydro One transmission stations (TS) including Wilson TS, Thornton TS, and Enfield TS and 9 distribution substations (DS).

OPUCN distribution system includes a total of 14 – 44kV primary distribution feeders, 8 from Wilson TS, 4 from Thornton TS, and 2 from Enfield TS along with up to 54 – 13.8kV primary distribution feeders to service customers either at primary voltages or at step down secondary voltages (347/600V, 120/208V or 120/240V).

Hydro One Transmission Stations

Currently, Hydro One's transmission stations do not have short circuit capacity or thermal capacity constraints. The information in the table was provided by Hydro One in the published "Hydro One List of Station Capacity" updated on August 30th, 2024 and indicates approximate amount of generation that can be added at each Hydro One owned station.

Station Name	Voltage (kV)	Available Short Circuit Capacity (MVA)	Available Thermal Capacity (MW)
Thornton TS	44	348.6	98.2
Wilson TS DESN1	44	273.2.0	112.1
Wilson TS DESN2	44	263.8	106.3
Enfield TS DESN1	44	257.9	91.9

Table 3 – Hydro One TS Capacity (Refer to Appendix A: Sections of Hydro One list of Station Capacity, August 30th, 2024)

OPUCN Distribution Stations

Table 4 illustrates the remaining short circuit and thermal capacity at each of the 9 OPUCN DS based on connections and pending connections on the 13.8kV voltage level:

Distribution Substation Transformer		Voltage (kV)	Available Short Circuit Capacity (MVA)	Available Thermal Capacity (MW)
MS2	**T1**	13.8	131.6	23
	T2	13.8	125.0	26
MS5	**T1**	13.8	133.1	28
	T2	13.8	126.9	20
MS7	**T1**	13.8	113.7	25
	T2	13.8	126.9	21
MS9	**T1**	13.8	133.1	23
	T2	13.8	132.7	26
MS10	**T1**	13.8	132.3	24
	T2	13.8	132.4	24
MS11	**T1**	13.8	132.7	27
	T2	13.8	132.9	22
MS13	**T1**	13.8	132.9	26
	T2	13.8	124.1	27
MS14	**T1**	13.8	127.0	24
	T2	13.8	126.7	22
MS15	**T1**	13.8	132.3	27
	T2	13.8	121.1	27

Note: The acceptable thermal capacity limit at a TS or DS is established by adding together 60% of maximum MVA rating of the single transformer and the minimum station load.

Table 4 – OPUCN Distribution Substation Capacity

In summary, it is vital to ensure that the addition of any proposed distributed generation will not negatively impact distribution equipment or create safety concerns due to short circuit conditions. The assessment presents that there are no constraints and that there is sufficient capacity on the distribution system to connect future DERs subject to specific Connection Impact Assessments (CIA). OPUCN does not anticipate any requirement for immediate investments as a result of this.

Existing Distribution Energy Resources Connections

OPUCN has connected approximately 406 DERs totaling to almost 10.15MW of generation capacity to the distribution system which are summarized in Tables 5 and 6.

Project Type	# of Connected DERs	Generation Capacity (kW)
MicroFIT	322	2562.74
FIT	6	940.0
Net-Metering	74	1502.71
CHP	2	2200.0
Microgrid	1	2450.0
BESS	1	500.0
Total	406	10155.45

Table 5 – Summary of Existing DERs Connected to the OPUCN Distribution System

Currently, there are 322 micro-FIT, 6 FIT and 74 net-metering distributed generation facilities that are connected to the distribution system totaling to about 5MW of renewable energy.

Also, 2 CHP, 1 microgrid and 1 BESS system are in-service and connected within OPUCN distribution system with a total installed capacity of 5.15MW. All of these systems are being used for load displacement to offset customer's load consumption.

The following table provides the total number of existing DERs that are in-service with its respective total generation capacity by classification as per the Distribution System Code (DSC). Please refer to Appendix B: Generator Classification for details on generation classifications.

Project Type	# of Connected Projects	Generation Capacity (kW)
Micro Generation	392	3082.6
Small Generation	12	3022.9
Mid-Sized Generation	2	4050.0
Large Generation	0	0
Total	406	10155.45

Table 6 – Existing DERs by Classification

Regional Planning and Consultations

In keeping with the Chapter 5 – Consolidated Distribution System Plan Filing Requirements, and the Regional Planning process, OPUCN is actively participating in Regional Planning meetings and submitted an updated load forecast to the lead transmitter (Hydro One) in identifying any needs within the GTA East region.

HydroOne is currently in process of reviewing load forecasting data submitted by all Distributors within GTA East. The needs assessment report is expected to be issued by December 2024. A Planning Status Letter has been requested from the Regional Planning coordinator (Hydro One) to further support this.

Investments to Facilitate Distributed Energy Resources

After the termination of FIT program, a significant decline was noticed in DER connections from the period of 2020-2022 but based on DER connections (net metering) energized in 2023 and pending applications, OPUCN has observed an increase in DER applications. This increase is expected to be consistent in coming years due to EV penetration and energy storage options available to residential customers.

As per the data available to OPUCN, no constraints are identified on the OPUCN distribution system to accommodate the potential connection of DERs, and therefore, OPUCN is not proposing any immediate planned capital expansions or enhancements investments related to these connections for the 2026- 2030 planning period. However, based on current increasing trends, we expect a bottle neck to be built up in OPUCN assets closest to customers such as distribution transformers and secondary wires size. We expect this threshold to be reached before Short Circuit / Thermal capacity constraints are encountered at the 13.8 or 44KV level. This will be further monitored as future proposed DERs are identified. In addition, OPUCN have submitted a request to HydroOne in order to increase capacity threshold allocation on its respective 44KV buses at HydroOne Transformer station. This is in regards to accommodate more DER connections in our network.

Appendix A: Sections of Hydro One List of Station Capacity, August 30th , 2024

Reference: Hydro One List of Station Capacity

https://www.hydroone.com/businessservices_/generators_/Documents/honi_lsc.pdf

Appendix B: Generator Classification

Reference: DSC Appendix F: Process and Technical Requirements for Connecting Embedded Generation Facilities
https://www.oeb.ca/sites/default/files/directive_con_appendixf_221203.pdf

Generator Classification	Rating
Micro	≤ 10 kW, for customer's own use
Small	(a) ≤ 500 kW connected on distribution system voltage < 15 kV (b) ≤ 1 MW connected on distribution system voltage ≥ 15 kV
Mid-Sized	(a) < 10 MW but > 500 kW connected on distribution system voltage < 15 kV (b) > 1 MW but < 10 MW connected on distribution system voltage ≥ 15 kV
Large	≥ 10 MW

Appendix G

Oshawa Power's Maintenance Manual

Oshawa PUC Networks Inc.

Distribution System

Maintenance Manual

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Date: March 2023

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Date: March 2023

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Executive Summary

This maintenance manual for Oshawa PUC Networks Inc. (OPUCN) is used to establish the maintenance program that will improve efficiency and prevent unnecessary or unexpected equipment outages. It identifies equipment required for maintenance, the categories, the methods and the justifications. A maintenance plan will be established from this manual so that the expenditure on the assets is maximized. This is very important as the revenue is limited and OPUCN is still expected to meet all the Ontario Energy Board (OEB) regulatory requirements in the Distribution System Code (DSC). Without such a program, it will be difficult to keep equipment in its top operational condition and will result in unexpected power outages, equipment damage, and high cost of repair or replacement in an emergency condition. Also, the public and employee safety of OPUCN will be improved as this manual will be an effective document to communicate work procedures, specifications and standards.

As specified in the Distribution System Code (DSC), all Local Distributor Companies (LDCs) must patrol/inspect the Outdoor Open Stations once a month, the Overhead and the Underground System once every three years. A summary report must be submitted annually to OEB. With the combination of time (frequency) and condition such as infrared scanning, OPUCN maintenance program will be in compliance with the OEB regulatory requirements.

Introduction and Background

Oshawa PUC Networks Inc. (OPUCN) is licensed by the Ontario Energy Board (OEB) as a Local Distributor Company (LDC) to supply electricity to 60,000 customers in the City of Oshawa. OPUCN purchases power from Hydro One at Wilson, Thornton, and Enfield Transformation Stations (TS) where the voltage is transformed from 230kV to 44kV. Through the overhead lines, OPUCN distributes electricity at 44kV to its large customers and its nine 13.8kV Municipal Stations. At the Municipal station, the voltage is converted from 44kV to 13.8kV. By way of the 13.8kV underground and overhead systems, the electricity is further distributed to locations close to customers where the voltage is reduced to a lower level to supply customers, such as hospitals, commercial premises, apartment buildings and residential homes.

The Engineering & Operation Business Unit of OPUCN is responsible to establish an annual capital and operating/maintenance plans for the electric distribution system to ensure that all requirements are met and the expenditure of funding is optimal. The capital plan is well organized and set up based on a detailed project list. Justifications and costs for projects are well documented. However, in the maintenance plan and the process to determine the needs must be defined. This is to ensure that maintenance resource will be spent in areas of high priority that is needed to comply with the regulatory requirements in the Distribution System Code (DSC) of the Ontario Energy Board (OEB).

Maintenance Policy, Objective & Strategy

Policy:

The Mission statement of OPUCN is "We earn the trust of our customers every day by delivering safe, sustainable, reliable energy our customer's value at a competitive rate"

To support the mission, the Maintenance Policy of the Engineering & Operations business unit is "To operate and maintain the OPUCN distribution system in the most efficient way so the expenditure on assets is maximized and the requirements of the Ontario Energy Board are met".

Objective:

The objective of a maintenance program is to prevent unnecessary or unexpected equipment outages. Without a program, it is impossible to keep equipment that supplies customers in a reliable condition. A failure in the operation of the equipment will result in unexpected power outages, equipment damage, and high cost of repair or replacement in an emergency condition. An effective maintenance program will provide the following:

1. Equipment is in top operational condition
2. Improve system reliability
3. Maximize the utilization of asset life cycle
4. Improve public and employee safety

Maintenance Definitions & Categories

Definitions:

1. Emergency Maintenance----Maintenance is performed in response to failure of equipment resulting in power outage, safety hazard and/or environmental problems. It is urgent and required immediate action. Equipment is repaired or replaced to restore service immediately and in some cases, permanent repair or replacement is done in subsequent days. This is an unplanned maintenance.

2. Preventive Maintenance----Maintenance is scheduled or performed in response to problems identified in inspection, testing and/or trouble reports. Equipment is repaired or replaced prior to a failure. Testing may be performed to predict the equipment condition. This is a planned maintenance.

Categories:

1. Main Category----Reactive
    - Sub-category----Station
    - Sub-category----Overhead System
    - Sub-category----Underground System

2. Main Category----Routine System Operations and Maintenance
    - Sub-category----Station
    - Sub-category----Overhead System
    - Sub-category----Underground System

Reactive Maintenance

Category: **Station**

Program: **Trouble Response & Restoration**

Description/ Justification:

This program is the trouble response call to a power outage, safety hazard and/or environmental problem due to equipment failure inside OPUCN's Municipal Stations and the underground riser cables between the stations and the line side of the first terminations at the riser poles outside the stations. Equipment is repaired or replaced to restore service immediately. It is urgent and requires immediate action. In some cases, permanent repair or replacement of equipment is done in a subsequent follow-up.

To maintain revenue flow, minimize customer complaints and meet the Ontario Energy Board (OEB) system reliability requirements, it is important to have the resources and equipment required to restore power without any delay.

Procedure:

There are nine Municipal Stations (MS): MS-2, MS-5, MS-7, MS-9, MS-10, MS-11, MS-13, MS-14 and MS-15. Trouble Calls will be directed through the Distribution Operator or Supervisor during regular hours and after hours, through a call center, Outage Management System, or SCADA system..

Reactive Maintenance

Category: **Overhead System**

Program: **Trouble Response & Restoration**

Description/ Justification: This program is the trouble response call to a power outage, safety hazard and/or environmental problem due to equipment or pole failure in the overhead system. The equipment or pole is repaired or replaced to restore service immediately. It is urgent and requires immediate action. In some cases, permanent repair or replacement of equipment is done in subsequent follow-up.

To maintain revenue flow, minimize customer complaints and meet the Ontario Energy Board (OEB) system reliability requirements, it is important to have the resources and equipment to restore power without any delay.

Procedure: Trouble Calls will be directed through the Distribution Operator or Supervisor during regular hours and after hours, through a call center, Outage Management System, or SCADA system.

Reactive Maintenance

Category: **Underground System**

Program: **Trouble Response & Restoration**

Description/ Justification: This program is the trouble response call to a power outage, safety hazard and/or environmental problem due to equipment or structure failure in the underground system. The equipment or structure is repaired or replaced to restore service immediately. It is urgent and requires immediate action. In some cases, permanent repair or replacement of equipment or structure is done in subsequent follow-up.

To maintain revenue flow, minimize customer complaints and meet the Ontario Energy Board (OEB) system reliability requirements, it is important to have the resources and equipment to restore power without any delay.

Procedure: Trouble Calls will be directed through the Distribution Operator or Supervisor during regular hours and after hours, through a call center, Outage Management System, or SCADA system..

Routine Systems Operations and Maintenance

Category: **Station**

Program: **Batteries and Chargers**

Description/ Justification: All the protective relays and their control circuits are powered by D.C. supply from batteries charged by station battery charger. Station batteries are used for the storage of electric energy that is readily available for the control of electrical equipment such as circuit breaker. Also, the batteries provide power for indication lights, alarms and SCADA control system. Failure to maintain the batteries and the battery charger will cause the protective system and the operation of circuit breakers inactive. This will result in damage to electrical equipment and possibly loss of the entire station.

Maintenance cycle is once every three months. Load test on batteries is once a year.

Procedure: Every three (3) months, check the charger output for current and voltage. Visually inspect batteries for evidence of corrosion, leakage, heating and venting at terminals, connectors and racks. Check and test voltage of each cell and the total battery voltage. Fill up water if required. Once a year, perform load test on the batteries.

Any deficiencies shall be reported and documented for follow-up repairs.

Routine Systems Operations and Maintenance

Category: **Station**

Program: **Full Station Maintenance**

Description/ Justification:

OPUCN owns and operates nine (9) Municipal Substations (MS) where the voltage is converted from 44kV to 13.8kV. By way of the 13.8kV underground and overhead systems, the electricity is further distributed to locations close to customers where the voltage is reduced to a lower level to supply customers, such as hospitals, commercial premises, apartment buildings and residential homes.

To ensure ultimate reliability, asset management and continuity of service, all mechanical and electrical components within the MS must be tested, inspected and maintained once every three (3) years.

Also, an oil sample shall be obtained yearly and subjected to inspection and testing by a 3rd party.

Procedure:

OPUCN has adopted and will utilize NETA MTS-2015 Standard for Maintenance Testing Specifications for Electrical Power Equipment & Systems. This maintenance testing standard is recognized internationally and was developed for use by those responsible for the continued operation of existing electrical systems and equipment to guide them in specifying and performing the necessary tests to ensure that these systems and apparatus perform satisfactorily, minimizing downtime, and maximizing life expectancy.

In addition, all Power Transformers located within OPUCN Municipal Substations will have an oil sample drawn yearly. This sample will be subjected to NETA MTS-2015 recommended transformer insulating liquid testing.

Routine Systems Operations and Maintenance

Category: **Station**

Program: **Infra-red Scanning**

Description/ Justification: One of the most common sources of trouble in the station equipment is deteriorating terminators and connectors resulting in overheating and eventual failure. Infra-red scanning of these components identifies these potential anomalies and allows for corrective measures to be taken before they fail causing power outage. Since the reliability of station equipment is very important, all the termination and joint components will be scanned once a year.

Procedure: The infrared scanning will be done once a year in conjunction with the full Distribution System infrared scanning program. Problems identified during the scanning will be recorded for follow-up repairs or replacements.

Routine Systems Operations and Maintenance

Category: **Station**

Program: **Municipal Station and Building(s) Inspection**

Description/ Justification:

Nine Municipal Stations (MS) are used to transform voltage from 44kV to 13.8kV. Through underground or overhead, the 13.8kV feeders will exit the stations and distribute electricity to the City of Oshawa. Proper operation of these stations is essential to the reliability of supply. Problems associated with equipment failure at stations have a high impact on overall system reliability.

Six of these stations are outdoor type surrounded by locked security fences. The terminations of power transformers are exposed, energized and readily accessible although the switchgears are metal enclosed. These stations are defined as "Outdoor Open Stations" in the Distribution System Code (DSC) of the Ontario Energy Board (OEB) and require monthly inspection. The other three stations are classified as "Indoor Enclosed Stations" since the equipment is installed inside buildings.

In order to simplify procedures and provide high reliable supply, all nine stations will be inspected monthly.

Procedure:

There are nine Municipal Stations (MS): MS-2, MS-5, MS-7, MS-10, MS-9, MS-11, MS-13, MS-14 and MS-15. Each station consists of 44kV circuit breakers, 44kV to 13.8kV station power transformers and cooling fans, cable terminators, 13.8kV circuit breakers in the switchgears, station service transformer, batteries, battery chargers, lighting, heating, ventilation, drains, door, lock, fence, building envelope and roof, safety equipment, fire extinguisher, eye-wash station and all associated devices used to provide protection, control, metering and monitoring of the station. Perform visual inspection on these items monthly.

Any deficiencies shall be reported and documented for follow-up repairs.

Routine Systems Operations and Maintenance

Category: **Station**

Program: **Customer Owned Station Inspection**

Description/ Justification: Various large customers throughout the city have privately owned substations intended to transformer 44kV power distribution to a voltage more suitable to their operation. As these substations are connected to Oshawa Power's distribution network, they have the potential to adversely affect the reliability of the system should they malfunction. Oshawa power has no jurisdiction or responsibility to maintain these privately owned substations and thus has no control over their condition.

Procedure: A visual inspection will be performed on the customer owned substation on a three year cycle to identify any obvious signs of disrepair that could cause a failure, resulting in a disruption to Oshawa Power's distribution network. Any deficiencies found will be reported to the customer with a required timeline for remediation. A follow-up inspection will be performed to ensure compliance.

Routine Systems Operations and Maintenance

Category: **Overhead System**

Program: **Infra-red Scanning**

Description/ Justification: One of the most common sources of trouble on the overhead system is deteriorating connectors resulting in overheating and eventual failure. Infra-red scanning of overhead line components identifies these potential anomalies and allows for corrective measures to be taken before they fail causing power outage.

Procedure: The infrared scanning will be done on geographic area basis in co-ordination with tree trimming and system patrols. In addition to the overhead line components, any electrical equipment such as overhead transformers, switches which exist in proximity will be scanned. All main feeder circuits will be scanned once a year and all single phase circuits will be done once every three years.

Problems identified during the scanning will be recorded and documented for follow-up repairs or replacements.

Routine Systems Operations and Maintenance

Category: **Overhead System**

Program: **System Patrol**

Description/ Justification: The Overhead Distribution System, over time, if not inspected can erode and deficiencies can become present. These deficiencies could include items such as missing/broken guys, broken insulators, unapproved third party attachments, missing or incorrect nomenclature, etc. These deficiencies can introduce reliability risks to the system or safety risks to the public.

Procedure: System patrols will be done on a three year cycle based on geographic areas in coordination with infrared scanning and tree trimming. The system patrol will look for all potential deficiencies in the overhead network.

Problems identified during the system patrol will be recorded and documented for follow-up repairs or replacement

Routine Systems Operations and Maintenance

Category: **Overhead System**

Program: **Load Break Switches**

Description/ Justification: This program includes maintenance on all three phase load break switches (LBS) also called air break switches (ABS). These switches are used on the distribution system to reconfigure overhead circuits on load as required to ensure sufficient supply to the customers during routine and emergency switching. Proper operation of these switches will shorten the outage restoration time resulting in the improvement of system reliability. Maintenance is performed on a three year cycle.

Procedure: Switch selection is coordinated through System Operator due to system loading considerations and the capability to take a switch out of service. Switch and the manual operating device will be cleaned, lubricated, aligned and adjusted. Any defective components will be replaced as required.

Other deficiencies shall be reported and documented for follow-up repairs.

Routine Systems Operations and Maintenance

Category: **Overhead System**

Program: **In-Line Switches**

Description/ Justification: This program includes maintenance on all 13.8kV and 44kV in-line switches. These switches are used on the distribution system to reconfigure overhead circuits as required to ensure sufficient supply to the customers during routine and emergency switching. Proper operation of these switches will shorten the outage restoration time resulting in the improvement of system reliability. Maintenance is performed on a three year cycle.

Procedure: Switch selection is coordinated through System Operator due to system loading considerations and the capability to take a switch out of service. Switch and the manual operating device will be cleaned, lubricated, aligned and adjusted. Any defective components will be replaced as required.

Other deficiencies shall be reported and documented for follow-up repairs.

Routine Systems Operations and Maintenance

Category: **Overhead System**

Program: **Distribution Automation Battery, Communication and Protection Control Maintenance, Inspection and Replacement**

Description/ Justification: This program includes maintenance, inspection and/or replacement of batteries, communication devices and all protection control equipment on all SCADA operated three phase load break switches. These switches are used on the distribution system to reconfigure overhead circuits on load as required to ensure sufficient supply to the customers during routine and emergency switching. Proper operation of these switches will shorten the outage restoration time resulting in the improvement of system reliability. All the overhead SCADA operated switches are powered by a D.C. supply from batteries charged by a control box charger. Failure to inspect, maintain and/or replace the batteries or the battery charger will cause the protective system and the operation of remote switches inactive. This will result in damage to electrical equipment and possibly loss of the entire feeder.

Full maintenance, inspection and replacement is performed on a three year cycle in conjunction with the Overhead Load Break Switch Maintenance Program. Simple battery inspection is performed once every three (3) months. Protection control equipment and communication device maintenance and inspection is performed yearly. Battery replacement is performed every three (3) years.

Procedure: **Protection Control/Communication Device:** Update relay firmware as directed by Protection & Control Engineer. Check protection control and communication devices settings to ensure proper communication, calibration and mechanism for opening and closing functions. Verify voltage and current transducer calibration, alarm circuit and SCADA points. This shall be completed yearly.

Battery & Charger: Every three (3) months, check the charger output for current and voltage. Visually inspect batteries for evidence of corrosion and leakage. Every three (3) years replace battery and if required, the charger.

Enclosure: Inspect enclosure gasket. Inspect enclosure for presence of corrosion, holes and moisture.

Routine Systems Operations and Maintenance

Category: **Overhead System**

Program: **Wood & Concrete Pole Inspection & Treatment**

Description/ Justification: This program includes wood and concrete pole inspection and treatment. Poles requiring immediate replacement as identified in the inspection are covered under the Capital Program. Distribution lines and equipment are mounted on poles throughout the City. It is important that the strength of pole is sufficient to support the overhead lines and equipment.

As wood is a natural material, the degradation of wood pole can occur inside and/or outside the pole. For concrete poles, the deterioration is the result of rusting on the re-enforcing steel bars caused by moisture and salt. Inspection and treatment of the deterioration of pole can reduce the risk of defective pole and the resulting in power outage and safety hazard.

Procedure: Poles are inspected and treated on an ongoing basis. Assessment techniques start with a simple visual inspection of poles accompanied by basic physical tests, such as prodding tests for external conditions and hammer tests to detect evidence of internal decay. If there is any indication of decay from these tests, a full assessment such as Resistograph and/or Ultra Sound test shall be applied. The inspection is done at the bottom of the pole only. The finding of rot at the top of pole will be reported by the Line Crew working on the pole.

The inspection record shall include basic identification information, pole type, class, species, height, date of installation and original treatment (if available), condition and damage to the pole.

If treatment is required, either the wrap method of external treatment or the Copper Boron Rod method for internal treatment shall be applied.

Any deficiencies shall be reported and documented for follow-up repairs.

Routine Systems Operations and Maintenance

Category: **Overhead System**

Program: **Tree Trimming**

Description/ Justification: While trees are aesthetically pleasing, they do present a reliability and safety hazard when they are close to the power lines. To minimize tree contact interruptions, a tree trimming program is required to maintain adequate clearance so the system reliability will not fall below the Ontario Energy Board (OEB) requirements. The tree trimming is completed on a three year cycle. Secondary overhead line routes and spot work to deal with the fast growing species will be performed as required.

Procedure: All tree trimming will be carried out according to approved arboricultural standards. All clearances must be relative to the estimated position of maximum sag and swing of the nearest conductor. All limbs or main stems of trees that could sag or fall into the lines when weighted with snow or ice shall be removed. All deadwood which, under normal wind conditions, could strike or fall into energized lines or electrical apparatus and cause damage and interruption, shall be removed. For the maintenance of tree symmetry, limbs may be removed.

Any deficiencies of equipment shall be reported and documented for follow-up repairs.

Routine Systems Operations and Maintenance

Category: **Underground System**

Program: **Manholes**

Description/ Justification: Manholes are enclosures found within the road allowance, located below grade, have a round lid and primarily contain cables. However, manholes may contain small electrical equipment and are considered a confined space. Periodic inspection is required to ensure the integrity of the structure, cable and electrical equipment. Inspection and maintenance will be performed once every 3 years or yearly if the manhole houses critical infrastructure.

Procedure: Visual inspection will be performed on the surface to ensure no obvious problems such as damaged lids. Follow rules and regulation, such as checking explosive gas, for entering confined space environment. The lids will be removed and confined space entry equipment will be set up. Perform detailed inspection on structures, cable racks, cables, splices, other equipment and environmental conditions.

Any minor deficiencies will be repaired during inspection. Major problems, such as structures, washing, cables and splices shall be documented and reported for follow-up repairs.

Routine Systems Operations and Maintenance

Category: **Underground System**

Program: **Pad-mount & Submersible Transformers (Single and Three Phase) and Switchgear**

Description/ Justification: Single and three phase pad-mounted transformers or switchgear are metal clad enclosures located above grade on concrete pads with lockable facilities. Submersible transformers are installed in below grade vaults. As required by the Distribution System Code (DSC) of the Ontario Energy Board (OEB), all major equipment for underground distribution system must be patrolled or visually inspected at least once every three years to identify obvious structural problems and hazards such as damaged equipment, enclosures and vandalism. The inspection will also identify any potential problems which will cause system outage and possible environmental disaster.

Procedure: For all pad-mount and submersible transformers as well as switchgear, external visual inspections will be performed to ensure no obvious problems such as missing locks, holes due to enclosures rusting or unleveled concrete pad foundation are present. Internal visual inspections with be performed on elbows and inserts, primary and secondary cables, secondary paddles, fiber board(s), nomenclature and terminations.

Any deficiencies shall be reported and documented for follow-up repairs.

Routine Systems Operations and Maintenance

Category: **Underground System**

Program: **Vaults—Downtown, Critical & Non-critical**

Description/ Justification:

There are three types of vaults---Downtown, Critical and Non-Critical. Downtown Vaults are below grade in the downtown core supplying power to commercial customers. Critical Vaults are defined as vaults either below grade, above grade or with poor access. These vaults are used to supply power to major customers, such as Health Centers and Shopping Malls. Non-critical vaults are typically above grade rooms in industrial/commercial type buildings with locked doors.

All vaults contain transformers and/or other switching devices, such as SF6 and vacuum switches, ventilation equipment and/or sump pumps. Periodic inspection and maintenance are required to ensure the integrity of the structure and equipment. Below grade vaults are considered a confined space.

Since Downtown Vaults are frequently subjected to leaking of contaminated water from the ceiling and walls of vaults, inspection and maintenance shall be performed twice a year, in spring and fall. For Critical Vaults, reliable power supply to customers is important. These vaults shall be inspected and maintained once a year. For Non-critical Vaults, the inspection and maintenance cycle shall be once every three years which will comply with the three years inspection requirements in the Distribution System Code (DSC) of the Ontario Energy Board (OEB).

All the underground remote switches are powered by D.C. supply from batteries charged by a control box charger. Batteries are used for the storage of electric energy that is readily available for the control of electrical equipment during outages. Also, the batteries provide power for communication, indication lights, alarms, SCADA control system and automation. Failure to maintain the batteries and the battery charger will cause the protective system and the operation of remote switches inactive. This will result in damage to electrical equipment and possibly loss of the entire feeder.

Procedure:

Visual inspection will be performed to ensure no obvious problems such as damaged ventilation. Set up confined space entry equipment and follow rules and regulation, such as checking explosive gas, for entering a confined space environment. Perform detailed inspection on structures, equipment and environmental conditions. Inspect gauges on transformers, SF6 and vacuum switches. Clean ventilations and remove debris. Test and lubricate sump pumps. Perform infra-red scanning on elbows, cables and terminations.

Protection Control/Communication Device: Update relay firmware as directed by Protection & Control Engineer. Check protection control and communication devices settings to ensure proper communication, calibration and mechanism for opening and closing functions. Verify voltage and current transducer calibration, alarm circuit and SCADA points. This shall be completed yearly.

Battery & Charger: Every three (3) months, check the charger output for current and voltage. Visually inspect batteries for evidence of corrosion and leakage. Test remote control of switch (if applicable) with no A.C supply and perform a load test during routine inspection cycle. Replace battery and if require, the charger, every three (3) years.

Enclosure: Inspect enclosure gasket. Inspect enclosure for presence of corrosion, holes and moisture.

Major problems, such as structures, cables and defective equipment shall be documented and reported for follow-up repairs.

Other deficiencies shall be reported and documented for follow-up repairs.

Process Maps

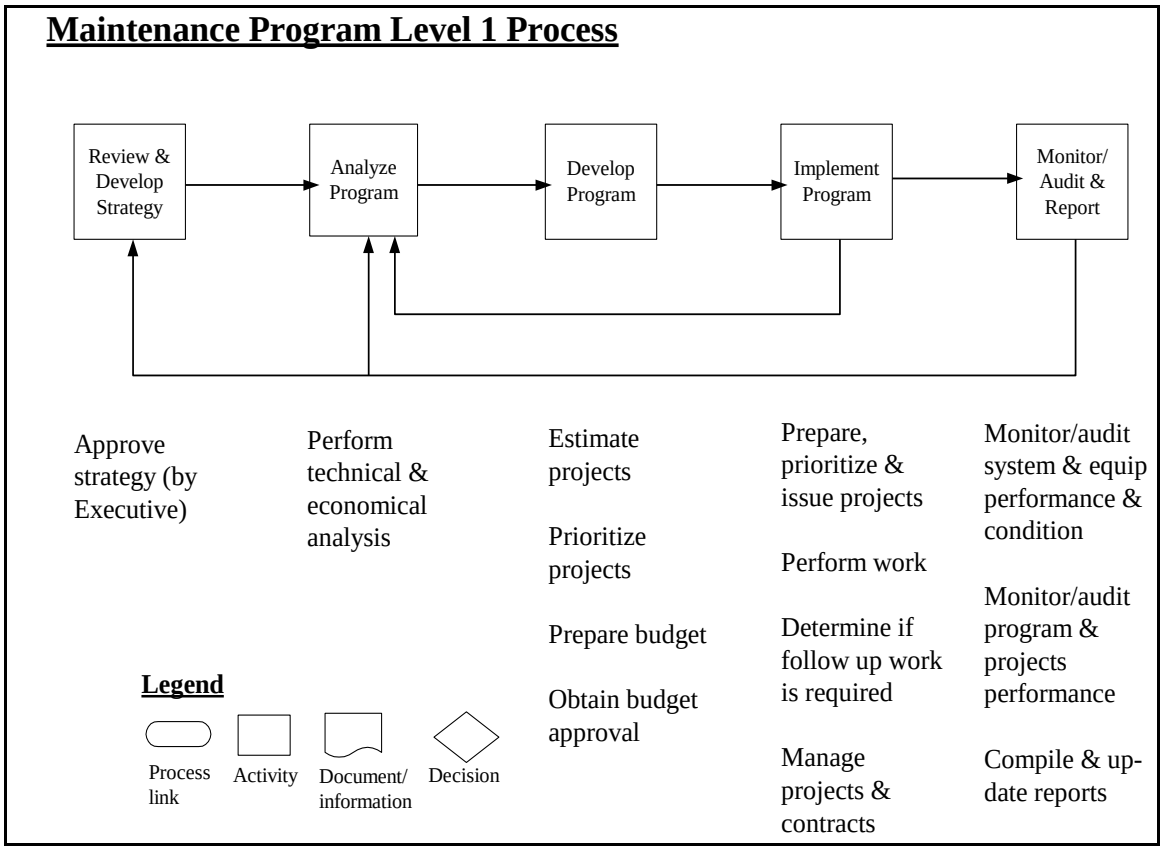


Figure 1: Maintenance Program Level 1 Pr 1

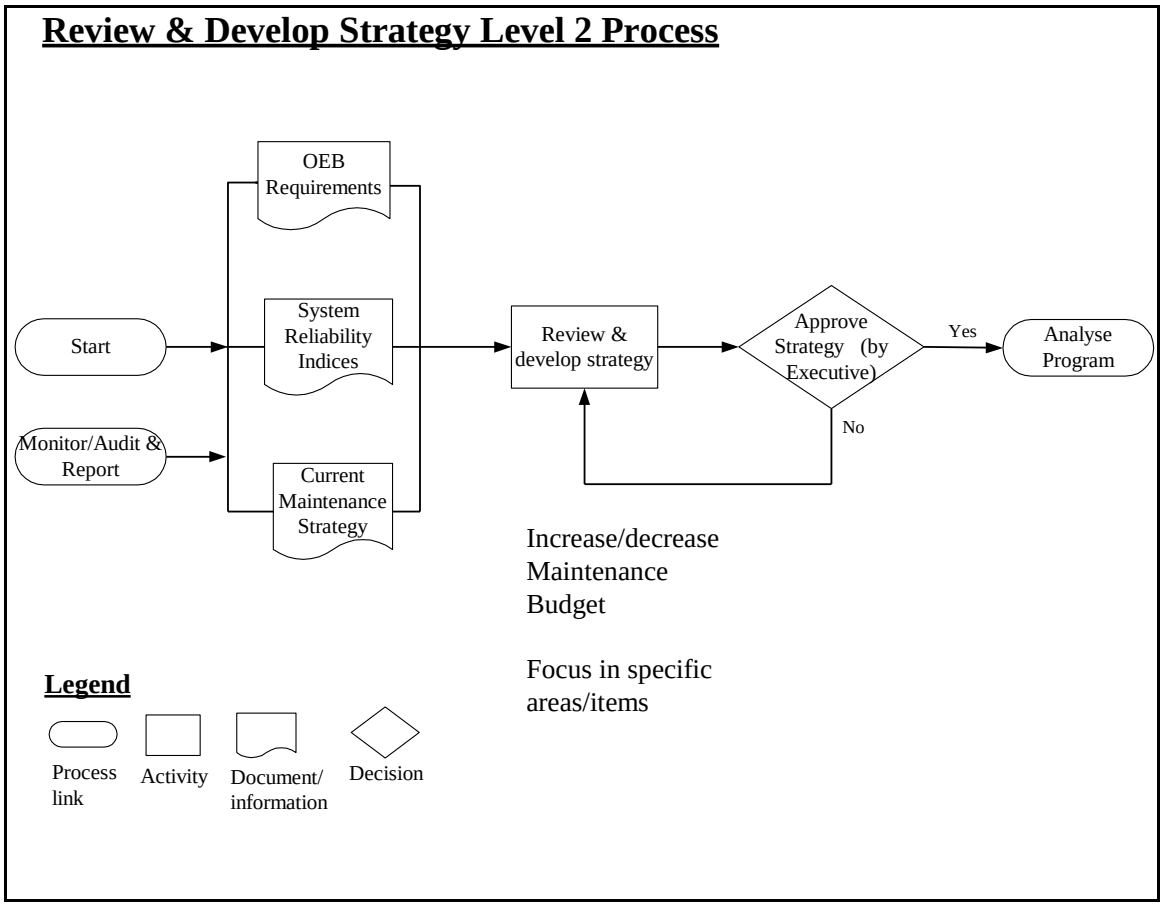


Figure 2: Review & Develop Strategy Level 2 Process

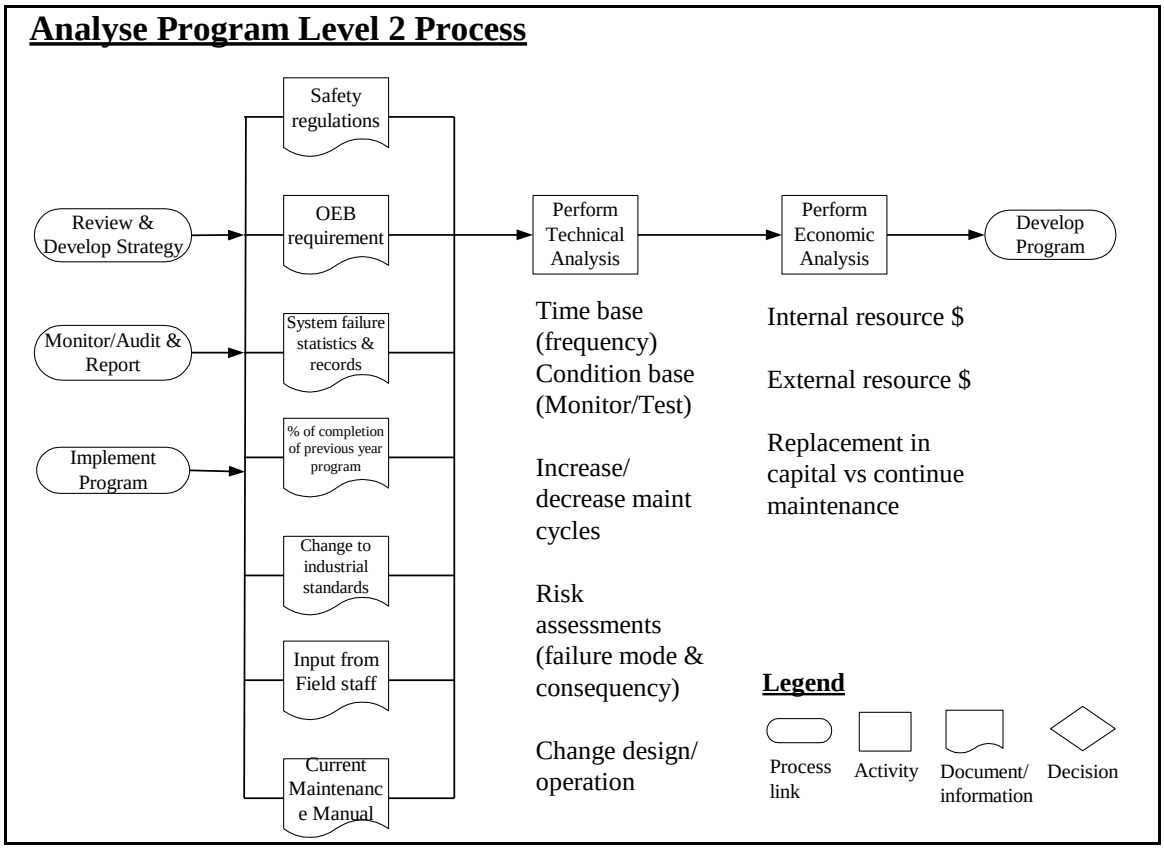


Figure 3: Analyse Program Level 2 Process

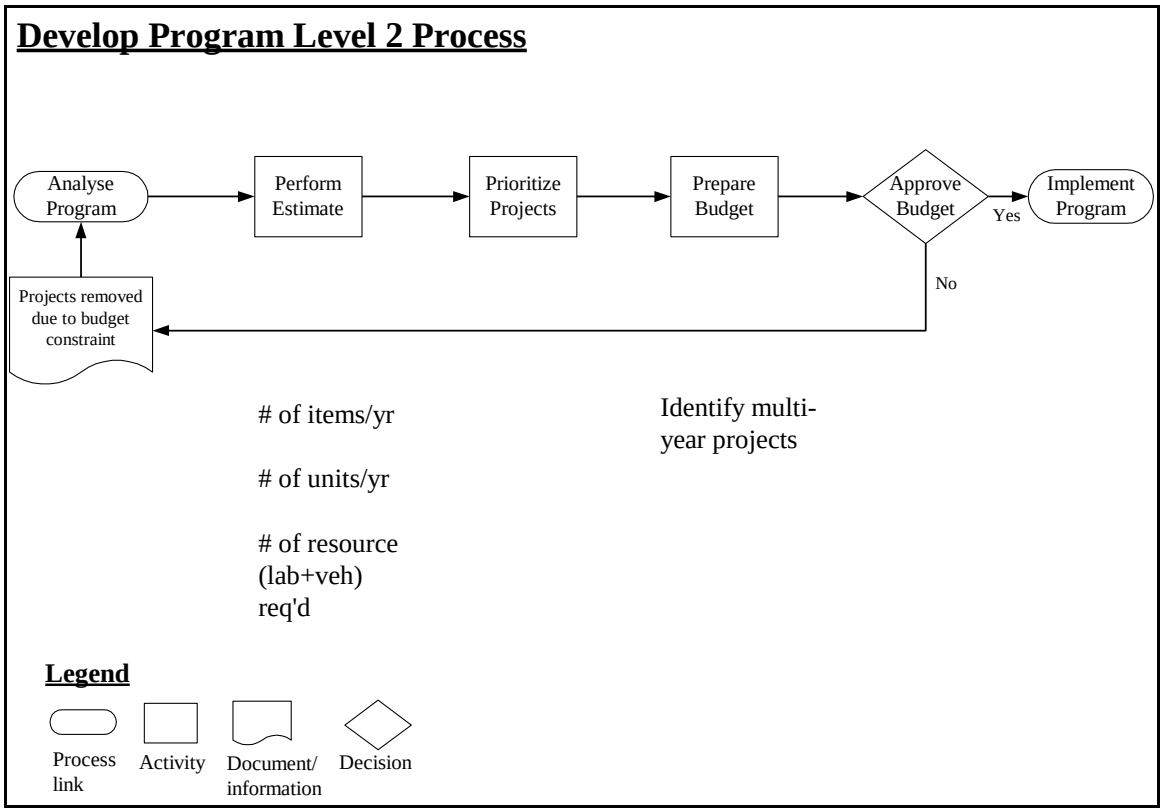


Figure 4: Develop Program Level 2 Process

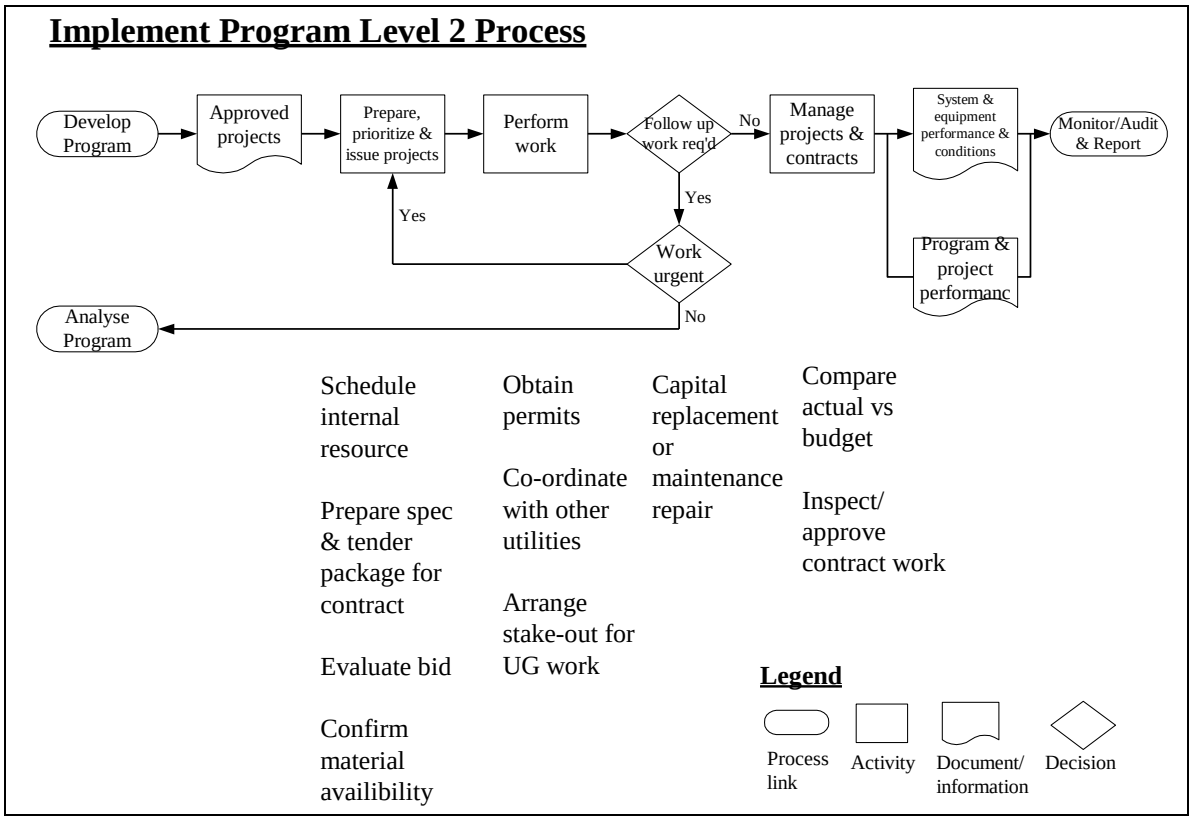


Figure 5: Implement Program Level 2 Process

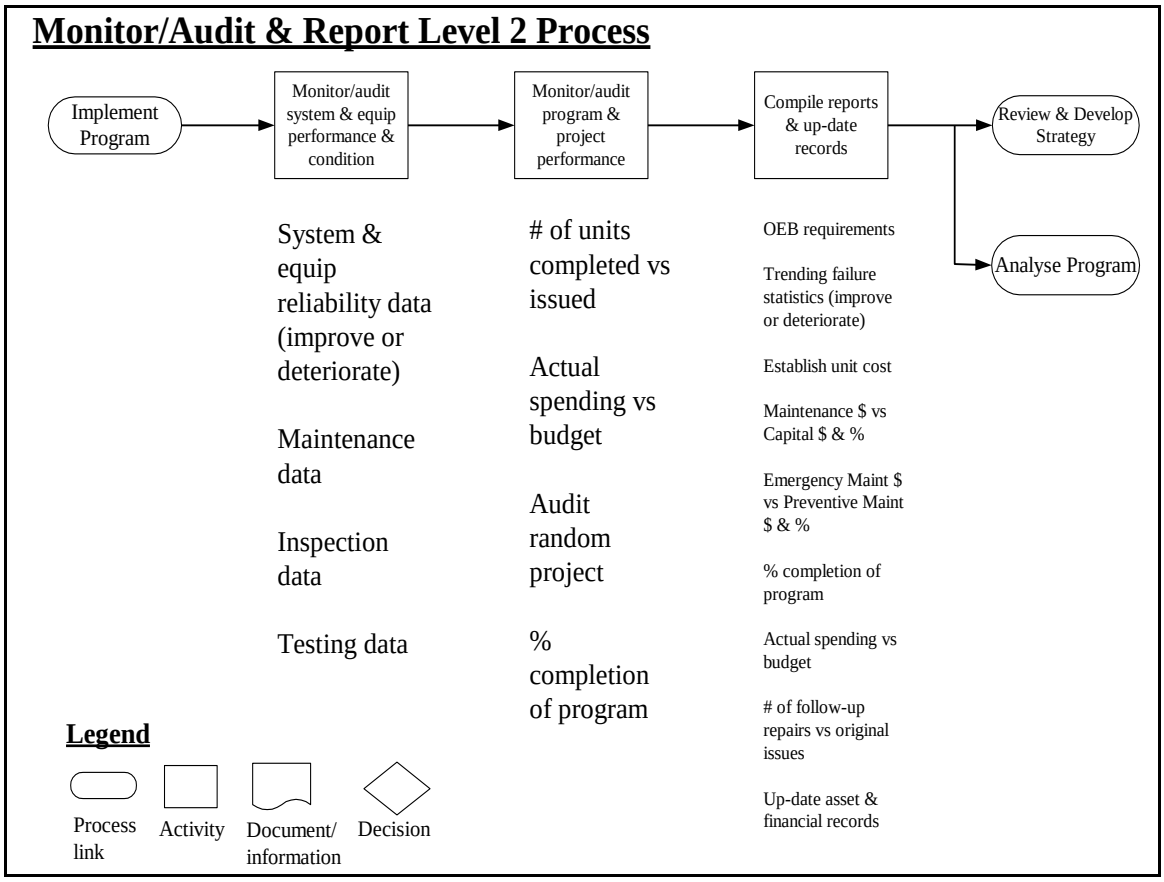


Figure 6 : Monitor/Audit & Report Level 2 Process

Appendix H

Asset Management Policy and SAMP

Policy and Procedure Manual		
Section: Corporate		**Policy #:** OPUCN-1011
Policy: Asset Management		
Approved by: Daniel Arbour, President & CEO		
Date: September 18, 2024	**Revision Date:** N/A	**Page:** Page 1 of 1

Purpose:

Oshawa PUC Networks Inc. (OPUCN) is committed to delivering safe and reliable services to its customers in a financially and operationally effective manner. OPUCN utilizes its distribution system assets to deliver services in its service area. The distribution system assets are capital-intensive and have very long lives. Providing good quality, valued, reliable and sustainable services depends on having the distribution system assets in good condition. OPUCN has developed an asset management policy to ensure a continual and consistent focus on delivering services in a way that balances risk and long-term costs. The policy establishes the core asset management principles that drive OPUCN's planning framework.

Policy:

This policy along with the strategic asset management plan, asset management processes, and objectives backed by up-to-date asset information form OPUCN's Asset Management System that ensures the distribution system shall be designed, procured, constructed, operated, maintained, renewed and retired in an efficient manner that:

- Supports OPUCN's corporate goals and asset management objectives;

- Supports the OEB's RRFE outcomes;

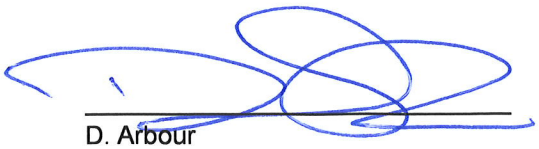
- Implements OPUCN's investment plan as documented in the Distribution System Plan;

- Complies with regulatory and statutory requirements
    - Health and safety of workers and the public;
    - Electricity supply quality and reliability;
    - Environmental Protection;
    - Good Utility Practice;
    - Financial and IFRS accounting practice; and

- Effectively controls and balances service levels with asset lifecycle costs and risks as well as reconciles with OPUCN's investment strategies and financing capabilities.

It is the responsibility of the OPUCN Board to ensure there are established roles, responsibilities, authorities and controls to achieve the asset management policy, strategy, objectives, and plans. Responsibility for asset management is held from the Board to the President and CEO of OPUCN.

The President & CEO has overall responsibility for the governance of OPUCN's Asset Management System and reporting on the status and effectiveness of OPUCN's Asset Management System.



D. Arbour
President & CEO

Sept 24, 2024
Date Signed

		SIGNATURE	DATE
APPROVED BY:	M. Weatherbee		2024-11-19

ISSUE/REVISION INDEX

Revision				Revision Details
No.	Prep. By	App. By	Date	
00	ADG	MW	2024-11-19	Released for Implementation

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Appendix A: Impact Matrix

EXECUTIVE SUMMARY

Oshawa Power is a local distribution company (LDC) for the city of Oshawa, in Ontario, Canada, serving over 63,000 customers across a 145 square kilometer urban territory. With three 230 kV to 44 kV Hydro One owned Transformer Stations (TSs) supplying nine 44 kV to 13.8 kV Oshawa Power owned Municipal Substations (MSs), the LDC serves a peak demand of over 200 MW.

Purpose of the Strategic Asset Management Plan

The Strategic Asset Management Plan (SAMP) outlines Oshawa Power's strategy for managing its assets to achieve optimal performance, reliability, and sustainability. The SAMP provides a framework for asset planning, acquisition, operation, maintenance, renewal, and disposal, aiming to enhance asset management practices and deliver value to customers. By implementing this plan, Oshawa Power aspires to uphold its vision of being a trusted and leading energy partner, ensuring safety, reliability, and cost-effectiveness while complying with regulatory requirements.

Structure of the SAMP

The SAMP is structured into several key sections, including Introduction, Applicability, Asset Management System, and Implementation. Each section details Oshawa Power's approach to managing its assets in alignment with its strategic objectives and operational themes. The operational themes for this SAMP are developed using quantifiable aspects of the company's values.

Vision, Mission, and Values

Oshawa Power's vision is to be a trusted and leading energy partner today and tomorrow. Its mission is to empower customers to thrive through the evolving energy transition. The company's values are **Safety, Stewardship, Innovation, Care for People, Courage to Act, and Customer Focus**. These values underpin the Strategic Initiatives included in Oshawa Power's 2026-2030 Strategic and Business Plan, which align with the OEB's Renewed Regulatory Framework for Electricity Distributors (RRFE) performance outcomes..

Scope of Applicability

The SAMP applies to all assets owned and operated by Oshawa Power, including distribution lines (overhead and underground), MSs, and other infrastructure. The plan ensures that asset management practices are sustainable, cost-effective, and socially responsible, guiding principles for making informed decisions to achieve strategic objectives.

Asset Management System

The Asset Management System (AMS) is designed to support Oshawa Power's goal of empowering customers through effective and efficient asset management. It provides a framework for decision-making related to asset planning, acquisition, operation, maintenance, renewal, and disposal. By adhering to this system, Oshawa Power aims to optimize the performance, reliability, and sustainability of its assets, ensuring cost-effectiveness and regulatory compliance.

Asset Management Objectives

Oshawa Power's asset management objectives are closely aligned with its vision, mission, values and strategic

initiatives. Oshawa Power developed operational themes to organize its asset management objectives. Each operational theme is supported by specific objectives, measures, and targets to ensure comprehensive management of the assets. For example:

- **Safety**: Zero injuries and no serious electrical incidents, supported by robust safety training and protocols.
- **Reliability**: Maintain SAIDI and SAIFI at or below the fixed five-year historical average updated every five-years, focusing on critical assets and proactive maintenance.
- **Customer Focus**: Enhance transparency, customer satisfaction, and engagement through surveys, accurate billing, and proactive communication.
- **Stewardship**: Ensure regulatory and environmental compliance, minimize revenue losses, and maintain high reliability.
- **Innovation**: Drive continuous improvement through grid and process automation, increasing operational efficiency, and considering non-wires solutions.

Asset Management Process

The AMS begins with identifying needs based on internal and external inputs and strategic investments. Investment portfolios are categorized into System Access, System Renewal, System Service, and General Plant. Alternatives are considered for desired outcomes, governed by the asset management strategy. The lifecycle of assets includes planning, acquisition, operation, maintenance, and disposal.

Asset Management Strategies

Oshawa Power employs several key strategies to achieve its asset management objectives:

- **Proactive Maintenance**: Regular inspections, testing, condition monitoring, and predictive maintenance to ensure reliability and minimize downtime and costs.
- **Asset Renewal and Replacement**: Prioritize assets nearing the end of their useful life or at high risk of failure based on risk assessments and condition data.
- **Customer Engagement**: Actively gather customer feedback through surveys and focus groups to inform planning and operational decisions and improve customer satisfaction.
- **Environmental Sustainability**: Reduce energy losses, promote energy efficiency, and integrate renewable energy sources to minimize environmental impact and comply with regulations.
- **Technology Innovation**: Invest in smart grid solutions, automation systems, and innovative technologies to enhance system reliability and asset utilization.

Asset Information

Oshawa Power maintains comprehensive asset information to support its AMS. This includes detailed records of assets, maintenance activities, condition and risk assessments, and performance data. Key components of the asset information system are:

- **Asset Registers**: Detailed information about each asset, including location, type, and age, stored in a Geographic Information System (GIS).

- **Maintenance Records**: Comprehensive documentation of all maintenance activities.
- **Condition & Risk Assessments**: Regular assessments to prioritize maintenance and renewal activities.
- **Performance Data**: Analysis of performance data to identify trends and areas for improvement.

Implementation of the Asset Management System

The successful implementation of the AMS involves an integrated approach that aligns leadership, engages stakeholders, invests in training, fosters collaboration and innovation, and emphasizes continuous improvement. Key steps include:

- **Leadership and Commitment**: Senior management provides direction, resources, and support for AMS implementation.
- **Training and Development**: Ongoing training programs ensure employees have the necessary skills and knowledge.
- **Collaboration and Innovation**: Partnering with industry and participating in research to drive asset management innovation.
- **Continuous Improvement**: Regularly reviewing practices to identify enhancement opportunities and incorporating lessons learned into future decision-making.

Risk Factors and Mitigation Strategies

Oshawa Power identifies and mitigates risks associated with asset management through comprehensive strategies. For instance, proactive maintenance reduces the likelihood of asset failures, while robust safety protocols and training minimize safety risks.

Performance Monitoring and Reporting

Performance monitoring and reporting are crucial for evaluating the effectiveness of AMS strategies. Oshawa Power tracks key performance indicators (KPIs) related to its operational themes. Regular reports provide insights into progress and areas for improvement.

Project Prioritization

Oshawa Power prioritizes projects based on their alignment with strategic objectives and operational themes. Projects are ranked using a risk-based approach, ensuring resources are allocated to those that deliver the most value while minimizing risk. Weightages are assigned to operational themes, and a quantified risk matrix is used to compare and rank projects.

By following these comprehensive strategies and maintaining robust asset information, Oshawa Power ensures the effective management of its assets, enhancing system reliability and sustainability, and ultimately achieving its vision of being a trusted and leading energy partner.

1.0 INTRODUCTION

Oshawa Power is a leading local distribution company (LDC) in Ontario, Canada, serving more than 63,000 customers, of which over 90% are residential, in a service territory spanning 145 square kilometers. The company's service territory is predominantly urban. Oshawa Power operates nine 44 kV to 13.8 kV Municipal Substations (MSs) and is served by three Hydro One 230 kV to 44 kV Transformer Stations (TSs). Oshawa Power manages approximately 1000 km of primary circuit at 13.8 kV. With a peak demand of above 200 MW and an annual energy consumption of over 1,000 GWh, Oshawa Power plays a critical role in providing reliable electricity to its customers in the City of Oshawa.

1.1 Purpose of the Strategic Asset Management Plan (SAMP)

The purpose of this SAMP is to outline Oshawa Power's approach to managing its assets effectively and efficiently to achieve its Asset Management objectives. The plan provides a framework for decision-making related to asset planning, acquisition, operation, maintenance, renewal, and disposal. By following this plan, Oshawa Power aims to optimize the performance, reliability, and sustainability of its assets, while ensuring cost-effectiveness and compliance with regulatory requirements.

By developing and implementing this SAMP, Oshawa Power aims to enhance its asset management practices, deliver value to its customers, and achieve its vision of being a trusted and leading energy partner today and tomorrow. The plan serves as a roadmap for Oshawa Power's asset management activities, guiding decisions and investments to ensure the safety, reliability, and sustainability of its electricity supply.

1.2 Structure of the SAMP

The SAMP is structured into several key sections, including Introduction, Applicability, Asset Management System, and Implementation. Each section details Oshawa Power's approach to managing its assets in alignment with its strategic objectives and operational themes. The operational themes for this SAMP are developed using quantifiable aspects of the company’s values.

1.3 Vision, Mission, and Values

Oshawa Power's vision is to be a trusted and leading energy partner today and tomorrow. The company's mission is to empower customers to thrive through the evolving energy transition. The company’s values are **Safety, Stewardship, Innovation, Care for People, Courage to Act, and Customer Focus**. These values underpin the Strategic Initiatives included in Oshawa Power’s 2026-2030 Strategic and Business Plans, whichalign with the OEB’s Renewed Regulatory Framework for Electricity Distributors (RRFE) performance outcomes.

Oshawa Power has identified five key operational themes. These operational themes are critical in helping us prioritize investments and form the basis of our risk-based project prioritization strategy as explained later in this document.

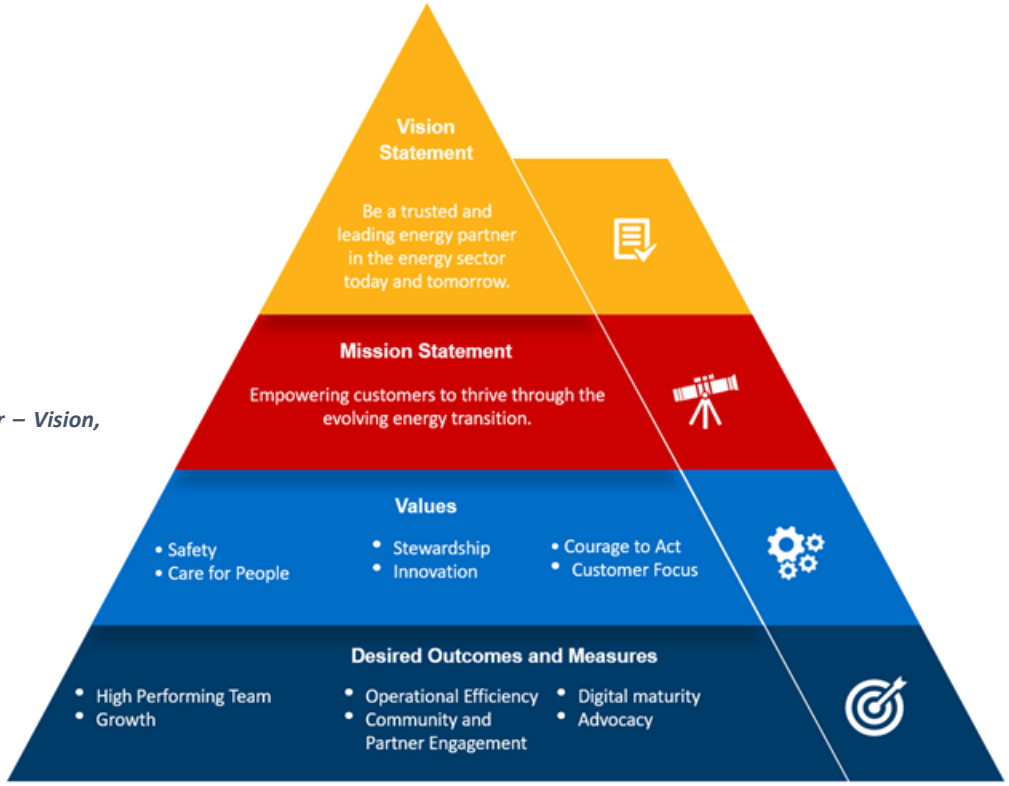


Figure 1: Oshawa Power – Vision, Mission and Values

Operational Themes

1. **Safety**: Top priority for customers and employees
2. **Reliability**: Minimize downtime and disruption
3. **Customer Focus**: Responsive customer service, positive reputation & brand identity
4. **Stewardship**: Environmental, Regulatory, and Financial stewardship
5. **Innovation**: Distribution Automation, IT system upgrades, System enhancements

Figure 2: Oshawa Power – Operational Themes

1.4 Importance of Asset Management

Effective asset management is crucial for Oshawa Power to fulfill its mission and achieve its vision. The company's assets, including distribution lines and MSs, are essential for the safe and reliable delivery of electricity to customers. Proper management of these assets is essential in ensuring safety of employees and customers, maintaining high levels of reliability, meeting customer needs, minimizing environmental impact, and driving innovation in the energy sector.

2.0 APPLICABILITY

2.1 Scope of Applicability

The Strategic Asset Management Plan (SAMP) developed by Oshawa Power is applicable to all assets owned and operated by the Local Distribution Company (LDC), including distribution lines, both overhead and underground, MSs, and other infrastructure necessary for the safe and reliable delivery of electricity to customers. The SAMP outlines the LDC's approach to managing these assets effectively and efficiently, ensuring the safety and reliability of its electricity supply.

By ensuring the applicability of the SAMP to all aspects of its asset management practices, Oshawa Power is committed to managing its assets in a sustainable, cost-effective, and socially responsible manner. The SAMP provides guiding principles for making asset management decisions, helps Oshawa Power achieve its strategic objectives, and maximizes value delivered to its customers and stakeholders.

2.2 Regulatory Compliance

Oshawa Power's asset management practices are in compliance with all relevant laws, regulations, and standards governing the electricity industry in the Province of Ontario, Canada. The LDC adheres to regulatory requirements related to safety, reliability, environmental stewardship, and financial management, ensuring that its asset management practices meet or exceed industry standards.

2.3 Integration with Business Processes

The SAMP is aligned with Oshawa Power's mission, vision, and values, as well as its strategic direction, business plan, and maintenance plan. The SAMP will be periodically reviewed and updated to ensure it remains aligned with the company's strategic direction.

2.4 Stakeholder Involvement

Stakeholder involvement is integral to the applicability of the SAMP. Oshawa Power engages with stakeholders, including customers, employees, regulators, municipal and regional government, and industry partners, to gather feedback, address concerns, and incorporate diverse perspectives into all its business planning processes.

2.5 Continuous Improvement

The SAMP is a living document that is subject to continuous improvement. Oshawa Power will regularly review and update the plan to reflect changes in its business environment, technological advancements, and industry best practices. By continuously improving its asset management practices, Oshawa Power ensures that its assets are managed effectively and efficiently, supporting its mission to be a trusted and

leading energy partner today and tomorrow.

3.0 ASSET MANAGEMENT SYSTEM

Oshawa Power's Asset Management System encompasses several key components as discussed in this section.

3.1 Asset Management Objectives

Oshawa Power's asset management objectives are closely aligned with its vision, mission, and operational themes. Our asset management objectives, its links to the OEB's RRFE Outcomes and operational themes, along with measures and targets are tabulated below:

Table 1: Asset Management Objectives

RRFE Outcome	Operational Theme	Asset Management Objectives	AM Objective Measures	AM Objective Targets
Operational Effectiveness	Safety	Ensure proper installation, operation, inspection & maintenance activities are established and followed to maintain the highest level of safety	Workplace injuries / incidents; Public safety; Safety Training.	No Loss Time (Zero injuries)
				No Serious Electrical Incidents (ESA Public safety)
				Implement safety training programs and improve safety protocols
Operational Effectiveness	Reliability	Strategically plan, design, build, operate & maintain Oshawa power's system to meet and exceed reliability targets	SAIDI, SAIFI	Maintain SAIDI / SAIFI at or below a fixed five-year historical average updated every 5 years
				Target critical assets prone to unplanned downtime
				Inspection / Proactive maintenance
Customer Focus	Customer Focus	Enhance transparency and	Customer Satisfaction;	Accuracy in Billing
				Customer surveys

		facilitate customer feedback and engagement to ensure needs and issues are addressed proactively.	Social Media engagement.	Educate / Enable transparency - Website, social media (X, Facebook, Instagram, LinkedIn)
				DSP consultations
Financial Performance	Stewardship	Ensure financial, regulatory, and environmental stewardship is upheld for all stakeholders	Regulatory / Environmental restrictions; Revenue Losses	Ensure all regulatory & environmental risks are mitigated.
				Minimize revenue losses by strategic investments & maintain high level of reliability
Public Policy Responsiveness	Innovation	Employ creative means, technological and otherwise, to create value through both evolutionary and revolutionary continuous improvement efforts, striving toward operational excellence.	Various continuous improvement measures	Increased Grid Automation
				Increased Process Automation
				Improved Operational efficiency
				Consideration of non-wires solutions

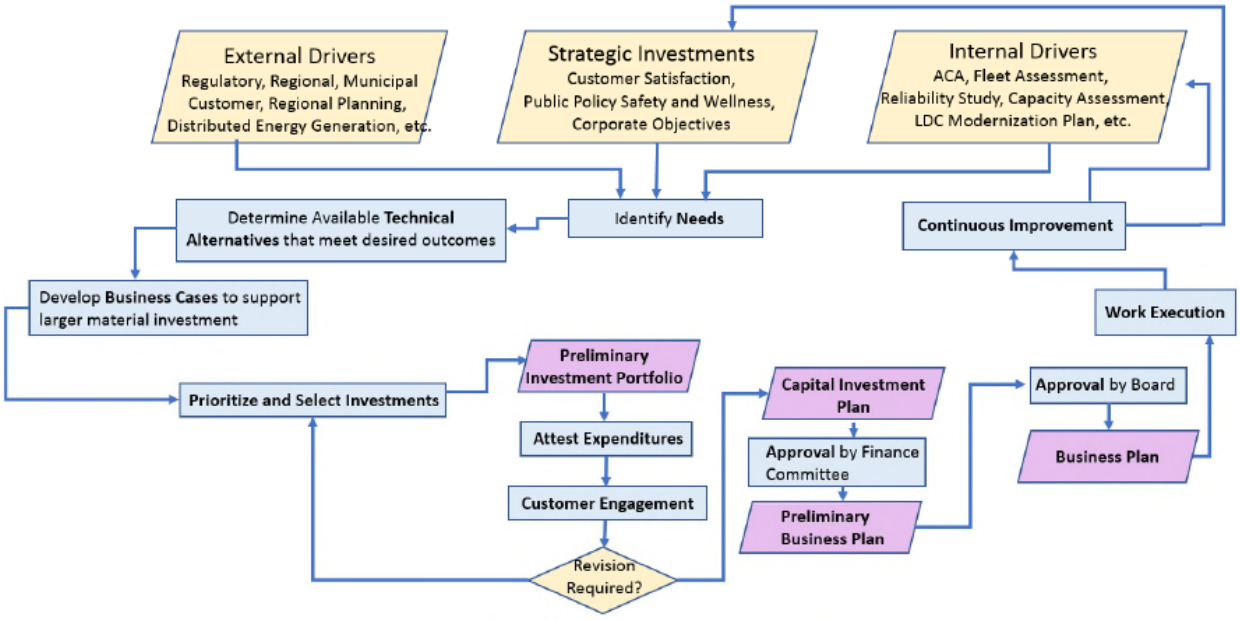
3.2 Asset Management Process

Oshawa Power's Asset Management Process begins with identifying the needs based on inputs and drivers which can be either internal, external, or driven by strategic investments to meet the objectives outlines above. Information collected from these investment drivers will determine the initial investments portfolio and are then classified into four categories, as defined in OEB's Chapter 5 filing requirements, namely - System Access, System Renewal, System Service and General Plant.

Available technical alternatives to meet desired outcomes are considered and developed that can range from "do nothing" to proceeding with a different solution to address identified needs. An example of this solution could be repairing vs replacement. Considerations are governed by Oshawa Power's Asset Management Strategy, as outlined in the next section, and assets are managed through their entire

lifecycle which includes planning, acquisition, operation, maintenance and disposal. Where needs are mandatory such as System Access projects, alternatives are not considered except for the timing of implementation.

Figure 3: Asset Management Process



3.3 Asset Management Strategies

Oshawa Power has developed a set of asset management strategies to align with its operational themes and achieve its asset management objectives. These strategies are focused on optimizing the performance, reliability, and sustainability of its assets while ensuring cost-effectiveness and regulatory compliance. The key strategies include:

1. **Proactive Maintenance**: Oshawa Power implements a proactive maintenance program to identify and address potential issues before they escalate. This includes regular inspections and testing, condition monitoring, and predictive maintenance techniques to ensure the reliability and longevity of its assets. By proactively maintaining its assets, Oshawa Power minimizes downtime, reduces maintenance costs, and enhances overall system reliability.
2. **Asset Renewal and Replacement**: Oshawa Power prioritizes asset renewal and replacement based on thorough risk assessments and condition data. By identifying assets that are nearing the end of their useful life or are at high risk of failure, the company can plan for timely replacement or refurbishment. This strategy ensures that critical assets are maintained in a safe and reliable condition, minimizing the risk of unexpected failures and service interruptions.

3. **Customer Engagement**: Oshawa Power actively engages with its customers to understand their needs and expectations regarding the reliability and quality of the electricity supply. Through surveys, focus groups, and other feedback mechanisms, the company gathers valuable insights that are used to inform asset management decisions. By incorporating customer feedback into its planning process, Oshawa Power can prioritize investments that directly benefit customers and enhance their overall satisfaction.
4. **Environmental Sustainability**: Oshawa Power is committed to minimizing its environmental impact through sustainable asset management practices. This includes reducing energy losses, promoting energy efficiency, and enabling the integration of renewable energy sources into its distribution network. By investing in environmentally friendly technologies and practices, Oshawa Power not only reduces its carbon footprint but also ensures compliance with increasingly stringent environmental regulations.
5. **Technology Innovation**: Oshawa Power invests in innovative technologies to improve the performance and efficiency of its asset, and offset large expenditures where possible. This includes deploying smart grid solutions, non-wire solutions and automation systems to enhance system reliability and optimize asset utilization. By embracing technological innovations, Oshawa Power can future-proof its operations and adapt to the evolving energy landscape, including the integration of distributed energy resources (DERs) and the transition to a more decentralized energy system.

Overall, these asset management strategies enable Oshawa Power to effectively manage its assets, enhance system reliability, and meet the evolving needs of its customers and stakeholders. By prioritizing investments that align with its operational themes and strategic objectives, Oshawa Power can achieve its vision of being a trusted and leading energy partner today and tomorrow.

3.4 Asset Information

Oshawa Power maintains comprehensive asset information to support its asset management activities. This information includes detailed records of its assets, including linear and station assets as well as other infrastructure. The asset information is used to inform decision-making processes related to asset maintenance, renewal, and replacement, as well as to support strategic planning and risk management activities. The key components of Oshawa Power's asset information system include:

1. **Asset Registers**: Oshawa Power maintains detailed asset register that contain information about each asset, including its location, type, age, in its Geographic Information System (GIS) . The GIS also provides a spatial representation of assets, enabling Oshawa Power to identify asset locations, assess their proximity to other assets, and analyze spatial data to support decision-making.
2. **Maintenance Records**: Oshawa Power keeps comprehensive maintenance records for each asset, documenting all maintenance activities, including inspections, repairs, and replacements. These records provide valuable insights into the condition of assets and help to inform maintenance planning and scheduling.

3. **Condition & Risk Assessments**: Oshawa Power conducts periodic condition assessments of its assets to evaluate their current condition and identify any issues or deficiencies. Risk assessments are also performed for critical assets such as MS transformers and breakers. These assessments help to prioritize maintenance and renewal activities based on the condition and criticality of these assets.
4. **Performance Data**: Oshawa Power collects and analyzes performance data such as SAIFI and SAIDI allowing them to assess its system level performance and reliability. By analyzing this data, Oshawa Power can identify trends and patterns that may indicate potential issues or areas for improvement.

By maintaining comprehensive asset information, Oshawa Power is able to make informed decisions about its assets, ensuring they are maintained in a safe, reliable, and cost-effective manner. The asset information system plays a critical role in supporting Oshawa Power's asset management activities and is instrumental in achieving its strategic objectives.

4.0 IMPLEMENTATION OF ASSET MANAGEMENT SYSTEM

The implementation of Oshawa Power's asset management system described in section 3.0 of this SAMP is the crucial step for Oshawa Power to enhance the efficiency and effectiveness of its asset management practices. Oshawa Power is committed to a well executed implementation processes leading to improved decision-making, cost savings, and increased reliability of assets. It involves the integrated approach to asset management, articulating potential risk factors associated with the LDC's asset management objectives, setting up mitigation strategies for those risks, as well as creating the appropriate Performance Monitoring and Reporting structures for them. Lastly, Oshawa Power has implemented a robust risk-based project prioritization methodology that helps guide our key investment decisions. These implementation steps are described in further detail in this section.

4.1 Integrated Approach to Asset Management Implementation

Oshawa Power has adopted an integrated approach to asset management implementation to optimize the performance of our assets and achieve strategic objectives. This approach involves aligning leadership and commitment, engaging stakeholders, investing in training and development, fostering collaboration and innovation and applying principles of continuous improvement throughout the implementation process. By integrating these key elements, Oshawa Power ensures that our asset management system is effectively implemented. Following are the components of this approach:

1. **Leadership and Commitment**: Oshawa Power's leadership plays a crucial role in driving the implementation of the SAMP. Senior management provides direction, resources, and support for the implementation process, demonstrating a strong commitment to effective asset management. Leadership also ensures that the goals and objectives of the SAMP are aligned with the LDC's overall strategic direction, both from the Senior Management down and from the rank-and-file employees up.

2. **Training and Development**: Oshawa Power invests in training and development programs to ensure that employees have the necessary skills and knowledge to perform their jobs. By providing ongoing training and development opportunities, Oshawa Power empowers its employees to contribute to the continuous success in meeting corporate objectives.
3. **Collaboration and Innovation**: Oshawa Power collaborates with industry partners and participates in research and development initiatives to drive innovation in asset management. The company explores new technologies, practices, and solutions to improve the performance, reliability, and sustainability of its assets. By fostering a culture of collaboration and innovation, Oshawa Power remains at the forefront of asset management best practices.
4. **Continuous Improvement**: Continuous improvement is at the core of Oshawa Power's approach to asset management. The company regularly reviews its asset management practices, processes, and procedures to identify opportunities for enhancement. Lessons learned from past experiences are incorporated into future decision-making, ensuring that Oshawa Power's asset management practices remain effective and efficient.

4.2 Risk Factors and Mitigation Strategies

Oshawa Power recognizes that risk factors are inherent in asset management and can impact the achievement of our objectives. Therefore, identifying and creating appropriate mitigation strategies for these risk factors are essential to implementing an effective and efficient asset management system. The table below presents at a high-level summary for each of our risk factor and Oshawa Power's mitigation strategies to address them. For a list of how Oshawa Power quantifies the impact of risk to each operational theme, see our Impact Matrix attached as *Appendix A*.

Table 2: Risk Factors and Mitigation Strategies

Risk Factors	Mitigation Strategies
Safety	
- Incident risk due to inadequate safety protocols or employee negligence	- Implement regular safety audits and training programs for employees. - Ensure compliance with safety regulations and standards.
- Compliance risk related to safety regulations and standards	- Conduct regular inspections and audits to ensure compliance. - Provide ongoing safety training and updates for employees.
- Training risk due to insufficient employee training on safety procedures and practices	- Implement a comprehensive safety training program for all employees. - Provide refresher training as needed.
Reliability	

Risk Factors	Mitigation Strategies
- Asset failure risk due to lack of maintenance or aging infrastructure	- Implement proactive maintenance strategies to identify and address potential failures. - Regularly inspect and maintain critical assets.
- Supply chain risk for maintenance materials and equipment	- Develop relationships with reliable suppliers. - Maintain adequate inventory of critical materials.
- Risk related to failure or obsolescence of proactive maintenance procedures	- Regularly update proactive maintenance procedures to ensure effectiveness. - Stay abreast of technological advancements.
Customer Focus	
- Outage risk due to equipment failures or inadequate response times	- Implement proactive maintenance strategies to prevent equipment failures. - Improve response times for outage restoration.
- Service quality risk related to not meeting customer expectations	- Conduct regular customer surveys to gather feedback and identify areas for improvement. - Implement customer-focused initiatives.
- Communication risk during outages or service disruptions	- Improve communication channels and protocols for outage notifications. - Provide regular updates to customers during outages.
Stewardship	
- Environmental risk related to environmental damage or non-compliance	- Implement environmental management systems to minimize impact. - Ensure compliance with environmental regulations.
- Financial risk due to inefficient asset management practices	- Implement cost-saving measures such as energy efficiency programs. - Optimize asset utilization and lifecycle management.
- Resource risk related to resource depletion or inefficiency in resource utilization	- Implement resource management strategies to optimize utilization. - Monitor resource consumption and identify areas for improvement.
Innovation	
- Technology risk of implementing new technologies that may not deliver expected benefits	- Conduct thorough feasibility studies and pilot tests before full implementation. - Monitor and evaluate the performance of new technologies.
- Integration risk with existing asset management systems	- Ensure compatibility and interoperability of new technologies with existing systems. - Provide training and support for system integration.
- Regulatory risk related to changes impacting the implementation of innovative practices	- Stay informed about regulatory changes and adapt innovation strategies accordingly. - Collaborate with regulators to address compliance issues.

4.3 Performance Monitoring and Reporting

Performance monitoring and reporting are critical components implementing Oshawa Power's asset management system, providing us with valuable insights into the effectiveness of their asset management strategies. By monitoring key performance indicators (KPIs) and reporting on progress, Oshawa Power identifies areas for improvement, track the success of our asset management initiatives, and make informed decisions to enhance asset performance. This section tabulates Oshawa Power's Performance Monitoring and Reporting initiatives for each operational theme.

Table 3: Performance Monitoring and Reporting

Performance Monitoring	Reporting
Safety	
- Number of safety incidents related to asset management	- Safety incident reports
- Compliance with safety regulations and standards	- Compliance report
- Employee training hours on safety procedures and practices	- Training completion records
Reliability	
- Number of unplanned asset failures	- Reliability records
- Maintenance materials and equipment availability	- Inventory logs
- Effectiveness of proactive maintenance procedures	- Maintenance Records
Customer Focus	
- Number and duration of power outages	- Reliability reports
- Customer satisfaction ratings related to service quality	- Customer satisfaction reports
- Timeliness and effectiveness of communication during outages	- Customer satisfaction reports
Stewardship	
- Environmental impact assessments	- Environmental impact records

Performance Monitoring	Reporting
- Cost of asset maintenance and operations	- Financial performance reports
- Resource utilization rates	- Monthly resource utilization reports
Innovation	
- Effectiveness of incorporated technology/innovative approach	- As-needed / project specific basis

4.4 Project Prioritization

Project prioritization is a crucial aspect that allows Oshawa Power to allocate resources effectively and focus on projects that align with our strategic objectives. By assigning weights to each operational theme and evaluating projects based on these criteria, Oshawa Power makes informed decisions about order of pursuing non-mandatory projects. This approach ensures that resources are allocated to projects that deliver the most value in terms of safety, reliability, customer focus, stewardship, and innovation. This section presents how Oshawa Power takes a risk-based approach that maximizes value while minimizing risk when prioritizing projects, while meeting out asset management goals.

This Project Prioritization methodology allows Oshawa Power to compare and rank projects in different business units within the LDC, e.g., overhead, underground, stations, IT etc., as well as across different investment categories, e.g., system renewal, system access etc. Projects are ranked based on the ratios of risk they alleviate to their cost, with overall objective being to minimize risk to cost ratio. *Two key factors to note are that only non-mandatory projects are prioritized and only those with similar cost structures are ranked against each other.*

To appropriately tie operational themes with prioritization, we have assigned a weighting to each operational theme in accordance with its impact on our overall strategic objectives and assigned a measure to assess the impact on each theme . The operational theme weightages and measures are tabulated below:

Table 4: Weightages and Measures for Operational Themes

Operational theme	Weighting	Measures
Safety	30%	Impact of Injury to public, including customers and employees
Reliability	20%	Impact to SAIFI/SAIDI
Customer Focus	20%	Impact to number and criticality of customers affected

Stewardship	20%	Environmental (e.g., oil leaks), financial (e.g., cash flow) and regulatory (e.g., OEB scorecard) impacts
Innovation	10%	Positive Impact on other Operational themes

Measuring risk to each operational theme has two factors associated with it – 1) the likelihood (i.e., probability) of a consequence, and 2) measure of consequence (i.e., impact) occurring if the project under consideration is not done. As such, Oshawa Power uses a 5 x 5 Risk Matrix, that quantifies the likelihood of a consequence and consequences from low to high, as tabulated below. The use of a quantified risk matrix allows Oshawa Power to compare projects based on relative risk scores, as is explained later in this section.

Table 5: Risk Matrix

Likelihood / Impact	Low	Medium-Low	Medium	High-Medium	High
Very Likely (>95%)	9	24	67	181	491
Likely (65 to 95%)	7	19	52	141	382
Somewhat Likely (25 to 65%)	5	14	37	100	273
Unlikely (5 to 25%)	2	5	15	40	109
Remote (<5%)	1	3	7	20	55

Notes:
1. For all operational themes, except innovation, the combination of Likelihood and Consequence that makes the risk score equal to any number mentioned in red text above makes the project a critical project

It must be noted here that for all operational themes, except innovation, we want to decrease the likelihood of a high consequence event, because of an investment in the project. For the innovation operational theme, we want to increase the likelihood of a high consequence because of the project.

Based on a combination of the Risk Matrix and Impact Matrix which provides guidance on quantifying the operational theme measures, and is attached as *Appendix A*, Oshawa Power is able to calculate the Total Risk Score (TRS) as defined by the following formulation:

$$TRS = \sum R_i \times W_{OTi} \text{ ; where}$$

- i = Index of the Operational theme (1 to 5 for Oshawa Power, since we have defined 5 operational themes)

- OT = Operational themes
- R_i = Risk to OT_i (obtained from the risk matrix, by defining likelihood and consequence)
- W_{OTi} = Weightage of OT_i (as defined in the impact matrix)

The steps prioritizing projects are then as follows:

- Calculate TRS for the do-nothing scenario.
- Calculate TRS if project under consideration is implemented.
- Calculate the difference in the TRS from steps 1 and 2 (ΔTRS).
- Calculate the Cost of Risk Factor (CRRF) for the project, by the following formulation:

$$CRRF = Project\ Cost\ /\ \Delta TRS$$

Once the CRRFs for similarly costing projects are calculated, they can then be prioritized – with the project receiving the lowest CRRF score prioritized the highest, since a low CRRF score indicates that maximum risk is alleviated for the minimum cost.

The above prioritization methodology is embedded in a digital tool Oshawa Power uses to prioritize our projects.

Figure 4: Project Prioritization Form

Invetment Category									
Grouping									
Subcategory									
Project Number									
Project Name									
Description									
Cost									
OT		Before				After			
		Likelihood	Consequence	Risk Value	Risk Score	Likelihood	Consequence	Risk Value	Risk Score
Safety	30%			0	0.00			0	0.00
Reliability	20%			0	0.00			0	0.00
Customer Focus	20%			0	0.00			0	0.00
Stewardship	20%			0	0.00			0	0.00
Innovation	10%			0	0.00			0	0.00
Total Risk Score (TRS)					0.00				0.00
Δ TRS		0.00							
CRRF ($/ Δ TRS)		0							

DOCUMENT END

APPENDIX A

OPERATIONAL THEMES AND IMPACT MATRIX

Operational Theme	Weight	Description	High	High-Medium	Medium	Medium-Low	Low
Safety	**30%**	Customer and Employee safety	Fatality	Hospitalization / serious injury	Hospitalization / minor injury	Minor injury, no loss time (No hospitalization)	Near miss
Reliability	**20%**	Reliable Supply	High SAIDI SAIFI impacts	High Medium SAIDI SAIFI impacts	Medium SAIDI SAIFI impacts	Medium-low SAIDI SAIFI impacts	Low SAIDI SAIFI impacts
Customer Focus	**20%**	Addresses customer needs, increases customer satisfaction, Reputation / Brand identity	Affects major locations - such as hospitals, arenas, municipal buildings - first reposndants, emergency services OR affects Approx 7.5K customers	Affects major commercial / industrial customers - eg: universities, colleges, manufacturing plants OR affects approx. 4.6K Customers	Affects approx. 2.5K customers	Affects approx. 500 customers	Affects approx. 20 customers
Stewardship	**20%**	Environmental (EX:oil leaks; pole treatment; PCB; Sf6;) minimizing losses (line, TX etc.) / regulatory / financial stewardship (EX: impact on cash flow; impact on shareholder return; long-term future cost exposure)	Financial liability resulting in significant reduction of shareholder return; significant environmental damage resulting in legal action, Signifcant fines; severe regulatory violations resulting in penalties, legal actions, suspension of operations	Environmental/regulatory/financial impacts resulting in moderate fines/penalties	Environmental/regulatory/financial impacts resulting in warnings with no penalties but with explanation	Environmental/regulatory/financial impacts resulting in warnings with no penalties or explanation	Low Environmental/regulatory/financial impacts
Innovation	**10%**	Automation, IT system upgrades, distrbiution system upgrades - based on future proofing (DERs), communications	Signifcant imapcts on safety / privacy / data protection OR affects 4 business values	Moderate Impacts on Safety / Significant Impact on Reliability OR affects 3 busniess values	Moderate Impact on reliability / Significant impact on customer focus or stewarship OR affects 2 business values	Moderate impact on customer focus or stewardhip	Minimal impact on customer focus or stewardship