2024 Cost of Service

EXHIBIT 2: RATE BASE AND CAPITAL

WASAGA DISTRIBUTION INC.

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2.2 Exhibit 2: Rate Base & Capital

2.2.1 Rate Base Overview

Wasaga Distribution Inc.'s (WDI) Rate Base is determined by taking the average of the balances at the beginning and the end of the Test Year, plus a working capital allowance which is 7.50% of the sum of the cost of power and controllable expenses. The use of a 7.50% rate is consistent with the Board's letter of April 18, 2022, and the Filing Requirements as issued by the Ontario Energy Board (OEB).

WDI did not undertake a lead/lag study.

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

The net fixed assets include those distribution assets associated with activities that enable the conveyance of electricity for distribution purposes. WDI does not have any non-distribution assets. Controllable expenses include operations and maintenance, billing and collecting, and administration expenses.

For the purpose of determining rate base, only in-service additions are included in the rate base calculation. Total capital expenditures include capital work in progress (CWIP) and WDI did not factor in CWIP into its rate base calculation.

WDI has calculated its 2024 Test Year rate base to be $24,746,197. The allowable return rate base is also included in the proposed Revenue Requirement found in Exhibit 6.

Table 2.1 illustrates WDI's calculation of the 2024 Test Year Rate Base, and is followed by Table 2.2, which shows WDI's Working Capital Allowance for the 2024 Test Year.

Table 2.1: 2024 Test Year Rate Base

	2024 Test Year
Net Capital Assets in Service:	
Opening Balance	21,779,585
Ending Balance	24,187,319
Average Balance	**22,983,452**
Working Capital Allowance	1,762,745
Total Rate Base	**24,746,197**

Table 2.2: 2024 Working Capital Allowance

Expenses for Working Capital	2024 Test Year
Eligible Distribution Expenses:	
3500-Distribution Expenses - Operation	63,011
3550-Distribution Expenses - Maintenance	1,017,951
3650-Billing and Collecting	1,207,141
3700-Community Relations	19,885
3800-Administrative and General Expenses	1,664,194
6105-Taxes other than Income Taxes	35,696
6205-Sub-account LEAP Funding	7,170
Total Eligible Distribution Expenses	**4,015,049**
3350-Power Supply Expenses	19,488,212
Total Expenses for Working Capital	**23,503,261**
Working Capital factor	7.50%
Total Working Capital Allowance	**1,762,745**

2.2.1.1 Rate Base Variance Analysis

This section provides an overview of WDI’s Rate Base and a Rate Base variance analysis, including the variances from the 2016 Board Approved Year to the 2024 Test Year. In accordance with the OEB’s Chapter 2 Filing Requirements for Electricity Distribution Rate Applications, the Rate Base used to determine the Revenue Requirement for the Test Year should be presented. This section provides yearly information on WDI's Rate Base, including information on forecast net fixed assets, calculated on a mid-year average basis, along with working capital allowance. Net fixed assets are gross assets in service minus accumulated amortization and contributed capital.

Table 2.3 below provides an analysis on the change in WDI's Rate Base from the 2016 Board Approved Year to the 2024 Test Year. Below, Table 2.3 is an explanation of what factors are driving this variance. In addition, Appendix 2 (A) of this Exhibit provides additional information on the year-over-year variances of WDI's Rate Base.

Table 2.3: 2016 Board Approved Rate Base Compared to 2024 Test Year Rate Base

	2016 Board Approved	2024 Test Year	% Change
Net Capital Assets in Service			
Opening Balance	12,013,060	21,779,585	
Ending Balance	12,718,688	24,187,319	
Average Balance	**12,365,874**	**22,983,452**	**85.86%**
Working Capital Allowance	1,966,498	1,762,745	
Total Rate Base	**14,332,372**	**24,746,197**	**72.66%**
Expenses for Working Capital	**2016 Board Approved**	**2024 Test Year**	**% Change**
Eligible Distribution Expenses			
3500-Distribution Expenses - Operation	77,011	63,011	
3550-Distribution Expenses - Maintenance	795,181	1,017,951	
3650-Billing and Collecting	1,027,236	1,207,141	
3700-Community Relations	17,803	19,885	
3800-Administrative and General Expenses	1,081,583	1,664,194	
6105-Taxes other than Income Taxes	28,000	35,696	
6205-Sub-account LEAP Funding	4,976	7,170	
Total Eligible Distribution Expenses	**3,031,790**	**4,015,049**	**32.43%**
3350-Power Supply Expenses	17,199,671	19,488,212	
Total Expenses for Working Capital	**20,231,461**	**23,503,261**	**16.17%**
Working Capital factor	9.72%	7.50%	
Total Working Capital Allowance	**1,966,498**	**1,762,745**	**-10.36%**

WDI's Rate Base for the 2024 Test Year is forecast to increase by $10,413,825 (72.66%) over the last Board Approved Rate Base. The reason for the variance between the 2024 Test Year and 2016 last Board Approved is mainly attributed to:

- Total changes in average Net Capital Assets increasing $10,617,578. This increase is primarily due to an addition of average annual capital additions per year of $2,050,135 per year. WDI's average depreciation per year is $676,490. WDI continues to replace assets with a cost that is greater than the cost of what is being replaced and being recovered by the depreciated expense. This pattern is further impacted by the existing age of WDI's overhead plant, many of which have already reached the end of its useful life, and this dictates the pace of replacement. The change in and extension of useful lives during the conversion to MIFRS also impacted this variance.
- Furthermore, WDI has experienced consistent growth since 2016, WDI is forecasting to have added up to 1,981 residential connections from 2016 up to 2024 Test Year (15.94% growth). WDI expects this trend to continue. In addition, WDI completed a new sub-station in 2022 with a total net cost of $4,807,791.
- Finally, annual changes in the power supply expense as well as eligible distribution expenses are also driving this variance. The power supply expense is forecasted to increase a total of $2,288,541 from the 2016 Board Approved Rate Base to the 2024 Test Year, with eligible distribution expenses forecasted to increase $983,259. However, this increase is more than offset by the change in the working capital factor from 9.72% to 7.50%, resulting in a total forecasted variance in working capital allowance of ($203,753).

2.2.2 Property, Plant and Equipment

2.2.2.1 Fixed Asset Continuity Schedule

WDI has filed the continuity schedules of its investment in capital assets, the associated depreciation provision and accumulated amortization, and the calculated net book value for each capital Uniform System of Accounts (USoA) for the 2016 to 2022 Historic Years, 2023 Bride Year and 2024 Test Year. These continuity schedules are included in Appendix 2 (B).

WDI disposes of assets in accordance with IFRS. WDI used five-year historical data from 2018-2022 to determine the disposal of assets for the 2023 Bridge and 2024 Test year.

2.2.2.2 Gross Assets – Property, Plant and Equipment

WDI chose to categorize its assets into four categories: Distribution Plant, General Plant, Contributions and Grants, and Work-in-Progress (WIP). In accordance with the USoA, WDI has included Gross Assets as follows:

- Distribution Plant Asset Accounts include USoA 1820 to 1860 – this includes assets such as distribution equipment, poles, wires, transformers, and meters.
- General Plant Asset Accounts include USoA 1611, 1612, 1805, 1905,1908,1980, and 2005 – this includes assets such as buildings, computer software and hardware.
- Contributions and Grants includes USoA account 2440 – this includes all contributions in aid of capital that WDI has received or forecasted to be received as per the Distribution System Code (DSC).
- WIP – this account includes all costs related to assets that are not considered in-service as of December 31st of the applicable fiscal year. Costs are transferred out of WIP and into the appropriate category above once designated in-service.

The following Tables show WDI's gross assets into the four categories described above, according to USoA as well as provide a year-over-year variance analysis of gross capital expenditures from the 2016 Board Approved Year to the 2024 Test Year.

1 **Table 2.4: 2016 Board Approved Gross Assets Compared to 2016 Actual**

Gross Assets							
Description		Last Board Approved	MIFRS Adjustment	Adjusted Board Approved	2016	Difference	% Change
Distribution Plant Assets							
Distribution Station Equipment							
1820	Distribution Station Equipment < 50 kV	3,380,805	(1,466,063)	1,914,742	1,914,742	-	0.00%
Overhead Plant							
1830	Poles, Towers & Fixtures	4,788,949	(2,351,216)	2,437,733	2,354,646	(83,087)	-3.41%
1835	Overhead Conductors & Devices	4,286,489	(2,341,866)	1,944,623	1,769,537	(175,086)	-9.00%
Underground Plant							
1840	Underground Conduit	341,941	(271,857)	70,084	107,572	37,488	53.49%
1845	Underground Conductors & Devices	6,125,048	(4,209,506)	1,915,542	1,900,362	(15,180)	-0.79%
Transformers							
1850	Line Transformers	5,217,985	(3,403,154)	1,814,831	1,898,981	84,150	4.64%
Services & Meters							
1855	Services (Overhead & Underground)	5,111,596	(3,076,726)	2,034,870	2,176,435	141,565	6.96%
1860	Meters (Smart Meters)	2,043,000	(539,252)	1,503,748	1,595,028	91,280	6.07%
General Plant Assets							
Building & Land							
1612	Land Rights	5,512	(5,512)	-		-	0.00%
1805	Land	121,775	(0)	121,775	121,775	-	0.00%
1905	Land	618,998	-	618,998	617,148	(1,850)	-0.30%
1908	Buildings & Fixtures	1,541,650	(404,487)	1,137,163	1,157,624	20,461	1.80%
IT Assets & Other Equipment							
1611	Computer Software	187,875	(32,728)	155,147	132,697	(22,450)	-14.47%
1980	System Supervisor Equipment	47,073	(6,295)	40,778	73,278	32,500	79.70%

2005	Property Under Finance Lease	126,793	(6,021)	120,772	120,772	-	0.00%
Contributions & Grants							
Contributed Capital							
2440	Deferred Revenue	(7,594,100)	6,071,585	(1,522,515)	(2,062,076)	(539,561)	35.44%
Work-in-Progress							
Total		**26,351,387**	**(12,043,098)**	**14,308,289**	**13,878,521**	**(429,768)**	**-3.00%**

When WDI adopted MIFRS, it netted its accumulated depreciation against its gross assets; Table 2.4 above reflects this adjustment under the column "MIFRS Adjustment".

The first material variance is a $258,172 difference in poles and overhead conductor. The Adjusted 2016 Board Approved Year is higher than the Actual 2016 Year because WDI forecasted significant reconductoring to one of its major roads that did not materialize. Instead, significant resources were shifted to support Bell-Make-Ready projects. Second, the positive difference of $84,150 in transformers over the Adjusted Board Approved Year is mainly because estimated disposals did not materialize. Third, the increase of $232,845 in services and meters over the Adjusted Board Approved Year is due to higher than estimated costs associated with new development and new connections and services for both 2015 and 2016. Furthermore, the $66,000 estimated disposal did not materialize. The variance in building and fixtures is a result of fencing, windows, and lighting that were not provisioned for in the Board Approved forecast. Finally, the increase in contributed capital of $539,561 is caused by higher-than-expected contributions for Bell-Make-Ready projects and new development.

1 **Table 2.5: 2016 Actual Gross Assets Compared to 2017 Actual**

Gross Assets					
Description		2016	2017	Difference	% Change
Distribution Plant Assets					
Distribution Station Equipment					
1820	Distribution Station Equipment < 50 kV	1,914,742	1,934,091	19,349	1.01%
Overhead Plant					
1830	Poles, Towers & Fixtures	2,354,646	2,800,819	446,173	18.95%
1835	Overhead Conductors & Devices	1,769,537	1,983,264	213,727	12.08%
Underground Plant					
1840	Underground Conduit	107,572	107,572	-	0.00%
1845	Underground Conductors & Devices	1,900,362	1,963,707	63,345	3.33%
Transformers					
1850	Line Transformers	1,898,981	2,078,405	179,424	9.45%
Services & Meters					
1855	Services (Overhead & Underground)	2,176,435	2,521,306	344,871	15.85%
1860	Meters (Smart Meters)	1,595,028	1,583,349	(11,679)	-0.73%
General Plant Assets					
Building & Land					
1612	Land Rights			-	0.00%
1805	Land	121,775	121,775	-	0.00%
1905	Land	617,148	617,148	-	0.00%
1908	Buildings & Fixtures	1,157,624	1,171,653	14,029	1.21%
IT Assets & Other Equipment					
1611	Computer Software	132,697	146,157	13,460	10.14%
1980	System Supervisor Equipment	73,278	73,278	-	0.00%
2005	Property Under Finance Lease	120,772	120,772	-	0.00%
Contributions & Grants					
Contributed Capital					
2440	Deferred Revenue	(2,062,076)	(2,477,830)	(415,754)	20.16%
Work-in-Progress					
Total		**13,878,521**	**14,745,466**	**866,945**	**6.25%**

The variances from 2016 Actual to 2017 Actual can be attributed to the installation of 128 poles, 9,237 meters of overhead conductor, 3,066 meters of underground conductor, 32 transformers, and 17,849 meters of secondary services. These installations were driven primarily by the completion of new developments, pole line expansions and rebuilds, and the set-up and installation of new customer connections. The change in Meters (1860) is due to the net purchase (less disposals) of 347 meters. Finally, the change in Buildings & Fixtures (1908) and Computer Software (1611) is due to upgrades to the Office Security System, the Geographic Information System (GIS), and the Website. Deferred Revenue can be primarily attributed to development projects, which are subject to economic evaluations, as well as Bell make-readies.

1 **Table 2.6: 2017 Actual Gross Assets Compared to 2018 Actual**

Gross Assets					
Description		2017	2018	Difference	% Change
Distribution Plant Assets					
Distribution Station Equipment					
1820	Distribution Station Equipment < 50 kV	1,934,091	1,934,091	-	0.00%
Overhead Plant					
1830	Poles, Towers & Fixtures	2,800,819	3,183,574	382,755	13.67%
1835	Overhead Conductors & Devices	1,983,264	2,117,192	133,928	6.75%
Underground Plant					
1840	Underground Conduit	107,572	107,572	-	0.00%
1845	Underground Conductors & Devices	1,963,707	2,007,380	43,673	2.22%
Transformers					
1850	Line Transformers	2,078,405	2,285,741	207,336	9.98%
Services & Meters					
1855	Services (Overhead & Underground)	2,521,306	2,837,510	316,204	12.54%
1860	Meters (Smart Meters)	1,583,349	1,677,216	93,867	5.93%
General Plant Assets					
Building & Land					
1612	Land Rights			-	0.00%
1805	Land	121,775	121,775	-	0.00%
1905	Land	617,148	617,148	-	0.00%
1908	Buildings & Fixtures	1,171,653	1,216,253	44,600	3.81%
IT Assets & Other Equipment					
1611	Computer Software	146,157	155,517	9,360	6.40%
1980	System Supervisor Equipment	73,278	73,278	-	0.00%
2005	Property Under Finance Lease	120,772	120,772	-	0.00%
Contributions & Grants					
Contributed Capital					
2440	Deferred Revenue	(2,477,830)	(2,613,308)	(135,478)	5.47%
Work-in-Progress					
Total		**14,745,466**	**15,841,711**	**1,096,245**	**7.43%**

2

3 The variances shown above can be attributed to the installation of 117 poles, 4,001 meters of
4 overhead conductor, 47 transformers, and 7,354 meters of secondary services. These installations
5 were driven primarily by the set-up and installation of new customer connections, and miscellaneous
6 conductor, pole, and transformer replacements. The change in Meters (1860) is due to the net

purchase (less disposals) of 129 meters. Finally, the change in Buildings & Fixtures (1908) and Computer Software (1611) is due to upgrades to the ceiling in our office, a new electronic sign, and upgrades to the WDI website and Outage Management System (OMS).

Table 2.7: 2018 Actual Gross Assets Compared to 2019 Actual

Gross Assets					
	Description	**2018**	**2019**	**Difference**	**% Change**
Distribution Plant Assets					
Distribution Station Equipment					
1820	Distribution Station Equipment < 50 kV	1,934,091	1,934,091	-	0.00%
Overhead Plant					
1830	Poles, Towers & Fixtures	3,183,574	3,507,321	323,747	10.17%
1835	Overhead Conductors & Devices	2,117,192	2,259,347	142,155	6.71%
Underground Plant					
1840	Underground Conduit	107,572	294,604	187,032	173.87%
1845	Underground Conductors & Devices	2,007,380	2,503,481	496,101	24.71%
Transformers					
1850	Line Transformers	2,285,741	2,835,022	549,281	24.03%
Services & Meters					
1855	Services (Overhead & Underground)	2,837,510	3,368,080	530,570	18.70%
1860	Meters (Smart Meters)	1,677,216	1,891,562	214,346	12.78%
General Plant Assets					
Building & Land					
1612	Land Rights			-	0.00%
1805	Land	121,775	121,775	-	0.00%
1905	Land	617,148	617,148	-	0.00%
1908	Buildings & Fixtures	1,216,253	1,222,046	5,793	0.48%
IT Assets & Other Equipment					
1611	Computer Software	155,517	158,694	3,177	2.04%
1980	System Supervisor Equipment	73,278	73,278	-	0.00%
2005	Property Under Finance Lease	120,772	120,772	-	0.00%
Contributions & Grants					
Contributed Capital					
2440	Deferred Revenue	(2,613,308)	(3,660,020)	(1,046,712)	40.05%
Work-in-Progress					
Total		**15,841,711**	**17,247,201**	**1,405,490**	**8.87%**

The variances shown above can be attributed to the installation of 94 poles, 4,405 meters of overhead conductor, 12,007 meters of conduit, 11,352 meters of underground conductor, 75 transformers, and 24,899 meters of secondary services conductor. These installations were driven primarily by the completion of new developments, miscellaneous conductor, pole, and transformer replacements, and the set-up and installation of new customer connections. The change in Meters (1860) is due to the net purchase (less disposals) of 1,129 meters. Deferred Revenue can be primarily attributed to development projects, which are subject to economic evaluations.

Table 2.8: 2019 Actual Gross Assets Compared to 2020 Actual

Gross Assets					
Description		2019	2020	Difference	% Change
Distribution Plant Assets					
Distribution Station Equipment					
1820	Distribution Station Equipment < 50 kV	1,934,091	1,934,091	-	0.00%
Overhead Plant					
1830	Poles, Towers & Fixtures	3,507,321	4,077,512	570,191	16.26%
1835	Overhead Conductors & Devices	2,259,347	2,842,934	583,587	25.83%
Underground Plant					
1840	Underground Conduit	294,604	294,604	-	0.00%
1845	Underground Conductors & Devices	2,503,481	2,735,071	231,590	9.25%
Transformers					
1850	Line Transformers	2,835,022	3,061,322	226,300	7.98%
Services & Meters					
1855	Services (Overhead & Underground)	3,368,080	3,677,867	309,787	9.20%
1860	Meters (Smart Meters)	1,891,562	1,871,453	(20,109)	-1.06%
General Plant Assets					
Building & Land					
1612	Land Rights			-	0.00%
1805	Land	121,775	121,775	-	0.00%
1905	Land	617,148	617,148	-	0.00%
1908	Buildings & Fixtures	1,222,046	1,230,080	8,034	0.66%
IT Assets & Other Equipment					
1611	Computer Software	158,694	158,694	-	0.00%
1980	System Supervisor Equipment	73,278	73,278	-	0.00%
2005	Property Under Finance Lease	120,772	120,772	-	0.00%
Contributions & Grants					
Contributed Capital					
2440	Deferred Revenue	(3,660,020)	(4,057,267)	(397,247)	10.85%
Work-in-Progress					
			84,832		
Total		**17,247,201**	**18,844,166**	**1,512,133**	**8.77%**

The variances shown above can be attributed to the installation of 124 poles, 18,531 meters of overhead conductor, 4,623 meters of underground conductor, 28 transformers, and 12,190 meters of secondary services conductor. These installations were driven primarily by the completion of new developments, municipal projects, miscellaneous conductor, pole, and transformer replacements, and the set-up and installation of new customer connections. The change in Meters (1860) is due to the purchase of new meters, meter reverification as well as the disposal of Primary Metering Equipment (PME). Deferred Revenue can be primarily attributed to development projects, which are subject to economic evaluations.

Table 2.9: 2020 Actual Gross Assets Compared to 2021 Actual

Gross Assets					
Description		2020	2021	Difference	% Change
Distribution Plant Assets					
Distribution Station Equipment					
1820	Distribution Station Equipment < 50 kV	1,934,091	1,934,091	-	0.00%
Overhead Plant					
1830	Poles, Towers & Fixtures	4,077,512	5,202,119	1,124,607	27.58%
1835	Overhead Conductors & Devices	2,842,934	3,494,475	651,541	22.92%
Underground Plant					
1840	Underground Conduit	294,604	570,074	275,470	93.51%
1845	Underground Conductors & Devices	2,735,071	3,059,735	324,664	11.87%
Transformers					
1850	Line Transformers	3,061,322	3,431,278	369,956	12.08%
Services & Meters					
1855	Services (Overhead & Underground)	3,677,867	4,127,925	450,058	12.24%
1860	Meters (Smart Meters)	1,871,453	1,879,022	7,569	0.40%
General Plant Assets					
Building & Land					
1612	Land Rights			-	0.00%
1805	Land	121,775	121,775	-	0.00%
1905	Land	617,148	617,148	-	0.00%
1908	Buildings & Fixtures	1,230,080	1,230,080	-	0.00%
IT Assets & Other Equipment					
1611	Computer Software	158,694	158,694	-	0.00%
1980	System Supervisor Equipment	73,278	86,578	13,300	18.15%
2005	Property Under Finance Lease	120,772	120,772	-	0.00%
Contributions & Grants					
Contributed Capital					
2440	Deferred Revenue	(4,057,267)	(5,318,072)	(1,260,805)	31.08%
Work-in-Progress					
		84,832	1,112,074		
Total		**18,844,166**	**21,827,768**	**1,956,360**	**10.38%**

The variances shown above can be attributed to the installation of 165 poles, 14,856 meters of overhead conductor, 2,657 meters of conduit, 7,010 meters of underground conductor, 49 transformers, and 20,512 meters of secondary services conductor. These installations were driven primarily by the completion of new developments, municipal projects, miscellaneous conductor, pole, and transformer replacements, and the set-up and installation of new customer connections. Finally, the change in System Supervisor Equipment (1980) is due to an upgrade to our Supervisory Control and Data Acquisition (SCADA) Network. Deferred Revenue can be primarily attributed to development projects, which are subject to economic evaluations.

Table 2.10: 2021 Actual Gross Assets Compared to 2022 Actual

Gross Assets					
Description		2021	2022	Difference	% Change
Distribution Plant Assets					
Distribution Station Equipment					
1820	Distribution Station Equipment < 50 kV	1,934,091	5,275,970	3,341,879	172.79%
Overhead Plant					
1830	Poles, Towers & Fixtures	5,202,119	5,472,317	270,198	5.19%
1835	Overhead Conductors & Devices	3,494,475	3,608,117	113,642	3.25%
Underground Plant					
1840	Underground Conduit	570,074	2,000,494	1,430,420	250.92%
1845	Underground Conductors & Devices	3,059,735	5,715,007	2,655,272	86.78%
Transformers					
1850	Line Transformers	3,431,278	4,339,351	908,073	26.46%
Services & Meters					
1855	Services (Overhead & Underground)	4,127,925	5,230,970	1,103,045	26.72%
1860	Meters (Smart Meters)	1,879,022	2,071,109	192,087	10.22%
General Plant Assets					
Building & Land					
1612	Land Rights			-	0.00%
1805	Land	121,775	691,775	570,000	468.08%
1905	Land	617,148	617,148	-	0.00%
1908	Buildings & Fixtures	1,230,080	1,230,080	-	0.00%
IT Assets & Other Equipment					
1611	Computer Software	158,694	168,594	9,900	6.24%
1980	System Supervisor Equipment	86,578	98,219	11,641	13.45%
2005	Property Under Finance Lease	120,772	120,772	-	0.00%
Contributions & Grants					
Contributed Capital					
2440	Deferred Revenue	(5,318,072)	(11,633,806)	(6,315,734)	118.76%
Work-in-Progress					
		1,112,074	752,936		
Total		**21,827,768**	**25,759,053**	**4,290,423**	**19.66%**

The variances shown above are due to the installation of 48 poles, 2,815 meters of overhead conductor, 28,326 meters of conduit, 26,875 meters of underground conductor, 89 transformers, and 57,825 meters of secondary services conductor. These were driven primarily by new developments, miscellaneous conductor, pole, and transformer replacements, set-up and installation of new customer connections, and the completion of new substation. Meters (1860) is due to the purchase of 249 meters, including a 44kV PME. Station Equipment (1820) and Land (1805) are due to the completion of a new substation. Finally, Deferred Revenue can be primarily attributed to the substation as well as development projects, which are subject to economic evaluations.

Table 2.11: 2022 Actual Gross Assets Compared to 2023 Bridge Year

Gross Assets					
Description		2022	2023	Difference	% Change
Distribution Plant Assets					
Distribution Station Equipment					
1820	Distribution Station Equipment < 50 kV	5,275,970	5,275,970	-	0.00%
Overhead Plant					
1830	Poles, Towers & Fixtures	5,472,317	6,564,280	1,091,963	19.95%
1835	Overhead Conductors & Devices	3,608,117	4,199,614	591,497	16.39%
Underground Plant					
1840	Underground Conduit	2,000,494	3,366,452	1,365,958	68.28%
1845	Underground Conductors & Devices	5,715,007	7,896,632	2,181,625	38.17%
Transformers					
1850	Line Transformers	4,339,351	5,158,647	819,296	18.88%
Services & Meters					
1855	Services (Overhead & Underground)	5,230,970	6,225,293	994,323	19.01%
1860	Meters (Smart Meters)	2,071,109	2,154,820	83,711	4.04%
General Plant Assets					
Building & Land					
1612	Land Rights			-	0.00%
1805	Land	691,775	691,775	-	0.00%
1905	Land	617,148	617,148	-	0.00%
1908	Buildings & Fixtures	1,230,080	1,230,080	-	0.00%
IT Assets & Other Equipment					
1611	Computer Software	168,594	218,594	50,000	29.66%
1980	System Supervisor Equipment	98,219	98,219	-	0.00%
2005	Property Under Finance Lease	120,772	120,772	-	0.00%
Contributions & Grants					
Contributed Capital					
2440	Deferred Revenue	(11,633,806)	(15,632,295)	(3,998,489)	34.37%
Work-in-Progress					
		752,936	700,000		
Total		**25,759,053**	**28,886,002**	**3,179,885**	**12.34%**

The variances shown above are based on forecasted installations of 150 poles, 5,400 meters of overhead conductor, 22,200 meters of conduit, 22,000 meters of underground conductor, 90 transformers, 22,200 meters of secondary services conductor, and the purchase of 660 new meters. These are forecasted to be driven primarily by the completion of new developments, the set-up and installation of new customer connections, miscellaneous overhead, transformer and underground replacements, pole line rebuilds, and work related to feeder/station redundancy. Deferred Revenue is forecasted to be primarily attributed to development projects, which are subject to economic evaluations.

Table 2.12: 2023 Bridge Year Gross Assets Compared to 2024 Test Year

Gross Assets					
Description		2023	2024	Difference	% Change
Distribution Plant Assets					
Distribution Station Equipment					
1820	Distribution Station Equipment < 50 kV	5,275,970	5,275,970	-	0.00%
Overhead Plant					
1830	Poles, Towers & Fixtures	6,564,280	7,679,950	1,115,670	17.00%
1835	Overhead Conductors & Devices	4,199,614	4,827,153	627,539	14.94%
Underground Plant					
1840	Underground Conduit	3,366,452	4,703,918	1,337,466	39.73%
1845	Underground Conductors & Devices	7,896,632	10,049,902	2,153,270	27.27%
Transformers					
1850	Line Transformers	5,158,647	6,107,326	948,679	18.39%
Services & Meters					
1855	Services (Overhead & Underground)	6,225,293	7,219,784	994,491	15.98%
1860	Meters (Smart Meters)	2,154,820	2,238,554	83,733	3.89%
General Plant Assets					
Building & Land					
1612	Land Rights			-	0.00%
1805	Land	691,775	691,775	-	0.00%
1905	Land	617,148	617,148	-	0.00%
1908	Buildings & Fixtures	1,230,080	1,255,080	25,000	2.03%
IT Assets & Other Equipment					
1611	Computer Software	218,594	218,594	-	0.00%
1980	System Supervisor Equipment	98,219	98,219	-	0.00%
2005	Property Under Finance Lease	120,772	120,772	-	0.00%
Contributions & Grants					
Contributed Capital					
2440	Deferred Revenue	(15,632,295)	(19,612,848)	(3,980,553)	25.46%
Work-in-Progress					
		752,936	500,000		
Total		**28,938,938**	**31,991,295**	**3,305,294**	**11.44%**

The variances shown above are based on forecasted installations of 165 poles, 8,000 meters of overhead conductor, 22,200 meters of conduit, 22,000 meters of underground conductor, 105 transformers, 22,200 meters of secondary services conductor, and the purchase of 660 new meters. These are forecasted to be driven primarily by the completion of new developments, municipal projects, the set-up and installation of new customer connections, miscellaneous overhead, transformer and underground replacements, pole line rebuilds, and new station equipment and grid technologies. Deferred Revenue is forecasted to be primarily attributed to development projects, which are subject to economic evaluations.

2.2.3 Depreciation, Amortization, and Depletion

WDI follows MIFRS and separates significant asset components appropriately. Each part of an item of PP&E with a cost that is significant in relation to the total cost of the item is depreciated separately. Depreciation is computed on a systematic basis over the useful life of the item of PP&E. The depreciable amount of an asset is determined after deducting its residual value. In practice, the residual value of an asset is often insignificant and therefore immaterial in the calculation of the depreciable amount. The residual value and useful life of an asset are reviewed at each financial year-end and, if expectations materially differ from previous estimates, the changes may be accounted for as a change in an accounting estimate in accordance with IAS 8 Accounting Policies, Changes in Accounting Estimates and Errors. Depreciation of an asset begins when it is available for use (i.e., when it is in the location and condition necessary for it to be capable of operating in the manner intended for management). Depreciation of an asset ceases at the earlier date that the asset is classified as held for sale in accordance with IFRS 5 and the date the asset is derecognized. WDI uses the half-year rule for recording depreciation in the year that the asset is added. The same methodology is used for the 2024 Test Year depreciation.

Table 2.13 below provides WDI's calculated Accumulated Depreciation from the 2016 Board Approved Year until the 2024 Test Year. This table breaks out the Accumulated Depreciation by USoA as well as by category, similar to the tables displaying the year-over-year variances of Gross Assets in Section 2.2.2.2 above. Table 2.13 below reconciles to the Accumulated Depreciation reported in Tab 2-BA of the Chapter 2 Appendices Workform.

1 **Table 2.13: Accumulated Depreciation from 2016 Board Approved Year to 2024 Test Year**

Accumulated Depreciation											
Description		Last Board Approved	2016	2017	2018	2019	2020	2021	2022	2023	2024
Distribution Plant Assets											
Distribution Station Equipment											
1820	Distribution Station Equipment < 50 kV	1,273,171	205,888	271,430	337,294	403,158	468,004	532,675	632,819	768,436	904,228
Overhead Plant											
1830	Poles, Towers & Fixtures	2,353,995	237,704	302,911	377,401	459,301	541,557	644,579	764,244	897,849	1,056,235
1835	Overhead Conductors & Devices	2,482,932	222,894	276,204	333,377	393,618	460,580	541,137	630,196	727,090	837,657
Underground Plant											
1840	Underground Conduit	67,387	4,416	6,615	8,814	12,884	18,828	27,523	53,277	106,994	187,750
1845	Underground Conductors & Devices	3,052,737	304,364	409,036	515,492	630,944	758,791	895,642	1,082,159	1,349,291	1,688,938
Transformers											
1850	Line Transformers	2,421,851	146,557	203,193	263,947	334,718	415,578	502,705	606,846	732,138	879,679
Services & Meters											
1855	Services (Overhead & Underground)	2,374,409	198,450	283,979	378,952	486,022	605,265	735,195	887,312	1,069,391	1,280,051
1860	Meters (Smart Meters)	835,766	362,068	479,835	590,804	721,897	845,512	996,515	1,154,304	1,302,968	1,434,162
General Plant Assets											
Building & Land											
1612	Land Rights	5,512									
1805	Land										
1905	Land										
1908	Buildings & Fixtures	490,352	87,361	119,386	152,876	187,626	222,799	258,096	293,393	328,690	364,314
IT Assets & Other Equipment											
1611	Computer Software	77,203	44,379	63,272	83,744	105,001	124,293	139,625	148,455	154,992	163,712
1980	System Supervisor Equipment	19,497	14,025	20,050	26,075	32,100	38,137	44,494	49,411	52,589	55,768

2005	Property Under Finance Lease	18,065	12,049	16,062	20,074	24,086	28,109	32,121	36,133	40,145	44,168
Contributions & Grants											
Contributed Capital											
2440	Deferred Revenue	(1,840,178)	(95,156)	(156,854)	(226,018)	(311,070)	(415,595)	(541,027)	(763,918)	(1,124,156)	(1,592,686)
Work-in-Progress											
Total		**13,632,699**	**1,744,999**	**2,295,119**	**2,862,832**	**3,480,285**	**4,111,858**	**4,809,280**	**5,574,631**	**6,406,417**	**7,303,976**

1

WDI has also filed Tab 2-C “Depreciation Expense” which reconciles with Tab 2-BA “Fixed Asset Continuity” (variances are immaterial) in the Chapter 2 Appendices excel workbook. WDI notes that it used the 2022 Chapter 2 Appendices’ Workform template for Tab 2-C.

WDI has adopted depreciation useful lives based on the information provided in the Kinectrics Asset Depreciation Study for Assets. These useful lives were approved in WDI’s 2012 COS Application (EB-2011-0103) and again in WDI’s 2016 COS Application (EB-2015-0107). Table 2.14 below provides these current useful lives as well as the proposed useful lives WDI would like to proceed with on a go-forward basis.

WDI confirms that no changes have been made to depreciation policy or service lives since its last COS Application (EB-2015-0107).

Table 2.14: Comparison of Depreciable Service Lives

USoA	Description	Current (EB-2015-0107)	Proposed Years
1611	Computer Software	10	10
1820	Distribution Station Equipment - Transformer	45	45
1820	Distribution Station Equipment - Equipment	40	40
1820	Distribution Station Equipment – Reclosures and Breakers	20	20
1820	Distribution Station Equipment - Structure/Civil	50	50
1830	Poles, Towers and Fixtures - All	45	45
1835	Underground Conductors and Devices- All	45	45
1840	Conduit	50	50
1845	Underground Conductor - Direct Buried	30	30
1850	Line Transformers – All	40	40
1855	Secondary Services	35	35
1860	Primary Metering Equipment	25	25
1860	GS>50 Meters	25	25
1860	Smart Meters	15	15
1908	Building and Fixtures	50	50
1980	System Supervisor Equipment	20	20
2055	Capital Leases – Communication Equipment	20	20
2055	Capital Leases – Towers	50	50

Tables 2.15 and 2.16 below, which are consistent with Tab 2-BB "Service Life" in the Chapter 2 Appendices excel workbook, provides a comparison between WDI's selected useful lives and those provided in Tables F-1 and F-2 of the Kinetrics Report.

Table 2.15: Service Life Comparison to F-1 Kinetrics Report

		Asset Details			Useful Life			USoA Account Number	USoA Account Description	Current		Proposed		Outside Range of Min, Max TUL?	
Parent*	**#**	**Category| Component | Type**			**MIN UL**	**TUL**	**MAX UL**			**Years**	**Rate**	**Years**	**Rate**	**Below Min TUL**	**Above Max TUL**
OH	1	Fully Dressed Wood Poles	Overall		35	45	75	1830	Poles, Towers and Fixtures	45	2%	45	2%	No	No
			Cross Arm	Wood	20	40	55	1830	Poles, Towers and Fixtures	45	2%	45	2%	No	No
	3	Fully Dressed Steel Poles	Cross Arm	Steel	30	70	95	1830	Poles, Towers and Fixtures	45	2%	45	2%	No	No
	4	OH Line Switch			30	45	55	1835	Underground Conductors and Devices	45	2%	45	2%	No	No
	7	OH Integral Switches			35	45	60	1835	Underground Conductors and Devices	45	2%	45	2%	No	No
	8	OH Conductors			50	60	75	1835	Underground Conductors and Devices	45	2%	45	2%	Yes	No
	9	OH Transformers & Voltage Regulators			30	40	60	1850	Line Transformers	50	2%	50	2%	No	No
TS & MS	12	Power Transformers	Overall		30	45	60	1820	Distribution Station Equipment	45	2%	45	2%	No	No
	16	Station Metal Clad Switchgear	Overall		30	40	60	1820	Distribution Station Equipment	40	3%	40	3%	No	No
			Removable Breaker		25	40	60	1820	Distribution Station Equipment	40	3%	40	3%	No	No
	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	40	3%	40	3%	No	No
	20	Solid State Relays			10	30	45	1820	Distribution Station Equipment	20	5%	20	5%	No	No
	21	Digital & Numeric Relays			15	20	20	1820	Distribution Station Equipment	20	5%	20	5%	No	No
	23	Steel Structure			35	50	90	1820	Distribution Station Equipment	50	2%	50	2%	No	No
UG	27	Primary Non-TR XLPE Cables in Duct			20	25	30	1845	Underground Conductor	30	3%	30	3%	No	No
	31	Secondary Cables Direct Buried			25	35	40	1855	Secondary Services	35	3%	35	3%	No	No
	34	Pad-Mounted Transformers			25	40	45	1850	Transformer	40	3%	40	3%	No	No
	40	Ducts			30	50	85	1850	Conduit	50	2%	50	2%	No	No
S	43	Remote SCADA			15	20	30	1980	SCADA	20	5%	20	5%	No	No

Table 2.16: Service Life Comparison to F-2 Kinetrics Report

	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
5	Station Buildings	Station Buildings	50	75	1820	Distribution Station Equipment	50	2%	50	2%	No	No
		Fence	25	60	1820	Distribution Station Equipment	50	2%	50	2%	No	No
6	Computer Equipment	Software	2	5	1611	Computer Software	10	10%	10	10%	No	Yes
8	Communication	Towers	60	70	2055	Capital Leases - Towers	50	2%	50	2%	Yes	No
		Wireless	2	10	1980	System Supervisor Equipment	20	5%	20	5%	No	Yes
10	Industrial/Commercial Energy Meters		25	35	1860	Meters	25	4%	25	4%	No	No
11	Wholesale Energy Meters		15	30	1860	Meters	25	4%	25	4%	No	No
13	Smart Meters		5	15	1860	Meters	15	7%	15	7%	No	No

2.2.4 Allowance for Working Capital

2.2.4.1 Derivation of Working Capital

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

a) The 7.5% Allowance Approach as indicated by the Board: or
b) The filing of a lead/lag study

WDI has used the rate of 7.5% for calculating the Working Capital Allowance as per letter issued by the Board on June 3, 2015, “Allowance for Working Capital for Electricity Distribution Rate Applications”. The Working Capital Allowance is the sum of the Cost of Power and controllable expenses (i.e., Operations, Maintenance, Billing & Collecting, Community Relations, Administration & General). WDI’s calculation in determining its Allowance for Working capital is illustrated in Table 2.17 below.

Table 2.17: Allowance for Working Capital Calculation

Expenses for Working Capital	Last Board Approved	2016	2017	2018	2019	2020	2021	2022	2023	2024
Eligible Distribution Expenses										
3500-Distribution Expenses - Operation	77,011	97,379	86,785	50,487	38,450	50,770	35,697	42,891	75,896	63,011
3550-Distribution Expenses - Maintenance	795,181	732,972	755,902	838,684	855,276	715,452	766,679	837,726	973,216	1,017,951
3650-Billing and Collecting	1,027,236	1,028,994	1,068,056	1,057,714	1,138,326	922,939	931,888	981,135	1,134,646	1,207,141
3700-Community Relations	17,803	13,129	16,346	10,553	11,307	17,399	9,487	15,636	22,172	19,885
3800-Administrative and General Expenses	1,081,583	1,145,764	1,192,303	1,237,492	1,422,721	1,789,944	1,270,680	1,436,189	1,419,258	1,664,194
6105-Taxes other than Income Taxes	28,000	31,858	31,232	31,306	31,380	31,571	31,780	32,206	34,061	35,696
6205-Sub-account LEAP Funding	4,976	4,785	4,971	4,227	2,841	5,525	7,359	5,149	5,155	7,170
Total Eligible Distribution Expenses	**3,031,790**	**3,054,881**	**3,155,596**	**3,230,462**	**3,500,301**	**3,533,601**	**3,053,570**	**3,350,932**	**3,664,403**	**4,015,049**
3350-Power Supply Expenses	17,199,671	17,324,648	15,177,499	14,602,669	15,895,035	20,851,819	18,165,828	18,398,642	19,027,822	19,488,212
Total Expenses for Working Capital	**20,231,461**	**20,379,529**	**18,333,095**	**17,833,131**	**19,395,336**	**24,385,420**	**21,219,398**	**21,749,574**	**22,692,225**	**23,503,261**
Working Capital factor	9.72%	9.72%	9.72%	9.72%	9.72%	9.72%	9.72%	9.72%	9.72%	7.50%
Total Working Capital Allowance	**1,966,498**	**1,980,890**	**1,781,977**	**1,733,380**	**1,885,227**	**2,370,263**	**2,062,525**	**2,114,059**	**2,205,684**	**1,762,745**

2.2.4.2 Power Supply Expense

The Power Supply Expense is made up of the sum of Independent Electricity System Operator (IESO) monthly charges. For the 2023 Bridge Year and the 2024 Test Year these have been estimated in the following manner:

Table 2.18: Summary of Cost of Power Expenses 2023-2024

USoA	2023 Bridge Year	2024 Test Year
4705-Power Purchased	14,002,251	14,288,136
4707-Global Adjustment	978,252	983,447
4708-Charges-WMS	828,494	844,670
4714-Charges-NW	1,582,310	1,580,774
4716-Charges-CN	1,023,455	1,075,068
4750-Charges-LV	537,430	639,176
4751-IESO SME	75,630	76,941
Misc A/R or A/P	-	-
Total	**19,027,822**	**19,488,212**

2.2.4.3 Cost of Power Calculations

In accordance with the Filing Requirements, the commodity price estimate used to calculate Cost of Power (COP) was determined in a way that bases the split between Regulated Price Plan (RPP) and Non-RPP customers and uses the most current RPP price.

Commodity

For the 2023 Bridge Year and the 2024 Test Year, the commodity prices used in the calculation were prices published in the Board's RPP Prices.

The commodity price for RPP customers was determined using the Average RPP Supply Cost pricing of $0.0934 kWh for RPP customers.

The commodity price for Non-RPP Class B customers was determined using the Average Hourly Energy Price (HOEP) of $0.0583 kWh and the Average Global Adjustment (GA) of $0.03904 kWh. WDI notes that the commodity charge will be updated to reflect any changes to commodity prices that may become available prior to the approval of its Application.

The remaining prices for Regulatory Items and Uniform Transmission Rates (UTR) used in the 2023 Bridge Year and the 2024 Test Year COP calculations are explained below.

Wholesale Market Service and Rural & Remote Protection Charges

WDI used $0.0041 per kilowatt hour (kWh) for the Wholesale Market Service (WMS) Charge in its 2023 Bridge Year and 2024 Test Year COP calculations. Table 2.19 provides a summary of these calculations.

Table 2.19: Forecast Wholesale Market Service Costs 2023-2024

Wholesale Market Service Class per Load Forecast	Units	2023 Volume	RPP Rate	$	2023 Volume	Non-RPP Rate	$	Total
Residential	kWh	114,232,124	0.0041	468,352	605,845	0.0041	2,484	470,836
GS < 50	kWh	19,156,020	0.0041	78,540	1,201,529	0.0041	4,926	83,466
GS > 50	kWh	656,369	0.0041	2,691	22,374,203	0.0041	91,734	94,425
Streetlight	kWh		0.0041		876,107	0.0041	3,592	3,592
USL	kWh	223,542	0.0041	917		0.0041		917
Subtotal				**550,449**			**102,916**	**653,236**

Wholesale Market Service Class per Load Forecast	Units	2024 Volume	RPP Rate	$	2024 Volume	Non-RPP Rate	$	Total
Residential	kWh	116,914,768	0.0041	479,351	620,072	0.0041	2,542	481,893
GS < 50	kWh	19,438,868	0.0041	79,699	1,221,517	0.0041	5,008	84,708
GS > 50	kWh	658,981	0.0041	2,707	22,463,263	0.0041	92,099	94,801
Streetlight	kWh		0.0041		885,890	0.0041	3,632	3,632
USL	kWh	233,209	0.0041	956		0.0041		956
Subtotal				**562,708**			**103,282**	**665,990**

WDI used $0.0004 per kilowatt hour for the Class B Capacity Based Recovery (CBR) Charge in its 2023 Bridge Year and 2024 Test Year COP calculations. Table 2.20 provides a summary of these calculations.

Table 2.20: Forecast Class B CBR Costs 2023-2024

Class B CBR	Units	2023	RPP	$	2023	Non-RPP	$	Total
Class per Load Forecast		Volume	Rate		Volume	Rate		
Residential	kWh	114,232,124	0.0004	45,693	605,845	0.0004	242	45,935
GS < 50	kWh	19,156,020	0.0004	7,662	1,201,529	0.0004	481	8,143
GS > 50	kWh	656,369	0.0004	263	22,374,203	0.0004	8,950	9,212
Streetlight	kWh		0.0004		876,107	0.0004	350	350
USL	kWh	223,542	0.0004	89		0.0004		89
Subtotal				**53,707**			**10,023**	**63,730**

Class B CBR	Units	2024	RPP	$	2024	Non-RPP	$	Total
Class per Load Forecast		Volume	Rate		Volume	Rate		
Residential	kWh	116,914,768	0.0004	46,766	620,072	0.0004	248	47,014
GS < 50	kWh	19,438,868	0.0004	7,776	1,221,517	0.0004	489	8,264
GS > 50	kWh	658,981	0.0004	264	22,463,263	0.0004	8,985	9,249
Streetlight	kWh		0.0004		885,890	0.0004	354	354
USL	kWh	233,209	0.0004	93		0.0004		93
Subtotal				**54,898**			**10,076**	**64,975**

WDI used $0.0007 per kWh for the Rural and Remote Electricity Rate Protection (RRRP) Charge in its 2023 Bridge Year and 2024 Test Year COP calculations. Table 2.21 provides a summary of these calculations.

Table 2.21: Forecast Rural and Remote Electricity Rate Protection Costs 2023-2024

RRRP Class per Load Forecast	Units	2023 Volume	RPP Rate	$	2023 Volume	Non-RPP Rate	$	Total
Residential	kWh	114,232,124	0.0007	79,962	605,845	0.0007	424	80,387
GS < 50	kWh	19,156,020	0.0007	13,409	1,201,529	0.0007	841	14,250
GS > 50	kWh	656,369	0.0007	459	22,374,203	0.0007	15,662	16,121
Streetlight	kWh		0.0007		876,107	0.0007	613	613
USL	kWh	223,542	0.0007	156		0.0007		156
Subtotal				**93,988**			**17,540**	**111,528**

RRRP Class per Load Forecast	Units	2024 Volume	RPP Rate	$	2024 Volume	Non-RPP Rate	$	Total
Residential	kWh	116,914,768	0.0007	81,840	620,072	0.0007	434	82,274
GS < 50	kWh	19,438,868	0.0007	13,607	1,221,517	0.0007	855	14,462
GS > 50	kWh	658,981	0.0007	461	22,463,263	0.0007	15,724	16,186
Streetlight	kWh		0.0007		885,890	0.0007	620	620
USL	kWh	233,209	0.0007	163		0.0007		163
Subtotal				**96,072**			**17,634**	**113,706**

Network and Connection

Electricity distributors are charged for transmission costs at the wholesale level and subsequently pass these charges on to their distribution customers through Retail Transmission Service Rates (RTSRs). For each distribution rate class there are two RTSRs:

1) RTSR Network Charge – Recovers the UTR Wholesale Network Service Charge.
2) RTSR Connection Charge – Recovers the UTR Wholesale Line and Transformation Connection Charge.
3)

For determining the 2023 Bridge Year COP, WDI used its approved rates. For the 2024 Test Year COP, proposed rates were used.

WDI acknowledges that the transmission costs may be updated to reflect any new rates that may become available prior to the approval of its Application.

Table 2.22 below provides a summary of these calculations.

Table 2.22: Forecast Network and Connection Transmission Costs

Transmission - Network	Units	2023	RPP	$	2023	Non-RPP	$	Total
Class per Load Forecast		Volume	Rate		Volume	Rate		
Residential	kWh	114,232,124	0.0102	1,165,168	605,845	0.0102	6,180	1,171,347
GS < 50	kWh	19,156,020	0.0093	178,151	1,201,529	0.0093	11,174	189,325
GS > 50	kW	1,334	3.7880	5,053	54,675	3.7880	207,109	212,162
Streetlight	kW		2.8572		2,589	2.8572	7,397	7,397
USL	kWh	223,542	0.0093	2,079		0.0093		2,079
Subtotal				**1,350,451**			**231,859**	**1,582,310**

Transmission - Connection	Units	2023	RPP	$	2023	Non-RPP	$	Total
Class per Load Forecast		Volume	Rate		Volume	Rate		
Residential	kWh	114,232,124	0.0067	765,355	605,845	0.0067	4,059	769,414
GS < 50	kWh	19,156,020	0.0059	113,021	1,201,529	0.0059	7,089	120,110
GS > 50	kW	1,334	2.2860	3,049	54,675	2.2860	124,987	128,036
Streetlight	kW		1.7673		2,589	1.7673	4,575	4,575
USL	kWh	223,542	0.0059	1,319		0.0059		1,319
Subtotal				**882,744**			**140,710**	**1,023,455**

Transmission - Network	Units	2024	RPP	$	2024	Non-RPP	$	Total
Class per Load Forecast		Volume	Rate		Volume	Rate		
Residential	kWh	116,914,768	0.0100	1,169,148	620,072	0.0100	6,201	1,175,348
GS < 50	kWh	19,438,868	0.0091	176,894	1,221,517	0.0091	11,116	188,010
GS > 50	kW	1,339	3.6988	4,954	54,893	3.6988	203,037	207,990
Streetlight	kW		2.7894		2,618	2.7899	7,303	7,303
USL	kWh	233,209	0.0091	2,122		0.0091		2,122
Subtotal				**1,353,117**			**227,657**	**1,580,774**

Transmission - Connection	Units	2024	RPP	$	2024	Non-RPP	$	Total
Class per Load Forecast		Volume	Rate		Volume	Rate		
Residential	kWh	116,914,768	0.0069	806,712	620,072	0.0069	4,278	810,990
GS < 50	kWh	19,438,868	0.0061	118,577	1,221,517	0.0061	7,451	126,028
GS > 50	kW	1,339	2.3453	3,141	54,893	2.3453	128,740	131,881
Streetlight	kW		1.8132		2,618	1.8132	4,747	4,747
USL	kWh	233,209	0.0061	1,423		0.0061		1,423
Subtotal				**929,853**			**145,216**	**1,075,068**

Smart Meter Entity Charges

For determining the 2023 Bridge Year COP, WDI used its approved rates. For the 2024 Test Year COP, proposed rates were used. Table 2.23 provides a summary of these calculations.

Table 2.23: Smart Meter Entity Costs

Smart Meter Entity Charge Class per Load Forecast	2023 Volume	RPP Rate	$	2023 Volume	Non-RPP Rate	$	Total
Residential	14,079	0.4200	70,960	75	0.4200	376	71,336
GS < 50	802	0.4200	4,041	50	0.4200	253	4,294
Subtotal			**75,000**			**630**	**75,630**
Smart Meter Entity Charge Class per Load Forecast	**2024 Volume**	**RPP Rate**	**$**	**2024 Volume**	**Non-RPP Rate**	**$**	**Total**
Residential	14,332	0.4200	72,233	76	0.4200	383	72,616
GS < 50	807	0.4200	4,069	51	0.4200	255	4,324
Subtotal			**76,302**			**638**	**76,941**

Low Voltage Charges

For determining the 2023 Bridge Year COP, WDI used its approved rates. For the 2024 Test Year, proposed rates were used. Table 2.24 provides a summary of these calculations.

1 **Table 2.24: Low Voltage Charges**

Low Voltage Class per Load Forecast	Units	2023 Volume	RPP Rate	$	2023 Volume	Non-RPP Rate	$	Total
Residential	kWh	105,789,131	0.0038	401,999	561,066	0.0038	2,132	404,131
GS < 50	kWh	17,740,183	0.0033	58,543	1,112,723	0.0033	3,672	62,215
GS > 50	kW	1,235	1.3103	1,619	50,634	1.3103	66,346	67,964
Streetlight	kW		1.0165		2,398	1.0165	2,437	2,437
USL	kWh	207,020	0.0033	683		0.0033		683
Subtotal				**462,843**			**74,587**	**537,430**

Low Voltage Class per Load Forecast	Units	2024 Volume	RPP Rate	$	2024 Volume	Non-RPP Rate	$	Total
Residential	kWh	108,273,498	0.0044	479,623	574,242	0.0044	2,544	482,167
GS < 50	kWh	18,002,125	0.0039	70,223	1,129,153	0.0039	4,405	74,628
GS > 50	kW	1,240	1.5114	1,875	50,835	1.5114	76,833	78,707
Streetlight	kW		1.1685		2,424	1.1685	2,833	2,833
USL	kWh	215,972	0.0039	842		0.0039		842
Subtotal				**552,563**			**86,614**	**639,176**

2

2.2.5 Distribution System Plan

WDI has filed its 2024-2028 Distribution System Plan (DSP) as Appendix 2 (C) at the end of this Exhibit.

2.2.6 Policy Options for the Funding of Capital

WDI is not proposing any qualifying Advanced Capital Module (ACM) capital projects as part of this COS Application.

2.2.7 Addition of Previously Approved ACM & ICM Project Assets to Rate Base

WDI has not historically applied for a rate rider to recover an investment via the OEB's Advanced Capital Module (ACM) or Incremental Capital Module (ICM). As such, section 2.2.8 of the filing requirements is not applicable.

WDI would like to note, however, that it may consider submitting an ICM in a future Price Cap IR Filing or an ACM in a future COS Filing in relation to the two new substations it has proposed in its 2024 DSP.

2.2.8 Capitalization Procedures

WDI does not have an official capitalization policy. However, the guidelines it follows when capitalizing assets are in accordance with the MIFRS accounting basis. WDI also follows the OEB APH for Electricity Distributors when applicable. WDI has not changed its capitalization guidelines since its last COS Application.

General Procedure for Capitalization:

Accounts 1830-1860 – Poles, OH, Conductors, Transformers, UG Conduit, Meters

The capitalized expenditures for these accounts include:

- Material and supplies direct costs
- Contractor Expenses

Material and Supplies Direct Costs:

- WDI only purchases meters, and these are capitalized in the year of purchase.

Contractor Expenses:

- WDI contracts Wasaga Resource Services (WRSI) and/or other third-party contractors for work needed to construct assets based on WDI's approved budget and capital plan.
- Work conducted with developers for new subdivisions and other non-discretionary work is subject to economic evaluations. A developer will submit a request for bid from WRSI and as a result, WRSI will perform a formal review of the total costs required to complete the project. Prior to the start of the project, WRSI will establish a line of credit with the developer in order to fund the work being conducted. At project completion, the project is fully funded by the developer plus a mark-up charged by WRSI. WDI will then conduct an economic evaluation on the project.

This is a Net Present Value calculation that determines the portion of capital assets, contributed capital and liabilities WDI will record on its balance sheet.

Account 1905 - Land Acquisition

The recorded cost of land includes:

- The purchase price;
- Costs of closing the transaction and obtaining title, which includes but are not limited to legal fees, survey costs and land transfer taxes:
- The cost of preparing the land for its particular use, such as clearing and grading. If the land is purchased for the purpose of constructing a building, all costs incurred up to the excavation of the new building should be considered land costs. Removal of an old building, clearing, grading and filling are considered land costs because they are necessary to get the land in condition for its intended purpose. Any proceeds obtained in the process of getting the land ready for its intended use, such as salvage receipts on the demolition of the old building or the sale of cleared timber, are treated as reductions in the price of the land.

Expenditures for land acquisition usually do not deteriorate with use or passage of time, therefore the cost of land is generally not exhaustible, and therefore not depreciable.

Account 1908 – Building

Capitalization of Building costs include, but are not limited to, the following:

- Original contract price of an asset;
- Expenses for remodeling, repairing, or changing a purchased building to make it available for the purpose for which it was acquired;
- Engineer’s fees for design as well as expenses for the preparation of plans, specifications, blueprints, etc.;
- Cost of building permits.

Accounts 1915 to 1955 – Office Furniture, Computer, Vehicles, Tools, and Other Equipment

For capitalization of expenditures with a service life of more than one year, the total invoice or contract price is used, including its freight to the destination. No storage, stockroom expenses or administrative charges are added.

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

WDI attests that it has not included any costs or included any Investments to Connect Qualifying Generation Facilities in its capital costs or in its DSP.

2.2.10 Appendices

Appendix 2 (A) Year-over-year Variance of Rate Base

Appendix 2 (B) 2016-2024 Continuity Schedules

Appendix 2 (C) 2024-2028 Distribution System Plan (DSP)

Appendix 2 (A) Year-over-Year Variance of Rate Base

2016 Actual Rate Base Compared to 2016 Board Approved Rate Base

	Last Board Approved	2016 Actual	% Change
Net Capital Assets in Service			
Opening Balance	12,013,060	11,824,513	
Ending Balance	12,718,688	12,133,522	
Average Balance	**12,365,874**	**11,979,017**	**-3.13%**
Working Capital Allowance	1,966,498	1,980,890	
Total Rate Base	**14,332,372**	**13,959,907**	**-2.60%**
Expenses for Working Capital	**Last Board Approved**	**2016 Actual**	**% Change**
Eligible Distribution Expenses			
3500-Distribution Expenses - Operation	77,011	97,379	
3550-Distribution Expenses - Maintenance	795,181	732,972	
3650-Billing and Collecting	1,027,236	1,028,994	
3700-Community Relations	17,803	13,129	
3800-Administrative and General Expenses	1,081,583	1,145,764	
6105-Taxes other than Income Taxes	28,000	31,858	
6205-Sub-account LEAP Funding	4,976	4,785	
Total Eligible Distribution Expenses	**3,031,790**	**3,054,881**	**0.76%**
3350-Power Supply Expenses	17,199,671	17,324,648	
Total Expenses for Working Capital	**20,231,461**	**20,379,529**	**0.73%**
Working Capital factor	9.72%	9.72%	
Total Working Capital Allowance	**1,966,498**	**1,980,890**	**0.73%**

1 **2017 Actual Rate Base Compared to 2016 Actual Rate Base**

	2016 Actual	2017 Actual	% Change
Net Capital Assets in Service			
Opening Balance	11,824,513	12,133,522	
Ending Balance	12,133,522	12,450,347	
Average Balance	**11,979,017**	**12,291,934**	**2.61%**
Working Capital Allowance	1,980,890	1,781,977	
Total Rate Base	**13,959,907**	**14,073,911**	**0.82%**
Expenses for Working Capital	**2016 Actual**	**2017 Actual**	**% Change**
Eligible Distribution Expenses			
3500-Distribution Expenses - Operation	97,379	86,785	
3550-Distribution Expenses - Maintenance	732,972	755,902	
3650-Billing and Collecting	1,028,994	1,068,056	
3700-Community Relations	13,129	16,346	
3800-Administrative and General Expenses	1,145,764	1,192,303	
6105-Taxes other than Income Taxes	31,858	31,232	
6205-Sub-account LEAP Funding	4,785	4,971	
Total Eligible Distribution Expenses	**3,054,881**	**3,155,596**	**3.30%**
3350-Power Supply Expenses	17,324,648	15,177,499	
Total Expenses for Working Capital	**20,379,529**	**18,333,095**	**-10.04%**
Working Capital factor	9.72%	9.72%	
Total Working Capital Allowance	**1,980,890**	**1,781,977**	**-10.04%**

2

1 **2018 Actual Rate Base Compared to 2017 Actual Rate Base**

	2017 Actual	2018 Actual	% Change
Net Capital Assets in Service			
Opening Balance	12,133,522	12,450,347	
Ending Balance	12,450,347	12,978,879	
Average Balance	**12,291,934**	**12,714,613**	**3.44%**
Working Capital Allowance	1,781,977	1,733,380	
Total Rate Base	**14,073,911**	**14,447,994**	**2.66%**
Expenses for Working Capital	**2017 Actual**	**2018 Actual**	**% Change**
Eligible Distribution Expenses			
3500-Distribution Expenses - Operation	86,785	50,487	
3550-Distribution Expenses - Maintenance	755,902	838,684	
3650-Billing and Collecting	1,068,056	1,057,714	
3700-Community Relations	16,346	10,553	
3800-Administrative and General Expenses	1,192,303	1,237,492	
6105-Taxes other than Income Taxes	31,232	31,306	
6205-Sub-account LEAP Funding	4,971	4,227	
Total Eligible Distribution Expenses	**3,155,596**	**3,230,462**	**2.37%**
3350-Power Supply Expenses	15,177,499	14,602,669	
Total Expenses for Working Capital	**18,333,095**	**17,833,131**	**-2.73%**
Working Capital factor	9.72%	9.72%	
Total Working Capital Allowance	**1,781,977**	**1,733,380**	**-2.73%**

2

2019 Actual Rate Base Compared to 2018 Actual Rate Base

	2018 Actual	2019 Actual	% Change
Net Capital Assets in Service			
Opening Balance	12,450,347	12,978,879	
Ending Balance	12,978,879	13,766,916	
Average Balance	**12,714,613**	**13,372,898**	**5.18%**
Working Capital Allowance	1,733,380	1,885,227	
Total Rate Base	**14,447,994**	**15,258,124**	**5.61%**

Expenses for Working Capital	2018 Actual	2019 Actual	% Change
Eligible Distribution Expenses			
3500-Distribution Expenses - Operation	50,487	38,450	
3550-Distribution Expenses - Maintenance	838,684	855,276	
3650-Billing and Collecting	1,057,714	1,138,326	
3700-Community Relations	10,553	11,307	
3800-Administrative and General Expenses	1,237,492	1,422,721	
6105-Taxes other than Income Taxes	31,306	31,380	
6205-Sub-account LEAP Funding	4,227	2,841	
Total Eligible Distribution Expenses	**3,230,462**	**3,500,301**	**8.35%**
3350-Power Supply Expenses	14,602,669	15,895,035	
Total Expenses for Working Capital	**17,833,131**	**19,395,336**	**8.76%**
Working Capital factor	9.72%	9.72%	
Total Working Capital Allowance	**1,733,380**	**1,885,227**	**8.76%**

2020 Actual Rate Base Compared to 2019 Actual Rate Base

	2019 Actual	2020 Actual	% Change
Net Capital Assets in Service			
Opening Balance	12,978,879	13,766,916	
Ending Balance	13,766,916	14,647,476	
Average Balance	**13,372,898**	**14,207,196**	**6.24%**
Working Capital Allowance	1,885,227	2,370,263	
Total Rate Base	**15,258,124**	**16,577,459**	**8.65%**

Expenses for Working Capital	2019 Actual	2020 Actual	% Change
Eligible Distribution Expenses			
3500-Distribution Expenses – Operation	38,450	50,770	
3550-Distribution Expenses – Maintenance	855,276	715,452	
3650-Billing and Collecting	1,138,326	922,939	
3700-Community Relations	11,307	17,399	
3800-Administrative and General Expenses	1,422,721	1,789,944	
6105-Taxes other than Income Taxes	31,380	31,571	
6205-Sub-account LEAP Funding	2,841	5,525	
Total Eligible Distribution Expenses	**3,500,301**	**3,533,601**	**0.95%**
3350-Power Supply Expenses	15,895,035	20,851,819	
Total Expenses for Working Capital	**19,395,336**	**24,385,420**	**25.73%**
Working Capital factor	9.72%	9.72%	
Total Working Capital Allowance	**1,885,227**	**2,370,263**	**25.73%**

2021 Actual Rate Base Compared to 2020 Actual Rate Base

	2020 Actual	2021 Actual	% Change
Net Capital Assets in Service			
Opening Balance	13,766,916	14,647,476	
Ending Balance	14,647,476	15,906,414	
Average Balance	**14,207,196**	**15,276,945**	**7.53%**
Working Capital Allowance	2,370,263	2,062,525	
Total Rate Base	**16,577,459**	**17,339,471**	**4.60%**

Expenses for Working Capital	2020 Actual	2021 Actual	% Change
Eligible Distribution Expenses			
3500-Distribution Expenses - Operation	50,770	35,697	
3550-Distribution Expenses - Maintenance	715,452	766,679	
3650-Billing and Collecting	922,939	931,888	
3700-Community Relations	17,399	9,487	
3800-Administrative and General Expenses	1,789,944	1,270,680	
6105-Taxes other than Income Taxes	31,571	31,780	
6205-Sub-account LEAP Funding	5,525	7,359	
Total Eligible Distribution Expenses	**3,533,601**	**3,053,570**	**-13.58%**
3350-Power Supply Expenses	20,851,819	18,165,828	
Total Expenses for Working Capital	**24,385,420**	**21,219,398**	**-12.98%**
Working Capital factor	9.72%	9.72%	
Total Working Capital Allowance	**2,370,263**	**2,062,525**	**-12.98%**

1 **2022 Actual Rate Base Compared to 2021 Actual Rate Base**

	2021 Actual	2022 Actual	% Change
Net Capital Assets in Service			
Opening Balance	14,647,476	15,906,414	
Ending Balance	15,906,414	19,431,486	
Average Balance	**15,276,945**	**17,668,950**	**15.66%**
Working Capital Allowance	2,062,525	2,114,059	
Total Rate Base	**17,339,471**	**19,783,009**	**14.09%**
Expenses for Working Capital	**2021 Actual**	**2022 Actual**	**% Change**
Eligible Distribution Expenses			
3500-Distribution Expenses - Operation	35,697	42,891	
3550-Distribution Expenses - Maintenance	766,679	837,726	
3650-Billing and Collecting	931,888	981,135	
3700-Community Relations	9,487	15,636	
3800-Administrative and General Expenses	1,270,680	1,436,189	
6105-Taxes other than Income Taxes	31,780	32,206	
6205-Sub-account LEAP Funding	7,359	5,149	
Total Eligible Distribution Expenses	**3,053,570**	**3,350,932**	**9.74%**
3350-Power Supply Expenses	18,165,828	18,398,642	
Total Expenses for Working Capital	**21,219,398**	**21,749,574**	**2.50%**
Working Capital factor	9.72%	9.72%	
Total Working Capital Allowance	**2,062,525**	**2,114,059**	**2.50%**

2

1 **2023 Bridge Year Rate Base Compared to 2022 Actual Rate Base**

	2022 Actual	2023 Bridge Year	% Change
Net Capital Assets in Service			
Opening Balance	15,906,414	19,431,486	
Ending Balance	19,431,486	21,779,585	
Average Balance	**17,668,950**	**20,605,535**	**16.62%**
Working Capital Allowance	2,114,059	2,203,752	
Total Rate Base	**19,783,009**	**22,809,287**	**15.30%**
Expenses for Working Capital	**2022 Actual**	**2023 Bridge Year**	**% Change**
Eligible Distribution Expenses			
3500-Distribution Expenses - Operation	42,891	75,896	
3550-Distribution Expenses - Maintenance	837,726	973,216	
3650-Billing and Collecting	981,135	1,134,646	
3700-Community Relations	15,636	22,172	
3800-Administrative and General Expenses	1,436,189	1,419,258	
6105-Taxes other than Income Taxes	32,206	34,061	
6205-Sub-account LEAP Funding	5,149	5,155	
Total Eligible Distribution Expenses	**3,350,932**	**3,664,403**	**9.35%**
3350-Power Supply Expenses	18,398,642	19,027,822	
Total Expenses for Working Capital	**21,749,574**	**22,692,225**	**4.33%**
Working Capital factor	9.72%	9.72%	
Total Working Capital Allowance	**2,114,059**	**2,205,684**	**4.33%**

2

1 **2024 Test Year Rate Base Compared to 2023 Bridge Year Rate Base**

	2023 Bridge Year	2024 Test Year	% Change
Net Capital Assets in Service			
Opening Balance	19,431,486	21,779,585	
Ending Balance	21,779,585	24,187,319	
Average Balance	**20,605,535**	**22,983,452**	**11.54%**
Working Capital Allowance	2,205,684	1,762,745	
Total Rate Base	**22,811,220**	**24,746,197**	**8.48%**
Expenses for Working Capital	**2023 Bridge Year**	**2024 Test Year**	**% Change**
Eligible Distribution Expenses			
3500-Distribution Expenses - Operation	75,896	63,011	
3550-Distribution Expenses - Maintenance	973,216	1,017,951	
3650-Billing and Collecting	1,134,646	1,207,141	
3700-Community Relations	22,172	19,885	
3800-Administrative and General Expenses	1,419,258	1,664,194	
6105-Taxes other than Income Taxes	34,061	35,696	
6205-Sub-account LEAP Funding	5,155	7,170	
Total Eligible Distribution Expenses	**3,664,403**	**4,015,049**	**9.57%**
3350-Power Supply Expenses	19,027,822	19,488,212	
Total Expenses for Working Capital	**22,692,225**	**23,503,261**	**3.57%**
Working Capital factor	9.72%	7.50%	
Total Working Capital Allowance	**2,205,684**	**1,762,745**	**-20.08%**

2

Appendix 2 (B) 2016-2024 Continuity Schedules

WDI has filed the 2016-2024 Continuity Schedules separately in excel format in tab 2-BA of the Chapter 2 Appendices Workform.

1 Appendix 2 (C) 2024-2028 Wasaga Distribution Inc. Distribution System Plan

Wasaga Distribution Inc.

2024 – 2028 Distribution System Plan

Table of Contents

5.2 Distribution System Plan

5.2.1 Distribution System Plan Overview

Wasaga Distribution Inc. (WDI) is an authorized electricity distributor regulated by the Ontario Energy Board (OEB). Under Distribution License ED-2002-0544, WDI is responsible for providing electricity distribution services within the Town of Wasaga Beach. As part of its 2024 rate application, WDI has developed a Distribution System Plan (DSP) that aligns with the requirements specified in the OEB's 'Chapter 5A – Small Utilities Distribution System Plan', issued on December 15th, 2022. This DSP encompasses the forecast period of 2024 to 2028 and has been included as an integral component of WDI's rate application.

WDI’s DSP documents WDI’s asset management processes and capital expenditure plan for the 2024-2028 period. The DSP documents the practices, and processes that are in place to ensure that investment decisions support WDI’s desired outcomes and provide value to the customer.

WDI’s DSP is designed to support the achievement of the four key OEB-established performance outcomes for electricity distributors. Table 1 shows how corporate goals and asset management objectives align with OEB performance outcomes:

Table 1 - OEB Performance Outcomes Alignment Summary

OEB Performance Outcomes	Corporate Goals	Asset Management Objectives Outcomes
Customer Focus: services are provided in a manner that responds to identified customer preferences.	Nurturing and Enhancing Stakeholder Relationships	**Customer Service**: aligning asset investments with customer expectations regarding reliability, expansion, and electrification.
Operational Effectiveness: continuous improvement in productivity and cost performance is achieved, and utilities deliver on system reliability and quality objectives	Prudent spending through sound operational and financial practices	**Reliability and Efficiency**: ensuring reliability and efficiency through balanced investments, effective capacity management, continuous improvement, and leveraging technological advancements for improved performance and visibility into system operations.
	Embracing Digitization	
Public Policy Responsiveness: utilities deliver on obligations mandated by the government (e.g., in legislation and regulatory requirements imposed further to Ministerial directives to the OEB).	Ensuring Effective Risk Management	**Safety**: prioritizing safety by ensuring assets are compliant with regulatory and industry standards to protect staff, contractors, and the public.
Financial Performance: financial viability is maintained, and savings from operational effectiveness are sustainable.	Long-term Financial Sustainability	**Financial Integrity**: managing investments with consideration to corporate long-term financial stability and delivering economically reliable power to customers

WDI has been engaging with its customers and stakeholders through multiple channels. Through these interactions, WDI believes its customers have a vision for a cost-effective, responsive, and reliable electricity service delivered through a resilient system.

To align with this customer-driven vision, WDI has devised an all-encompassing investment strategy aimed at expanding, renewing, and maintaining its distribution system assets. The primary objective of this plan is to uphold a fundamental level of high-quality service to WDI's customers.

Despite WDI's best efforts to maintain a reliable system, the service is still subject to unplanned outages from events like storms where trees fall onto power lines causing a faulted condition. Customer feedback has demonstrated a desire to explore solutions that quickly resolve outages and provide customers with more timely information.

WDI has organized the required information using the section headings in the Distribution System Plan Filing Requirements. Investment projects and activities have been grouped into one of the four (4) OEB-defined investment categories listed in Table 2 below, based on the 'trigger' driver of the expenditure:

Table 2 - Investment Categories

Investment Category	Investment Description
System Access	System Access investments are modifications (including asset relocation) to the distribution system WDI is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via WDI's distribution system. This also includes meter re-verification as mandated by Measurement Canada and the OEB.
System Renewal	System Renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of WDI's distribution system to provide customers with electricity services.
System Service	System Service investments encompass modifications to WDI's distribution system to ensure the distribution system continues to meet WDI operational objectives while addressing anticipated future customer electricity service requirements and grid modernization.
General Plan	General Plant investments encompass modifications, replacements, or additions to WDI's assets that are not part of the distribution system; including land and buildings; tools and equipment; rolling stock and electronic devices and software used to support day-to-day business and operations activities.

The electric distribution system is capital-intensive, making it crucial to make wise capital expenditures and maintenance strategies to guarantee the long-term viability of the distribution network. WDI's DSP documents the practices, and processes in place to ensure that decisions on capital investments and maintenance plans cost-effectively support WDI's desired outcomes and provide value to all stakeholders.

The variability in individual capital investment categories considers the unique impact of System Access work and other concurrent demands on WDI's capacity to finance and carry out various projects. In this context, non-mandatory work like System Renewal, System Service, and General Plant projects undergo thorough assessment, scheduling, and management to align with the corporation's objectives. If System Access projects do not come to fruition, other investment categories funding will not be impacted. However, if unforeseen System Access projects emerge, they may require a re-evaluation and potential reshuffling of priorities among other investment categories to accommodate the unexpected demands.

In the previous DSP period, in response to budget constraints resulting from excess spending in other investment categories, WDI deprioritized planned system renewal projects. In response, in 2021, WDI implemented new project management controls to enhance cost and schedule management. These controls are part of a broader improvement plan aimed at increasing the likelihood of successfully executing System Renewal, System Service and General Plant projects within the 2024-2028 DSP period. This strategic initiative underscores WDI's commitment to achieving effective cost and schedule management, ensuring goal attainment without budget overruns.

Table 3 summarizes the proposed annual capital investments spend within the four designated categories for the 2024 – 2028 period.

Table 3 - Capital Investment Summary 2024 - 2028

Category	2024	2025	2026	2027	2028
System Access	4,896,480	3,065,000	3,421,200	3,593,624	3,347,296
System Renewal	1,916,242	1,870,175	1,346,471	1,411,310	1,748,699
System Service	500,000	230,000	4,450,000	230,000	4,615,000
General Plant	25,000	26,000	26,500	31,500	27,000
Total Expenditures	**7,337,722**	**5,191,175**	**9,244,171**	**5,266,434**	**9,737,995**
Contributed Capital	3,985,958	2,365,700	4,566,079	2,680,301	4,661,136
Net Capital Expenditures	**3,351,764**	**2,825,475**	**4,678,092**	**2,586,133**	**5,076,859**

5.2.2 Coordinated Planning with Third Parties

5.2.2.1 Overview of the consultations

Presented in Table 4 is a summary of the consultations in which WDI actively engages. Additional information regarding the consultations can be found in the noted references and subsequent discussions.

Table 4 - Consultation Summary

Purpose of Consultation	Initiator	Other Participants	Deliverables –Scope and Timing	Impact on DSP
Regional Planning	HONI and IESO	IESO, HONI, South Georgian Bay/Muskoka Region LDCs	South Georgian Bay-Muskoka Regional Infrastructure Plan	No impact on DSP
Customer consultations to provide advice and obtain feedback	WDI	Customers	Customer survey specific to DSP – Q4 2022; Customer Satisfaction Survey – Q1 2023; Various Social Media interactions	Customer Priority Survey preferences have been integrated into the investment plans
Overhead plant locations approval on roadways	WDI	Town of Wasaga Beach, Simcoe County	Town or County approval of proposed WDI plant location within the road allowance	No specific impact on DSP
Road authority work schedule coordination	WDI	Town of Wasaga Beach and/or Simcoe County	Determination of timing and scope of road authority work that may impact existing WDI plant	Relocations resulting from road works have an impact on System Access Investments.
Telecommunications Entities	WDI	Bell Canada, Rogers Communications	Consultation of timing and scope of telecommunication projects in service territory. Coordinating attachment transfers for rebuild projects	No specific impact on DSP No specific impact on DSP
Property Developers	Developer(s)		Development information such as plans and associated schedules and budgets.	Significant impact on DSP in System Access
REG	WDI	IESO, HONI, other LDCs	No REG investments planned	No specific impact on DSP
Utility Coordination Meetings	Municipality	Municipality, Bell Canada, Rogers Communications Inc., Enbridge Gas	Pre and Post construction season for utility coordination	No specific impact on DSP

Regional Planning

WDI did not initiate the consultation but has participated in regional planning meetings facilitated by the Independent Electricity System Operator (IESO). The meetings involve the IESO, Hydro One Networks Inc. (HONI) and LDCs as assigned to the regional group.

The South Georgian Bay/Muskoka Scoping Assessment Outcome Report was published in November 2020 and the South Georgian Bay/Muskoka Regional Infrastructure Plan was published in December 2022. In the reports, two sub-regions formed part of the technical study – Barrie/Innisfil and Parry Sound/Muskoka. WDI is considered outside of both these sub-regions as it was determined that local needs can be addressed through local planning between the HONI and WDI. This study did not impact the DSP development. Through conversations with HONI, WDI was able to determine that there is still available capacity through their transmission substations (TS) without the need for additional TS capacity, rather gained by transferring load among feeders from the TS.

The Regional Infrastructure Plan has been provided in Appendix A.

Customer Consultations

WDI maintains regular contact with its customers primarily through informal engagements. Customer interaction is frequently conducted via the company website, social media platforms, and customer engagement gatherings. In addition to participating in the local home show, WDI has developed a website that includes social media channels and online forms for customers to ask questions, offer feedback and exchange their experiences.

WDI periodically conducts customer satisfaction surveys as part of the balanced scorecard and other reporting and regulatory requirements for the OEB. Surveys consistently demonstrate that customers are very satisfied with the service provided by WDI. WDI carefully reviews the survey findings to evaluate if any adjustments to corporate programs and strategies are necessary based on the feedback received from customers. This process ensures that WDI remains responsive to the needs and preferences of its customers. In 2023, WDI enlisted the services of Advanis Inc. to conduct individual customer satisfaction surveys. The results of these surveys indicated an overall customer satisfaction index score of 81%.

More specifically related to the DSP development, WDI canvased individuals in Q4 of 2022. The survey identified individual expectations and investment priorities. This information was used to help determine the level of ratepayer support for WDI's plant investment position in the DSP that is designed to maintain existing service levels. This level of ratepayer support for plant investment is a driver of DSP investments over the 2024 – 2028 planning period. There were 81 respondents to this survey, and WDI understands that the small sample size may not provide strong enough evidence to be relied upon as representing its ratepayer base. Therefore, these results were used cautiously.

Participants were tasked with identifying key priorities, and the resulting main concerns were as follows:

- 82.5% of respondents chose affordable cost of electricity but would support an increase in their monthly bills.
- 80% of respondents chose maintaining and upgrading equipment with the expectation that investments would be used to maintain system reliability.
- Investing in vegetation management, modern technologies and supporting decarbonization goals were identified as secondary priorities.

Regarding customer satisfaction, WDI maintains its dedication to prioritizing affordability, reliability, and sustainability in pivotal organizational choices. In line with this commitment, WDI intends to amplify its presence on social media and traditional communication channels as part of a comprehensive media and public relations strategy and aims to enhance education regarding the electricity industry.

WDI's investment plans to further integrate customer feedback, include:

- Deploying smart devices to improve outage response times.
- Investing in a customer-facing online outage map and other digital services to improve customer communication.
- Investing in Esri Geographic Information System (GIS) to better support asset tracking and system visibility
- Implementing grid technology solutions to better support Distributed Energy Resources (DER) integration and electrification of the grid

Town of Wasaga Beach

1. WDI plant locations approval on roadway consultations: Municipal Consent (MC) is the authorization for a utility company to occupy a specific location within the road right-of-way. As part of the typical project planning process, WDI consults with road authority to obtain MC for new pole locations in the road right-of-way for each project where applicable. WDI initiates the process and provides the road authority with detailed project construction plans for new/replacement infrastructure proposed in road allowances. This is a regular administrative consultation process and does not have a material impact on the DSP investment plan.

   WDI also provides timely locates and drawing mark-ups to support other third parties (e.g., Enbridge) with their Municipal Consent (MC) applications.

2. Road works consultations: Major work in the road right-of-way (e.g., widening and/or urbanization) by the road authority may require the relocation of WDI infrastructure. WDI works closely with the road authority to ensure coordination and synergy gains in addition to early awareness of issues that may impact distribution system locations and capacity. Coordinated proactive planning can have a significant impact on project development and execution with better outcomes for all parties.

   This may involve road authority coordination with other entities such as gas and telecommunication utilities. This is a regular administrative consultation process and does have a material impact on the DSP investment plan under System Access.

3. Utility Coordination Meetings: WDI actively engages in two Utility Coordination Meetings annually, held before and after the construction season. These meetings are initiated by the municipality to foster effective communication among different utilities, resolve any conflicts that may arise, and encourage collaboration on joint trench initiatives. The participating entities include:

   - Town of Wasaga Beach: Engineering, Public Works
   - WDI: Operations
   - Bell Canada: Planning
   - Rogers Communications: Planning, Municipal and Utility Relations, Enbridge Gas: Planning, Construction

Telecommunications Entities

WDI offers support to Telecommunications Entities by providing prompt locates and making necessary upgrades to its pole lines upon request. Additionally, WDI assists them by offering drawing mark-ups and providing relevant comments for their MC applications.

Telecommunication Entities are provided with an annual list of pole line rebuild project scopes and schedules. This proactive communication aims to enable them to plan and execute attachment transfers promptly facilitating smooth operations and minimizing disruptions.

The impacts of the Accelerated High-Speed Internet Program (AHSIP) to support Ontario's new Broadband and Infrastructure Expansion Act, 2021 have not been added to this DSP as the designated communications partner for the area (i.e., Rogers) is still assessing the project and has yet to respond to our inquiries.

Property Developers

The main goal of consultations with developer groups is to share information and coordinate long-term planning such that the needs of all parties can be considered when planning for resources. Consultations occur on a project-by-project basis. Although detailed information about upcoming projects is not typically available five years in advance, these consultations do provide an estimate of the volume of anticipated projects involving new customer connections, subdivision developments, and expansions. Nevertheless, the predictability of these consultations is challenged by fluctuations in home sales, which are influenced by various economic, social, and market factors.

Other Coordination

WDI consults with its neighbouring utilities, such as Hydro One Distribution and EPCOR Electric Distribution Ontario Inc., on various matters such as joint use of poles, mutual assistance during severe weather incidents, etc.

WDI also actively seeks feedback from its employees regarding opportunities for enhancing operational efficiency.

Renewable Energy Generation (REG) WDI has not proposed any REG investments during the 5-year DSP period, and as such, no letter from the IESO is required.

5.2.3 Performance Measurement for Continuous Improvement

5.2.3.1 Metrics to Monitor DSP Performance

WDI's primary focus has been on ensuring consistent and high-quality service for its distribution customers while also facilitating growth. To assess the performance of its DSP, WDI regularly evaluates their performance based on established standards and values. These standards are aligned with key OEB-established performance outcomes.

Customer Focus: Satisfaction Survey

The Customer Focus objective is to ensure that the goals of the asset management plan and the plan itself is relevant and is delivering service and information to customers in the way in which they would like to receive it.

Measure	Target
Customer Survey response	Customer survey results +/- 5% previous year for: a) Customer Care b) Company Image c) Operational Efficiencies

Biennially, WDI undertakes customer satisfaction surveys to obtain feedback on the overall value of service offered to customers. Customers (residential and commercial) are engaged to provide high-level feedback on their perceptions of WDI performance and where they think WDI could improve service. WDI consistently meets or surpasses its objective of maintaining an Overall Customer Satisfaction Index score within a 5% variance from the results of the previous survey, as depicted in Figure 1 .

Figure 1 - Customer Satisfaction Survey Results

*Customer satisfaction surveys performed biennially

<u>Operational Effectiveness: System Reliability</u>

The Operational Effectiveness objective is to ensure the appropriate management of the system and assets to provide a sustainable and reliable service to our customers.

Measure	Target
SAIDI	1.35
SAIFI	0.94
Distribution Loss Factor	<5%

The Manager of Operations at WDI conducts a thorough review of service reliability issues, specifically trouble calls, as reported in field crew reports. Additionally, logs from the answering service are examined, covering after-hours calls managed by the staff responsible for providing call answering services outside of regular business hours. Meetings and discussions are regularly conducted to assess and address any exceptional issues that may arise.

OEB-defined baselines are used to compare rolling 5-year averages for System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) excluding loss of supply (LOS) and major event days (MED). For this DSP, it is assumed that OEB baselines will be derived from 2018 to 2022 reliability performance and will remain in place for most of the DSP period. The baselines are used as targets for reliability performance expectations in the current year. SAIDI and SAIFI are defined as:

$$\text{SAIDI} = \text{System Average Interruption Duration Index}$$
$$= \frac{\text{Total Customer Hours of Interruptions}}{\text{Total Customers Served}}$$

$$\text{SAIFI} = \text{System Average Interruption Frequency Index}$$
$$= \frac{\text{Total Customer Interruptions}}{\text{Total Customers Served}}$$

Based on the historical period of 2018 - 2022, WDI's SAIDI target for 2024 - 2028 is 1.35 customer-hours of interruptions, and WDI's SAIFI target is 0.94 customer interruptions.

These indices provide WDI with an annual measure of its service performance for internal benchmarking and comparisons with other distributors. WDI records and reports service quality and reliability figures to the OEB annually, in compliance with the OEB's Electricity Reporting & Record Keeping Requirements, section 2.1.4. All interruptions are categorized based on specific cause codes, following OEB reporting guidelines, to offer a deeper understanding of the nature of these interruptions. Table 5 presents a comprehensive list of these cause codes, each accompanied by a succinct description for clarity.

Table 5 - Interruption Cause Codes

Code	Cause of Interruption	
0	Unknown	Customer interruptions with no apparent cause.
1	Scheduled	Customer interruptions due to the disconnection at a selected time.
2	Loss of Supply	Customer interruptions due to problems associated with assets owned and/or operated by another party, and/or in the bulk electricity supply system. Determined by ownership demarcation.
3	Tree Contacts	Customer interruptions caused by faults resulting from tree contact with energized circuits.
4	Lightning	Customer interruptions due to lightning striking the distribution system.
5	Equipment Failure	Customer interruptions resulting from equipment failures due to deterioration from age, incorrect maintenance or imminent failures detected by maintenance.
6	Adverse Weather	Customer interruptions resulting from rain, ice storms, snow, winds, extreme temperatures, freezing rain, frost, or other extreme weather conditions. (Exclusive of Code 3 and Code 4)
7	Adverse Environment	Customer interruptions due to equipment being subject to abnormal environments, such as salt spray, industrial contamination, humidity, corrosion, vibration, fire, or flooding.
8	Human Element	Customer interruptions due to the interfacing of distribution staff with the distribution system.
9	Foreign Interference	Customer interruptions beyond the control of the distributor, such as those caused by animals, vehicles, dig-ins, vandalism, sabotage, and foreign objects.

Tracking outage performance by cause code provides information on specific outage causes that are reviewed and corrective action is taken to improve negative trending. As with the reliability indices, a historical performance range is used as a target. The results outside this range indicate positive or negative trending. Negative trending may indicate that WDI may be required to undertake specific actions to improve service reliability. A detailed account of historical reliability is captured in section 5.2.3.2.

Distribution System Losses are the difference between the total amount of electricity delivered into the distribution system (input) and the total amount of electricity delivered/consumed by the customers (output). The Distribution Loss Factor is calculated by the following equation:

Distribution Loss Factor = Total Distribution Losses ÷ Total kWh Purchased

WDI annually monitors system losses to assess system performance, ensuring that system losses do not surpass 5%. The historical data presented in Table 6 reveals WDI Distribution Loss Factors, averaging 4.61% over the past 5 years.

Table 6 - Distribution System Loss Factor

2018	2019	2020	2021	2022	Average
4.51%	4.70%	4.78%	4.55%	4.48%	4.61%

To monitor and improve its overall system's line losses WDI is planning on investing in SCADA devices during this DSP period.

Public Policy Responsiveness: Safety

The Public Policy Responsiveness objective is to ensure that the safety of the public, of workers remains the number one priority.

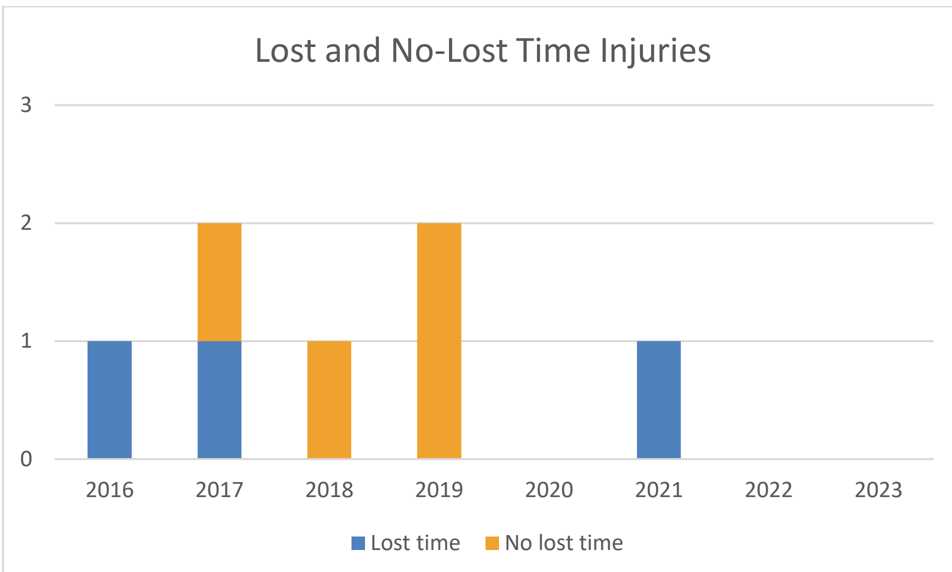
Measure	Target
Lost/no-lost time injuries	Zero
O. Reg. 22/04 non-compliance	Zero

A no-lost time claim occurs when a work-related injury necessitates healthcare but does not result in any additional time off work beyond the day of the accident. On the other hand, a lost time claim is initiated when a worker experiences a work-related injury or disease that leads to one or more of the following:

- Extended absence from work beyond the day of the accident
- Loss of wages or earnings.
- Permanent disability or impairment

The historical data displayed in Figure *2* illustrates WDI Lost and No-Loss Time claims with WISB from January 2016 to the current year-to-date.

Figure 2 - Lost and No-Lost Time Injuries



While WDI aimed for zero lost and no-lost time injuries, these cases serve as opportunities for WDI to reevaluate and strengthen its safety measures to prevent such incidents in the future. Each lost time injury underscores the importance of ongoing commitment to workplace safety and continuous improvement. It is worth noting that the historical data displayed in Figure 2 reveals WDI Lost and No-Loss Time claims with WISB from January 2016 to the current year-to-date, demonstrating a reduction in claims from 2020 onward.

As with every other Ontario distributor, WDI's design, construction, inspection, and maintenance practices are audited annually as required by O. Reg. 22/04. The utility can be deemed to be in one of three performance categories:

- In compliance
- Needs improvement
- Not in compliance

WDI's objective is to maintain compliance in all categories being audited. Over the past five years, WDI has consistently been assessed as in compliance with O. Reg. 22/04. This demonstrates WDI's commitment to adhering to the regulatory requirements outlined in the regulation.

Financial Performance: Financial Integrity

The Financial Performance objective is to ensure that the maintenance program and prioritized investments are scheduled and delivered on time to mitigate rate impacts while managing acceptable levels of risk.

Measure	Target
Investment Spending	Annual Capital +/-10%
Investment Scheduling	>80% annual Capital projects / programs completed on time

WDI will be monitoring its execution of the projects and programs included in the DSP. On an annual basis, WDI will calculate for that year, and on a cumulative basis for the five years of the DSP, its actual capital spending compared to the approved capital spending.

WDI’s target for this measure is that DSP actual spending is within 10% of the approved DSP capital budget. WDI has not submitted an application since 2016 so a comparison between the approved spending is not relevant. Its annual capital spending is far above the approved capital spend in 2016 largely due to load growth within the service territory and investments made into obsolete assets. A detailed account of historical actual versus planned capital expenditures is captured in section 5.4.1.2.

Performance Scorecard

The OEB Regulatory Framework for Electricity (RRFE) performance scorecard is reviewed annually to ensure performance aligns with the overall corporate business objectives and regulatory targets. Underperformance would result in measures being taken to realign with performance expectations.

Annual performance variances that are not within target ranges or meet minimal performance thresholds would result in an assessment to identify the underlying causes. This review could lead to adjustments in current or future strategies aimed at restoring performance to satisfactory levels.

The RRFE performance scorecard metrics indicate that WDI is effective in achieving RRFE performance outcomes as measures show historical performance is within target values. The OEB has ranked all Ontario LDCs in one of five efficiency groups (1 – 5) with Group 1 being deemed the most efficient and Group 5 being deemed the least efficient. WDI is currently ranked in Group 1 regarding Efficiency Assessment (stretch factor = 0.15%).

WDI's most recent Scorecard is provided in Appendix B.

5.2.3.2 Service Quality and Reliability

Figure 3 - Appendix 2-G

Appendix 2-G
Service Reliability and Quality Indicators

Service Reliability

Index	Excluding Loss of Supply and Major Event Days					Including Major Event Days, Excluding Loss of Supply					Including Loss of Supply, Excluding Major Event Days					Including Loss of Supply and Major Event Days				
	2018	2019	2020	2021	2022	2018	2019	2020	2021	2022	2018	2019	2020	2021	2022	2018	2019	2020	2021	2022
SAIDI	0.78	1.39	2.86	1.23	0.48	1.85	3.02	5.44	2.34	0.72	0.78	2.16	3.34	1.23	0.57	3.86	4.75	5.92	2.34	1.65
SAIFI	0.62	0.61	2.39	0.63	0.46	1.36	0.95	3.35	1.15	0.59	0.62	1.24	3.10	0.63	0.51	2.61	2.16	4.06	1.15	1.02

5 Year Historical Average

Index	Excluding Loss of Supply and Major Event Days	Including Major Event Days, Excluding Loss of Supply	Including Loss of Supply, Excluding Major Event Days	Including Loss of Supply and Major Event Days
SAIDI	1.348	2.674	1.616	3.703
SAIFI	0.943	1.481	1.220	2.201

SAIDI = System Average Interruption Duration Index
SAIFI = System Average Interruption Frequency Index

Service Quality

Indicator	OEB Minimum Standard	2018	2019	2020	2021	2022
Low Voltage Connections	90.0%	100.00%	100.00%	100.00%	100.00%	100.00%
High Voltage Connections	90.0%					
Telephone Accessibility	65.0%	99.99%	99.98%	99.97%	99.91%	99.83%
Appointments Met	90.0%	100.00%	100.00%	100.00%	100.00%	100.00%
Written Response to Enquires	80.0%	100.00%	100.00%	99.62%	99.15%	100.00%
Emergency Urban Response	80.0%	100.00%	100.00%	100.00%	100.00%	100.00%
Emergency Rural Response	80.0%					
Telephone Call Abandon Rate	10.0%					
Appointment Scheduling	90.0%	99.77%	99.81%	98.97%	100.00%	100.00%
Rescheduling a Missed Appointment	100.0%					
Reconnection Performance Standard	85.0%	100.00%	100.00%	100.00%	100.00%	100.00%

<u>Service Reliability</u>

Table 7 provides a detailed breakdown of outage counts by cause code for the five-year period from 2018 to 2022. These outages serve as a critical metric to assess service reliability. Concurrently, WDI conducts a systematic analysis of the causes behind these outages, seeking deeper insights to formulate strategies for improvement.

Table 7 - Number of Interruptions by Cause Code and Year

Code	2018	2019	2020	2021	2022
(0) Unknown/ Other	6	5	16	5	5
(1) Scheduled Outage	40	39	55	58	36
(2) Loss of Supply	2	3	3	0	4
(3) Tree Contact	14	12	18	20	21
(4) Lightning	0	0	3	0	0
(5) Defective Equipment	30	21	30	25	25
(6) Adverse Weather	16	18	7	22	16
(7) Adverse Environment	0	0	1	0	5
(8) Human Element	0	1	1	0	0
(9) Foreign Interference	8	8	11	15	8
(10) Major Events	2	2	1	1	1

Major events, defined as unforeseeable and uncontrollable incidents, are tracked using the IEEE Standard 1366 threshold. Since WDI's last Cost of Service filing, 11 major events have been recorded, as summarized in Table 8.

Table 8 - Major Events Experienced

Date	Cause(s)	Customers Interrupted	Customer Hours of Interruption	SAIDI/Day	T_{MED}
20-Jun-16	6	13128	8152.0	36.89	9.22
16-Aug-16	6	1802	9695.8	43.77	9.22
26-Dec-16	6	876	3285.0	14.73	9.22
17-Jan-17	6	13104	21281.0	95.42	11.95
4-May-18	2, 6	19329	31768.5	138.29	14.19
13-Nov-18	6	7977	10450.0	45.64	14.19
16-May-19	2	4727	4412.0	19.08	16.74
27-Sep-19	2, 9	4737	22900.0	98.71	16.74
23-Oct-20	6	13827	36872.0	157.17	27.33
11-Dec-21	5, 9	7587	16200.0	67.42	44.35
23-Dec-22	2, 3, 6	7587	15998.6	64.26	41.17

Customers Interrupted and Customer-Hours Interrupted are key indicators of outage extent and duration, respectively. Table 9 and Table 10 provide historical data on these metrics categorized by cause code and year.

Table 9 – Number of Customer Interruptions by Cause Code and Year

Code	2018	2019	2020	2021	2022
(0) Unknown/ Other	41	1361	1275	132	1421
(1) Scheduled Outage	554	605	454	483	292
(2) Loss of Supply	17080	16917	10073	0	6384
(3) Tree Contact	2494	2447	6510	2537	1783
(4) Lightning	0	0	3	0	0
(5) Defective Equipment	2177	818	13342	612	347
(6) Adverse Weather	11101	1919	23804	12111	3858
(7) Adverse Environment	0	0	1	0	21
(8) Human Element	0	14	6	0	0
(9) Foreign Interference	2348	6132	2321	819	971
(10) Major Events	27306	12962	13827	7587	7587

Table 10 - Customer-Hours of Interruptions by Cause Code and Year

Code	2018	2019	2020	2021	2022
(0) Unknown/ Other	79.90	1073.15	530.04	204.80	383.68
(1) Scheduled Outage	520.20	1721.55	689.77	278.10	325.37
(2) Loss of Supply	27545.00	24052.00	6820.35	0.00	13832.87
(3) Tree Contact	3089.10	3962.00	8149.73	3170.20	3469.30
(4) Lightning	0.00	0.00	157.65	0.00	0.00
(5) Defective Equipment	1470.40	809.10	17743.09	1702.90	571.37
(6) Adverse Weather	15890.00	8710.90	47291.57	26978.30	4525.57
(7) Adverse Environment	0.00	0.00	0.25	0.00	25.22
(8) Human Element	0.00	3.50	1.90	0.00	0.00
(9) Foreign Interference	4359.60	25998.40	2873.50	1599.20	1301.07
(10) Major Events	42219.00	36232.00	36872.00	16200.00	15998.55

WDI employs the SAIDI and SAIFI to measure reliability These metrics are evaluated under three scenarios:

1. By including all power interruptions.
2. By excluding interruptions due to Loss of Supply (LOS).
3. By excluding interruptions due to LOS and Major Event Days (MED).

WDI's reliability metric values for the historical period are listed in the Figure 3 - Appendix 2-G and illustrated in Figure 4 and Figure 5.

Figure 4 - System Average Interruption Frequency Index

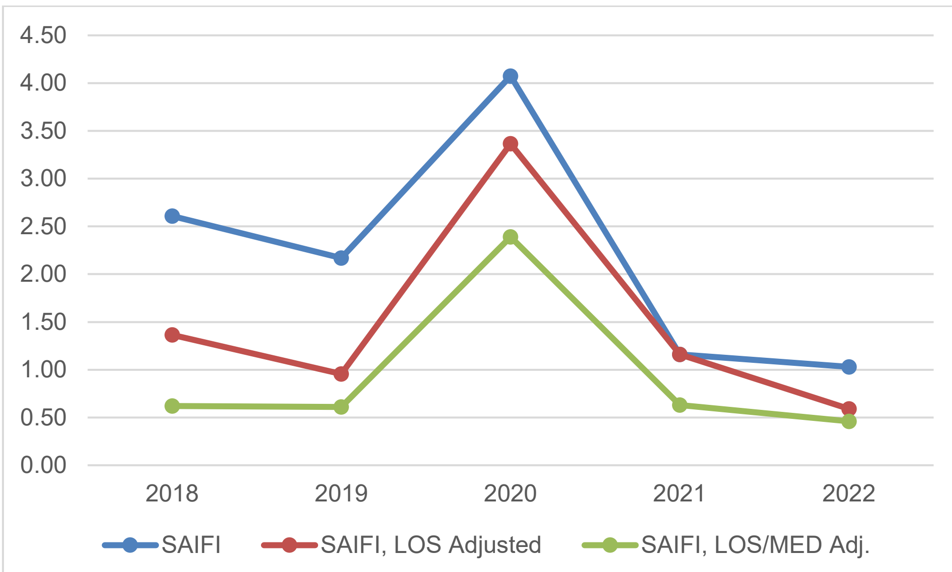
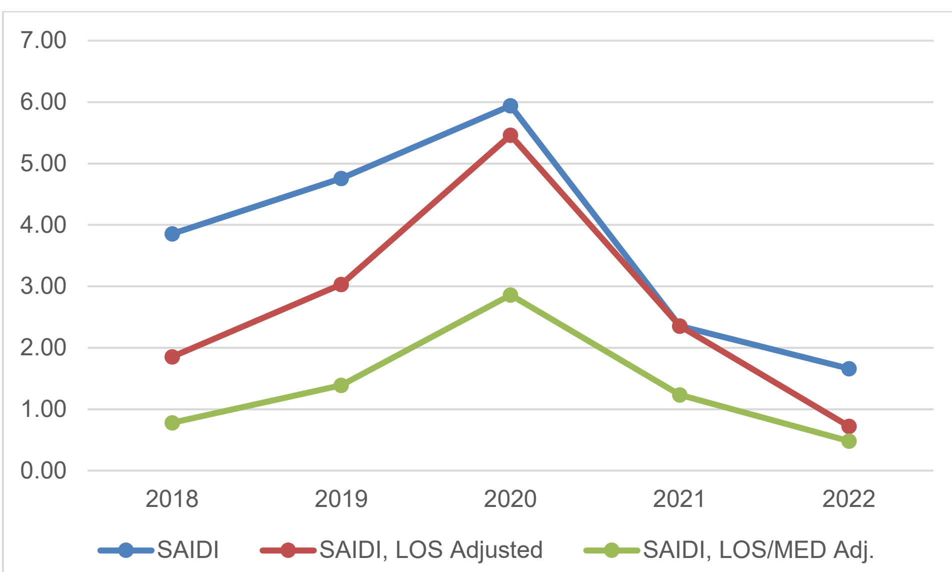


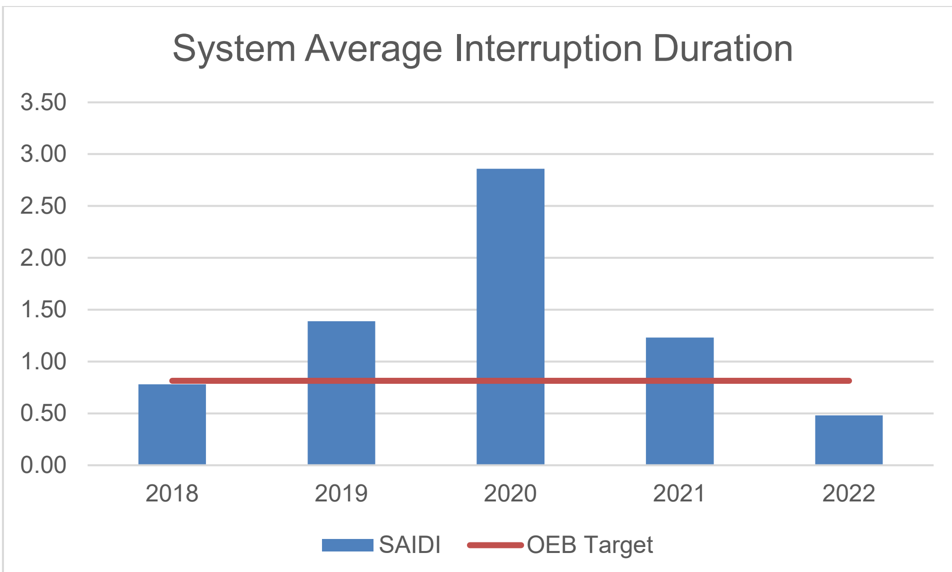
Figure 5 - System Average Interruption Duration Index



As previously mentioned, the OEB sets its SAIDI and SAIFI targets based on the utility's performance over the preceding five years. In the period spanning 2018 to 2022, WDI attained an average of 0.814 customer hours of interruptions and an average of 0.808 interruptions per customer.

Figure 6 illustrates the SAIDI performance for WDI, adjusted for LOS and MED, compared to the OEB target of 0.814 customer hours of interruption. Notably, in the years 2019, 2020, and 2021, WDI's SAIDI exceeded the OEB's prescribed threshold.

Figure 6 - Adjusted SAIDI Performance



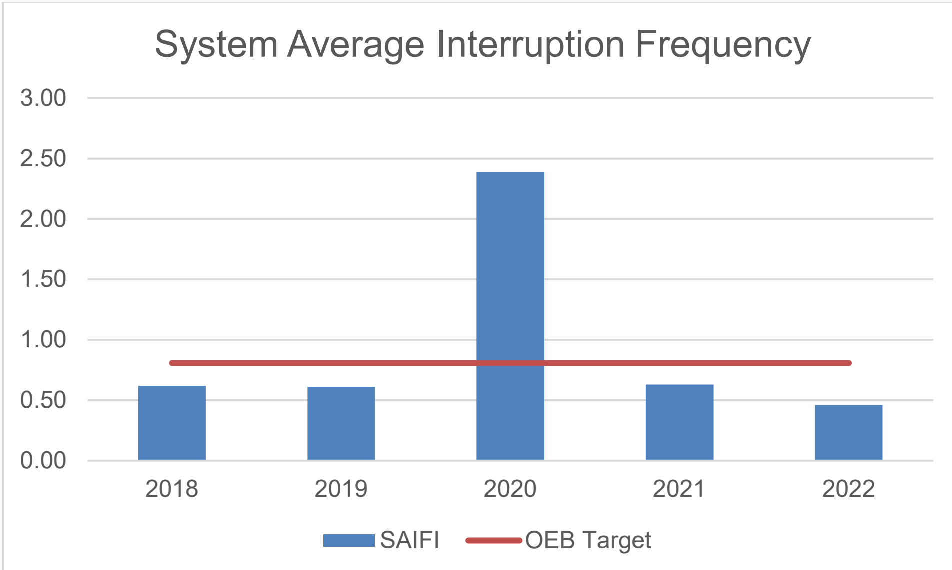
In 2019, WDI achieved an average of 1.39 customer hours of interruptions, which was predominantly due to Foreign Interference. A greater-than-usual number of vehicles were involved in collisions with hydro poles. To address this issue, WDI has implemented protective barriers in identified trouble spots.

In 2020, WDI achieved an average of 2.86 customer hours of interruptions. Due to the higher-than-normal number of storms that year, Adverse Weather was WDI's largest interruption cause.

In 2021, WDI's average customer hours of interruptions was 1.23. This was mainly due to underground burn-offs in newly built subdivisions.

Figure 7 shows the LOS and MED adjusted SAIFI for WDI, plotted against the OEB target of 0.808.

Figure 7 - Adjusted SAIFI Performance



In 2020, WDI customers experienced outages 2.39 times on average, which is above the target. As noted previously, the 2020 result was predominately due to adverse weather.

To combat the issues with equipment failure in adverse weather, WDI has adopted a proactive asset renewal plan for the coming years, which adheres to the latest industry standards, and has accelerated its vegetation management schedule within the service territory. The combination of these two approaches has already shown to be effective, as 2022 has the utility's lowest recorded SAIDI and SAIFI of the historic period.

The asset renewal plan implementation should also prove effective in dealing with vehicle collisions. Newer and stronger poles are more likely to survive an impact without an unplanned interruption.

Furthermore, WDI intends to deploy line sensors to locate faults due to adverse weather conditions and tree contacts more accurately. This will speed up the time it takes for trouble crews to locate and clear some faults. WDI uses the SAIDI and SAIFI reliability indexes to gauge the system reliability performance and maintain tight control over capital and maintenance spending. Several investments in the System Renewal and System Service category that are planned to replace obsolete assets and accommodate load growth will assist in maintaining system reliability.

These include planned renewal of obsolete assets such as poles, transformers, and conductors, as well as new substation construction.

Other initiatives that will reduce the number of controllable outages include:

- Testing of wood poles.
- Proactive vegetation management.
- Ongoing inspection and maintenance of assets to identify and mitigate potential problems.

With WDI being a fast-growing utility, it will continue to strive to provide reliable service to its 14,000+ customers while carefully managing its investment strategies for renewing its aging and deteriorating assets. WDI is also continuing to make investments in system reliability through smart devices such as fault indicators, control systems and outage response software, which will continue to help improve overall system reliability over the long term.

Service Quality

WDI monitors and documents compliance with the Service Quality Requirements (SQR) specified in Chapter 7 of the OEB's DSC. Service quality data is gathered monthly and submitted in an annual report to the OEB. As shown in Figure 3 - Appendix 2-G, WDI has exceeded the OEB minimum requirement for each indicator during the historical period and expects to continue meeting or exceeding these requirements. If a downward trend is observed in the SQRs, the best course for corrective action will be examined and implemented.

5.3 Asset Management Process

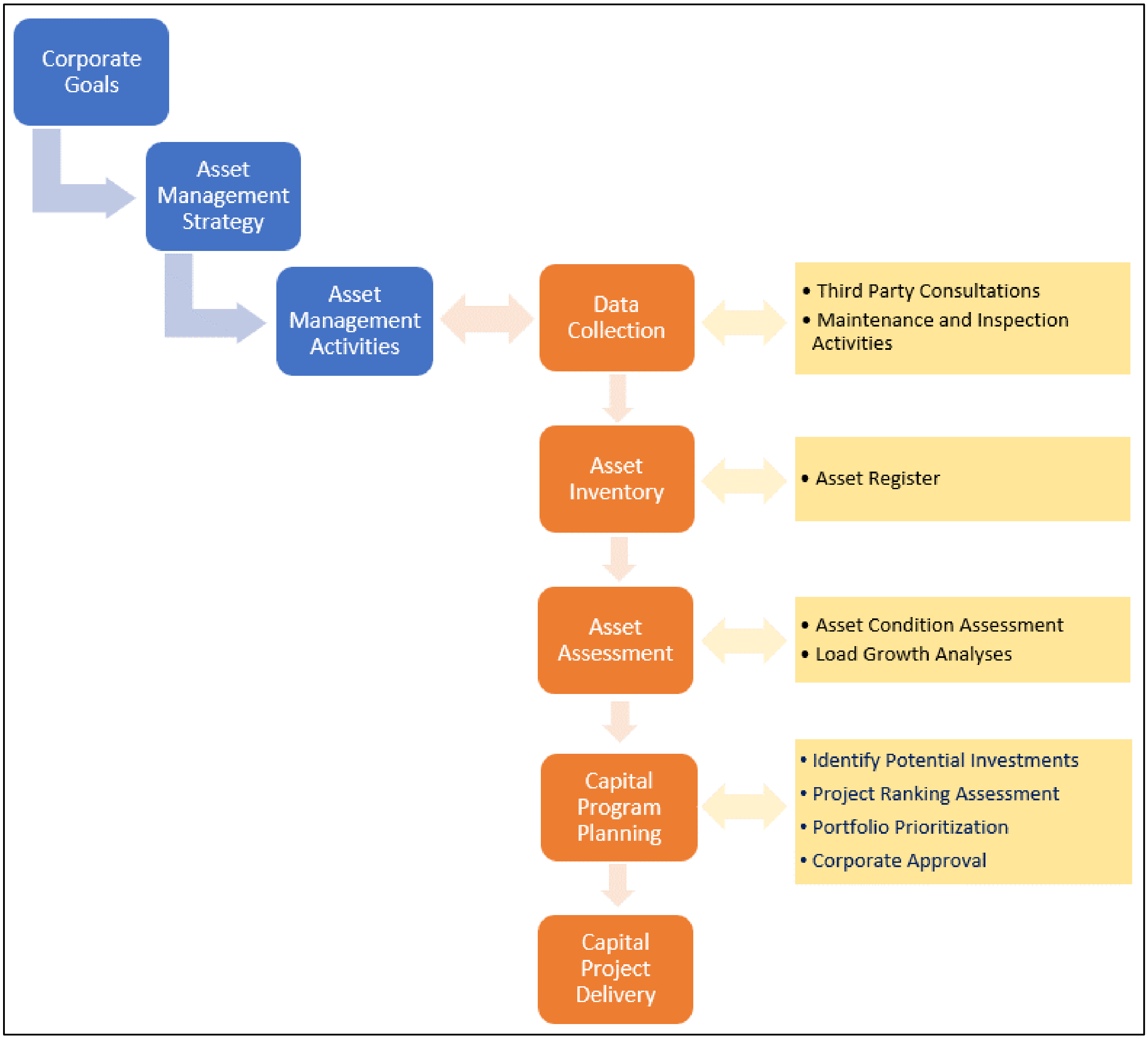
This section of the DSP provides a high-level overview of WDI's asset management process.

5.3.1 Asset Management Planning Process

WDI's Asset Management Plan serves as the cornerstone of the DSP and underpins all capital investments. The decision-making process centers on achieving a balance between asset performance, risk reduction and financial sustainability while adhering to electrical system design standards, accepted construction codes, customer preferences, and manufacturing specifications. Every asset owned by WDI is carefully managed throughout its entire lifecycle to maximize utilization and cost-effectiveness.

The Asset Management Planning Process consists of three main components, where one is comprised of multiple steps. These components are essentially the key stages or phases of the overall process, and the steps within each component represent the specific actions or tasks that need to be carried out to complete that phase effectively. In summary, the process can be broken down as illustrated in Figure 8:

Figure 8 - Asset Management Planning Process Overview



The Asset Management Planning Process consists of three main components. These three components are outlined as follows:

<u>Corporate Goals</u>

WDI regularly assesses its corporate goals to ensure alignment with current industry trends, compliance with regulatory directives, and responsiveness to customer needs. These corporate goals encompass:

- Long-term financial sustainability.
- Prudent spending through sound operational and financial practices.
- Ensuring Effective Risk Management.
- Nurturing and Enhancing Stakeholder Relationships.
- Embracing Digitization.

Asset Management Strategy

WDI's asset management strategy is built upon these key principles:

1. Safety: Ensuring asset safety for staff, contractors, and the public.
2. Reliability and Efficiency: Optimizing investments for high performance.
3. Customer-Centric Investments: Aligning with customer expectations.
4. Continuous Improvement: Adapting to evolving requirements and enhancing efficiency.
5. Regulatory Compliance: Meeting strict standards.
6. Financial Stability and Reliability: Balancing investments for stability and reliable service.
7. Environmental Considerations: Integrating environmental factors.
8. Capacity Management: Handling growth and utilization needs.
9. Technological Advancement: Utilizing technology for better performance and visibility.

Drawing from these principles, WDI has established four key Asset Management Objectives (AMOs), as outlined in Table 11, which readily align with the outcomes defined by the OEB.

Table 11 - Asset Management Objectives

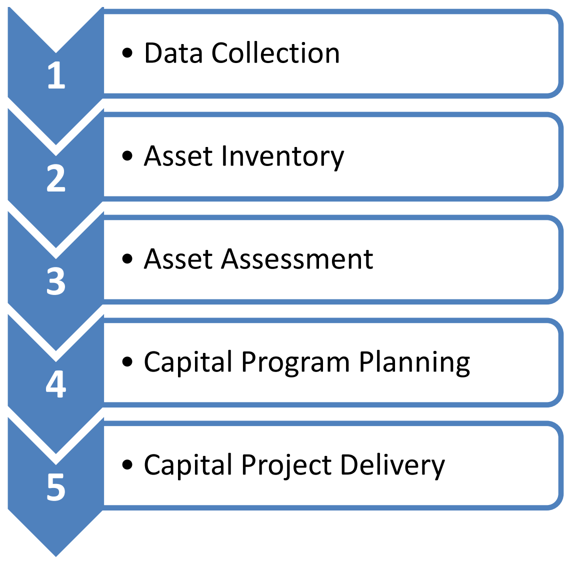
OEB Performance Outcomes	Asset Management Objectives	Asset Management Objective Descriptions
Public Policy Responsiveness	Safety	Prioritizing safety by ensuring assets are compliant with regulatory and industry standards to protect staff, contractors, and the public.
Operational Effectiveness	Reliability	Monitor and address asset condition issues in a timely manner to ensure the continued reliable supply of electricity delivery.
Customer Focus	Customer Service	Ensure that corporate performance and asset management plans are in sync with customer expectations regarding reliability, expansion, and electrification.
Financial Performance	Financial Integrity	Manage investment planning to mitigate rate impacts while maintaining corporate financial stability and long-term sustainable performance.

By adhering to these principles, WDI aims to meet the diverse needs of its stakeholders while ensuring a sustainable and reliable distribution system.

Asset Management Activities Cycle

WDI's asset management process is a systematic approach used to plan and optimize ongoing capital, operating and maintenance expenditures on the distribution system and general plant. The safeguarding of its assets in accordance with its asset management objectives is achieved through a five-step process shown in Figure 9 and detailed in the following sub-sections.

Figure 9 - Asset Management Activities Cycle



Changes Since the Last DSP Filing

A significant change from the previous DSP is the utilization of consultants for the Asset Condition Assessment and Load Growth Analysis. These two initiatives have produced action items that impact both forecasted 2024-2028 DSP investments and future considerations, significantly enhancing WDI's long-term planning efforts.

Furthermore, WDI experienced significant changes due to the COVID-19 pandemic and a leadership transition. These shifts had a lasting impact, leading to improved planning and adaptability. As Ontario emerged from pandemic restrictions, WDI swiftly adjusted to new consumer trends and supply chain challenges. At the same time, the change in leadership presented both challenges and opportunities, cultivating a renewed culture focused on growth and collaboration. This change in leadership also had a direct impact on the WDI's DSP. The new leadership's priorities and strategic vision influenced how the DSP was developed and executed. This meant that the plan was adjusted to align with the organization's evolving goals and objectives, ensuring that the distribution system remained adaptable, efficient, and aligned with the company's long-term strategy.

5.3.1.1 Data Collection

The first step in the asset management activities cycle is data gathering, which plays a pivotal role in maintaining a robust distribution system and facilitating growth. Data collection is executed through various methods, including:

a) Conducting Routine Maintenance and Inspection Activities: This involves tasks like pole testing and infrared inspection. WDI consistently adheres to the requirements of O. Reg. 22/04 for asset inspection and continually looks for ways to improve asset inspection procedures.
b) Consulting with Developers, the Municipality, and Other Entities on Growth Plans: As detailed in section 5.2.2, WDI actively engages in discussions with developers, the municipality, and other relevant entities to align asset management efforts with anticipated growth plans.
c) Gathering feedback, opinions, and suggestions from various stakeholders. These stakeholders can include customers, employees, suppliers, community members, and others who have an interest in or are affected by the organization's activities.

In addition to gathering distribution system-specific data, WDI also collects comprehensive information pertaining to the current operations, processes, and performance relating to the General Plant. This holistic approach to data collection allows WDI to gain a thorough understanding of the entire operational landscape, facilitating informed decision-making and continuous improvement efforts across the organization.

5.3.1.2 Asset Inventory

The second element is the inventory of the asset data collected. WDI's asset register is not a unified source of information, as it comprises both digital and paper records that are stored in distinct locations with specific owners. The four key components that comprise the Asset Register are the GIS, the Microsoft Great Plains financial management system, the Customer Information System (CIS) and Operations Records databases/files.

The GIS serves as the primary component of the asset register, containing attribute information (location, age, size, etc.) for all non-General Plant assets. Asset data is input from a multitude of sources including, but not limited to construction as-built records, legacy records, annual testing, inspection and maintenance program results, trouble calls, fault information, etc. Cyclically, all assets are visited through planned inspections or maintenance and the asset data is verified, corrected, or updated. WDI's GIS is constantly evolving, aiming to integrate additional asset information by transferring or linking asset inspection and maintenance data from Operations' paper files and individual electronic databases.

General Plant assets (other than land and buildings) are non-geospatial assets and are managed separately through the Microsoft Great Plains financial management system.

Table 12 - Asset Register

Asset Register			
Asset register component	**Owner/Location**	**Asset information**	**Information media**
GIS	Operations	Asset location (GPS coordinates) Attributes (voltage, size, age, conductor length) Other comments of significance	digital database composed of multiple map layers of assets
Microsoft Great Plains Financial Management System	Accounting/Regulatory	- Asset value - Purchase, job, and construction history Asset useful life studies Contributed capital	digital database
Harris NorthStar CIS	Customer Service (third-party)	- Meter information (physical attributes, consumption, etc.)	digital database
Operations Records	Operations	Outage history -SAIFI, SAIDI stats database, trouble reports	digital and paper files
	Operations	Maintenance Records -transformers, switchgear, poles, stations, meters	digital and paper files
	Operations	Inspection Records - transformers, switchgear, poles, Infrared, stations	digital and paper files
	Operations	Asset utilization records -station, feeder loading	digital and paper files

5.3.1.3 Asset Assessment

The third element is the asset assessment. Asset assessment involves a thorough examination of the asset register and the information gathered during consultations to identify recommendations for potential projects. This process leverages both the formal documentation of assets in the register and insights gained from discussions and input obtained during consultations to pinpoint opportunities for improvement and strategic projects.

In 2022, WDI engaged Kinectrics Inc. to perform a condition assessment of its key distribution assets currently in service. This assessment encompassed the evaluation of thirteen (13) sub-categories within nine (9) asset categories, resulting in the creation of an asset health index and a condition-based Flagged-for-action plan for each asset category. The health index gauges the state of WDI’s equipment by scrutinizing various condition parameters linked to the factors that may eventually lead to an asset's retirement. This aspect is critical to the asset management process since it guarantees a thorough and effective evaluation of the assets before project development, risk analysis, and project prioritization.

The 2021 Asset Condition Assessment (ACA) Report can be found in Appendix C.

The ACA also identified data gaps in asset data and WDI will continue to add more condition-based data to its Asset Register in the coming years. Assets such as distribution pole mount and pad mount transformers, underground cables, and overhead switches would benefit from an optimal condition assessment as they degrade in the years to come due to electrification loading from sources such as electric vehicles.

To assess growth and system capacity, WDI has engaged Essex Energy to undertake a comprehensive Load Growth Analysis. This analysis delves into the implications of various factors, including commercial and residential growth, municipally proposed intensification nodes, and the adoption of electrification on WDI's existing distribution system.

The resulting report not only presents a detailed analysis of these influences but also offers valuable Distribution System Electrification Readiness Recommendations. These recommendations are designed to effectively mitigate the impacts identified, thereby ensuring the continued reliability and efficiency of the electricity distribution system. Notably, these recommendations include considerations for System Service investments, such as the construction of a new municipal station, reflecting a strategic approach to enhancing the overall infrastructure and preparedness for load growth through expansions and electrification.

It is important to note that the primary purpose of this report is to inform our internal planning and decision-making processes. However, the insights and recommendations provided will play a crucial role in guiding our future strategies and investments, ensuring that WDI can continue to meet the evolving needs of its stakeholders and provide sustainable and high-quality services.

Load Growth Analysis Report is attached as Appendix D.

The assessment of stakeholder input guides enhancements in areas such as the corporate website, information technology components, and building/work yard improvements.

5.3.1.4 Capital Program Planning

The fourth element is the development of the capital program. This is done annually as part of the budget process. WDI submits its 5-year capital plan associated with a rate application. This element has four (4) steps.

Step 1 – Identifying Potential Investments

WDI relies on external and internal sources of investment drivers to identify potential investment needs across the organization. The three (3) tasks of investment identification are the following:

1. Identify investment needs based on relevant drivers:
   Determine the external and internal drivers and the mutually contributing influences.
   (a) External drivers: These sources are generally beyond WDI's management and control, resulting in investments for service obligations, including road authority projects, provincial agency projects, customer connections, environmental obligations, regional planning requirements, regulatory compliance or compliance with safety codes and standards.
   (b) Internal drivers: These sources are generally under WDI's management and control, resulting in investments to deliver corporate objectives, including asset condition assessment, poor performing feeders, service quality indicators, operational requirements, employee and public safety, reliability performance and capacity constraint relief. In essence, WDI is reviewing the performance of the distribution system and ensuring that the objectives and customer requirements are achieved.
   (c) Mutual contributing influences: These sources are a combination of external and internal factors and result in investments that are typically customer-focused, including REG connections, customer engagement and customer survey responses.
2. Categorize investment needs: Pursuant to Chapter Five of the Filing Requirements for Electricity Distribution Rate Applications, investments are grouped and placed specifically into the four investment categories as described in Table 1.

   Based on the identified drivers, WDI develops business cases for potential capital projects and evaluates all projects in a consistent manner. This ensures that capital investment needs across the entire service area are afforded equal opportunity to be assessed for selection and funding within the capital portfolio.

3. Identify solutions and determine available technical alternatives: To develop investment strategies in response to each investment need, WDI carefully examines various inputs and alternatives. This evaluation encompasses not only conventional infrastructure solutions but also explores non-traditional approaches like CDM (Customer Demand Management) and innovative technologies. This assessment considers the cost of each alternative, weighed against its anticipated potential for mitigating risks.

Step 2 - Project Ranking Assessment

This step of the Capital Program Planning cycle is critical and requires a structured approach to ensure optimal and efficient capital investment, supported by empirical evidence. Effective assessment is crucial when evaluating non-mandatory System Renewal, System Service, and General Plant projects; there are typically more projects than can be completed within a fiscal year due to limited resources and funding. To evaluate each project, WDI uses a two-step ranking assessment matrix.

The ranking assessment matrix does not include mandatory (System Access) or reactive replacements. These are mandatory projects and must be funded. In general, mandatory projects are defined as:

- New/modified customer service connections (System Access)
- Road authority required plant relocation projects (System Access)
- Mandated service obligations (System Access)
- Renewable energy projects (System Access)
- Emergency plant replacement (System Renewal - reactive)
- Safety-related projects (System Service

Potential projects and investments carry varying benefits and risks with respect to the AMOs. Consequently, it is imperative to establish the relative significance of each AMO in relation to each other. This determination aids in identifying the projects that should receive prioritization. Each objective has been assigned a relative weight, with the sum of these weights totalling 1.0.

Table 13 – Asset Management Objective Weighting Summary

Objective	Interpretation	Weight
Safety	Organizational efforts are made to ensure that worker and public safety are paramount in day-to-day activities.	0.35
Reliability	Reliability is a key priority amongst WDI staff and with WDI customers	0.30
Customer Service	WDI strives to ensure that customer expectations and priorities are considered during the capital planning process.	0.20
Financial Integrity	Managing corporate long-term financial stability and delivering economically reliable power to customers	0.15
Total		1.00

The ranking assessment procedure is integral to WDI's decision-making process for both immediate and future capital planning. It involves assigning values to projects, which are then multiplied by criticality multipliers. This multiplication process prioritizes projects with a more significant impact on a larger number of customers and assets. By applying these multipliers, project placement is adjusted to reflect the extent of their influence on customers and assets. The specific customer and asset multipliers can be found in the table below.

Table 14 - Criticality Multiplier Values

Criticality Multipliers		
# Customers	**Assets**	**Value**
Up to 15	Up to 100m of Primary Line	1.0
Up to 25	Up to 200m of Primary Line	1.1
Up to 30	Up to 350m of Primary Line	1.2
Up to 50	Up to 500m of Primary Line	1.5
More than 50	More than 500m of Primary Line	1.9

Step 3 – Portfolio Prioritization

Part of the project selection and prioritization process is preparing an estimate. An estimate, based on historical spending and current vendor estimates, allows WDI to determine the approximate resources needed to complete each project. These amounts are added to the ranking assessment matrix spreadsheet, and aid WDI in selecting and prioritizing the project portfolio.

Initial investment prioritization is based on the following criteria:

- The highest ranked project for the least cost (best ratio).
- If necessary, the highest rank values.
- If necessary, the lowest cost.

At his point, mandatory projects are included ensuring that essential requirements are met, and critical aspects of asset management are addressed within the plan. WDI's approach involves utilizing historical trending and municipal growth plans, alongside the Load Growth Analysis, to effectively manage non-mandatory work. Moving forward, WDI will maintain its long-term capital structure, striving for the optimal balance of 50% debt and 50% equity for new investments. In doing so, WDI may reevaluate asset prioritization to ensure the preservation of this capital structure over the long term. Furthermore, resource allocation and procurement will be adjusted as necessary to accommodate and support its growth initiatives.

The resultant portfolio is then reviewed to determine the total capital request compared to the available funding constraint. If the total capital request is below the available funding constraint, no further action is required. If the total capital request exceeds the available funding constraint, further ranking assessments are required to reduce, remove, or defer projects. Consequently, the entire portfolio is reviewed, and the draft portfolio is determined.

Step 4 – Corporate Approval

Each year, the WDI Board of Directors approves the capital investment projects that have been planned for execution. Once these projects receive Board approval, they are integrated into the annual work plans and their progress is tracked through project quarterly status updates, reviewed by the Audit and Finance Committee, and presented to the Board of Directors.

The objective is to align the annual budget as closely as possible with the financial expenditures. However, there is flexibility for projects to be rearranged or new projects to be introduced in response to changing conditions. This flexibility is maintained while adhering to the capital spend profile defined in the DSP. In the event of significant changes, an incremental capital model submission would be made to the OEB to ensure transparency and regulatory compliance.

5.3.1.5 Capital Project Delivery

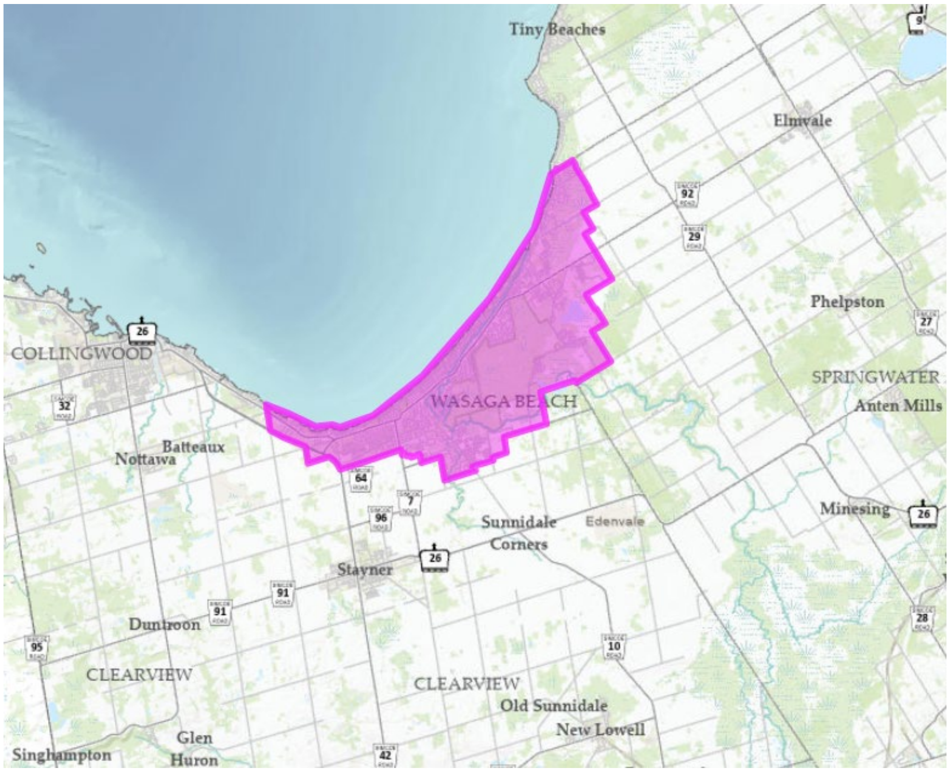
WDI's project management process is designed to ensure the streamlined and effective execution of capital projects, all while maintaining financial responsibility and adhering to project objectives. During the project execution phase, rigorous progress monitoring guarantees budget and schedule compliance, with regular reporting facilitating prompt corrective actions when needed. Upon project completion, a financial closure process is initiated, guided by accounting principles to ensure precise documentation of capital expenses.

5.3.2 Overview of Assets Managed

5.3.2.1 Description of the Distribution Service Area

WDI is nestled along the picturesque shores of Georgian Bay in the western region of Simcoe County. The distribution service area of WDI corresponds with the municipal boundaries of the Town of Wasaga Beach. WDI has the crucial responsibility of overseeing and maintaining distribution and infrastructure assets, as depicted in Figure 10, covering an expansive 61-square-kilometre area.

Figure 10 - Distribution Service Territory



Temperature and Weather

The WDI service area experiences four distinct seasons and significant temperature variations between seasons. Summers are warm to hot, often with high humidity, while winters are cold, and at times extremely so. During the summer season, severe weather in the area primarily takes the form of thunderstorms and windstorms. These weather events can pose a threat to overhead distribution plant, potentially causing damage. In contrast, winter severe weather conditions typically involve snow squalls, high winds, and occasional episodes of freezing rain. Snow squalls bring heavy localized snowfall and substantial accumulation. Strong winds worsen snow squalls and create hazards. Infrequent freezing rain events in winter lead to ice accumulation on surfaces, which can result in damage.

Service Area Density

The WDI service area contains mostly urban residential customers with a diverse local commercial sector. Key commercial sectors include:

- Retail Trade
- Accommodation and food services
- Health Care and Social Assistance
- Recreation

Wasaga Beach is shifting from a community based primarily on tourism to a more balanced and complete community.

Customer and Economic Growth

The Town of Wasaga Beach is nestled along the pristine shores of South Georgian Bay and is home to over 23,000 full-time residents. That population swells significantly in the summer months when cottagers and vacationers arrive. It is a prime tourist destination for summer recreational activities. Five commercial neighbourhoods support the town with a sixth emerging in the west end, as well as other shops and stores located throughout the community.

The Town of Wasaga Beach is one of the fastest-growing communities in Ontario with a 20% population growth between 2016-2021. As of December 31, 2022, WDI presently serves approximately 14,900 customers (not including streetlight connections). From 2018 to 2022 the average annual customer growth rate was 1.7% for WDI. The residential sector was the primary driver for customer growth. There are currently over 1,700 residential units in the final stages of municipal approval or under construction.

Table 15 - Customer Accounts and Average Growth by Class

Customer Class	# of Accounts	Annualized 5-year Growth
Residential	13,978	1.8%
GS<50	849	0.7%
GS >50	36	0.0%
Unmetered Scattered Load	45	4.4%

The economic development strategy in Wasaga Beach focuses on four (4) strategic themes:

- Continue to build a strong diversified economy through business retention, expansion, and attraction.
- Ready for business investment with a ‘business first’ attitude.
- Continue to unify Wasaga Beach to support the community's economic development, its brand, and its evolution.
- Building the community with continuity, consistency, communication, and collaboration.

The goal of the economic development strategy in Wasaga Beach is to establish a strong year-round economy and create an environment that encourages the retention of existing businesses and attracts new and diverse investments. The primary objectives are to boost local employment, attract working-age residents, and build a sustainable and well-rounded community.

5.3.2.2 System configuration

WDI is a registered Market Participant dealing directly with the IESO. WDI, the embedded distributor, receives its bulk power supply through 44 kV feeders originating from Stayner TS, which is owned by Hydro One, the host distributor. Consequently, WDI deals with both the IESO and Hydro One for the purchase of electricity which is passed through to its customers. As an embedded utility, WDI is billed monthly by Hydro One for Transmission and Low Voltage Charges.

WDI does not serve as a host distributor for any utilities within its service area, which is bordered by Hydro One Networks Inc. (HONI) and EPCOR Electric Distribution Ontario Inc.

WDI's wholesale electric supply comes from two (2) 44 kV sub-transmission feeders (M4: dedicated and M5: not dedicated) originating at Stayner TS. There are also two (2) shared 8.32 kV feeders (F1 and F2) originating from the HONI-owned Brocks Beach Distribution Station. These feed the westernmost section of Wasaga Beach. The 44 kV feeder system is owned and operated by HONI outside the Wasaga Beach municipal boundaries. WDI owns and operates the portions of the 44 kV feeders inside its service territory. There are four (4) IESO Registered Wholesale Metering points at the service area borders.

While there are some large users (>500 kVA service capacity) that take power directly from the 44 kV feeders through customer-owned substations, the vast majority of WDI customers are supplied via the 8.32 kV primary distribution network, which is comprised of 21 interconnected feeders emanating from six (6) WDI owned municipal stations (MS) as summarized in Table 16.

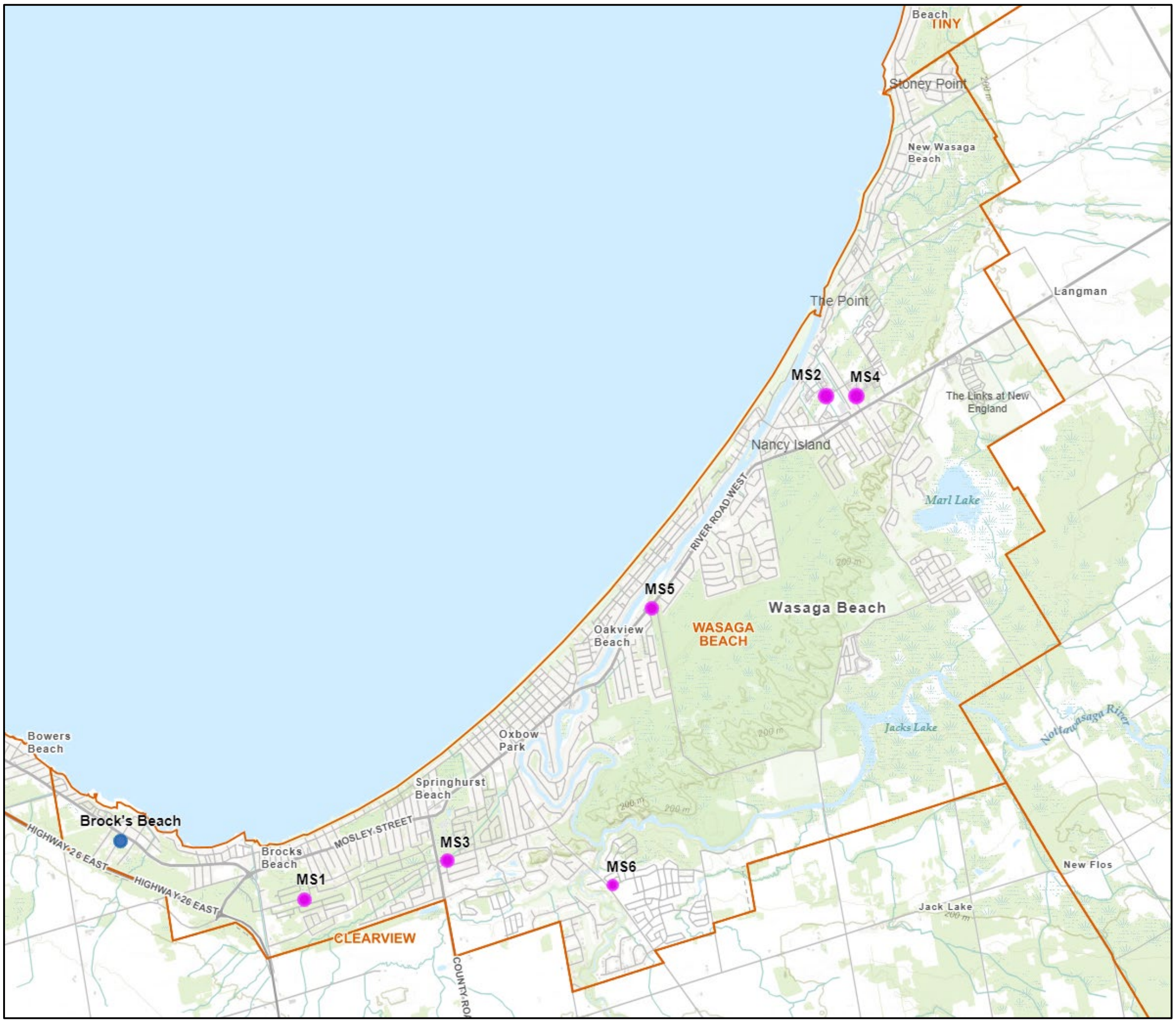
Table 16 - Municipal Station Summary

MS Name	Year	Details	Transformer Sizes	Feeders
MS1	2008	Primary 44 kV; Secondary 8.32 kV	7.5 MVA	3
MS2	2009	Primary 44 kV; Secondary 8.32 kV	5 MVA	2
MS3	1979	Primary 44 kV; Secondary 8.32 kV	10 MVA	4
MS4	1992/2009[1]	Primary 44 kV; Secondary 8.32 kV	10 MVA	4
MS5	1995	Primary 44 kV; Secondary 8.32 kV	10 MVA	4
MS6	2022	Primary 44 kV; Secondary 8.32 kV	10 MVA	4

Note 1: The station transformer was refurbished in 2009 after an internal fault was detected.

MS locations are shown in the Figure 11 below.

Figure 11 – Municipal Station Locations



WDI's distribution system is fully integrated whereby all stations are tied together (interconnected) through open points such that if one station is lost, all load from the lost station can be supplied by the remaining station(s). This network of 8.32 kV feeders is used to move the power to residential and small commercial neighbourhoods where it is again transformed down, through local overhead and pad mount transformation facilities to user utilization levels of 600/347 V, 120/208 V and 120/240 V. As of the end of 2022, the 8.32 kV and 44 kV circuits consisted of approximately 350 km of overhead conductors and 225 km of underground conductors. A significant amount of the underground 8.32 kV circuitry is single-phase distribution within residential subdivisions.

There are no submersible transformer installations, cable chambers, room vaults or other confined spaces in the distribution system.

WDI does not have any transmission or high voltage assets above 50 kV deemed previously by the OEB as distribution assets.

5.3.2.3 Information by Asset Type

Information regarding WDI's key assets by asset category, population, average age, and Health Index are shown in the table below:

Table 17 – Asset Health Index Results Summary

Asset category	Population	Average Health Index	Health Index Distribution					Average Age	Note
			Very Poor (<25%)	Poor (25 - <50%)	Fair (50 - <70%)	Good (70 - <85%)	Very Good (>=85%)		
MS Transformers	5	92%				1	4	22	1
MS Switchgear	19							19	1
OH Conductors (Primary+ 44 kV)	350.2	74%	34.8	48.8	30.2	55.2	181.2	39	1
OH Conductors (Secondary + Service)	121.5	64%	4.4	2.1	3.3	1.1	8.9	41	1
OH 44 kV Load Break Switches	7	100%					7	16	1
Pole Mounted Transformers (1-Ph)	757	66%	223	39	19	65	410	27	1
Pole Mounted Transformers (3-Ph)	24	46%	3	15		1	5	38	1
Wood Poles	5090	57%	573	1945	687	633	1248	40	1
Other Poles (Steel, Concrete, Composite)	79				79			N/A	2
Pad Mounted Transformers (1-Ph)	800	86%	5	18	132	105	540	20	1
Pad Mounted Transformers (3-Ph)	79	85%		10	3	14	50	21	1
Pad Mounted Switchgear	19	91%				3	16	13	1
UG Cables (Primary + 44 kV)	226.3	79%	12.2	40.4	20.5	12.2	141.0	20	1
UG Cables (Service)	481.0	96%	0.6	1.8	0.0	13.1	308.2	20	1

Note 1 - Asset Health Index Distribution based on the Asset Condition Assessment completed by Kinectrics in 2022.

Note 2 - Asset assumed in mid-life condition based on inspection/patrol exception reporting.

Health Indexing quantifies equipment conditions based on numerous parameters that are related to the degradation factors leading to an asset's end-of-service life. The Health Index is a measure of an asset's overall condition, usually expressed as a percentage, where 100% indicates a brand-new asset and 0% indicates an asset that has reached the end of its useful life.

Asset Information

Asset condition information varies with the criticality of the asset. Critical station equipment (i.e., MS Transformers) are inspected, tested, and maintained regularly and generally have more information such as age, loading, and oil test results. Tests would readily indicate if the Health Index of the equipment is overstated.

The poles older than 20 years undergo periodic testing, and the Resistograph method was employed from 2015 to 2018. This non-destructive test approach provided enhanced condition information. The Health Index is based on age and pole inspection status condition. A new round of pole testing has begun in 2023 and will conclude in 2025.

When assessing the Health Index for the Overhead Conductors asset category, considerations such as age, cumulative probability of survival at a given age, and conductor size were considered.

When evaluating the Health Index for the Underground Conductors asset category, factors such as age, the cumulative probability of survival at a given age, conductor sheathing, and installation information (such as direct burial or in duct) are considered.

The Health Index assessment for asset categories with insufficient condition data available is based simply on age and the cumulative likelihood of survival at a given age. These include:

- MS Switchgear
- 44 kV Load Break Switches
- Pole Mounted Transformers
- Pad Mounted Transformers
- Pad Mounted Switchgear

Meters, which are another asset group, are serviced and replaced in accordance with the regulations set forth by Measurement Canada.

The Flagged-for-action plan refers to a 10-year plan identifying how many units within each asset category require some action. In most cases the required action is replacement, however, for the assets replaced proactively other options are available, e.g., refurbishment, enhanced maintenance, operating solution, real-time monitoring, or even “do nothing”.

Table 18 - Summary of Flagged-for-action Assets

Asset Category	1st Year Action		10-Year Action in Total	
	Quantity	Percentage	Quantity	Percentage
MS Transformers	0	0.0%	0	0.0%
MS Switchgear	0	0.0%	0	0.0%
OH Conductors (Primary+ 44 kV)	12.4	3.5%	103.6	29.6%
OH Conductors (Secondary)	3.1	2.6%	25.8	21.2%
OH 44 kV load Break Switches	0	0.0%	0	0.0%
Pole Mounted Transformers (1-Ph)	35	4.6%	257	33.9%
Pole Mounted Transformers (3-Ph)	2	8.3%	11	45.8%
Wood Poles	143	2.8%	1192	23.4%
Pad Mounted Transformers (1-Ph)	17	2.1%	171	21.4%
Pad Mounted Transformers (3-Ph)	2	2.5%	20	25.3%
Pad Mounted Switchgear	0	0.0%	4	21.1%
UG Cables (Primary + 44 kV)	13.7	6.1%	87.4	38.6%
UG Cables (Secondary+ Service)	4.6	1.0%	85	17.7%

While the condition-based flagged-for-action plan is used as a guide for renewal investment, equipment inspection, test, and maintenance information are used to assess the remaining useful life for each individual asset. Inspection exception reporting would identify individual asset conditions that lead to end-of-service life determination and near-term actions to replace those units would be put in place.

In general, the determination of issues of immediate or future asset performance concern is enhanced by WDI staff expert knowledge and distribution system awareness. Detailed explanations of Asset Lifecycle Optimization practices can be found in section 5.3.3.

5.3.2.4 Assessment of Existing System Capacity

WDI is a summer-peaking utility, as the demand for electricity in its service area increases during the summer months due to hot and humid weather conditions, as well as the influx of tourists and the use of cottages in the area. In contrast, winters in the WDI service area are typically cold and consistent year-over-year, requiring electricity for space heating.

44 kV feeder capacity

WDI is embedded within HONI's 44 kV distribution system. Recent regional planning consultations have determined that there are no current loading constraints at the 44 kV feeder level.

Future growth load forecasts are regularly reviewed with HONI.

Station Utilization

Station capacity for planning purposes is based on 75% of the nameplate rating of the station transformers. Short-time fluctuations in demand load would not be expected to exceed the nameplate rating of the station transformer. When peak loading exceeds 75% of the transformer rating the excess amount would be permanently transferred to another station with available capacity whose peak loading after the transfer would be below 75% or if this is not possible, due to system constraints or other issues, new facilities would be planned to be constructed.

The 75% planning guideline allows MS to back each other up to various degrees to handle short-term system disturbances and maintenance needs. Limitations in feeder interconnectivity may result in some loading over a transformer's average rating for short periods. Fans installed on transformers enable a higher load capacity. Table 19 below summarizes station 2022 load data as it relates to ONAN, and ONAF ratings, where applicable.

Table 19 - Station Utilization Summary

MS Name	Transformer Nameplate Rating (MVA) (ONAN/ONAF)	2022 Avg Load (MVA)	Avg % Utilization (ONAN)	2022 Peak Load (MVA)	Peak % Utilization (ONAF)
MS1	7.5/10	2.899	38.7%	4.141	41.4%
MS2	5	1.711	34.2%	2.444	48.9%
MS3	10	5.377	53.8%	7.718	77.2%
MS4	10/13.3	6.994	69.9%	10.373	78.0%
MS5	10/13.3	6.962	69.6%	9.923	74.6%
MS6 [1]	10/12.5/15	0.0	0.0%	0.0	0.0%
Total	**52.5/61.6**	**23.943**	**45.6%**	**34.599**	**56.3%**

Note 1: MS6 was under construction in 2022 and will be put into service in 2023.

Loads exceeding planning guidelines will be reviewed through grid maximization studies once MS6 is operational in 2023. While MS6 implementation will result in a reduction in station utilization on MS3 and MS5, MS4 will remain unaffected by MS6's energization.

The existing peak loads and forecasted loads within the WDI service area highlight the imperative need for System Service investments, as detailed in Appendix D: Load Growth Analysis Report. These investments are critical for accommodating load growth resulting from expansion and electrification, improving system redundancy, and ensuring reliability.

WDI has a spare MS transformer (Primary 44 kV, Secondary 8.32 kV, 7.5 MVA) that can be used for emergency replacement of any of the WDI MS transformers that supply the 8.32 kV distribution system.

5.3.3 Asset Lifecycle Optimization Practices

WDI, like other local distribution companies, employs various processes to identify, document, and categorize asset performance and condition, crucial for its asset-intensive nature. This approach is vital for optimizing asset lifecycle.

WDI's goal is to enhance asset performance while adhering to safety, reliability, cost, and customer service standards. Assessing inputs helps determine whether assets need sustaining, renewal, or minor maintenance to remain operational.

WDI's asset lifecycle management involves gauging asset health through condition factors reflecting degradation, supported by annual inspections, tests, and maintenance. These observations, coupled with historical reliability and failure analysis, inform sustainment and renewal decisions. Results shape annual capital budgets and prioritize asset renewals based on the latest data.

WDI combines inspections, analysis, investment planning, business cases, and portfolio prioritization to deliver optimal value to both the company and its customers as illustrated in Figure 12.

Figure 12 - Asset Lifecycle Management

5.3.3.1 Asset Replacement Practices

WDI employs a mixed approach for asset replacement, combining planned and reactive practices. Asset replacement decisions are driven by several considerations, including asset failure history, deterioration-related failure risk, safety risks, functional and operational obsolescence, performance trends, alignment with standards, capacity needs, and external requests like roadway improvements.

WDI uses run-to-failure, proactive replacement, and equipment re-use approaches to best manage the renewal of the distribution system as described in Table 20.

Table 20- Asset Replacement Approach Summary

Renewal Approach	Description
Run to Failure	While every asset can potentially remain in service until it fails, this "run to failure" strategy isn't universally suitable or efficient. Repeatedly replacing failing assets with like-for-like replacements without upgrades can be ineffective. WDI might miss opportunities to enhance asset capabilities. Assets with minimal impact on safety, the environment, or customer service may operate until they fail, considering redundancy, contingencies, and spare components.
Proactive Replacements	Proactive replacement, which involves replacing assets before they fail, is suitable when the replacement contributes to public safety, environmental protection, operational effectiveness, and system reliability. This approach can involve clustered replacements or replacements at separate locations based on the specific asset type.
Equipment Re-Use	To optimize equipment value and minimize replacement costs, WDI has developed a procedure for the re-use of equipment returned from the field. The procedure complies with O. Reg. 22/04, section 6(1)(b) – Approval of Electrical Equipment and ensures that used equipment meets current standards and poses no undue hazard for re-use in new construction. Examples of equipment subject to potential reuse are distribution transformers, insulators, and insulator brackets. All equipment subject to reuse must meet certain minimum condition criteria and must be deemed safe to use by a competent person.

Renewal Practices by Asset Category

WDI's renewal practices that apply to each asset category are described in detail below.

1. Station Assets Replacement: The station infrastructure plays a pivotal role in transforming supply from the sub-transmission system to distribution voltage levels for WDI's distribution system. WDI has established a health index for their power transformers and engages specialized contractors to maintain their stations on a three-year cycle. This maintenance encompasses a comprehensive condition assessment and correction of any identified deficiencies.

During monthly inspections, any shortcomings are promptly addressed upon submission of the inspection report. Minor repairs are carried out as an integral part of the inspection process. Other matters, such as station security, appearance, perimeter fencing, building access, vegetation within the fenced area, and additional work, are scheduled based on urgency and contractor availability.

2. Distribution Transformers: WDI's approach to managing its distribution transformer fleet involves replacing transformers exhibiting deterioration (rated as poor or very poor) that could jeopardize public or employee safety. This includes situations where physical structures are corroded or damaged, the enclosure of energized components is compromised, or there's a risk of environmental contamination through oil leakage. This replacement policy applies to both proactive and run-to-failure scenarios. WDI has established an asset condition health index for all its distribution transformers.
    a) Overhead Transformer Replacement: For single-phase overhead transformers, WDI holds that both in-service failure and planned replacement would cause similar customer inconvenience. Consequently, WDI primarily employs a run-to-failure renewal strategy. Similarly, WDI extends this strategy to three-phase overhead transformer banks, even though these cater to larger commercial customers. In cases of individual transformer failure or damage within overhead three-phase banks, WDI typically replaces only the affected unit. This approach efficiently restores power while managing costs. We replace old transformers when rebuilding street segments.
    Additionally, overhead transformers are also replaced proactively where overload conditions call for a size upgrade or where the renewal of pole lines presents opportunities for efficiency, as the renewal of multiple assets simultaneously offers operational and financial benefits.
    b) Pad Mount Replacement: Pad mount transformers, being easily accessible to the public, hold the potential to pose significant health and safety threats if not properly maintained. To mitigate these risks, WDI conducts frequent inspections of these assets and has developed a health index condition assessment for all pad mounted transformers within its system. In line with its commitment to ensuring public safety and preventing in-service failures, WDI adopts a proactive replacement approach for these transformers.
3. Pole Replacement: WDI predominantly relies on wooden poles, which play a crucial role in their distribution system. Recognizing their customers' dependency on consistent electrical service and the direct link between service reliability and pole health, WDI opts for a proactive pole replacement program. To ensure the longevity of this pole infrastructure, WDI conducts regular tests and inspections, assessing the health index and overall condition of the poles.

Pole selection for replacement hinges on the level of deterioration. Key degradation indicators considered during inspection include remaining pole strength, top rot and feathering, and shell and ground line rot. Other defects like horizontal cracks, mechanical damage, or electrical burns are also noted. While asset condition assessments gauge deterioration, they don't fully account for operational concerns and pole criticality.

WDI's strategy involves replacing poles classified as very poor and poor, prioritizing those with the highest criticality. This determination factors in circuit type, configuration, location, attachments, and future projects. This approach is vital in maintaining the integrity of the pole infrastructure and safeguarding service reliability.

4. Underground Primary Cable Replacement: Although the failure of a single cable segment has minimal impact on reliability, a decrease in performance and multiple failures across the asset group would negatively affect local customer reliability. Within the distribution system, underground primary cables hold critical status. While these cables have infrequently failed in WDI's system, cable terminations undergo visual inspections on riser poles and transformers. In the absence of specific problems, WDI follows a run-to-failure approach.

   As failure frequency increases, WDI will take proactive replacement into account, integrating it into planned renewal projects. This approach underscores WDI's dedication to upholding reliable service while addressing potential future challenges.

   When cable replacement takes place, direct buried primary cable will be substituted with new primary cable installed in duct. This change is anticipated to yield improved reliability and an extended useful life.

5. Underground Secondary Cable Replacement: The failure of low-voltage secondary cable assets, particularly those that are direct buried, typically requires a great deal of effort and time to replace. However, they usually serve individual customers exclusively. Cable terminations and connections are inspected visually at riser poles, meter bases, and transformers. Given their very low reliability impact, the renewal strategy for secondary cables is run to failure.

6. Overhead Conductor Replacement: These are long-life items and failures are rare. Given this, the renewal strategy for overhead wires is run to failure. These will be replaced when they are deemed to be undersized, or unsafe to work on using approved live line techniques, such as various known restricted conductors. Whenever possible, WDI synchronizes overhead conductor replacements with pole replacement projects to minimize expenses and reduce disruptions for customers.

7. Reactive Replacements: There asset failures pose low risks to public and employee safety, have low environmental impacts, where there are spare parts available, where restoration duration and cost are low, there is low impact on system reliability and customer service, WDI generally relies on a reactive replacement strategy. An example of this is noted earlier with a run-to-failure asset such as single-phase overhead transformers.

   Reactive replacements also cover other distribution system asset failures, accidents, theft of equipment, vandalism, or an adverse weather event such as lightning. For all these events, emergency replacement is required to restore power to customers. Equally important are any assets that are identified during inspection or maintenance that require immediate replacement due to safety concerns or imminent failures. These items take precedence and require swift action. Sustained investments in reactive replacement projects uphold uninterrupted electricity supply for customers and ensure compliance with the regulatory requirements of WDI's distribution license.

<u>Impact of System Renewal on Maintenance</u>

WDI's system renewal investments aim to replace assets that are functionally obsolete, deteriorated, or approaching the end of their lifespan. These assets often demand increased inspections and maintenance to ensure their ongoing functionality until they are eventually replaced. If these assets are replaced at a rate that maintains the average condition of the equipment class, there would likely be minimal or no change to operations and maintenance (O&M) costs in scenarios with no growth. However, in scenarios with growth (more cumulative assets to maintain each year), there could still be upward pressure on O&M costs.

When replacement rates improve the average condition of the equipment class, certain maintenance activities' costs, such as pole testing and reactive repairs, could decrease. Overall, this is projected to lead to reduced O&M repair-related costs.

5.3.3.2 Asset Inspection and Maintenance Practices

Inspecting and maintaining the distribution system is crucial for minimizing risks, safeguarding reliability, and ensuring continuous customer service. WDI holds that routine inspection and maintenance lead to lower costs, fewer service disruptions, and decreased necessity for emergency spending.

WDI engages in inspection and maintenance activities for both the distribution system and station assets. These endeavours involve inspections, tests, and measurements to assess asset health. Preventive maintenance contributes to extending asset lifespan, while corrective maintenance might be carried out following inspections and tests.

WDI adheres to the criteria outlined in the DSC, O. Reg. 22/04, as well as the guidelines provided by the Electrical Safety Authority (ESA) in developing and implementing its asset inspection and maintenance practices.

The goal of asset inspection and maintenance is to maximize the asset's lifecycle, ensuring optimal performance and functionality until it reaches a condition that necessitates refurbishment or replacement. This approach helps WDI effectively manage its assets and make informed decisions regarding maintenance, refurbishment, or replacement based on their condition.

During inspection and testing, WDI records data based on a specified list of attributes recommended by manufacturers and for the requisite condition factors used to assess condition. Any defective items that are urgent in nature are reported immediately and timely corrective action is taken.

Overall, asset condition evaluation aims to ensure that:

- Safety: Ensuring that the assets remain safe for continued operation in proximity to the public and are suitable for competent and knowledgeable staff to work on, adhering to approved procedures.
- Performance: Verifying that the assets are operating within specifications, which includes:
  - Operating within the device's current and voltage capabilities.
  - Maintaining their functionality without any deterioration that could impair their normal operation.
  - Preserving the same level of security as when they were initially installed correctly.

Inspection activities include visual inspections and physical testing to provide data regarding the condition of assets in the field. The results are then compared against normal operating ranges to identify changes in asset performance and provide an indication of the life cycle degradation of the asset. If corrective maintenance is required, it includes the replacement of components that are found to be defective, inoperable, failing, or have already failed.

After the inspections are completed, deficiency reports are returned to engineering, processed, and converted into a database to document follow-up and ensure completion within a reasonable time.

In summary, the inspections allow for deficiencies and the general condition of system components and related equipment, including vegetation growth, to be documented with sufficient lead time and for subsequent analysis to support maintenance and capital planning.

The inspection and maintenance program is summarized in Table 21, with further details provided below.

Table 21 - Inspection and Maintenance Program Summary

Program	Field Asset	Practice	Schedule
MS			
	Station sites	Visual inspection	Monthly
	Station transformers	Oil tests	Biennially
	Station equipment (arrestors, breakers, relays, RTUs)	Maintenance and electrical testing	3-years cycle
	Station equipment	Infrared inspection	Biennially
Distribution Lines			
	44 kV Load break switch	Visual inspect. & maintenance	Every 3 years
	Poles	Resistograph test of wood poles >20 yrs. old	6-year cycle
		Visual inspection	3-years cycle
	Overhead system	Visual inspection	3-years cycle
		Infrared inspection	Biennially
		Vegetation Management	4-year cycle
	Underground system	Visual inspection	3-years cycle
		Corrosion Treatment	As needed
	Meters	Reverification	Measurement Canada specifications

MS Inspections and Maintenance

WDI's six substations are visually inspected monthly by WDI staff. These inspections comprehensively evaluate the overall station conditions, covering elements like fences, gates, locks, buildings, grounding, and all components. For power transformers, visual checks encompass the tank, cooling systems, gauges, and tap changers, aligned with utility best practices. Switchgear evaluations involve visual inspections, component measurements, and status checks. Any deficiency reports resulting from the monthly inspections are addressed when the report is submitted. Minor repairs such as light bulb replacements are completed as part of the inspection. Other aspects relating to the security and the appearance of the station, such as the perimeter fence, building access integrity, vegetation within the fenced enclosure and any other work, are scheduled based on urgency and crew availability. Major deficiencies prompt corrective actions based on risk assessment.

Oil tests are meticulously performed on station transformers to monitor their long-term health, allowing the identification of trends or patterns indicative of potential problems. The results are documented for continuous monitoring and trend analysis, which guide the initiation of action plans in response to anomalies.

Furthermore, specialized contractors will perform scheduled, comprehensive maintenance, as outlined in Table 22. This maintenance includes in-depth condition assessments and the correction of all identified deficiencies.

Table 22 - Municipal Station Maintenance Activities and Schedule

Task	Annual	3 Years	As Required
Transformer Cooling Stage Testing		X	X
Tap Changer Operation Testing Maintenance		X	X
Dissolved Gas Analysis	X		X
Oil Quality Analysis	X		X
Relay Communication and Timing Testing		X	X
Breaker Timing Testing		X	X
Breaker Contact Resistance Testing		X	X
Batteries and Charger Testing		X	X
Facility – Fence, Ground Resistance Testing		X	X

Distribution Lines Inspections

44 kV Load Break Switch Inspection	44 kV load break switches are visually inspected as per DSC requirements and when they are operated.
Resistograph Testing:	Wood poles testing assesses the integrity of the wood pole prior to a failure occurring and assists in avoiding the consequences of a failure. A non-destructive testing method is used to test poles and provides a remaining strength result, as a percentage. Remaining strength is a key metric used in the ACA health indexing process which further increases the data WDI has available for appropriately identifying and selecting pole candidates for immediate replacements or future overhead rebuilds and strategic pole replacements.
Visual Inspections	Visual inspections are used to identify potential safety and reliability problems, to plan mitigation actions to reduce the safety risk to the public and to assess the risk of asset failure. Visual inspections follow a prescribed format to capture key asset condition attributes.

	WDI inspects the distribution system by geographic zones, completing approximately one-third of its distribution system each year, as per the minimum requirements of the Distribution System Code (DSC). The visual patrol includes both the overhead and underground distribution systems. The visual inspection program is driven by OEB compliance requirements, ESA compliance requirements, utility best practices, and the need to maintain reliability, mitigate equipment failures, and reduce the risk to both public and employee safety. Generally, an overhead system visual patrol inspects the condition of overhead assets, including wood poles and their attachments, such as pole-mount distribution transformers, switches, and surrounding vegetation. Inspections address risk management by actively monitoring the condition of assets visually, to identify potential safety, failure, and reliability problems, to plan mitigation actions and to reduce the safety risk to the public. The underground distribution system is also inspected to assess the condition of underground assets including pad mount transformers and civil structures based on visual cues. The buried assets cannot be entirely inspected visually like the overhead assets. Nevertheless, all visible assets are carefully examined to determine their condition. Issues such as broken bushings, oil leaks, corrosion, and base condition (cracks or severe deterioration) are noted for replacement consideration.
Infrared Inspection	Thermal scans of the complete overhead system and all station equipment are taken to determine if there is any excess heating, which can be a sign of poor electrical connections, low oil, or unit overloading. Where hot spots are detected, work orders are created to further investigate and remedy the hot spot.

Distribution Lines Maintenance

General	When performing maintenance for a particular asset, WDI follows the applicable maintenance procedure recommended by manufacturers. The primary purpose for these types of diagnostic maintenance is to repair the asset to its operable state. Minor repairs are performed at the time of the inspection if it is feasible to do so. Defective assets that require major repair work, and cannot be completed initially, are identified and flagged so that they can be scheduled for replacement in the future. Any defective items that are urgent in nature are to be reported immediately so that timely corrective action can be implemented.
44 kV Load Break Switch	WDI deploys several three-phase gang-operated load break switches on its 44 kV distribution system network. These switches are critical to the overall performance of the distribution system and allow sections of line to be isolated to safely perform work activities or isolate both WDI and customer-owned substations. WDI maintains these switches on a three-year cycle or sooner based on inspections, recent operating issues or as part of planned customer shutdown. During scheduled switch maintenance, the switches are operated (i.e., exercised) to ensure their functionality. All components are cleaned, inspected, and oiled where required, and damaged and/or worn parts are replaced.
Corrosion Treatment	Corrosion treatment plays a vital role in preserving pad mount equipment, impacting functionality, safety, and cost-effectiveness. It safeguards optimal performance by prolonging equipment lifespan. Compliance with regulations increased resilience against environmental factors, and decreased maintenance costs further emphasize the importance of efficient corrosion treatment. In the end, this practice ensures both operational reliability and the aesthetic appeal of transformers.
Vegetation Management	Vegetation management, or tree trimming, is deemed a preventive maintenance program. WDI‘s overhead distribution areas have a relatively heavy mature tree canopy. Tree contact with energized lines can cause the following: • Interruption of power due to short circuit to ground or between phases. • Damage to conductors, hardware, and poles.

	• Danger to persons and property within the vicinity due to falling conductors, hardware, poles, and trees. • Danger of electric shock potential from electricity energizing vegetation. To mitigate direct contact between trees and distribution assets, WDI conducts tree trimming in accordance with industry best practices. Depending on the size, shape and growth pattern of each tree species, the tree trimmers remove sufficient material from the tree to limit the possibility of contact during high wind situations or limbs breaking due to excessive snow and ice loads. This work is primarily carried out by contractors. However, WDI employees are responsible for executing reactive and emergency vegetation management as well as tree clearing for capital projects as needed throughout the year. For several years, WDI has been scheduling its vegetation management in a five-year cycle rotation as referenced in the last DSP. WDI has opted to move into a four-year cycle for its vegetation management activities. The four-year forestry cycle will reduce off-cycle trimming requirements that manifest in several fast-growing species over a prolonged growth period. These off-cycle trims are often reactive in nature and prompted by customer concerns or power interruptions. They also add additional costs because they are reactive in nature and not part of an advanced schedule.

5.3.3.3 Risk Management

WDI recognizes that conducting thorough inspections of assets, evaluating their condition, and gathering comprehensive data is crucial for obtaining a clear understanding of each distribution asset's current stage in its lifecycle and the replacement needs of that asset. These mitigating strategies enable informed and cost-effective decision-making and support the corporation's objectives for managing risks. The information obtained from these inspections complements the data received through maintenance programs, enhancing the ability to assess asset risk accurately. By combining inspections, condition assessments, maintenance programs and growth plans, WDI aims to optimize its asset management strategies.

Asset performance during an investment cycle is collected and utilized in the next investment planning period. mandatory investments are automatically included in the investment plan. Non-mandatory asset investment is valued and scored. The project ranking assessment considers the implicit risk of not investing in the upcoming investment cycle. For example, critical asset investments such as station transformers and 44 kV plant will score relatively high on benefit compared to distribution transformer investments due to the higher widespread impact that a failure of a critical asset has. This has also led to the development of proactive replacement strategies for higher risk high-cost critical assets (i.e., poles and conductors) and reactive replacement strategies for lower-risk low-cost assets (i.e., distribution transformers).

It is evident that in non-mandatory distribution asset replacement investments, there is a need for a long-term smoothed proactive investment program for poles and conductors. The programs are structured to remain within OEB rate mitigation guidelines and will result in an increasing amount of risk for those assets nearing end of life that await replacement towards the later years of the replacement program. In this sense, risk is balanced against the reality of unsustainable rate increases that would be needed to eliminate all asset risk in a short period. Assets with the lowest life remaining index in a particular category are addressed first. Other assets with higher remaining life are deferred to future periods. Individual asset priority position in the program will be managed as more asset information is obtained through ongoing annual inspection and testing to optimize replacement risk decisions.

In consideration of WDI's Asset Management Objectives and the other drivers of capital planning, it has been determined that multi-year renewal programs for poles with "very poor" and "poor" condition will best balance risk, value, and rate impact. Priority areas are where restricted conductors are also present to capitalize on synergies. By focusing on these specific locations, we can maximize the benefits of achieving multiple goals simultaneously. This approach allows us to optimize efficiency and effectiveness in these areas, leading to improved overall performance and outcomes.

Table 23 - Key Renewal Programs

Asset	Quantity	Program length	Program Cost
Poles	2500 +	10+ years	$14 M+
Restricted Conductor	15,000 m +	5 years	$0.6 M+

The miscellaneous pole replacement programs and the pole line rebuild projects are planned to replace approximately 750 poles and all the restricted conductor segments during the 2024 - 2028 DSP period.

5.3.4 System Capability Assessment for Renewable Energy Generation and Distributed Energy Resources

Based on the current and expected future applications for the next five years, there are certain constraints that could hinder the connection of green energy generation projects within WDI's service area. These constraints will be evaluated on a case-by-case basis. Consequently, no additional capital investments are necessary for expanding capacity to accommodate the integration of renewable energy generation, beyond those planned for growth due to development and electrification.

During this DSP period, regulations from the OEB pertaining to net metering and the response of LDCs to distributed energy resources are anticipated to create conditions that will enable a greater number of connections for renewable generation. WDI is in the process of implementing a GIS upgrade and related system to monitor and evaluate the impacts of these connections on the distribution system.
As an embedded distributor within HONI's system, larger distributed generators and battery systems must adhere to HONI's interconnection requirements. WDI bears the responsibility of ensuring that these requirements are met.

5.3.4.1 Applications Over 10 kW

There are no current applications for renewable generators over 10 kW for connection in the WDI service territory.

HONI's 44 kV distribution system encompasses WDI's embedded distribution system. The decision regarding the capacity to connect >10 kW REGs to WDI's system lies with HONI. To establish a new connection, applicants must undergo a Connection Impact Assessment (CIA), and the approval of HONI is required before the connection can be authorized to proceed.

5.3.4.2 Capacity Available

WDI currently has six (6) renewable energy generators exceeding 10 kW, with a combined capacity of 1,009.2 kW. These generators are connected to feeders indicated with asterisks in Table 24. All these connections have undergone Connection Impact Assessments (CIAs) and received approval in collaboration with Hydro One. Additionally, there are 53 <10 kW projects, totalling 445.3 kW, currently connected to the WDI distribution system.

Under conservative assumptions, the allowable generation capacity at the feeder level is limited to a maximum of 7% of the feeder's peak load. Table 24 provides feeder-specific data related to available capacity.

Table 24 - Available REG Capacity by Feeder

Feeder	2022 Peak (kW)	7% of Peak (kW)	Connected REG (KW)	Available REG Capacity (kW)
1F1	2,692	188.4	1.0	187.4
1F2	1,215	85.1	0.0	85.1
1F3	916	64.1	17.4	46.7
2F1	2,091	146.4	10.0	136.4
2F2	462	32.3	0.0	32.3
3F1*	2,955	206.9	201.8	**5.1**
3F2	0			
3F3	3,380	236.6	10.0	226.6
3F4*	1,633	114.3	270.0	**-155.7**
4F1	3,607	252.5	20.0	232.5
4F2	3,318	232.3	18.6	213.7
4F3*	2,557	179.0	121.8	57.2
4F4	2,593	181.5	10.0	171.5
5F1	2,755	192.9	35.1	157.8
5F2*	3,571	250.0	153.7	96.3
5F3	2,372	166.0	39.8	126.2
5F4	1,321	92.5	17.7	74.8
6F1	0			
6F2	0			
6F3	0			
6F4	0			
Brock's Beach*	1,074	75.2	527.6	**-452.4**
Total			**1,454.5**	**1,241.3**

5.3.4.3 Constraints

The WDI system faces a few constraints regarding the connection of REGs:

- Feeder 3F1 is constrained because it has the combined total of connected REGs for both 3F1 and 3F2, as 3F2 is currently out of service. Once service is restored to 3F2, the constraint on 3F1 will be alleviated.
- Feeder 3F4 has a constraint due to the connection of a 250 kW Feed-in Tariff project. Any proposed REG connections in this area will necessitate a CIA to accurately determine if the connection can be accommodated.
- The constraint at Brock's Beach results from two Feed-in Tariff connections totalling 500 kW. Like Feeder 3F4, any proposed REG connections in this area will require a CIA to assess their feasibility accurately.

Given that WDI does not host any embedded distributors, there are no constraints or limitations for an embedded distributor that may arise as a result of connections of REGs within WDI's service territory.

5.3.5 CDM Activities to Address System Needs

WDI is currently not aware of any Conservation and Demand Management (CDM) initiatives that would significantly impact its planning process for the 2024-2028 investment period. However, WDI is committed to staying informed and will initiate investigations if new information about CDM initiatives arises. To ensure fairness among all customers, WDI will conduct a comprehensive cost/benefit analysis of these potential initiatives, assessing their effectiveness and impact on their capital investment program. The goal is to make decisions that prioritize the best interests of all customers and maximize the value of CDM.

5.4 Capital Expenditure Plan

WDI’s DSP outlines the program of system investment decisions that have been formulated using information obtained from WDI's asset management and capital expenditure planning processes. These investments, which can be identified either by category or specific project, are justified, in part or in whole, by referencing specific aspects of WDI's asset management and capital expenditure planning process.

The Capital Expenditure Plan section provides insight into WDI’s capital investments over seven historical years (2016-2022), forecasted 2023, and five forecast years (2024-2028).

WDI expects load and customer growth in line with development plans within its service territory. System Access investments will provide for new customer connections over the period of the 2024-2028 DSP.

Investments in System Renewal will guarantee the maintenance of customer service levels regarding reliability. The primary emphasis will be on replacing poles that have reached the end of their useful life. A total of 2518 poles have been identified as being in poor or very poor condition. Throughout the DSP period, we will implement aggressive replacement programs to address these poles. The objective is to allocate resources strategically, with the aim of building capacity for a shift in focus from pole line upgrades to underground replacements in the subsequent investment period. This strategic adjustment is prompted by the aging infrastructure, which may result in an increased frequency of in-service failures.

Storm hardening refers to a set of measures and strategies implemented to strengthen infrastructure and systems to better withstand the impact of severe weather events. Pole line rebuild projects (System Renewal) will result in higher strength poles and conductors compared to the original installation thereby implicitly hardening the line. From an operating perspective, WDI has enhanced its preventative maintenance practices around vegetation management to mitigate the impacts of severe wind and storm events.

Despite WDI's best efforts to maintain a reliable system, the service is still subject to unplanned outages from events like storms where trees fall onto power lines causing a faulted condition. Customer feedback during these outages has demonstrated a desire to resolve these outages quickly (resiliency), and to provide more timely information. To improve on this performance, WDI intends to invest in System Service improvements by incorporating smart devices like line sensors. These devices will expedite fault detection and customer restoration, potentially offering a more cost-effective and safer response. This approach should reduce the time spent in the field searching for faults.

WDI believes that its customers want to continue to participate in the opportunities surrounding distributed energy resources and electrification. To prepare for this grid evolution, WDI will implement grid technology solutions such as a digital model of its system that permits advanced analytics. This technology will be essential to maintain safety and reliability with the complexities introduced by EV charging behaviours and exported energy from batteries and solar generation. With System Service investments, WDI has developed a plan to continue to upgrade, modify and keep secure these grid technology solutions to maintain pace with the growing distributed energy resources.

WDI does anticipate some General Plant capital expenditures during this DSP period. These funds will be directed towards improving our operations by investing in property accessibility and functionality. This includes making enhancements to the layout, navigation, and overall efficiency of our facilities to make workflows smoother. These initiatives underscore our commitment to continuous improvement and ensuring that our facilities are designed to meet the evolving needs of our operations.

WDI actively participates in the Regional Planning process to identify any system capacity or operational constraint relief that can be achieved through cooperative planning and program execution with regional distributors and transmitters.

5.4.1 Capital Expenditure Summary

Table 25 – Appendix 2-AA and 2-AB

Appendix 2-AA
Capital Projects Table

Net Capital/Gross Capital

Projects	2016	2017	2018	2019	2020	2021	2022	2023 Bridge Year	2024 Test Year	2025	2026	2027	2028
Reporting Basis													
System Access													
Development	378,659	269,485	0	1,246,233	345,735	482,307	4,792,587	4,442,119	4,151,480	2,165,000	2,221,200	2,293,624	2,347,296
Metering	120,930	21,859	139,499	183,487	75,926	7,569	182,453	103,684	150,000	200,000	200,000	200,000	200,000
Municipal Project	0	14,139	0	157,283	666,015	1,620,412			400,000	400,000	700,000	800,000	500,000
New/Upgraded Customer Connections	230,120	259,335	316,204	232,815	235,955	316,315	289,594	422,008	195,000	300,000	300,000	300,000	300,000
Pole Line Expansion	220,389	370,722											
System Access Gross Expenditures	950,098	935,540	455,703	1,819,818	1,323,632	2,426,603	5,264,633	4,967,811	4,896,480	3,065,000	3,421,200	3,593,624	3,347,296
System Access Capital Contributions	379,761	377,288	82,259	1,043,525	397,247	1,217,156	4,020,314	3,978,894	3,855,508	2,235,250	2,433,020	2,544,580	2,440,202
Sub-Total	570,338	558,252	373,443	776,293	926,385	1,209,447	1,244,319	988,917	1,040,972	829,750	988,180	1,049,044	907,094
System Renewal													
Insulator Replacement	3,080	1,574											
Metering				50,120									
Miscellaneous Overhead Replacement	296,267	292,228	517,313	456,573	522,642	576,054	325,199	260,484	260,900	260,900	266,118	271,440	276,869
Miscellaneous Transformer Replacement	114,467	45,357	222,155	140,377	60,848	142,886	120,756	83,399	83,500	83,500	85,170	86,873	88,611
Miscellaneous Underground	15,585		38,240			34,869	34,174	100,592	100,000	100,000	102,000	104,040	106,121
Station Equipment		19,349											
Pole Line Rebuild								1,220,331	1,471,842	1,425,775	893,183	948,956	1,277,099
System Renewal Gross Expenditures	429,399	358,507	777,708	647,069	583,490	753,809	480,129	1,664,806	1,916,242	1,870,175	1,346,471	1,411,309	1,748,700
System Renewal Capital Contributions	207,398	38,466	53,219	3,187		43,649	7,000	25,000	130,450	130,450	133,059	135,720	138,435
Sub-Total	222,001	320,041	724,490	643,882	583,490	710,160	473,129	1,639,806	1,785,792	1,739,725	1,213,412	1,275,589	1,610,266
System Service													
Feeder/Station Redundancy					98,204			547,631	100,000		220,000		220,000
Load Break Switch						39,670							
Miscellaneous Underground				7,667									
Miscellaneous Undergrounding							30,384						
New Station							4,807,791				4,000,000		4,165,000
Scada Equipment	32,500												
Station Equipment							4,545		100,000				
Grid Technologies									300,000	230,000	230,000	230,000	230,000
System Service Gross Expenditures	32,500	0	0	7,667	98,204	39,670	4,842,720	547,631	500,000	230,000	4,450,000	230,000	4,615,000
System Service Capital Contributions	0	0	0	0	0	0	2,295,053	0	0	0	2,000,000	0	2,082,500
Sub-Total	32,500	0	0	7,667	98,204	39,670	2,547,667	547,631	500,000	230,000	2,450,000	230,000	2,532,500
General Plant													
Miscellaneous Building Upgrades	46,768	14,029	44,600	5,793	8,034			50,000	10,000	10,200	10,400	10,600	10,800
Miscellaneous Software Upgrades	15,000	13,460	9,360	3,177			21,541		15,000	15,300	15,600	15,600	15,600
Scada Equipment						13,300							
Miscellaneous General Plant										500	500	5,300	600
General Plant Gross Expenditures	61,768	27,489	53,960	8,970	8,034	13,300	21,541	50,000	25,000	26,000	26,500	31,500	27,000
General Plant Capital Contributions	0	0	0	0	0	0	0	0	0	0	0	0	0
Sub-Total	61,768	27,489	53,960	8,970	8,034	13,300	21,541	50,000	25,000	26,000	26,500	31,500	27,000
Miscellaneous													
Total	**886,606**	**905,782**	**1,151,893**	**1,436,812**	**1,616,113**	**1,972,577**	**4,286,657**	**3,226,354**	**3,351,764**	**2,825,475**	**4,678,092**	**2,586,133**	**5,076,860**

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

First year of Forecast Period:
2024

CATEGORY	Historical Period (previous plan[1] & actual)								
	2016			2017			2018		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var
	$		%	$		%	$		%
System Access	1,051,605	950,098	-9.7%	831,364	935,540	12.5%	670,951	455,703	-32.1%
System Renewal	650,000	429,399	-33.9%	743,600	358,507	-51.8%	903,432	777,708	-13.9%
System Service	10,000	32,500	225.0%	10,000	-	-100.0%	20,000	-	-100.0%
General Plant	30,000	61,768	105.9%	10,000	27,489	174.9%	10,000	53,960	439.6%
TOTAL EXPENDITURE	1,741,605	1,473,765	-15.4%	1,594,964	1,321,537	-17.1%	1,604,383	1,287,371	-19.8%
Capital Contributions	437,855	587,159	34.1%	368,164	415,754	12.9%	299,487	135,478	-54.8%
NET CAPITAL EXPENDITURES	1,303,750	886,606	-32.0%	1,226,800	905,782	-26.2%	1,304,896	1,151,893	-11.7%
System O&M	$ 872,192	$ 830,351	-4.8%	$ 898,358	$ 842,687	-6.2%	$ 925,308	$ 889,171	-3.9%

CATEGORY	Historical Period (previous plan[1] & actual)								
	2019			2020			2021		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var
	$		%	$		%	$		%
System Access	1,187,200	1,819,818	53.3%	1,110,006	1,323,632	19.2%	4,605,280	2,426,603	-47.3%
System Renewal	615,501	647,069	5.1%	627,811	583,490	-7.1%	1,758,833	753,809	-57.1%
System Service	10,000	7,667	-23.3%	10,000	98,204	882.0%	1,222,500	39,670	-96.8%
General Plant	-	8,970	--	-	8,034	--	45,000	13,300	-70.4%
TOTAL EXPENDITURE	1,812,700	2,483,524	37.0%	1,747,817	2,013,360	15.2%	7,631,613	3,233,382	-57.6%
Capital Contributions	671,506	1,046,712	55.9%	589,999	397,247	-32.7%	3,446,441	1,260,805	-63.4%
NET CAPITAL EXPENDITURES	1,141,194	1,436,812	25.9%	1,157,818	1,616,113	39.6%	4,185,172	1,972,577	-52.9%
System O&M	$ 953,068	$ 893,726	-6.2%	$ 981,660	$ 766,222	-21.9%	$ 822,296	$ 802,376	-2.4%

CATEGORY	Historical Period (previous plan[1] & actual)						Forecast Period (planned)				
	2022			2023			2024	2025	2026	2027	2028
	Plan	Actual	Var	Plan	Actual[2]	Var					
	$		%	$		%	$				
System Access	6,601,507	5,264,633	-20.3%	4,967,811	-	-100.0%	4,896,480	3,065,000	3,421,200	3,593,624	3,347,296
System Renewal	1,073,914	480,129	-55.3%	1,664,806	-	-100.0%	1,916,242	1,870,175	1,346,471	1,411,309	1,748,700
System Service	4,128,093	4,842,720	17.3%	547,631	-	-100.0%	500,000	230,000	4,450,000	230,000	4,615,000
General Plant	100,000	21,541	-78.5%	50,000	-	-100.0%	25,000	26,000	26,500	31,500	27,000
TOTAL EXPENDITURE	11,903,514	10,609,024	-10.9%	7,230,248	-	-100.0%	7,337,722	5,191,175	9,244,171	5,266,433	9,737,996
Capital Contributions	6,768,842	6,322,367	-6.6%	4,003,894	-	-100.0%	3,985,958	2,365,700	4,566,079	2,680,300	4,661,136
NET CAPITAL EXPENDITURES	5,134,672	4,286,657	-16.5%	3,226,354	-	-100.0%	3,351,764	2,825,475	4,678,092	2,586,133	5,076,860
System O&M	$ 868,886	$ 880,618	1.4%	$1,076,965	$ -	-100.0%					

There are no expenditures for non-distribution activities in WDI's budget.

5.4.1.1 Historical Plan vs Actual Capital Variance Explanation

Table 26 below provides WDI's historical capital expenditures. WDI has not incorporated any non-distribution activities in the 5-year capital expenditures for the 2016-2020 period.

Table 26- Historical DSP Planned Versus Actual Capital Expenditures

Category	2016-2020 DSP PLAN		
	Plan	Actual	Variance
System Access	2,299,114	3,204,711	39.4%
System Renewal	3,540,343	2,493,904	-29.6%
System Service	60,000	138,370	130.6%
General Plant	60,000	160,221	167.0%
Grand Total	**5,959,458**	**5,997,206**	**0.6%**

In the past, the DSP budget figures were presented after factoring out capital contributions. The same approach was maintained for the variance explanations to ensure clear and consistent comparisons between historical and actual figures. Additionally, certain projects were initially categorized incorrectly. To enhance clarity, WDI aligned them using the same classifications.

System Access:

WDI is obligated to connect new load and new renewable generation. WDI uses an economic evaluation methodology prescribed in the DSC to determine the level, if any, of capital contributions for each project. These contribution levels are then included in the annual capital budget. Investment schedules are typically coordinated to align with the needs of third parties.

WDI has a mandated service obligation to install metering equipment and grant access to poles for third-party attachments. Additionally, WDI is obligated to comply with the requirements of the Public Service Works on Highways Act. The Act outlines a specific formula for cost apportionment, enabling the road authority to contribute 50% of the cost of labour and labour-saving devices towards relocation costs. This cost apportionment formula has been applied to allocate costs for road authority projects that require the relocation of WDI's infrastructure.

WDI employs a practice of soliciting input from developers, road authorities, and third-party attachers during the formulation of capital plans and budgets. Home sales are subject to fluctuations due to various economic, social, and market factors. Additionally, municipal changes in leadership, policy priorities, or administrative procedures can significantly impact project timelines and scope. New leadership may bring different development visions, altering objectives and even prompting project re-evaluations. Changes in provincial financing mechanisms, including funding availability, allocation criteria, and budgeting procedures, can likewise empower or limit local projects. Reduced provincial funding may compel municipalities to seek alternatives or scale down projects, while increased support can fuel ambitious endeavours. These factors contribute to the variances observed.

The Sunnidale Pole Line Expansion project was initially planned to span two years. However, the workload in 2016 turned out to be lighter than expected, with most of the work concentrated in 2017. Except for this variation, the trend consistently demonstrates surpassing the anticipated budget for System Access over the entire historical duration, totalling an excess of 39.4% compared to the initial plan.

The overspending is a result of unexpected municipal projects and higher-than-anticipated mandatory spending. This situation has been exacerbated by the increased number of connections required, further contributing to the overall budget overrun.

Unplanned and deferred work initiated by external agencies often impacts the resources available for system renewal projects.

System Renewal

System renewal is a mix of non-mandatory (planned end-of-life replacement) and mandatory (emergency replacement) investments. Non-mandatory investments are identified in the spending plans, prioritized, and scheduled. The focus of projects falling under the system renewal category is the replacement of poles and distribution transformers, as well as their components that have been deemed obsolete.

The main driver of variance from plan to actual during this period was driven by carry-over projects from previous years that were not completed. WDI got behind on its renewal projects prior to 2020, driven by the large volume of work from customer-initiated, mandatory projects. This problem was perpetuated throughout the 2016-2020 DSP period.

Other notable variance triggers:

1. The system renewal plan did not contain contributed capital. Upon adding contributed capital to the overall expenditure, the variance for the historical period changes from -29.6% to -21.0%.
2. A municipal project that was delayed had an initial allocation of $100,000 for 2017 and $300,000 for 2018. When this project is reintroduced, it will be reclassified under the System Access category.

Due to budget overruns in other project categories, WDI encountered resource constraints. Consequently, the planned system renewal projects were sacrificed or deprioritized in favour of other project categories. In response to these challenges, WDI implemented new project management controls in 2021. Mechanisms were introduced with the aim of improving WDI’s capacity to effectively manage project costs and schedules. The introduction of these controls is part of an overarching improvement plan, with the specific goal of increasing the likelihood of successfully executing the system renewal projects within the 2024-2028 DSP period. This tactical move indicates WDI's commitment to achieving better cost management and scheduling, ensuring that the goals set for this period are met without falling victim to budget overruns.

System Service

In the last DSP, no "material" projects were reported in this category. Nevertheless, WDI did allocate a modest budget to provide some funding and invested in System Service projects as they emerged. System Service investments were non-mandatory investments made to ensure consistent service delivery and meet operational objectives.

The unplanned projects completed consist of:

1. Replacement of Analogue Equipment with Digital Equipment for Scada Tower and Communication: The upgrade involved substituting obsolete analog equipment with digital components at the recommendation of the service provider.
2. Beachfront Undergrounding: This project involved relocating backyard overhead construction from two areas along the beachfront to underground locations within the municipal right-of-way. The upgrade enhanced operational efficiency and removed overhead trespasses.
3. Express Cables for Feeder/Station Redundancy: Implemented to enhance system reliability, this project focused on the Villas of Upper Wasaga Express Cable installations to ensure redundancy for feeders and stations.
4. Load break Switch: This project involved the installation of a load break switch, contributing to the system's operational flexibility and security.

<u>General Plant</u>

During the last DSP, there were no "material" projects reported within this category. Nonetheless, WDI did set aside a small budget for funding. While certain projects initially intended to remain below the reporting threshold and eventually exceeded their allocated budgets, unplanned projects also emerged during operations. General plant expenditures covered a range of investments, including:

1. Office Lighting Retrofit: This project involved upgrading lighting from fluorescent to LED technology, enhancing energy efficiency and illumination quality.
2. Fencing: Investment in fencing to enhance security and define property boundaries.
3. GIS Upgrade and Maintenance: This project focused on upgrading and maintaining the GIS, a vital tool for mapping and managing the distribution network. The GIS has been moved to System Service for the 2024-2028 DSP.
4. Website Upgrade and Maintenance: Enhancements and ongoing maintenance of the company's website to improve user experience and information accessibility.
5. Office Security System: Implementation of a comprehensive security system to safeguard office premises and assets.
6. Outage Management System (OMS): Investment in an OMS to streamline outage detection, response, and communication, enhancing service reliability.
7. Building Renovations: This encompasses various enhancements, such as installing new windows, creating office partitions within the Engineering department, and modifying the parking lot layout. These renovations aim to improve functionality, aesthetics, and working conditions.

Post 2016-2020 DSP (years 2021 and 2022)

In both 2021 and 2022, the organization navigated through a series of significant shifts that left a lasting impact. As Ontario emerged from COVID-19 restrictions, WDI quickly adapted to new consumer behaviours and supply chain disruptions. Simultaneously, a change in leadership brought challenges and opportunities, fostering a renewed culture of growth and collaboration. During this period, WDI completed a thorough asset conditions assessment, which played a pivotal role in shaping the development of this DSP. Additionally, the application for OEB rate adjustments faced a three-year deferral, prompting WDI to reevaluate financial strategies for stability. These years represented a transformative phase, characterized by adaptability, resilience, and strategic advancement.

For the years 2021 and 2022, WDI's annual budgets are used to compare planned versus actual spending levels. These budgets encompassed not only the new expenses but also included Work in Progress (WIP) figures carried over into subsequent years. It's worth noting that the inclusion of WIP figures may result in inflated budgets, potentially affecting the accuracy of the comparison analysis. A large portion of the underspending in 2021 can be attributed to the construction of MS6 as evidenced by the $1.1 million WIP carried over into 2022.

Table 27 – 2021 and 2022 Historical Planned Versus Actual Capital Expenditures

Category	2021			2022		
	Plan	Actual	Variance	Plan	Actual	Variance
System Access	4,605,280	2,426,603	-47.3%	6,601,507	5,264,633	-20.3%
System Renewal	1,758,833	753,809	-57.1%	1,073,914	480,129	-55.3%
System Service	1,222,500	39,670	-96.8%	4,128,093	4,842,720	17.3%
General Plant	45,000	13,300	-70.4%	100,000	21,541	-78.5%
Total Expenditures	7,631,613	3,233,382	-57.6%	11,903,514	10,609,024	-10.9%
Capital Contributions	3,446,441	1,260,805	-63.4%	6,768,842	6,322,367	-6.6%
Work In Progress	85,000			1,100,000		
Net Capital Expenditures	4,100,172	1,972,577	-51.9%	4,034,672	4,286,657	6.2%

System Access – The projected figures represent updated plans that include items with unutilized funds from a specific year, which were then incorporated into the subsequent year's plan. This inclusion pertains to projects that extend across multiple years. Additionally, certain projects did not come to fruition as intended. One project initially slated for 2021 was rolled over into 2022 but unfortunately remains unrealized.

System Renewal – The design work for pole line rebuild projects scheduled for a particular year is conducted in the preceding year and is then accounted for as a carryover in WIP. Furthermore, certain municipal projects did not materialize according to plan.

System Service – MS6 construction began in 2021 and was carried over into 2022. Developers funded the beautification of MS6 at the entrance of the recently established residential subdivision, leading to increased levels of capital contributions for 2022. This category also included a pole line upgrade to facilitate a feeder-rated tie between MS3 and MS6 resulting in feeder redundancy, and increased load distribution capabilities.

General Plant – Investments in General Plant included upgrades to the corporate website, the internal computer network, and SCADA equipment. Scheduled building upgrades were deferred because of COVID-19 restrictions, which subsequently presented challenges in securing contractors for the projects.

5.4.1.2 Historical Actual vs Planned Capital Expenditures

WDI has opted to use historical actual expenditures that are from 2016 to 2020 (5 years) when comparing to planned spend from 2024 to 2028 (also a span of 5 years). This choice of comparing planned DSP periods not including the deferral years for both historical and forecasted data aims to allow for a more straightforward comparison of total spend values across all categories. Deferred years could introduce anomalies that make it challenging to draw clear conclusions about the company's spending behaviour and trends.

Table 28 - Historical Actual Versus Planned Capital Expenditures

Category	2016-2020 DSP Actual	2021-2023 Historical Actual and Forecast	2024-2028 DSP Forecast
System Access	5,484,791	12,659,048	18,323,600
System Renewal	2,796,174	2,798,152	8,292,897
System Service	138,370	5,530,612	10,025,000
General Plant	160,221	84,841	136,000
TOTAL EXPENDITURE	8,579,556	21,072,654	36,777,497
Capital Contributions	2,582,350	11,587,066	18,259,174
NET CAPITAL EXPENDITURES	5,997,206	9,485,588	18,518,323

WDI has observed significant increases in costs for essential materials and components (such as meters, conductors, and transformers), surpassing inflation rates. These price hikes are influenced by rising demand for key materials, often composed of copper and aluminum. These materials are also vital in electric vehicle components, leading WDI to anticipate sustained price pressures in the foreseeable future. This presumption is factored into the forecasted figures.

System Access: From 2016 to 2020, historical capital expenditures for System Access totalled $5,484,791. Looking ahead to the period from 2024 to 2028, the capital expenditure forecast for System Access is set at $18,668,600.

WDI based its System Access plan on historical actual data, but it's important to note that there are indications of economic uncertainty and a temporary growth slowdown expected in 2024, with a subsequent recovery in 2025 and 2026. In anticipation of increased demands, WDI is projecting a significant rise in gross expenditures. However, this increase will be counterbalanced by a corresponding increase in capital contributions.

The driving force behind this expenditure increase lies in the requirements imposed by external entities such as developers, road authorities, and various infrastructure projects occurring within WDI's service territory.

System Renewal: The historical capital expenditure from 2016 to 2020 for System Renewal was $2,796,174. The capital expenditure forecast from 2024 to 2028 for System Renewal is $8,292,897. WDI is continuing with a robust renewal program based on its asset condition assessments and asset replacement practices to ensure long-term financial sustainability. This program includes an accelerated renewal initiative designed to create capacity for future underground renewal requirements.

System Service: The historical capital expenditure from 2016 to 2020 for System Service was $138,370. The capital expenditure forecast from 2024 to 2028 for System Service is $10,025,000. WDI must increase annual expenditure in this category to modernize its GIS and implement other grid technologies. Additionally, two new municipal substations are proposed in the forecast to accommodate growth, electrification, and EV adoption. The first will be required and the second is a placeholder should it be required during the forecast period.
General Plant: The capital expenditure historical average from 2016 to 2020 for General Plant is $160,221. The capital expenditure forecast for 2024 to 2028 for General Plant is $136,000. Proposed investments in this category are to improve storage and work yard functionality. There are also expenditures required to meet ongoing demands such as the implementation of the "Green Button" initiative and other customer communication tools required to meet customer expectations.

5.4.1.3 Forecast Expenditures

A summary of the proposed investment levels for each of the investment categories can be found below in a copy of Table 3 - Capital Investment Summary 2024 – 2028.

Table 3 - Capital Investment Summary 2024 - 2028

Category	2024	2025	2026	2027	2028
System Access	4,896,480	3,065,000	3,421,200	3,593,624	3,347,296
System Renewal	1,916,242	1,870,175	1,346,471	1,411,310	1,748,699
System Service	500,000	230,000	4,450,000	230,000	4,615,000
General Plant	25,000	26,000	26,500	31,500	27,000
Total Expenditures	7,337,722	5,191,175	9,244,171	5,266,434	9,737,995
Contributed Capital	3,985,958	2,365,700	4,566,079	2,680,301	4,661,136
Net Capital Expenditures	3,351,764	2,825,475	4,678,092	2,586,133	5,076,859

During the 2024-2028 period, WDI has 3 key drivers of its capital investment:

1. Community Growth and Compliance: WDI is legally obligated to connect customers as per the Electricity Act, its Electricity Distribution License, and the DSC. This obligation includes system planning to accommodate anticipated growth in demand as the community develops.
2. System Renewal: WDI plans to proactively replace outdated infrastructure to fulfill its commitment to maintaining a safe and reliable electricity supply for its customers.
3. Technology and Operational Enhancements: Planned investments in System Service and General Plant technology are guided by operational and business requirements. These investments aim to establish a secure work environment, improve employee satisfaction and workspace conditions, optimize operational efficiencies and productivity, and ultimately enhance customer service and value.

The specific investment drivers for each category are described below:

System Access

Expenditures within the System Access category are driven by external requirements such as servicing new customer loads and relocating distribution assets to suit road or municipal authorities. The timing of investments in this category are driven by the needs of external parties and are considered mandatory. Investments in System Access are captured in the table below.

Table 29 - System Access Forecasted Expenditures

Project	2024	2025	2026	2027	2028
Development	4,151,480	2,165,000	2,221,200	2,293,624	2,347,296
Municipal Project	400,000	400,000	700,000	800,000	500,000
New/Upgraded Customer Connections	195,000	300,000	300,000	300,000	300,000
Metering	150,000	200,000	200,000	200,000	200,000
System Access	**4,896,480**	**3,065,000**	**3,421,200**	**3,593,624**	**3,347,296**

The System Access investment key drivers encompass:

a) Customer Growth and Expansion: The ongoing development of the Town of Wasaga Beach propels the need for new customer connections. This includes projects like site redevelopment, subdivisions, and establishing fresh connections to accommodate the evolving urban landscape.

The observed decrease in System Access investments after 2024 is largely because there are no commitments from developers on projects in the years 2025 to 2028. However, since the level of investment required under this investment category is largely dependent on third-party requests, the level of actual investments for System Access may slightly deviate year-to-year from the proposed investment levels, depending upon the number of stakeholder requests received for services.

Active developments can be followed through the municipal planning process by visiting the following link: Active Developments of Wasaga Beach.

b) Municipal Infrastructure Alignment: The execution of municipal projects often necessitates the relocation of our power infrastructure. This adaptive measure ensures our systems harmonize seamlessly with changing urban environments and development initiatives. To access municipal project timelines, please refer to the document titled "Capital Works Roads 2022.pdf" on the Wasaga Beach website at the following link: Capital Works Roads 2022.pdf

c) Regulatory Compliance and Infrastructure Modernization: Our commitment to regulatory standards is a driving force for meter-related activities. These include installation, reverifications, and replacements that adhere to the stringent regulations outlined by Measurement Canada. This drive aligns with our broader goal of modernizing our infrastructure and maintaining compliance with established norms.

In summary, forecasted growth in the Town of Wasaga Beach will continue to push the 2024-2028 System Access needs of new subdivision connections, connection upgrades due to site redevelopment, and plant relocation.

System Renewal

Expenditures within the System Renewal category are largely driven by the condition of distribution system assets and are driven by the overall reliability, safety, and sustainment of the distribution system. System renewal spending will focus on planned proactive pole line rebuilds. Specific high-performance risk areas will be prioritized during the 2024-2028 period at increased levels that manage the risk of equipment failure while mitigating rate impacts to customers. These areas have been informed by WDI's condition-based asset data and supported by the flagged-for-action plan in Kinectrics' Asset Condition Assessment Report. Investments in System Renewal are captured in Table 30 below.

Table 30 - System Renewal Forecasted Expenditures

Project	2024	2025	2026	2027	2028
Pole Line Rebuild	1,471,842	1,425,775	893,183	948,956	1,277,099
Miscellaneous Pole Replacement	260,900	260,900	266,118	271,440	276,869
Miscellaneous Transformer Replacement	83,500	83,500	85,170	86,873	88,611
Miscellaneous Underground	100,000	100,000	102,000	104,040	106,121
System Renewal	**1,916,242**	**1,870,175**	**1,346,471**	**1,411,310**	**1,748,699**

The ever-evolving energy landscape that includes widespread electrification, changing customer needs and a need to storm harden existing assets on the power grid calls for proactive investment across all grid components. System Renewal projects will concentrate on:

- High-Performance Risks: overhead line rebuilds. Historical investments were focused on scattered asset replacements. Forecast investments will target specific pole line segments requiring a complete rebuild (poles, conductors, transformers, etc.). This approach aims to harness the benefits of simultaneously replacing multiple obsolete assets, such as cost savings and operational efficiencies.
    - Pole Failure Risk: multiyear planned pole replacement programs that address obsolete assets. During the 2023 pole inspection and resistograph testing, a total of 1,325 poles underwent rigorous assessment. The results revealed noteworthy findings, including three poles requiring immediate attention due to emergency conditions. Additionally, 32 poles were found to have failed the inspection and 4 poles were flagged for retesting in 2025 to ensure their continued structural integrity and adherence to safety standards. These comprehensive evaluations and subsequent actions demonstrate a proactive approach toward maintaining a robust and reliable pole infrastructure.
    - Conductor Failure Risk: "Restricted Conductors" include No. 4 ACSR, No. 4 Special ACSR, and No. 6 Copper Conductors. These conductors are commonly associated with installations that are 60 years old or older. The age of these conductors in combination with over-tensioning, their small strand size used in long spans, and poorer quality in their original manufacture all seem to be contributing factors to the breakage of these Restricted Conductors. During the 2024-2028 DSP period, WDI will complete the removal of these conductors from service.

- Transformer Failure Risk: Distribution transformer life is affected by voltage surges (lightning, switching) current surges (from secondary cable faults), mechanical damage (vehicle contacts, corrosive salts) loading and ambient temperatures. Transformers subjected to these conditions face a heightened risk of experiencing catastrophic failure. To ensure the safety of workers and the public, and service reliability, transformer loading is continually monitored. Whenever necessary, corrective measures are promptly taken to address the situation.

- Emergency needs: emergency reactive replacement of distribution system assets (poles, transformers, switches, switchgear, cable, conductor, insulators, guys, anchors, etc.) due to unanticipated failure, storms, motor vehicle accidents, vandalism, etc.

System Renewal projects tend to be multi-year programs and are paced to balance the AMO needs of the program regarding available resources and managing the program impacts on the customers' bills.

System Service

Expenditures in the System Service category are driven by the need to ensure that the distribution system continues to meet its operational objectives (such as reliability, and grid flexibility), while being able to address future anticipated customer electricity requirements. Investments in System Service are captured in the table below.

Table 31 - System Service Forecasted Expenditures

Project	2024	2025	2026	2027	2028
New Station			4,000,000		4,165,000
Grid Technologies	300,000	230,000	230,000	230,000	230,000
Feeder Expansions and Station Redundancy	100,000		220,000		220,000
Station Equipment	100,000				
System Service	**500,000**	**230,000**	**4,450,000**	**230,000**	**4,615,000**

System Service projects will include:

- Within the 2024-2028 DSP period, WDI is poised to experience some significant customer growth in the eastern region of Wasaga Beach. Presently, these developments remain unconfirmed, and in the immediate term, initial phases could be accommodated within existing capacity. However, as a long-term solution, WDI is advocating the implementation of a new municipal substation.

- A provision has been designated as a placeholder, considering the potential requirement for a second substation. This second substation would be intended to facilitate additional growth, support electrification, and accommodate the adoption of electric vehicles.
- Sustained investments in grid technologies, including the GIS. The engineering team is strategically preparing for the transition to Esri ArcGIS Pro as a replacement for Autodesk Map3D. This upgrade not only facilitates the utilization of industry-standard software but also empowers WDI to utilize GIS for comprehensive utility asset database management, system mapping, analysis, and various geospatial functions. This enhancement effectively supports both operational and business requirements.
- Parallel to the ArcGIS upgrade, there is a proposal to implement Esri's "Utility Network" (UN) data model. This model structures the database's backend, while ArcGIS Pro software acts as the frontend for visualizing and manipulating data. The UN model is engineered to represent all elements of the distribution system, encompassing wires, devices, circuits, and the capacity to accurately replicate real-world behaviour into network features. Migrating the data model to UN will modernize GIS utility management and functionalities, fully harness the potential of the ArcGIS Pro platform, and enhance operational efficiency and safety.
- Other grid technology proposals include the implementation of fault indicators at select locations. This initiative seeks to provide real-time visibility of the distribution system while also enabling instrument transformer spot checks in alignment with the updated IESO market regulations. Furthermore, it aims to bolster outage management capabilities, thereby enhancing overall operational efficiency.
- Investments into SCADA equipment - replacement of obsolete generic SCOUTs with SEL RTAC units. RTAC devices are designed to interface with various substation devices, process data, and execute automation logic in real-time.
- Replacing breaker-controlling relays is a proactive step to ensure the continued safe and reliable operation of electrical systems while leveraging the benefits of newer technology, improved features, and industry support.

In summary, System Service spending will continue to focus on improving operational performance and increasing capacity.

General Plant

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

Table 32 - General Plant Forecasted Expenditures

Project	2024	2025	2026	2027	2028
Building and Fixtures	10,000	10,200	10,400	10,600	10,800
IT Hardware	7,500	7,650	7,800	7,800	7,800
IT Software	7,500	7,650	7,800	7,800	7,800
Miscellaneous General Plant		500	500	5,300	600
General Plant	**25,000**	**26,000**	**26,500**	**31,500**	**27,000**

- Investments in specialized racking systems will maximize the use of our available space and streamline our inventory management processes.
- Upgrading the surface of the work yard will yield enhanced safety, increased accessibility, and decreased long-term maintenance needs. Additionally, the upgrade will lead to improved access and more effective drainage.
- IT Hardware and Software programs are comprised of an ongoing business requirement to replace end-user computers and software, as well as network infrastructure and software.
- Customers have told us that they want improved communications, particularly during outages. Customer's expectations have changed and there is a more participative nature to their behaviour. To respond to these changing expectations, WDI plans to invest in customer experience enhancements including improving the outage map and customer portals, as well as digitizing some customer interactions.
- Other considerations are investments in various tools and small equipment necessary to carry out the operations and maintenance activities of the engineering, operations departments.

In summary, General Plant spending will continue to focus on the optimization of business support resources to ensure their effective utilization, maintenance, and value contribution to the organization.

5.4.1.4 Investments with a project lifecycle greater than one year

For capital projects spanning multiple years, costs remain under construction WIP until the capital project is in service. Therefore, capitalization will only occur at the end of the project once it is in service and is considered to be "used and useful."

A key example of a multi-year capital project discussed in this DSP is pole line rebuild projects. While the expenses associated with these projects extend over multiple years, with design work carried out in the year prior to construction, the costs will be maintained as WIP throughout the project's implementation. These costs will only be classified as capitalized once the project reaches its operational phase.

5.4.1.5 Forecast impact of system capital investment on O&M costs

WDI's approach to operations and maintenance is centred on minimizing reactive and emergency-type work by employing efficient operations and a well-designed maintenance program. This includes taking proactive measures such as predictive and preventative maintenance to prevent equipment failures and minimize unplanned downtime. WDI constantly monitors its customer responsiveness and system reliability to ensure the effectiveness of its maintenance strategy. This monitoring is coordinated with WDI's capital project work, so that if maintenance programs identify issues that require capital investments, WDI can adjust its capital spending priorities to address them.

Predictive Maintenance: Predictive maintenance activities involve the testing of elements of the distribution system. These activities include infrared thermography testing, transformer oil analysis, planned visual inspections and pole testing. Any identified deficiencies are prioritized and addressed within a suitable time frame. Preventative Maintenance: Preventative maintenance activities include inspection, servicing, and repair of system components. This includes overhead and pad mounted switch maintenance. Also included are regular inspection and repair of substation components and ancillary equipment. The work is performed using a combination of time and condition-based methodologies. This also includes tree trimming across our operational area on a four-year cycle. This is an important element to mitigate the growing climate change risk where increased windstorms are experienced resulting in tree contact unplanned outages. WDI is investigating a four-year MSA with a contractor to procure competitive pricing for this maintenance.

Emergency Maintenance: This item includes unexpected system repairs to the electrical system that must be addressed immediately. The costs include those related to repairs caused by storm damage, motor vehicle accidents, emergency tree trimming and on-call premiums. WDI constantly evaluates its maintenance data to adjust predictive and preventative actions. The ultimate objective is to reduce this emergency maintenance. WDI uses an answering service to contact "on call" operations and supervisory staff in the event of service problems outside of normal business hours. Investments in System Service grid technologies like line sensors will speed up the time it takes to fault isolate and restore customers, lowering the costs associated with emergency maintenance.

Service Work: The majority of costs related to this work pertain to service upgrades requested by customers, and requests to provide safety coverage for work (overhead line cover-up). This includes service disconnections and reconnections by WDI for all service classes; assisting pre-approved contractors; the making of final connections after Electrical Safety Authority ("ESA") inspection for service upgrades; and changes of service locations.

Network Control Operations: WDI maintains a Supervisory Control and Data Acquisition (SCADA) system.

Metering: The metering department is responsible for the installation, testing, and commissioning of new and existing simple and complex metering installations. Testing of complex metering installations ensures the accuracy of the installation and verifies meter multipliers for billing purposes. Revenue Protection is another key activity performed by Metering, by proactively investigating potential diversion and theft of power.

Substation Services: Substation services activities address the maintenance of all equipment at WDI's six substations. This includes both labour costs and non-capital material spending to support both scheduled and emergency maintenance events. As with the maintenance activities, the substation maintenance strategy focuses on minimizing, to the extent possible, emergency-type work by improving the effectiveness of WDI's planned maintenance program (including predictive and preventative actions) for its substations.

Engineering: The Engineering department is responsible for managing drafting and design services for capital projects and supplying distribution system asset information to various departments within WDI. Engineering costs are allocated to different accounts, including operations, maintenance, capital, and third-party receivables, based on the total costs of labour, and materials.

Operations: The Operations department is accountable for managing the procurement, control, and movement of materials within WDI's service centre. This includes monitoring inventory levels, issuing material receipts, material issues, and material returns as required. The cost of the stores activities is allocated to all departmental, capital, and third-party receivable accounts as an overhead cost based on direct material costs.
System investments will result in:

- The addition of incremental plant (e.g., new poles, switchgear, transformers, etc.).
- The relocation/replacement of existing plant (e.g., road widenings).
- The replacement of obsolete assets with new assets (e.g., conductors, poles, transformers, etc.).
- New/replacement system support expenditures (e.g., hardware, software, etc.).

<u>Upward Pressures</u>
Incremental plant additions, such as new MS6 c/w transformer and switchgear, will integrate into the Asset Management System, requiring additional ongoing O&M resources. This is anticipated to elevate O&M costs.

Neutral Pressures

Relocation or replacement of existing plant assets typically results in minimal changes to ongoing O&M resources, as periodic inspections remain necessary. Replacing older equipment with newer counterparts may slightly extend their lifespan and affect repair-related O&M charges. Generally, planned system investments in this category are expected to have a neutral impact on O&M costs.

Downward Pressures

Replacing obsolete assets with new ones demands ongoing allocation of resources for O&M, especially in repairs. Assets like poles have limited repair options and are often replaced when they reach the end of their useful life or sustain critical damage. Direct buried cables allow for repair-related activities until a certain point, after which replacement becomes necessary due to end-of-life conditions. Planned cable replacements in subdivisions transition from repair (O&M) to replacement (capital) in response to cable failures. If assets nearing the end of their life are replaced at a rate that maintains the average condition of the equipment class, little to no change in O&M costs is expected under no-growth scenarios. However, growth scenarios may exert upward O&M cost pressure due to an increasing number of assets to maintain each year.

Replacing assets at rates that improve the average equipment class condition can reduce costs associated with specific maintenance activities, such as pole testing and reactive repairs, contributing to a downward O&M cost trend.

Additional Considerations

Expenditures for locating services have risen notably due to legislative changes and the growth in the number of assets requiring locates.

System support expenditures, like GIS, are expected to enhance asset understanding, leading to more efficient design, maintenance, and investment activities. This will result in increased and accurate operating data for engineering analysis and service quality reporting. Improved asset information will partially offset growth-related O&M activity increases.

In summary, system investments are projected to exert upward O&M cost pressures related to growth and support, while simultaneously creating downward pressure on repair-related O&M costs. Overall, these investments are not expected to significantly impact total O&M costs in the forecast period.

5.4.2 Justifying Capital Expenditures

WDI's overall capital plan consists of many converging inputs that drive and influence the direction of the capital expenditures. WDI's objective regarding capital expenditures is to meet all regulated requirements while managing the assets in a manner that minimizes the costs to WDI customers and ratepayers.

<u>Customer Value</u>

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

Asset management objectives, which drive planning and decision-making, include ensuring public and worker safety, maintaining system reliability and resiliency, customer expectations alignment, and long-term financial stability, all of which deliver value to customers.

By prioritizing System Access projects such as new customer connections, service requests, new subdivisions, and municipality urbanization projects, WDI ensures that customer needs and requests are being met.

The scope of capital investments planned in the System Renewal category has also been determined with the objective of keeping power supply reliability from deteriorating below an acceptable level while also keeping the overall investment envelope for this DSP within a range that would not result in retail rates escalations beyond the affordability of WDI's customer base. This is in alignment with the top two customer priorities identified in a recent survey, which corresponds to "affordable cost of electricity" and "maintaining and upgrading equipment" to ensure a safe and reliable electricity supply.

The proposed System Service investments deliver value to customers by accommodating expected load growth and improving grid operation performance. By developing and investing in projects such as new substation and feeder redundancy projects, WDI is ensuring that customer needs, and growth will be met over the forecast period and beyond. WDI's plans to install fault indicators will help to reduce the duration of outages and improve response times, which is consistent with customer's desire for a reliable electricity supply and improved outage response times.

WDI's General Plant investments are also selected and prioritized such that WDI can continue to operate safely, and efficiently, and support other work. Recent and planned IT-related upgrades including the migration to a GIS with UN and ongoing upgrades to its OMS will allow WDI to make faster decisions to troubleshoot and improve its system reliability and continue to make prudent decisions into asset maintenance and replacement to keep costs down for customers.

To align WDI's overall capital budget envelope with customer expectations, WDI has prioritized and optimized its proposed capital investments such that the highest-risk projects have been budgeted over the forecast, while some less critical scoped projects have been deferred.

<u>Technological Changes and Innovation</u>

With the emergence of new and changing OEB, ESA and other public sector policies, net-zero targets, increasing prioritization of electrification, innovative technologies, and customer expectations, the distribution grid is quickly evolving from a system-centric, top-down, one-way power flow system to a customer-centric, bi-directional power flow system. Customers now have the capability to generate their own electricity via DERs, and as a result, distribution system planning and operations are becoming increasingly complex, and maintaining grid integrity is becoming more challenging. Practices which have historically been acceptable for the traditional grid need to evolve and an improved and more modernized grid is required to accommodate this evolution.

Where possible, WDI investigates and leverages innovative ways to improve asset and system performance, operations, and maintenance to meet the needs of customers and demonstrate leadership in technology advancement. A few examples of technological improvements planned over the forecast period are noted below:

- GIS Upgrade: The migration from its current AutoCAD Map 3D GIS to a comprehensive geographic information system called Esri ArcGIS Pro complete with a Utility Network Model. The new GIS will enable bi-directional information flow between SCADA and the GIS and will enable WDI to perform real-time spatial analysis such as circuit tracing and heat maps. Transitioning to this dynamic, robust, and integrated spatial database will improve the overall business intelligence, decision-making process, and operational optimization throughout the organization.

- Distribution Automation and Modernization: WDI's plans to install fault and load transmitter and receiver systems to improve the overall reliability of the distribution system through accurate fault indication and load monitoring. The system will enable WDI to locate faults faster and make informed switching decisions. Restoring power quickly is essential to ensuring satisfied customers and better reliability metrics. Highly accurate (1% typical) load data also enables phase balancing and system planning.

- Investments into SCADA equipment - WDI plans to install new RTAC devices. The SEL RTAC is a powerful, multifunctional platform designed for the most demanding utility and industrial applications. With precise, deterministic processing, integrated cybersecurity features, and rugged, industrial-grade hardware, the RTAC ensures reliable performance for critical operations, even in the harshest operating environments.

The above-noted investments will help prepare WDI for future integration with an advanced distribution management system (ADMS) and eventually a Distributed Energy Resource Management System (DERMS). Although WDI is not planning to have a fully implemented and integrated ADMS/DERMS system within the next five years, the future implementation of these systems will be key to managing dynamic power flow in the distribution system and future facilitation of transactional electricity markets at the LDC level over time.

Consideration of Traditional Planning Needs

WDI undertakes load studies to identify areas that may require investments to accommodate the required capacity. Load growth is a direct input into planning for System Access and System Service type projects. Load growth is also a key input into the regional planning process.

Asset condition and reliability data are key inputs considered by WDI when identifying, selecting, and prioritizing System Renewal expenditures. A 10-year flagged-for-action plan arose from a recently completed Asset Condition Assessment. In the absence of investments into asset renewal, the existing infrastructure presents a high risk of failure in service, affecting supply system reliability and public safety.

Overall Capital Expenditures

Over the forecast period, WDI's capital expenditures are designed to achieve the four performance outcomes established by the OEB, while also adhering to WDI's established asset management objectives. This includes continuing to deliver safe, reliable, and affordable power, while also accommodating the expected load growth in WDI's service territory.

5.4.3 Material Investments

WDI's capital expenditure plan is the result of the elements described fully in this DSP. It is guided by corporate strategy, customer engagement and regulatory requirements. For each of the non-mandatory projects/programs, a detailed write-up, highlighting the drivers, justification, and analysis, is provided. All material projects have the following business case information provided:

A. General Information on the project/program
B. Evaluation criteria and information requirements for each project/program
    I. Alternatives Considered
    II. Recommendation
    III. Cost Implications
    IV. Execution Benefit and Risks

Table 33 lists the non-mandatory projects/programs' material investments during this DSP period. Following this table are the business cases exclusively for projects that exceed the $10,000 cost threshold in 2024, recognizing the potential for inflation to increase their value beyond $10,000 in years after 2024.

Table 33 – Non-Mandatory Project Investments Summary

Project		2024	2025	2026	2027	2028
System Renewal		**1,916,242**	**1,870,175**	**1,346,471**	**1,411,310**	**1,748,699**
SR1	Pole Line Rebuild	1,471,842	1,425,775	893,183	948,956	1,277,099
SR2	Miscellaneous Pole Replacement	260,900	260,900	266,118	271,440	276,869
SR3	Misc. Transformer Replacement	83,500	83,500	85,170	86,873	88,611
SR4	Miscellaneous Underground	100,000	100,000	102,000	104,040	106,121
System Service		**500,000**	**230,000**	**4,450,000**	**230,000**	**4,615,000**
SS1	New Municipal Stations			4,000,000		4,165,000
SS2	Grid Technologies	300,000	230,000	230,000	230,000	230,000
	SS2a - GIS Migration and Integrations	290,000	100,000	100,000	100,000	100,000
	SS2b – SCADA Upgrades		120,000	120,000	120,000	120,000
	SS2c - Miscellaneous Grid Technologies	10,000	10,000	10,000	10,000	10,000
SS3	Feeder Expansions and Station Redundancy	100,000		220,000		220,000
SS4	Station Equipment	100,000				
General Plant		**25,000**	**26,000**	**26,500**	**31,500**	**27,000**
GP1	Building and Fixtures	10,000	10,200	10,400	10,600	10,800
GP2	IT Hardware	7,500	7,650	7,800	7,800	7,800
GP3	IT Software	7,500	7,650	7,800	7,800	7,800
GP4	Miscellaneous General Plant		500	500	5,300	600
Total Expenditures		**2,441,242**	**2,126,175**	**5,822,971**	**1,672,810**	**6,390,699**

System Renewal Programs

SR1 - Pole Line Rebuilds

A. General Information on the project/program

System Renewal investments refer to the replacement and/or refurbishment of assets within WDI's distribution system to extend their original service life and ensure the continued delivery of safe and reliable electricity services to customers. To maintain a high level of service and mitigate risks associated with aging infrastructure, WDI proactively manages the replacement of assets that are in poor condition or nearing the end of their useful life. The replacement plans are designed to achieve planning objectives related to reliability, customer satisfaction, and operating cost control. By undertaking System Renewal investments, WDI can maintain a modern and efficient distribution system, ensuring that customers continue to receive reliable and safe electricity services.

The Pole Line Rebuilds project specifically targets the replacement of pole lines that have reached the end of their useful life, as determined through WDI's asset and risk management processes. This project aims to address the aging infrastructure and mitigate risks associated with pole lines that no longer meet the required standards or pose safety hazards. By undertaking pole line rebuilds, the project ensures the continued reliability and safety of the electrical distribution system.

The primary investment drivers encompass safety, aimed at mitigating risks associated with equipment failures, and compliance with ESA and CSA standards.

In determining project priorities, WDI considered the following characteristics of its distribution system:

- Poles aged 50+ years
- Restricted Conductor (#4 and #6 Cu, #4 ACSR)
- Flagged-for-action assets identified in the Asset Condition Assessment
- Balancing of human and financial resources

The Pole Line Rebuilds projects have undergone a risk ranking process that considers multiple perspectives, including safety, reliability, customer satisfaction, and financial aspects. Optimal timing for these projects involves strategically spreading out the capital costs over DSP period and beyond. This approach helps to manage financial implications while ensuring that WDI has the necessary resources and materials to complete the projects on time.

B. Evaluation criteria and information requirements for each project/program

I. Alternatives Considered

Alternative 1 - Maintain Status Quo: Historical investments were focused on scattered asset replacements. This alternative was considered and rejected because it would not fully harness the synergistic benefits of group asset replacement, which encompasses coordinated planning and execution, efficient resource allocation, and the deployment of advanced technologies across multiple assets.

Alternative 2 – Do Nothing: This alternative was considered and rejected because it fails to address the reliability, safety, and financial risks associated with not replacing the assets which include asset failure and sustained outages.

Alternative 3 – Replace Overhead Lines: This alternative effectively addresses the reliability, safety, and financial risks associated with maintaining the status quo. By implementing this alternative, we can proactively address the concerns and challenges related to the current state and minimize potential negative impacts.

Alternative 4 – Undergrounding Overhead Lines: The option of undergrounding overhead lines was explored but ultimately abandoned due to its lack of cost-effectiveness. Implementing underground lines would result in increased customer rates, which contradicts the expressed desire of customers to mitigate cost increases while providing the same level of service and responsible management.

II. Recommendation

Alternative 3 is recommended as the preferred and cost-effective alternative for addressing the need. By renewing and upgrading the pole lines in a planned and something manner, WDI can proactively address the concerns and challenges related to the current state and minimize potential negative impacts. This approach aims to harness the benefits of simultaneously replacing multiple obsolete assets, such as cost savings and operational efficiencies.

This program will replace and upgrade approximately 750 poles, 13+ km of restricted conductor and open bus secondary. Over 90 pole-mount transformers will also be reviewed during the design phase. This analysis will consider current customer loading, optimal location, and future needs.

To manage the financial implications effectively, the optimal timing for these projects involves spreading out the capital costs strategically over the DSP period and potentially beyond. By completing the engineering and procurement of these projects in advance, it facilitates the subsequent construction phase. This approach ensures that WDI has the required resources and materials at hand to complete the projects on time while effectively managing the financial aspects of the initiatives.

III. Cost Basis

Costs have been estimated based on historical experience, high-level estimates, and inflationary impacts. Costing has been evenly spread over the DSP period to ensure WDI has the resources and materials to ensure project completion on time.

Project	2024	2025	2026	2027	2028
SR1 - Pole Line Rebuild	**1,471,842**	**1,425,775**	**893,183**	**948,956**	**1,277,099**
46 N Pole Line Rebuild	111,200				
Beachwood Rd (roundabout to SW604) Pole Line Rebuild	410,850				
Old Mosley (203 Old Mosley to Mosley) Pole Line Rebuild	186,200				
49 S & Crocus Drive Pole Line Rebuild	137,942				
Lanes off 23rd (incl. Norman) Pole Line Rebuild	378,700				
Schooner Drive & Rapid Street Pole Line Rebuild	79,150				
13 S & Old Mosley (to 14 S) Pole Line Rebuild	95,200				
16 N&S Pole Line Rebuild	41,700				
13 N & Sandpiper Ln Pole Line Rebuild	30,900				
Mosley St (18th to east 10th) Pole Line Rebuild		679,985			
32 S Pole Line Rebuild		213,866			
Earl St & Mary St Pole Line Rebuild		180,964			
Beachwood Rd (SW604 to Marilyn) Pole Line Rebuild		219,350			
Old Mosley (14S to 15S) Pole Line Rebuild		82,256			
15 N&S (to 27 River Oak Lane) Pole Line Rebuild		49,354			
Shore Lane (from 16th S East) Pole Line Rebuild			269,640		
32 N & McCague (32N to 35N) Pole Line Rebuild			117,968		

Project	2024	2025	2026	2027	2028
33 N Pole Line Rebuild			106,733		
59 S Pole Line Rebuild			106,733		
68 N Pole Line Rebuild			73,028		
31 S Pole Line Rebuild			106,733		
Shore Lane (50N to 45N) Pole Line Rebuild			112,350		
Knox Road East Pole Line Rebuild				391,085	
69 N Pole Line Rebuild				92,020	
52 S Pole Line Rebuild				103,523	
64 N Pole Line Rebuild				97,771	
70 N Pole Line Rebuild				92,020	
Iris Dr Pole Line Rebuild				69,015	
Robert S Pole Line Rebuild				103,523	
Shore Lane (57 to 50) Pole Line Rebuild					227,429
Deerbrook Drive Pole Line Rebuild					227,429
Stroud Crescent Pole Line Rebuild					122,462
Vigo Rd Pole Line Rebuild					52,484
Shore Lane (60 to 57) Pole Line Rebuild					99,136
Forest Ave Pole Line Rebuild					75,810
River Ave Cr Pole Line Rebuild					116,630
74 N Pole Line Rebuild					64,147
74 S Pole Line Rebuild					69,978
Shore Lane (71 to 67) Pole Line Rebuild					58,315
Middlebrook Road Pole Line Rebuild					64,147
Park Dr Pole Line Rebuild					69,978
Poplar Glen Rd Pole Line Rebuild					29,158

IV. Execution Benefits and Risks

Execution risks associated with this project include customer-initiated delays or restricted access to work sites, inclement weather, delays to material shipments from vendors, unforeseen delays such as striking rock when digging, tree conservation and municipal consent forms. WDI coordinates scheduling with third parties to alleviate these issues where practical.

Safety - Poles that have reached the end of their useful life pose a safety risk to both workers and the public. At this stage, the pole's structural strength has decreased below the minimum acceptable level as per the CSA Standard for Overhead Construction. Replacement of these poles in accordance with CSA construction standards and compliance with O. Reg. 22/04 helps to restore the system to a structurally safe condition.

The breakage of Restricted Conductors appears to be influenced by several contributing factors. These include the age of the conductors, over-tensioning during installation, the use of small strand sizes for long spans, and lower quality in their original manufacturing. Inspection and Maintenance programs have confirmed that a significant number of these conductors are in deteriorated condition. Replacement of these conductors in accordance with CSA construction standards and compliance with O. Reg. 22/04 helps to restore the system to a structurally safe condition.

Reliability Planning - When aged infrastructure is replaced, the new infrastructure is installed in compliance with current standards. This often involves the installation of stronger components compared to the ones being replaced. This upgrade brings about storm-hardening benefits, enhancing the system's resilience and ability to withstand adverse weather conditions. Furthermore, the installation of new conductors also provides the advantage of increased capacity, which is beneficial for the transition to electrification. The upgraded infrastructure can accommodate higher loads, enabling a smoother transition to electric-powered systems and supporting the growing demands of electrified technologies.

Customer – Concerns about outage occurrences and the overall cost of electricity support the need to consider rate mitigation efforts while managing risk and smoothing spending over time for non-urgent investments necessary to maintain acceptable reliability, safety, and service performance levels.

Cost - Risk is effectively managed by pacing the projects throughout the forecast period, allowing for annual spending variations in other investment categories while still adhering to the overall budget framework and maintaining the existing reliability levels. Additionally, unplanned replacements typically incur higher costs compared to planned replacements. This is primarily due to the need to rearrange crew schedules, expedite asset orders, and impose outages on short notice, resulting in increased expenses.

By replacing segments of pole lines and strategically grouping the planned replacements based on geographic proximity, we can leverage the synergies of contiguous pole replacements. This approach enables us to replace poles on the same street simultaneously, rather than in random locations, leading to improved operational and financial efficiencies.

SR2 - Miscellaneous Pole Replacement

A. General Information on the project/program

The Miscellaneous Pole Replacement program comprises both planned and unplanned projects. Unplanned pole replacements are carried out in emergency situations due to unexpected failure, storms, motor vehicle accidents, vandalism, etc. In contrast, the miscellaneous planned pole replacement program is an annual routine program that determines the need to replace end-of-life wood pole structures due to aging infrastructure or degradation from insect activity, decomposition, weather damage, or woodpecker activity. Scheduled replacements of individual poles are determined based on the findings of various inspection processes such as resistograph testing, WDI's asset management program, and feedback received from customers who express concerns about the poles. Replacement of these wood pole structures, and their associated components, will ensure the continued reliability and integrity of WDI's distribution system.

The program for Miscellaneous Pole Replacement has undergone a risk assessment based on multiple perspectives such as safety, reliability, customer satisfaction, and financial considerations.

B. Evaluation criteria and information requirements for each project/program

I. Alternatives Considered

This program is reserved for poles that have reached their end of functional life and the cost of maintenance and/or the frequency of service disruptions have reached an unacceptable or uneconomic level. The projects and activities falling under this category are driven by the relationship between an asset or asset system's ability to continue performing at an acceptable standard in a predictable manner, and the consequences for the customers served by the asset(s) if this ability deteriorates, leading to failure.

When considering the appropriate solution WDI typically consider the following options. Each failure is assessed on a case-by-case basis to determine the most appropriate solution considering, cost, customers impacted, length of outage, and availability of spare assets that are required.

- Like for Like replacement: this solution is undertaken when the current failed asset meets the latest standards.
- Upgrade to latest USF standards: this solution is enacted when the failed asset does not meet the latest standards and is therefore replaced with an asset that meets the latest standards.
- Replacement: In addition, WDI considers if any assets associated with the failed asset require replacing.

II. Recommendation

The Miscellaneous Pole Replacement program is part of WDI's system renewal program budget. The recommendation is the scheduled replacement of pole assets in poor condition or emergency replacement of damaged or failed poles. The program follows a one-for-one replacement approach, which includes reattaching existing devices and foreign plant. On average, it addresses approximately 35 poles per year based on historical data.

The timelines for the program are determined based on the assessment of poles that have reached the end of their lifespan and are more susceptible to failures, necessitating frequent emergency repairs. The specific timing is influenced by inspection results, instances of failure, and customer feedback. WDI operations must ensure that sufficient resources and materials are allocated to ensure the timely completion of the project.

III. Cost Basis

The costs have been estimated for by considering historical experience, high-level estimates, and accounting for inflationary impacts.

Project	2024	2025	2026	2027	2028
SR2 - Misc. Pole Replacement	**260,900**	**260,900**	**266,118**	**271,440**	**276,869**

IV. Execution Benefits and Risks

Execution risks associated with this project include customer-initiated delays or restricted access to work sites, inclement weather, delays to material shipments from vendors, unforeseen delays such as striking rock when digging, tree conservation and municipal consent forms. WDI coordinates scheduling with third parties to alleviate these issues where practical.

Safety - Poles that have reached the end of their useful life pose a safety risk to both workers and the public. At this stage, the pole's structural strength has decreased below the minimum acceptable level as per the CSA Standard for Overhead Construction. Replacement of these poles in accordance with CSA construction standards and compliance with O. Reg. 22/04 helps to restore the system to a structurally safe condition.

The planned and proactive replacement of assets with high failure and/or performance risk is inherently safer than reactive replacement as the working conditions can be controlled, and the optimal replacement plans can be determined in advance.

Reliability Planning – pole failure may involve an entire feeder depending on location and the protective device activated. These types of major interruptions could last between 6 and 8 hours.

When replacing aged poles, new poles are installed in accordance with current standards, which usually results in the installation of higher-class poles than the ones removed. This upgrade typically leads to storm-hardening benefits, improving the system's ability to withstand severe weather conditions.

Customer – Concerns about outage occurrences and the overall cost of electricity support the need to consider rate mitigation efforts while managing risk and smoothing spending over time for non-mandatory investments necessary to maintain current service performance levels.

Cost – Assets failing unexpectedly during service lead to increased replacement expenses (including overtime) and higher outage costs for customers due to prolonged unplanned service interruptions. To mitigate this risk, we proactively replace poles identified as a risk during routine testing and inspections. We strategically time these proactive replacements throughout the forecast period, allowing flexibility to address annual spending variations in other investment categories while upholding the overall budget for sustaining reliability. However, it's important to note that emergency pole replacements do occur, irrespective of pole condition.

The use and configuration of poles proposed in this program are based on an average cost for pole replacement, and actual costs may vary depending on the specific work required.

SR3 - Miscellaneous Transformer Replacement

A. General Information on the project/program

The Miscellaneous Transformer Replacement program comprises both planned and unplanned projects. Unplanned pole replacements are carried out in emergency situations when transformers fail unexpectedly. In contrast, the miscellaneous planned transformer replacement program is an annual routine program that determines the need to replace or upgrade transformers due to age degradation or load conditions. Scheduled replacements of individual transformers are determined based on the findings of inspections, WDI's asset management program, and various analytical processes such as transformer loading data analysis. Replacement of these transformers, and their associated components, will ensure the continued reliability and integrity of WDI's distribution system.

The program for Miscellaneous Transformer Replacement has undergone a risk assessment based on multiple perspectives such as safety, reliability, customer satisfaction, and financial considerations.

B. Evaluation criteria and information requirements for each project/program

I. Alternatives Considered

This program is reserved for transformers that have reached their end of functional life and the cost of maintenance and/or the frequency of service disruptions have reached an unacceptable or uneconomic level. The projects and activities falling under this category are driven by the relationship between an asset or asset system's ability to continue performing at an acceptable standard in a predictable manner, and the consequences for the customers served by the asset(s) if this ability deteriorates, leading to failure. No other alternatives have been identified or considered at this time.

II. Recommendation

The Miscellaneous Transformer Replacement program is part of WDI's system renewal program budget. The recommendation is to schedule transformer assets replacements that are in poor or overloaded condition and to perform emergency replacements for damaged or failed equipment. The program follows a one-for-one replacement approach, which includes reattaching existing devices and foreign plant. On average, it addresses approximately 10 transformers per year based on historical data.

The timelines for scheduled replacements are established through assessments of transformers that have reached their lifespan and are susceptible to failures caused by overloading. These transformers necessitate frequent emergency repairs, highlighting the need for prompt replacements. The decision for emergency replacements is influenced by inspection findings and instances of failure. WDI operations are responsible for allocating adequate resources and materials to ensure the project is completed in a timely manner.

III. Cost Basis

The costs have been estimated by considering historical experience, high-level estimates, and accounting for inflationary impacts. To ensure WDI has the necessary resources and materials for timely project completion, the costing has been evenly spread over the duration of the DSP period. This approach ensures a balanced allocation of resources and helps maintain project timelines.

Project	2024	2025	2026	2027	2028
SR3 – Mis. Transformer Replacement	**83,500**	**83,500**	**85,170**	**86,873**	**88,611**

IV. Execution Benefits and Risks

Execution risks associated with this project include customer-initiated delays or restricted access to work sites, inclement weather, delays to material shipments from vendors, tree conservation and municipal consent forms. WDI coordinates scheduling with third parties to alleviate these issues where practical.

Safety - Transformers that have reached the end of their useful life pose a safety risk to both workers and the public. Replacement of these transformers in accordance with CSA standards and compliance with O. Reg. 22/04 helps to restore the system to a safe and reliable condition.

Proactive replacement eliminates the potential impact of an oil spill on the environment.

Reliability Planning - Replacing aged transformers, will mitigate the risk of unplanned outages due to equipment failure. In addition, replaced transformers may be resized to accommodate EV uptake in the area.

Customer – Concerns about outage occurrences and the overall cost of electricity support the need to consider rate mitigation efforts while managing risk and smoothing spending over time for non-emergency investments necessary to maintain current service performance levels.

Cost - End of life equipment may fail unexpectantly and result in higher replacement costs (overtime, etc.) and higher outage costs to customers due to extended duration of unplanned outages. Risk is managed by pacing through the forecast period to accommodate annual spending variances in the other investment categories while maintaining the overall budget envelope to maintain current levels of reliability. Actual costs may vary depending on the specific work required.

System Renewal projects tend to be multi-year programs and are paced to balance the AMO needs of the program regarding available resources and managing the program impacts on the customer's bill.

It's important to highlight that WDI has taken proactive measures in response to significant challenges within the supply chain, particularly concerning the procurement of transformers. To address this issue, WDI has collaborated with the USF-led initiative, aiming to establish standardized specifications for transformers. This initiative involves coordination with other utilities that are also grappling with supply chain limitations. As part of this collective effort, a joint request for proposal (RFP) was issued to numerous vendors.

The primary objective behind this collaboration is to leverage the combined purchasing power of the participating utilities. By streamlining the type and features of transformers and increasing the volume of purchases, the initiative seeks to secure a more favourable position within the production line. This strategy aims to yield cost efficiencies both in terms of production and transportation.

As a direct result of this initiative, WDI is now able to place an order for transformers in 2023 where if WDI had not participated in this buying group, WDI would not have the ability to place an order for single phase units. This proactive approach not only demonstrates WDI's commitment to addressing supply chain challenges but also underscores the benefits of collaborative efforts in navigating industry-wide constraints.

SR4 - Miscellaneous Underground Replacement

A. General Information on the project/program

The Miscellaneous Underground Replacement program comprises both planned and unplanned projects. Unplanned cable replacements are carried out in emergency situations due to unexpected failure, excavator dig-ins, vandalism, etc.

Assets such as direct buried cable offer opportunities for repair-related activities, such as splices, up to a certain point before further repairs are no longer feasible due to end-of-life conditions. In some cases, cable faults are not repaired due to the cable being at the end of its useful life. In these instances, the faulted cable section is usually replaced, often involving a section of cable between two distribution transformers, or between a transformer and a customer premise.

Faulted cables can disrupt load-balancing mechanisms within the looped system. Replacing these cables allows for effective load management and redistribution, preventing overload on other parts of the system.
The program for Miscellaneous Underground Replacement has undergone a risk assessment based on multiple perspectives such as safety, reliability, customer satisfaction, and financial considerations.

B. Evaluation criteria and information requirements for each project/program

I. Alternatives Considered

This program is reserved for cables that have reached their end of functional life and the cost of maintenance and/or the frequency of service disruptions have reached an unacceptable or uneconomic level. The projects and activities falling under this category are driven by the relationship between an asset or asset system's ability to continue performing at an acceptable standard in a predictable manner, and the consequences for the customers served by the asset(s) if this ability deteriorates, leading to failure. No other alternatives have been identified or considered at this time.

II. Recommendation

The Miscellaneous Underground Replacement program is part of WDI’s system renewal program budget. The recommendation is to schedule cable asset replacements that are in damaged or failed condition and no longer suitable for maintenance.

Replacements are completed on an as-needed basis. The decision for emergency replacements is influenced by inspection findings and instances of failure. WDI operations are responsible for allocating adequate resources and materials to ensure the project is completed in a timely manner.

III. Cost Basis

While these cables have infrequently failed in WDI's system, WDI is budgeting for contingencies by setting aside financial resources to address unforeseen circumstances or needs that might arise in the future. It's a proactive approach to ensure that funds are available if certain events occur, even if their occurrence is uncertain.

Project	2024	2025	2026	2027	2028
SR4 - Misc. Underground Replacement	**100,000**	**100,000**	**102,000**	**104,040**	**106,121**

IV. Execution Benefits and Risks

Safety - Cables that have reached the end of their useful life pose a safety risk to both workers and the public. Replacement of these cables in accordance with CSA standards and compliance with O. Reg. 22/04 helps to restore the system to a safe and reliable condition.

Reliability Planning - Replacing faulted cables plays a significant role in mitigating the risk of unplanned outages and maintaining the reliability of a looped electrical system. In essence, replacing faulted cables is not only about fixing immediate problems; it's a strategic measure to uphold the stability, resilience, and efficiency of the electrical system. It maintains load transfer capabilities and ensures that the system functions as designed, ultimately benefiting both consumers and WDI.

Customer – A reliable power supply is a key factor in customer satisfaction. Minimizing unplanned outages through cable replacement helps maintain positive relationships with consumers.

Cost - Specialized equipment and tools are required for excavating for underground cable replacement. Working with a trusted partner specializing in this field will be critical to keeping costs in check.

Depending on the age and condition of the surrounding infrastructure, cable replacement might reveal additional issues that need to be addressed, increasing overall project costs.

System Service Programs

SS1 – New Municipal Stations

A. General Information on the project/program

The ongoing development of the Town of Wasaga Beach propels the need for new customer connections. This includes projects like site redevelopment, subdivisions, and establishing fresh connections to accommodate the evolving urban landscape. The need for a new station is substantiated by factors including the ongoing active development within the Town of Wasaga Beach (Active Developments) and the findings outlined in the Load Growth Analysis Report found in Appendix D.

In the immediate term, initial phases and small developments could be accommodated within the existing capacity. However, as a long-term solution, WDI is advocating the implementation of a new municipal substation.

B. Evaluation criteria and information requirements for each project/program

I. Alternatives Considered

Alternative 1 - Maintain Status Quo: This alternative was considered and rejected because it fails to address WDI's obligation to connect a customer in compliance with the Electricity Act, WDI's Electricity Distribution License and the DSC.

Alternative 2 – The construction of a new station will alleviate distribution capacity constraints in the eastern region of the town.

Alternative 3 – This option explores a non-wires alternative in the form of a Battery Energy Storage System (BESS). Despite having a 3 MW BESS, WDI would still need a 5 MW conventional station. With an energy capacity cost of $1125 per kWh, the expense of a 3 MW BESS would total $3,375,000. That budget would cover the construction of a conventional 10 MW station.

II. Recommendation

Alternative 3 is recommended as the preferred and cost-effective alternative for addressing the need. The construction of a new station is imperative to alleviate distribution capacity constraints in the eastern region of the town. These limitations pose a significant risk, potentially hindering the growth and expansion opportunities for local businesses, consequently limiting revenue potential. Furthermore, neglecting to address these capacity constraints could result in non-compliance with regulatory requirements, potentially leading to penalties and legal complications. The load growth analysis clearly underscores the urgency of enhancing the distribution system's capacity to meet the increasing demands of the town, ensuring its ability to support ongoing development projects and secure a prosperous and compliant future.

III. Cost Basis

The costs have been estimated on a recent experience with MS6 construction, and accounting for inflationary impacts.

A provision has been designated as a placeholder, considering the potential requirement for a second substation. This second substation would be intended to facilitate additional growth, support electrification, and accommodate the adoption of electric vehicles. The decision to proceed with the second station may be postponed to the subsequent DSP period, contingent on the requirements and preferences of customers.

Project	2024	2025	2026	2027	2028
SS1 - New Municipal Stations			**4,000,000**		**4,165,000**

IV. Execution Benefits and Risks

Safety - Existing stations and equipment may become overloaded, leading to increased wear and tear, reduced efficiency, and potential in service catastrophic failure.

Reliability Planning - Operating existing stations at or above their capacity limits can result in reduced operational efficiency, increased operating costs, and decreased asset lifespan.

Customer – A reliable power supply is a key factor in customer satisfaction. Capacity constraints may lead to service interruptions and outages, affecting customer satisfaction and potentially causing financial losses.

Cost - There is a likelihood of developer capital contributions, which can offset WDI's expenditures for this project. This potential financial support from developers can help reduce the project's financial burden on WDI, making it a cost-effective initiative.

The inability to meet capacity demands can hinder business growth and expansion opportunities, limiting revenue potential.

Failure to address capacity constraints may lead to non-compliance with regulatory requirements, which can result in penalties and legal issues.

SS2 – Grid Technologies

SS2a – GIS Migration and Integrations

A. General Information on the project/program

WDI's engineering team has leveraged Autodesk Map3D software for utility asset database recording, system mapping, and other geospatial functions to support operational and business needs.

Autodesk Map 3D is primarily focused on Computer-Aided Design (CAD) and 3D modeling. It's part of Autodesk's suite of software, which includes AutoCAD, and is often used in engineering, construction, and infrastructure design.

Esri ArcGIS is a comprehensive GIS platform. Its primary focus is on spatial analysis, mapping, and geospatial data management. It's widely used in various industries for spatial decision-making and analysis. ArcGIS is known for its versatility and ability to integrate with various data sources and software applications. It has a vast ecosystem of extensions and add-ons.

The GIS team is proposing a migration to ArcGIS Pro, the next-generation Esri GIS desktop software, with the aim of enhancing the asset repository, improving geospatial data management and analysis, and facilitating better integration with other business processes.

In addition to upgrading the desktop tool, it is also necessary to replace the underlying data model with Esri's Utility Network (UN), a requirement to edit and analyze utility network data using ArcGIS Pro. The Utility Network (UN) model offers a digital representation of the network systems that is more accurate, more useful, and more reliable than the out-of-the-box Geometric Network model. The data model migration to UN will modernize GIS utility maintenance and functionality, will deliver the full value of the ArcGIS Pro platform, and can result in increased operational efficiency, customer value, reliability, and safety.

B. Evaluation criteria and information requirements for each project/program

Alternatives Considered

Alternative 1 - Maintain Status Quo: This alternative was considered but ultimately rejected due to limitations in Autodesk Map3D, particularly in the software's support for third-party integrations, live mobile viewing, and analytical capabilities.

Alternative 2 – Do Nothing: This alternative was considered and rejected because it fails to address the reliability, safety, and financial risks associated with not replacing the assets which include asset failure and sustained outages.

II. Recommendation

Alternative 3 is recommended as the preferred and cost-effective alternative for advancing asset management tools, digitizing operational processes.

In addition, adoption of the new UN data model will allow WDI to set the foundation work to support grid modernization as described in the paper entitled Esri road ahead for network management white paper.

III. Cost Basis

Costs proposed for 2024 are for the implementation of Esri ArcGIS Pro and the migration of the existing dataset. Downstream costs are for system improvements to modernize WDI operational processes by adding mobile forms, mobile map viewing, and third-party integrations such as smart meter load data.

For example, future integrations would include a Work Management System that would help WDI to have electronic work orders that could be sent electronically to the appropriate person in the field, the work completed and then signed off and sent back electronically. This would leave the staff involved in the work orders lifecycle with more time to be productive, and would decrease the chance for human error, as Staff are not handling and storing paperwork in the office/trucks. Moreover, the WMS would make ESA O. Reg. 22-04 Audit effortless and more organized, as electronic copies can be shared with the auditors.

Project	2024	2025	2026	2027	2028
SS2a – GIS Migration and integrations	290,000	100,000	100,000	100,000	100,000

IV. Execution Benefits and Risks

The execution risk is around the data model migration. Automated tools involved in data migration may introduce errors to the dataset, and data may be lost in translation during migration to the new database. The mitigation strategy associated with this risk includes a review of assumptions early in the project, iterative testing of migration tools, and hiring a consultant experienced in migrations to ensure data quality upon completion.

There is also a change management risk. Software training for engineering staff and administrators is part of the project scope.

Safety – Accurate mobile network maps and records contribute to worker safety, especially under emergency conditions. Providing field crews with accurate and up-to-date maps and information reduces the risk of accidents and injuries during maintenance and repair activities.

Reliability Planning – GIS can help ensure reliability by tracking, analyzing, and reporting on various safety-related parameters, such as equipment condition and maintenance history.

Customer – The GIS will be used to create outage maps that display real-time information about affected areas. Customers can access these maps online or through mobile apps to see the outage's extent and expected resolution time. Having access to this information empowers customers and reduces uncertainty.

WDI is planning to introduce interactive GIS-based tools that enable customers to report and communicate various issues, such as the presence of danger trees, downed wires, or service interruptions. This initiative aims to enhance customer engagement and provide a more efficient means for customers to convey critical information to the utility for prompt response and issue resolution.

Cost - GIS allows utilities to perform spatial analysis, helping identify high-risk areas prone to issues like outages, equipment failures, or overloads. This data-driven approach aids in strategic planning, ensuring that resources are allocated effectively to address safety concerns.

SS2b – Grid Technologies – SCADA Upgrades

A. General Information on the project/program

As part of its broader strategy, WDI is venturing into distribution automation and modernization by investing in a series of critical upgrades, with a primary focus on the installation of key components such as communication and control devices in addition to remote devices. These components are strategically designed to deliver valuable data to the SCADA system. The driving force behind this investment is primarily the pursuit of enhanced reliability. By incorporating remote sensors, WDI can continuously monitor its distribution feeders and promptly alert its staff to any emerging issues within the distribution network. This heightened awareness translates to quicker response times during system disruptions, ultimately improving service restoration.

Furthermore, efficiency emerges as a secondary but significant driver of this investment. The acquisition of highly accurate load data, typically at a 1% precision level, enables crucial activities such as phase balancing and systematic planning, further underlining WDI's commitment to a resilient and efficient grid infrastructure.
Moreover, WDI's plans encompass significant investments in replacing obsolete generic SCOUTs with SEL RTAC units. These RTAC devices are purpose-built to interface with a variety of substation devices, process data, and execute automation logic in real time. Such investments further reinforce the utility's commitment to grid modernization and improved operational capabilities.

B. Evaluation criteria and information requirements for each project/program

I. Alternatives Considered

Alternative 1 - Maintain Status Quo: This project is a necessary step in the modernization of the distribution system. The status quo is no longer a viable option.

Alternative 2 – Implementation of New SCADA Devices: This project benefits all customers by maintaining or improving both SAIDI and SAIFI. WDI believes that this investment provides excellent value as it provides increased customer satisfaction due to its positive impact on reliability.

II. Recommendation

Alternative 2 is recommended. Installing modern SCADA equipment enhances distribution system monitoring and control. It accelerates restoration during outages with fewer resources, reduces line losses through enhanced planning, and enables the integration of distributed energy resources.

The installations will be coordinated and performed with zero or minimal interruptions to existing customers.

III. Cost Basis

This is the first investment of its kind at WDI, so there are no comparators for this expenditure.
The costs have been estimated based on publicly available pricing information, and they include additional adjustments for estimated labour and machinery costs to support the investment as well as inflationary impacts.

Project	2024	2025	2026	2027	2028
SS2b – SCADA Upgrades		120,000	120,000	120,000	120,000

IV. Execution Benefits and Risks

This project is to reduce or eliminate risks that currently exist. This far outweighs the risks of implementation. However, risks could include local access at poles, challenges with telecommunications signals and integration with the SCADA master. These will all be managed with adequate planning, testing and project management.
Safety – All installations will be in accordance with CSA standards and O. Reg. 22/04.
Reliability Planning - This project aids in achieving operational efficiency and reliability objectives by helping to maintain or decrease both SAIDI and SAIFI. Additionally, it contributes to efficiency goals by reducing the time required to locate system disruptions.

This will give WDI the ability to optimize circuit loading and balancing which would also reduce line losses. As the use of DERs and electrical vehicle charging increases, it will be important that WDI has the ability to monitor and control the distribution system on a 24/7 basis.

Customer – A reliable power supply is a key factor in customer satisfaction. Minimizing response and restoration times for unplanned outages helps maintain positive relationships with consumers.

Cost - WDI has identified that improving communication equipment in the system would reduce O&M costs while increasing reliability. This is achieved through having real-time access to the field devices to monitor the health and status. For WDI, faster restoration, minimizing truck roll, crew dispatch time and improved power quality monitoring would be realized if proceeding with this program.

SS3 – Feeder Expansions and Station Redundancy

A. General Information on the project/program

System Service investments are essential for maintaining consistent service delivery and fulfilling operational objectives. These investments are crucial to support the expansion, operation, and reliability of the distribution system.

These non-mandatory System Service projects are identified through WDI's Asset Management process, system planning, and operational requirements. They aim to address forecasted load changes that may affect the system's ability to consistently provide services.

In the 2024-2028 forecast period, this program encompasses to-be-planned System Service projects. These projects will be geared towards resolving system capacity issues and aligning with WDI's operational objectives, which encompass safety, reliability, power quality, and system efficiency.

One notable aspect of these projects involves feeder expansions, which facilitate the interconnection of stations and enhance redundancy. This, in turn, increases the system's load transfer capabilities and ensures a robust and reliable distribution network.

The main driver is to improve load switching capability between various WDI stations and other facilities that supply the WDI service territory.

B. Evaluation criteria and information requirements for each project/program

I. Alternatives Considered

Alternative 1 - Maintain Status Quo (do nothing): This project is a necessary step in connecting the proposed new station. The status quo is no longer a viable option.

Alternative 2 – Finalize the requirements for a new station and plan connection routes: Complete this project in coordination with multiple developers who have proposed developments in an area where capacity constraints currently exist.

II. Recommendation

Alternate 2 is recommended as the finalization of requirements for a new station and the planning of connection routes is a crucial project that serves to benefit developers. Its primary objective is to address capacity constraints promptly, facilitating the connection of proposed developments to the electrical grid. This proactive approach ensures that developers can access the necessary power resources in a timely and efficient manner, thereby supporting their projects and promoting sustainable growth.

Additionally, these projects will facilitate the interconnection of stations, further enhancing the flexibility and reliability of the electrical grid. This interconnection capability will contribute to a more robust and efficient distribution network, benefitting both developers and existing customers, and the overall system's operational objectives.

III. Cost Basis

Costs have been estimated based on historical experience, high-level estimates, and inflationary impacts. The costing for 2024 pertains to finalizing an ongoing connection between MS3 and MS6. Meanwhile, the other budgetary figures align with the proposed construction projects for new stations.

Project	2024	2025	2026	2027	2028
SS3 - Feeder Expansions and Station Redundancy	100,000		220,000		220,000

IV. Execution Benefits and Risks

The absence of contingency interconnections can disrupt critical business operations and continuity planning, making it difficult to manage crises effectively.

Safety – Inadequate contingencies can compromise safety, especially if the system is unable to respond effectively to critical events that pose risks to personnel and the public.

Reliability Planning – Without additional interconnections, the system lacks redundancy, making it more vulnerable to single points of failure. This increases the risk of extended outages during equipment failures or other contingencies.

Customer – Extended service disruptions due to the lack of contingency interconnections can harm the organization's reputation and erode customer trust.

Cost - There is a likelihood of developer capital contributions, which can offset WDI's expenditures for this project. This potential financial support from developers can help reduce the project's financial burden on WDI, making it a cost-effective initiative.

SS4 – Station Equipment

A. General Information on the project/program

In 2012, WDI took the proactive step of replacing its aging electro-mechanical relays at MS3 with more advanced solid-state relays to improve the reliability and efficiency of the electrical system. However, just six months after the replacement, one of these newly installed solid-state relays failed. WDI promptly removed it from service, sent it back to the manufacturer for repair, and reintroduced it into its system within the same year.

Unfortunately, this relay failed again within a mere month. Recognizing the severity of the issue, the manufacturer sent a replacement relay, which WDI promptly put into service. Despite these actions, the problem persisted, leading WDI to initiate thorough station investigations in an attempt to pinpoint the root cause of these recurring relay failures.

In 2013, WDI decided to take further action by replacing the breakers, hoping that this would resolve the issue. However, despite best efforts, the problem persisted. To gain a deeper understanding of the situation, WDI conducted a comprehensive station protection scheme study, hoping to identify any vulnerabilities or shortcomings in the relay settings that could be contributing to the relay failures.
Regrettably, even after these extensive investigations and upgrades, the affected feeder has remained out of commission since 2020 due to ongoing relay failures. As of 2023, WDI continues to grapple with this issue and is conducting further investigations to uncover the elusive problem. Unfortunately, attempts to collaborate with the manufacturer in finding a solution have been met with uncooperative responses, further complicating efforts to resolve this challenging and persistent issue within WDI's electrical system.

B. Evaluation criteria and information requirements for each project/program

III. Alternatives Considered

Alternative 1 - Maintain Status Quo (do nothing): This project is imperative in realizing optimal system utilization, by maintaining system balance, reliability, and redundancy. The status quo is no longer a viable option.

Alternative 2 – Replacing the MS3 station relays with new devices: Replace the current relays with industry-standard devices that enable robust manufacturer support and collaboration with members of shared alliances.

IV. Recommendation

Alternate 2 is recommended because ensuring the reliability of critical systems is of utmost importance, particularly in light of the safety risks posed by the existing relays due to their high failure rate and lack of industry support. Replacing these relays not only addresses safety concerns but also guarantees compatibility with modern control systems installed at MS6, facilitating training and operational efficiencies. Moreover, the adoption of newer relays with advanced features like remote monitoring, diagnostics, and communication capabilities not only enhances circuit breaker functionality but also minimizes the need for frequent, costly repairs and maintenance, ultimately reducing ongoing expenses.

In summary, replacing breaker-controlling relays is a proactive step taken to ensure the continued safe and reliable operation of electrical systems while leveraging the benefits of newer technology and improved features.

VII. Cost Basis

Costs have been estimated based on high-level estimates. The expenditures for 2024 pertain to replacing four (4) breaker control relays at MS3. The replacements will be scheduled after completing comprehensive maintenance and investigative efforts to determine the root cause of the recurring relay failures.

Project	2024	2025	2026	2027	2028
SS4 - Station Equipment	100,000				

VIII. Execution Benefits and Risks

The inoperability of a feeder can severely disrupt critical operations and reliability planning. It hampers the ability to effectively manage emergencies, exacerbating the challenges faced during such critical times.

Safety – Malfunctioning relays compromise safety. Failure to isolate faulty equipment may expose workers and the public to electric shock, arc flash incidents, and other hazards.

Reliability Planning – When relays fail to respond correctly, it can lead to unnecessary power outages and prolonged downtime for critical operations, ultimately diminishing the overall reliability of the electrical system. Moreover, a malfunctioning protection relay can create a situation where frequent false alarms or missed fault detections erode confidence in the system's capability to effectively safeguard against electrical faults.

Customer – Frequent power interruptions or safety incidents stemming from relay malfunctions can damage the company's reputation and erode customer trust.

Cost - When relays malfunction, they may fail to trip circuit breakers or disconnect faulty equipment in the presence of electrical faults or overload conditions. This oversight can result in significant damage to expensive electrical assets like transformers. Additionally, the unplanned outages arising from protection relay malfunctions can disrupt operations, necessitate emergency responses, and introduce operational inefficiencies.

APPENDICES

Appendix A: The Regional Infrastructure Plan

Appendix B: 2022 OEB Scorecard

Appendix C: 2021 Asset Condition Assessment Report

Appendix D: Load Growth Analysis Report

1 # Appendix A: The Regional Infrastructure Plan

South Georgian Bay-Muskoka

REGIONAL INFRASTRUCTURE PLAN

December 16, 2022

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Prepared by:
Hydro One Networks Inc. (Lead Transmitter)

With support from:

Company
Independent Electricity System Operator (IESO)
Alectra Utilities Corporation (Alectra)
Hydro One Networks Inc. (Distribution)
InnPower
Orangeville Hydro
Elexicon Energy
Lakeland Power
Epcor Electricity Distribution Ontario Inc
Newmarket-Tay Power Distribution Ltd
Wasaga Distribution Inc.

Disclaimer

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address electrical supply needs identified in previous planning phases and also any additional needs identified based on new and/or updated information provided by the RIP Technical Working Group.

The preferred solution(s) that have been identified in this report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP Technical Working Group.

Technical Working Group participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the RIP report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the RIP report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the RIP report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the RIP report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE WITH SUPPORT FROM THE TECHNICAL WORKING GROUP IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE SOUTH GEORGIAN BAY-MUSKOKA REGION.

The participants of the South Georgian Bay-Muskoka Regional Infrastructure Plan ("RIP") Technical Working Group ("TWG") included members from the following organizations:

- Independent Electricity System Operator ("IESO")
- Alectra Utilities Corporation ("Alectra")
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- InnPower
- Orangevile Hydro
- Lakeland Power
- EPCOR Electricity Distribution Ontario Inc.
- Newmarket-Tay Power Distribution Ltd.
- Wasaga Distribution Inc.

This RIP is the final phase of the second cycle of the South Georgian Bay-Muskoka Regional Planning (RP) process. It follows the completion of the South Georgian Bay-Muskoka Integrated Regional Resource Plan ("IRRP") which was subdivided into two sub-regions; Barrie Innisfil and Parry Sound/Muskoka both completed in May 2022. This also follows completion of the South Georgian Bay-Muskoka Needs Assessment ("NA") and Scoping Assessment ("SA") in April 2020 and November 2020, respectively.

The South Georgian Bay-Muskoka RIP provides a consolidated summary of needs and recommended plans for the region over a 10-year planning horizon (2022-2032) based on available information. The load forecast for the 2033-2042 period is provided to show the longer term needs and trend. All needs for this long-term horizon will be reviewed again and confirmed in future regional planning cycles.

The first cycle of Regional Planning process was completed in August 2017 with the publication of the South Georgian Bay-Muskoka RIP report, which provided a description of needs and recommendations of preferred wires plans to address near-term needs.

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

The following needs and projects identified in the previous regional planning cycle have been completed:

- Orillia TS M6E/M7E Switches (2021) - Hydro One installed new 230kV motorized disconnect switches on the M6E and M7E circuits (at Orillia TS) to improve load restoration time.

- Minden TS (2021) – Replacement of end-of-life (EOL) 230/44kV 42MVA (T1/T2) transformers with new 230/44kV 83MVA units.

The following needs and projects identified in the previous regional planning cycle are currently underway:

- Parry Sound TS (2023) - Replace existing 230/44kV 42MVA transformers (T1/T2) with new 230/44kV 83MVA units and replace station protection and station service equipment.

- Barrie TS (2023) Replace and upgrade existing 115/44kV 83MVA transformers (T1/T2) with new 230kV/44kV 125MVA transformers. Remove Essa TS T1/T2 autotransformers and convert Barrie TS supply circuits (E3B/E4B) from 115kV to 230kV.

- Orangeville TS (2023)- Replace existing T1/T2 230/44/27.6 kV 75/125 MVA transformers with two 230/27.6 kV 50/83 MVA units and reconfigure the dual voltage switchyard to a standard DESN that would supply the 27.6 kV load. Also replace and upgrade T3/T4 230/44 kV 50/83 MVA transformers with two 230/44 kV 75/125 MVA units to accommodate additional capacity.

II. Newly Identified needs:

The major infrastructure investments in this 2nd cycle recommended by the TWG in the South Georgian Bay-Muskoka Region over the near and medium-term (2022-2032) period are given in Table 1 below, along with their planned in-service date and budgetary estimate for planning purposes.

Table 1. South Georgian Bay-Muskoka Region - Recommended Plans over the 2022-2032 Study Period

Need	Station / Circuit	Investment Description	Lead	Planned In-Service Date[1]	Cost ($M)[2]
Station Capacity	Everett TS	Modify current transformer (CT) ratio setting the low voltage 44kV transformer breakers	HONI	2023	0.5
	Barrie TS	Construct new 230/27.6kV 83MVA transformer station and connect to 230kV E28B/E29B circuits	HONI / Inn Power	2027	44
	Waubaushene TS	Replace and upgrade existing 230/44kV 83MVA transformers (T5/T6) with new 230/44kV 125MVA units.	HONI / Hydro One Dx	2027	20
Asset Renewal - Transmission Line	M6E / M7E (Orillia TS x Coopers Fls)	Replace end- f-life (EOL) transmission line conductor (25km)	HONI	2026	30
	E8V / E9V (Orangeville TS x Essa JCT)	Replace EOL transmission line conductor and associated assets (56km)	HONI	2027	70
	D1M / D2M (Minden TS x Otter Creek JCT)	Replace EOL transmission line conductor and associated assets (62 km)	HONI	2028	70
Asset Renewal - Transmission Station	Wallace TS	Replace existing EOL 230/44kV 42MVA transformers (T3/T4) with new 230/44kV 42MVA units	HONI	2025	25
	Midhurst TS	Replace existing 230/44kV 125MVA EOL transformer (T4) with a new 230/44kV 125MVA unit	HONI	2026	12
	Orillia TS	Replace existing EOL 230/44kV 125MVA transformer (T2) with new 230/44kV 125MVA unit	HONI	2025	12
	Bracebridge TS	Replace existing EOL 230/44kV 83MVA transformer (T1) with new 230/44kV 83MVA unit	HONI	2026	10
	Alliston TS	Replace existing EOL 230/44kV 83MVA transformer (T3/T4) with new 230/44kV 83MVA units	HONI	2030	16

The South Georgian Bay-Muskoka TWG recommends that Hydro One and LDCs continue with the implementation of infrastructure investments listed in Table 1 while keeping the TWG apprised of project status.

[1] Planned in-service dates are tentative and subject to change

[2] Costs are based on budgetary planning estimates and excludes the cost for distribution infrastructure (if required).

The next regional planning cycle for the South Georgian Bay-Muskoka Region must be triggered within five years, beginning with the Needs Assessment (“NA”) phase. It is expected that the next NA will start in Q2 2025. However, the next regional planning cycle can be started earlier if required to address any emerging needs.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN (“RIP”) TO ADDRESS THE ELECTRICITY NEEDS OF THE SOUTH GEORGIAN BAY-MUSKOKA REGION.

The report was prepared by Hydro One Networks Inc. (Transmission) (“Hydro One”) on behalf of the Technical Working Group (“TWG”) in accordance with the regional planning process established by the Ontario Energy Board (“OEB”) in 2013. The TWG included members from the following organizations:

- Independent Electricity System Operator (“IESO”)
- Alectra Utilities Corporation (“Alectra”)
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- InnPower
- Orangeville Hydro
- Lakeland Power
- EPCOR Electricity Distribution Ontario Inc.
- Newmarket-Tay Power Distribution Ltd.
- Wasaga Distribution Inc.

Electrical supply to the South Georgian Bay-Muskoka region is provided through two (2) 500/230kV auto-transformers at Essa TS, the 230kV transmission lines connecting Minden TS to Des Joachims TS, the 230kV circuits E8V and E9V coming from Orangeville TS, and the single 115kV circuit S2S connecting to Owen Sound TS. There are sixteen (16) Hydro One step-down transformer stations in the region, most of which are supplied by circuits radiating out from Essa TS, and the majority of the distribution system is at 44kV, except for Orangeville TS which has 27.6kV and 44kV feeders. Figure 1-1 represents the South Georgian Bay-Muskoka Region Map.

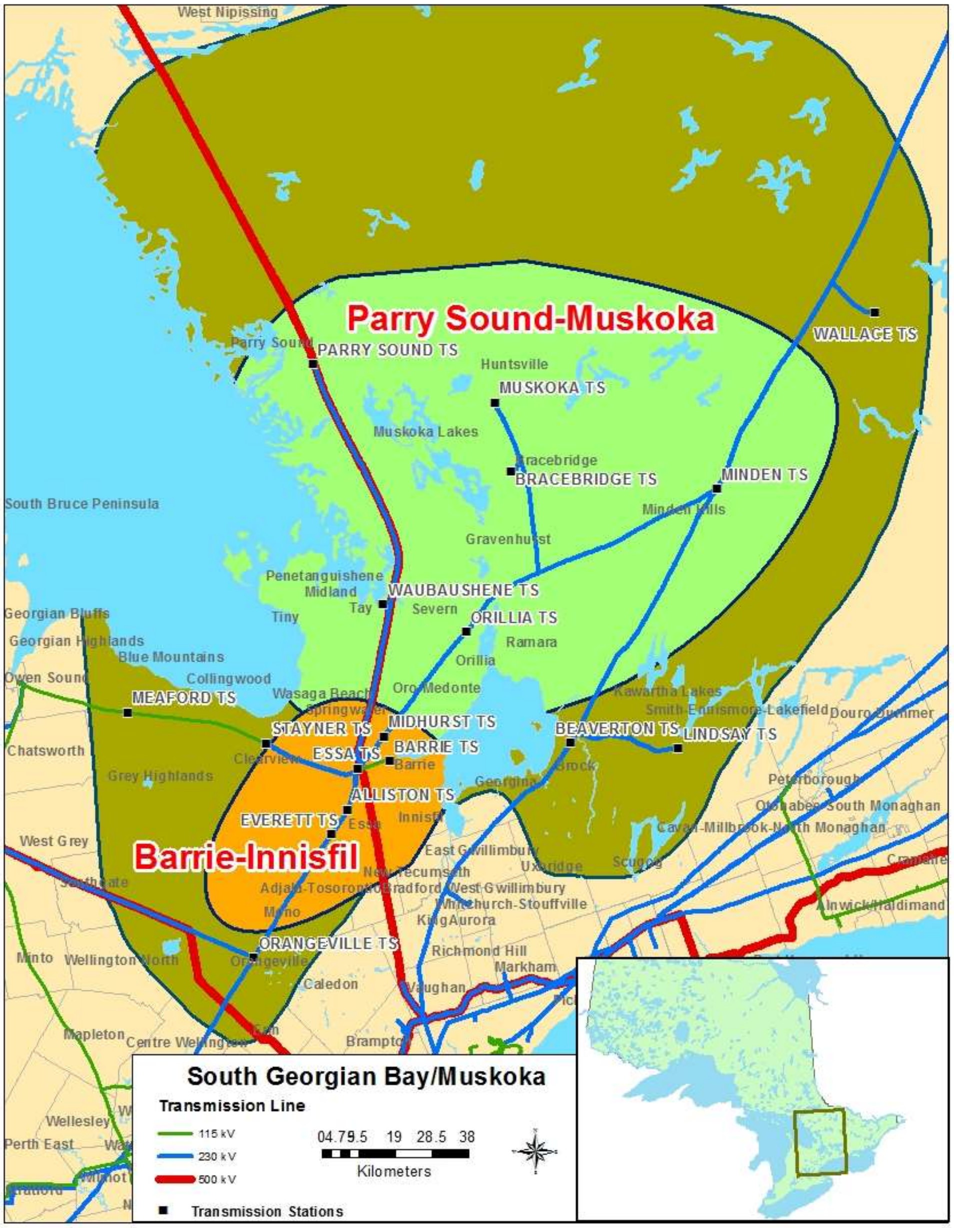


Figure 1-1 South Georgian Bay-Muskoka Region Map

1.1 Objectives and Scope

This RIP report examines the needs in the South Georgian Bay-Muskoka Region. Its objectives are to:

- Provide a comprehensive summary of needs and wires plans to address the needs for the region.
- Identify new supply needs that may have emerged since previous planning phases (e.g., Needs Assessment, Scoping Assessment, Local Plan, and/or Integrated Regional Resource Plan).
- Assess and develop wires plans to address these new needs.
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviewed factors such as the load forecast, asset renewal for major high voltage transmission equipment, transmission and distribution system capability along with any updates with respect to local plans, conservation and demand management ("CDM"), renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant wires plans to address near and medium-term needs (2022-2032) identified in previous planning phases (i.e., Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan).
- Identification of any new needs over the 2022-2032 period and wires plans to address these needs based on new and/or updated information.
- Consideration of long-term needs identified in the South Georgian Bay-Muskoka IRRP or identified by the TWG.

1.2 Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process;
- Section 3 describes the regional characteristics;
- Section 4 describes the transmission work completed over the last ten years;
- Section 5 describes the load forecast and study assumptions used in this assessment;
- Section 6 describes the results of the adequacy assessment of the transmission facilities in the region over the study period and identifies the needs;
- Section 7 discusses the needs, provides alternatives to address each need, and recommends a preferred solutions; and,
- Section 8 provides the conclusion and next steps.

2. REGIONAL PLANNING PROCESS

2.1 Overview

Planning for the electricity system in Ontario is done at essentially three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Regional planning looks at supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115 kV and 230 kV portions of the power system that supply various parts of the province.

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: The Needs Assessment ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Technical Working Group (TWG) determines whether further regional coordination is necessary to address them. If no further regional coordination is required to address the need(s), further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer to develop a Local Plan ("LP") to address them. These needs are local in nature and can be best addressed by a straightforward wires solution. The TWG considers various factors in determining that a LP is the appropriate planning approach.

In situations where identified needs require further coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the TWG, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and decides on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend a preferred wires solution. Similarly, resource options which the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities, Indigenous communities, business sectors and other interested stakeholders and establishes a Local Advisory Committee (LAC) in the region or sub-region.

The RIP phase is the final phase of the regional planning process and involves: discussion of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and, development of a wires plan to address these needs. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive and consolidated report of a wires plan for the region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter to the LDC(s). Respecting the OEB timeline provision of the RIP, planning level stakeholder engagement is not undertaken during this phase. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and LDCs for the region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the regional planning process taking effect.
- The NA, SA, IRRP and LP phases of regional planning.
- Conducting wires planning as part of the RIP for the region or sub-region.
- Planning for connection capacity requirements with the LDCs and transmission connected customers.

Figure 2 -1 illustrates the various phases of the regional planning process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome.

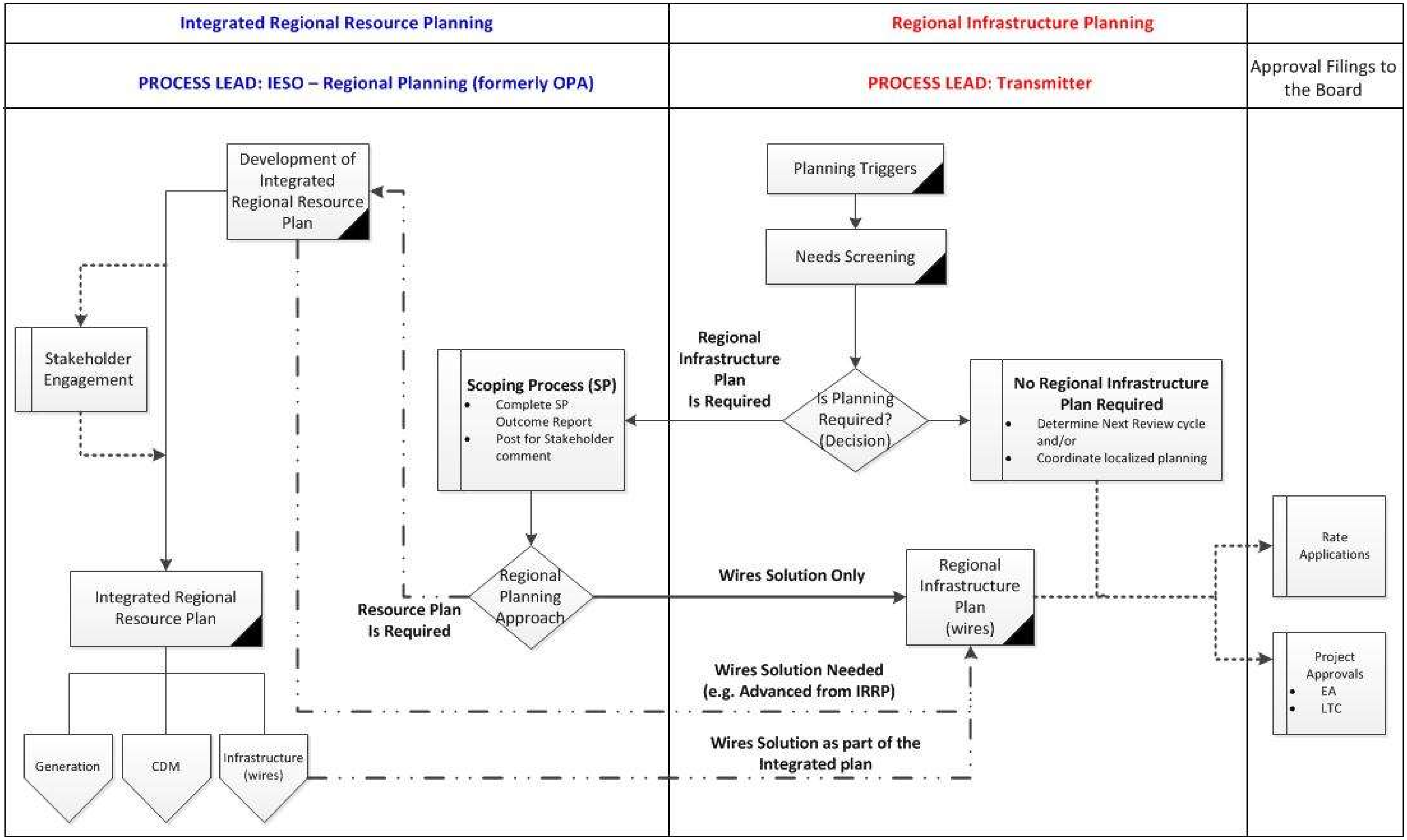


Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of a four step process (see Figure 2-2) as follows:

1. Data Gathering: The first step of the RIP process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the technical working group (TWG) to reconfirm or update the information as required. The data collected includes:
    - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs. As agreed by TWG members, the load forecast from the IRRP was used for this RIP.
    - Existing area network and capabilities including any bulk system power flow assumptions.
    - Other data and assumptions as applicable such as asset condition, load transfer capabilities, and previously committed transmission and distribution system plans.

2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and medium-term needs may be identified at this stage.

3. Alternative Development: The third step is the development of wires options to address the needs and determine a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact, and costs.

4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

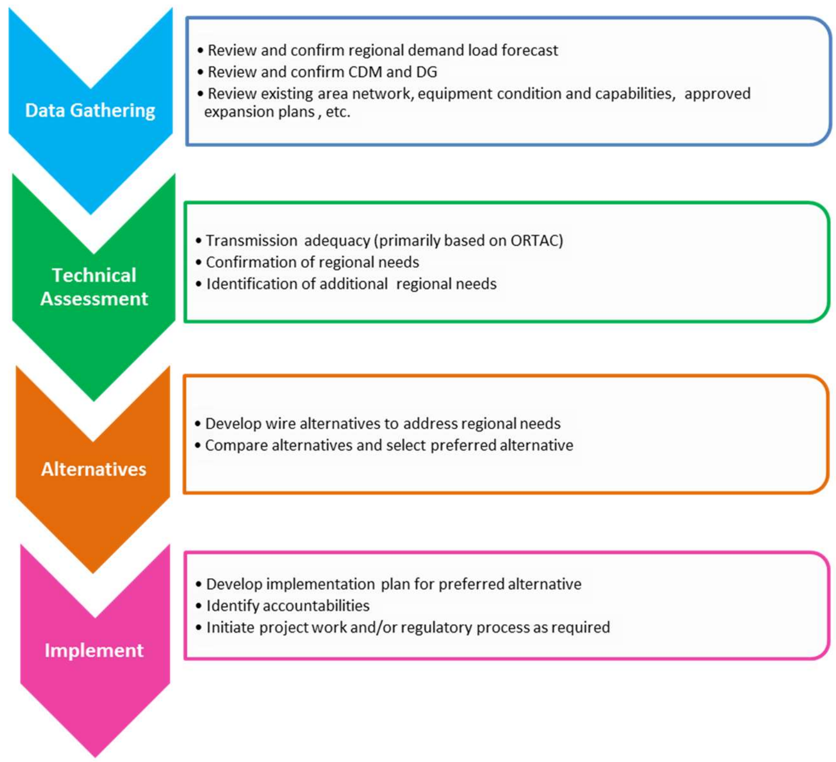


Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE SOUTH GEORGIAN BAY/MUSKOKA REGION IS COMPRISED OF THE BARRIE/INNISFIL AND THE PARRY SOUND/MUSKOKA SUB-REGIONS. ELECTRICAL SUPPLY TO THE REGION IS PROVIDED FROM TWO AUTO-TRANSFORMERS AT ESSA TS, THE 230KV TRANSMISSION LINES D1M, D2M, D3M AND D4M CONNECTING MINDEN TS TO DES JOACHIMS TS, THE 230KV CIRCUITS E8V AND E9V COMING FROM ORANGEVILLE TS AND THE SINGLE 115KV CIRCUIT S2S CONNECTING TO OWEN SOUND TS.

The existing facilities in the Region are summarized below and depicted in the single line diagram shown in Figure 3-1. The 500kV system is part of the bulk power system and is not studied as part of this report.

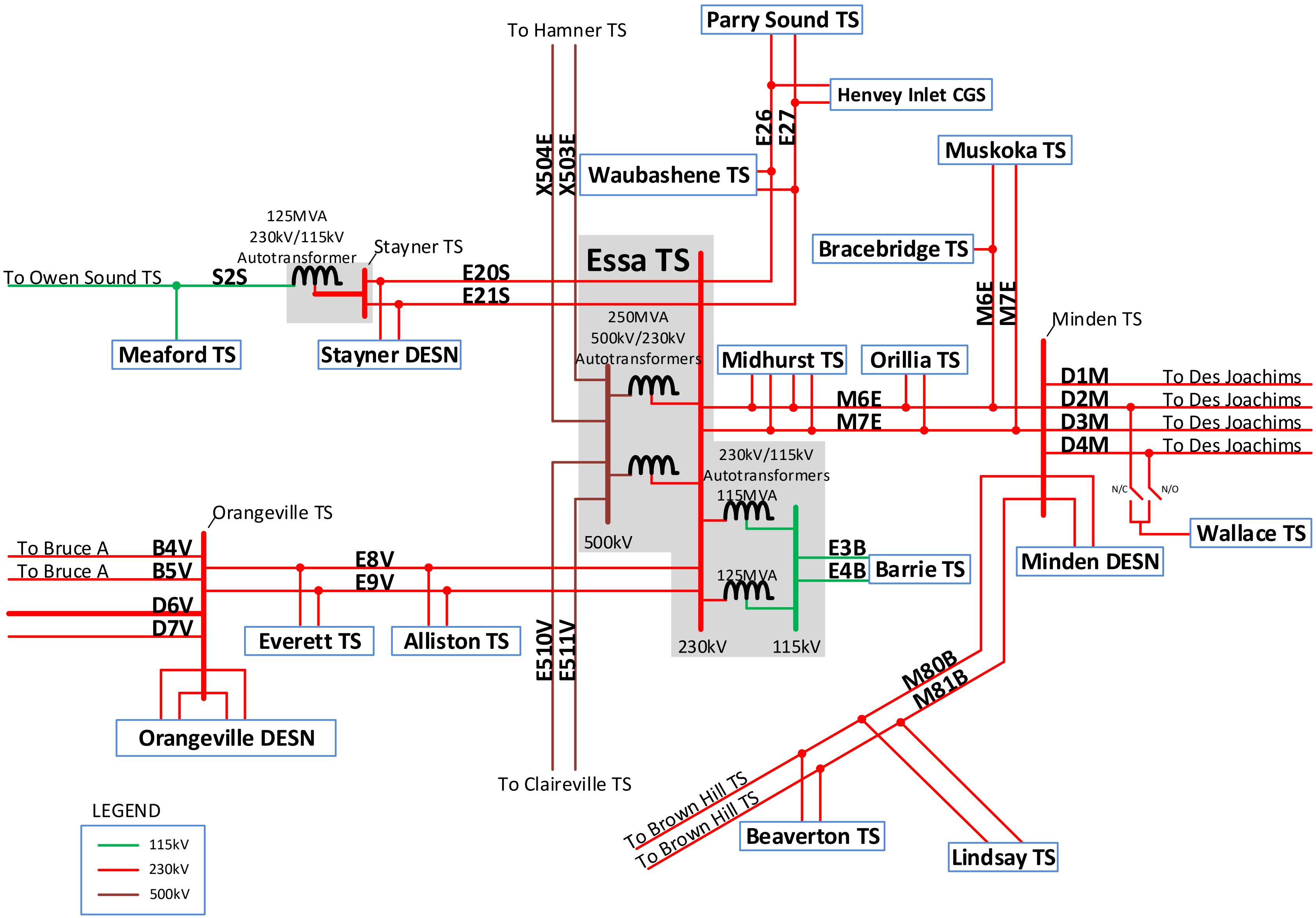
There are sixteen (16) HONI step-down transformer stations in the Region, most of which are supplied by circuits radiating out from Essa TS, and the majority of the distribution system is at 44kV, except for Orangeville TS which has 27.6kV and 44kV feeders.

The April 2020 South Georgian Bay/Muskoka Region second cycle NA report, prepared by Hydro One, considered the South Georgian Bay/Muskoka as a whole. Subsequently as a result of the Scoping Assessment, the South Georgian Bay/Muskoka Region was divided into two sub-regions, Barrie/Innisfil Sub-Region and Parry Sound-Muskoka Sub-Region.

The Barrie/Innisfil Sub-Region roughly encompasses the City of Barrie and the towns of Innisfil, New Tecumseth and Bradford West Gwillimbury. It includes the townships of Essa, Springwater, Clearview and Mulmur, Adjala-Tosorontio. The Barrie/Innisfil Sub-Region includes the areas supplied by Midhurst TS, Barrie TS, Everett TS, and Alliston TS, and transmission circuits E8V/E9V, E3B/E4B, and M6E/M7E.

This Parry Sound/Muskoka sub-region roughly encompasses the Districts of Muskoka and Parry Sound, and the northern part of Simcoe County. The Parry Sound/Muskoka Sub-Region includes the areas supplied by Parry Sound TS, Waubaushene TS, Orillia TS, Bracebridge TS, Muskoka TS, Minden TS, and transmission circuits M6E/M7E and E26/E27.
The following circuits are not included in the South Georgian Bay/Muskoka Region:

- The 230kV circuits, B4V and B5V, and all stations which they supply. These circuits and stations are included in the Greater Bruce/Huron Region.
- The 230kV circuits, D6V and D7V, and all stations which they supply. These circuits and stations are included in the Kitchener/Waterloo/Cambridge/Guelph Region.



Note: BATU project will convert E3B/E4B to 230kV and connect Barrie TS directly to Essa TS 230kV bus (In-Service 2023)

Figure 3-1 South Georgian Bay-Muskoka Region Single Line Diagram

4. TRANSMISSION FACILITIES COMPLETED IN THE LAST TEN YEARS AND/OR UNDERWAY

OVER THE LAST TEN YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN COMPLETED BY HYDRO ONE, OR ARE CURRENTLY UNDERWAY, AIMED AT IMPROVING THE SUPPLY CAPABILITY AND RELIABILITY IN THE SOUTH GEORGIAN BAY-MUSKOKA REGION.

A summary and brief description of the major projects completed and/or currently underway over the last ten years is provided below:

- Midhurst TS and Orillia TS Capacitor Banks (2012) – Installation of four (4) 44kV, 32.4 MVAr capacitor banks at Midhurst TS and Orillia TS (two banks at each station) to minimize post-contingency voltage decline on the low voltage buses at both stations and defer the overload on circuit M6E.

  Meaford TS Transformer Replacement (2015) – The 115/44 kV, 25/42 MVA T1/T2 transformers were at end-of-life (EOL) and replaced like-for-like.

- Orillia TS M6E/M7E Switches (2021) – Loss of M6E and M7E resulted in violation of ORTAC load restoration criteria based on the peak load forecast. Hydro One installed new 230kV motorized disconnect switches on the M6E and M7E circuits (at Orillia TS) to improve load restoration time.

- Minden TS Transformer Replacement (2021) – The 230/44kV, 42MVA T1/T2 transformers were at EOL and replaced with new 230/44kV 83MVA units.

The following projects are underway:

- Barrie TS (2023) – This investment will convert the existing 115kV E3B/E4B circuits to 230kV and connect directly to the Essa 230kV bus. Barrie TS will be rebuilt with new 230/44kV 75/125MVA transformers and connect to the new 230kV E28/E29B circuits. The 230/115kV autotransformers at Essa TS will also be removed as part of this investment.

- Orangeville (2023) – Based on asset condition assessment the existing T3/T4 230/44kV 83MVA transformers will be replaced with new 125MVA units and also, the existing nonstandard three winding 230/44/27.6 125MVA transformers (T1/T2) be replaced with new dual winding 230/27.6, 83MVA units. This investment also involves reconfiguration of low voltage equipment and transfering existing 44kV feeders from T1/T2 DESN to the T3/T4 DESN.

- Parry Sound TS (2023) - Parry Sound TS transformer supply capacity has been exceeded, and transformers have also been assessed at being end of life and in need of replacement due to their asset conditions. Hydro One will be installing new 230/44kV 83MVA transformers units to address both end of life and capacity needs at this station.

5. FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

During the study period, the load in the South Georgian Bay-Muskoka Region is expected to grow at an average annual rate of approximately 2% (summer) and 1.8% (winter) from 2022 to 2032.

Figure 5-1 shows the South Georgian Bay-Muskoka Region extreme summer weather net load forecast from 2022 to 2042. The load forecasts from the Barrie Innisfil sub-region IRRP and Parry Sound/Muskoka sub-region IRRP were adopted as agreed to by the TWG. The load forecast shown is the regional non-coincident forecast, representing the sum of the load in the area for the step-down transformer stations.
Non-coincident forecast for the individual stations in the region is available in Appendix D and is used to determine any need for station capacity relief.

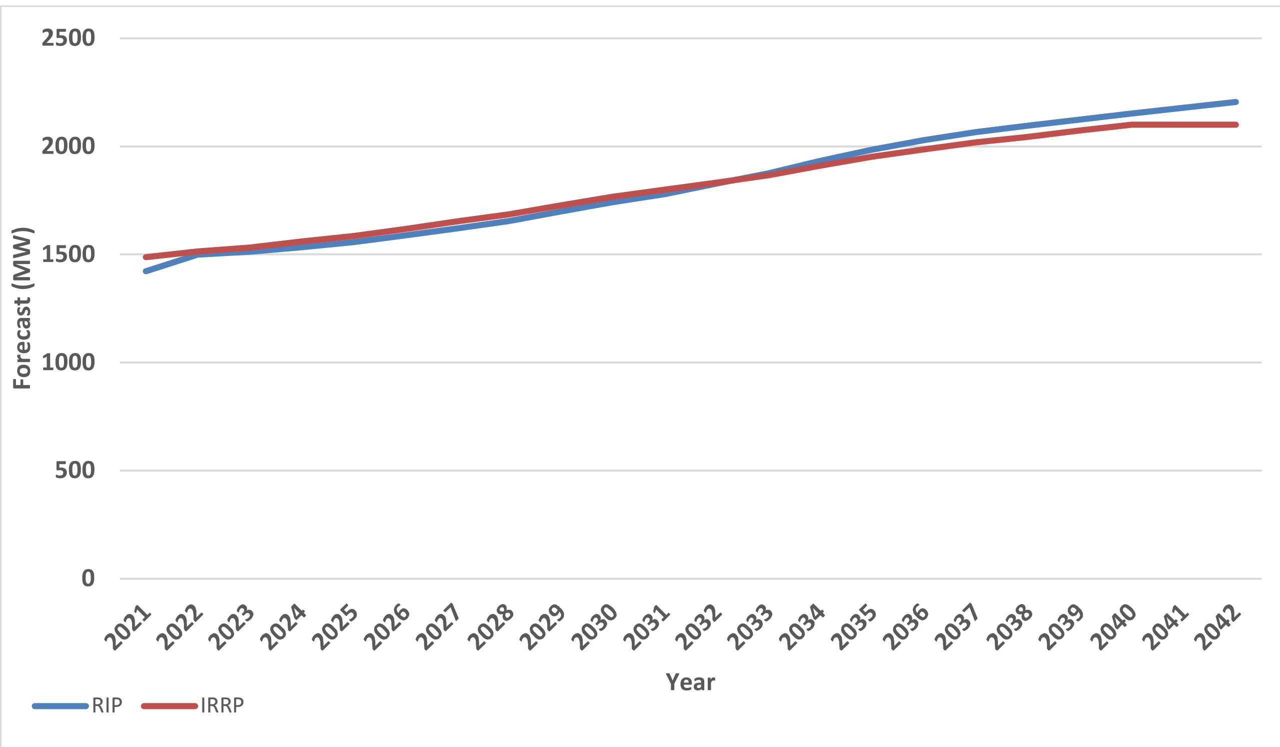


Figure 5-1 South Georgian Bay-Muskoka Region Non–Coincident Net Summer Peak Load Forecast

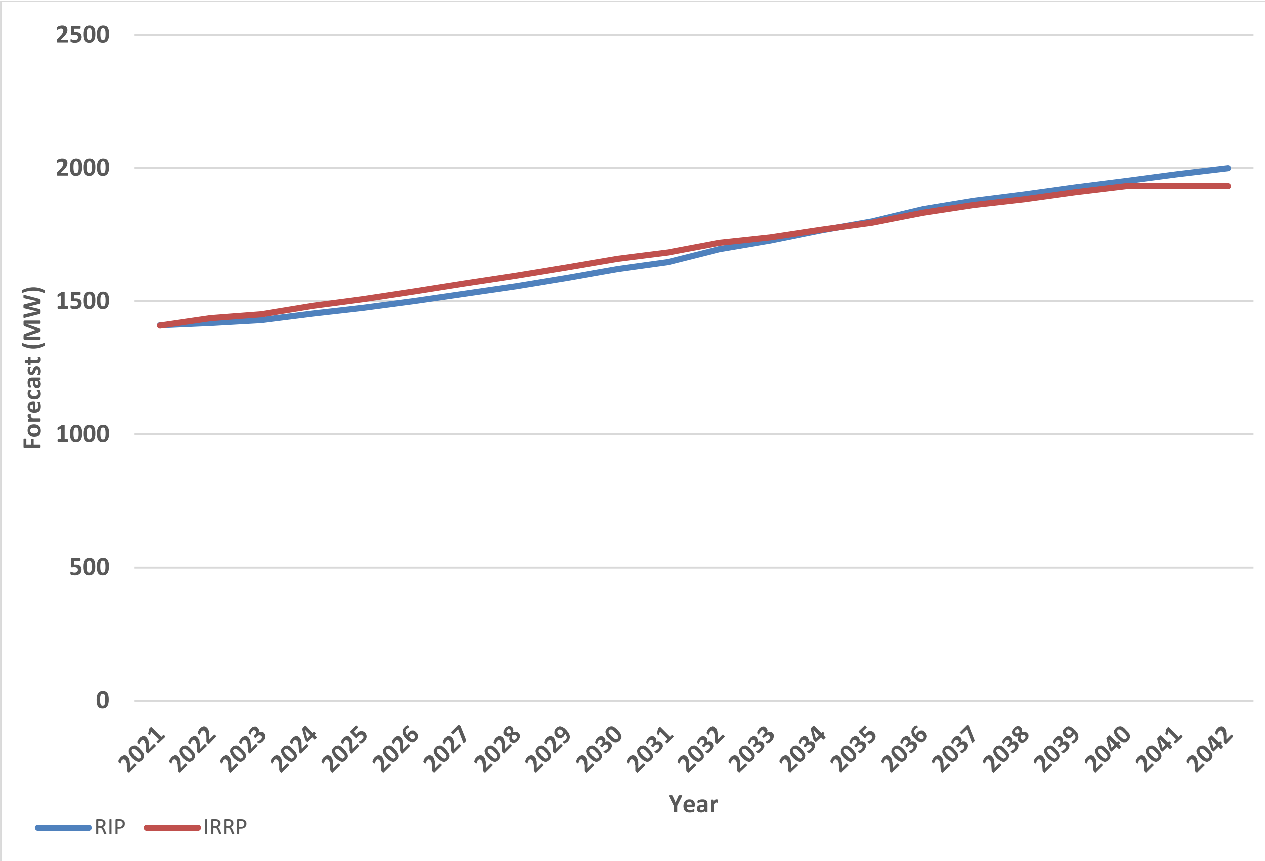


Figure 5-2 South Georgian Bay-Muskoka Region Non–Coincident Net Winter Peak Load Forecast

5.2 Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2022-2032. However, a longer term forecast up to 2042 is provided to identify long-term needs and align with the IESO's Barrie Innisfil sub-region and Parry Sound/Muskoka sub-region IRRPs.
- LDCs reconfirmed load forecasts up to 2040. The additional two years of forecasts were extrapolated based on growth rate as a reasonable position to complete the 20 years period.
- All planned facilities for which work has been initiated and are listed in section 4 are assumed to be in-service.
- Both summer and winter loads were considered to assess line and transformer loadings.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks, or on the basis of historical power factor data.
- Normal planning supply capacity for transformer stations in the region is determined by the summer 10-day Limited Time Rating (LTR).
- Bulk transmission line capacity adequacy is assessed by using coincident peak loads in the area. Capacity assessment for radial lines and stepdown transformer stations use non-coincident peak loads.
- Adequacy assessment is conducted as per ORTAC.

6. ADEQUACY OF EXISTING FACILITIES AND REGIONAL NEEDS

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION SYSTEM AND TRANSFORMER STATION FACILITIES SUPPLYING THE SOUTH GEORGIAN BAY-MUSKOKA REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE NEAR AND MID-TERM PERIOD.

Within the current regional planning cycle, four regional assessments have been conducted for the South Georgian Bay-Muskoka Region. The findings of these assessments are inputs to this RIP. These assessments are:

1) South Georgian Bay-Muskoka Region second cycle Needs Assessment (NA) Report, April 2020
2) South Georgian Bay/Muskoka second cycle Scoping Assessment Outcome Report, November 2020
3) Barrie/Innisfil sub-region second cycle Integrated Regional Resource Planning (IRRP), May 2022
4) Parry Sound/Muskoka sub-region second cycle Integrated Regional Resource Planning (IRRP), May 2022

The NA and IRRP reports identified several regional needs based on the forecasted load demand over the near to mid-term period. A detailed description and status of plans to meet these needs is given in Section 7.

This section provides a review of the adequacy of the transmission lines and stations in the South Georgian Bay/Muskoka Region. The adequacy is assessed using the load forecasts provided in Appendices D. The assessment assumes all projects currently underway (described in section 4) are in-service and specifically, the Barrie Area Transmission Reinforcement project and Orangeville/Parry Sound transformer replacements are in-service by 2023.

Sections 6.1- 6.3 present the results of the adequacy assessment and Table 6-1 lists the region’s near, mid, and long-term needs identified in both the IRRP and RIP phases.

6.1 500 kV and 230 kV Transmission Facilities

All 500 kV and 230 kV transmission circuits in the South Georgian Bay-Muskoka Region are classified as part of the Bulk Electricity System (“BES”). They connect the Region to the rest of Ontario’s transmission system. The 230 kV circuits also serve local area stations within the region and the power flow on these circuits vary depending on the bulk system transfers as well as the local area loads.

6.1.1 500/230 kV Transformation Facilities

Bulk power supply to the South Georgian Bay-Muskoka Region is provided by 500/230 kV autotransformers at Essa TS which serves as a hub for major power flows between Hanmer TS (Sudbury) and Clairville TS (Toronto). Additional support for the region is provided from the 230 kV generation facilities (Des Joachims GS, Henvey Inlet CGS)

6.1.2 230 & 115 kV Transmission Circuits

The 230kV circuits in the region are as follows;

- E20S/E21S (Essa TS x Stayner TS)
- E26/E27 (Essa TS x Parry Sound TS)
- M6E/M7E (Essa TS x Minden TS)
- D1M/D2M/D3M/D4M (Minden TS x Des Joachims)
- 115 kV - S2S (Stayner TS x Owen Sound TS)

Table 6-1 below highlights the line section(s) and violations identified in the IRRP and reaffirmed in this RIP.

Table 6-1 South Georgian Bay-Muskoka Region - Lines Sections Exceeding ratings

No.	Line	Section	Contingency	Year Line Rating exceeded
1	M6E/M7E	Essa TS x Midhurst TS	N-1[1]	2034
2	M6E	Minden x Coopers Fls JCT	N-1[2]	2038
3	M6E	Minden x Coopers Fls JCT	N-1-1[3]	2040

[1] Loss of one of either M6E or M7E will result in overload of the companion circuit.
[2] Minden TS HL7 breaker fail.
[3] M7E O/S followed by loss of Essa TS T3

The options and preferred solutions to address these needs are discussed further in Section 7 of the report.

6.2 Step-Down Transformation Facilities

There are sixteen (16) step-down transformer stations in the South Georgian Bay-Muskoka Region as listed in Table 6-2.

Table 6-2 South Georgian Bay-Muskoka Region - Step-Down Transformer Stations

Alliston TS	Everett TS	Minden TS	Parry Sound TS
Barrie TS	Lindsay TS	Muskoka TS	Stayner TS
Beaverton TS	Meaford TS	Orangeville TS	Wallace TS
Bracebridge TS	Midhurst TS	Orillia TS	Waubaushene TS

This RIP reviewed the step-down transformation capacity for the stations within the South Georgian Bay-Muskoka Region. The NA and IRRP studies had previously indicated that the following stations require capacity relief within the study period. This RIP has further confirmed those needs and based on the load forecast, the stations which require capacity relief during the 2022-2032 study period are shown in Table 6-3 below. The need timeframe defines the time when the peak load forecast exceeds the most limiting seasonal (summer or winter) 10-day LTR.

Table 6-3 South Georgian Bay-Muskoka Region - Stations Requiring Relief in the study period (2022-2032)

Station	Capacity (MW)	2022 Loading (MW)	Need Date
Everett TS	86	85	Immediate
Barrie TS	162[3]	98	2027
Waubaushene TS	94	90	2027

Further, based on the load forecast, the stations requiring relief beyond the study period are listed below:

- Midhurst TS (T1/T2) – 2033
- Midhurst TS (T3/T4) – 2034

6.3 Asset Renewal for Major HV Transmission Equipment

A number of Hydro One facilities in the South Georgian Bay-Muskoka Region will require replacement over the 2022-2032 study period as listed in Table 6-4 below.

Asset renewal needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as (but not limited to):

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

The major high voltage equipment considered includes the following:

1. 230/115kV autotransformers;
2. 230 and 115kV load serving step-down transformers;
3. 230 and 115kV breakers where:
    - replacement of six breakers or more than 50% of station breakers, the lesser of the two
4. 230 and 115kV transmission lines requiring refurbishment where:
    - Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like
5. 230 and 115kV underground cable requiring replacement where:
    - Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like

[3] After completion of the BATU project

Table 6-4 South Georgian Bay-Muskoka Region - Planned Replacement Work

No.	Station / Line Section	Planned In-Service Date*
	In Execution/Construction	
1	Barrie TS (T1/T2)	2023
2	Orangeville TS (T1/T2 & T3/T4)	2023
3	Parry Sound TS (T1/T2)	2023
	In Development	
4	Wallace TS (T3/T4)	2025
5	Midhurst TS (T4)	2026
6	Orillia TS (T2)	2025
7	Bracebridge TS (T1)	2026
8	Waubaushene TS T5/T6	2027
9	Alliston TS (T3/T4)	2030
10	M6E/M7E – Cooper Falls Jct x Orillia TS	2026
11	E8V/E9V – Orangeville TS x Essa Jct	2027
12	D1M/D2M – Otter Creek Jct x Minden TS	2028

*The planned in-service dates are tentative and subject to change.

6.4 Load Security and Load Restoration

Load security and load restoration needs were reviewed as part of the current study. The ORTAC Section 7 requires that no more than 600 MW of load be lost as a result of a double circuit contingency.

Further, loads are to be restored in the restoration times[4] specified as follows:

- All loads must be restored within 8 hours.
- Load interrupted in excess of 150 MW must be restored within 4 hours.
- Load interruped in excess of 250 MW must be restored within 30 minutes.

This RIP further confirms there are no identified load security and restoration violations within the study period. The technical working group does not recommend any further action.

[4] These approximate restoration times are intended for locations that are near staffed centres. In more remote locations, restoration times should be commensurate with travel times and accessibility

7. REGIONAL PLANS

THIS SECTION DISCUSSES NEEDS, PRESENTS WIRES ALTERNATIVES AND THE PREFERRED WIRES SOLUTIONS FOR ADDRESSING THE ELECTRICAL SUPPLY NEEDS FOR THE SOUTH GEORGIAN BAY-MUSKOKA REGION.

The electrical infrastructure needs for the South Georgian Bay-Muskoka Region are summarized in Table 7-1. These needs include those previously identified in the NA for the South Georgian Bay-Muskoka Region and IRRPs for the Barrie/Innisfil and the Parry Sound/Muskoka Sub-Regions as well as any new needs identified during the RIP phase. All estimated costs included in the altnerative analysis are considered as planning budgetary estimates and are used for comparative purposes only.

Table 7-1 South Georgian Bay-Muskoka Region – Near, Medium and Long Term Needs

Type	Section	Needs	Timing
Station Capacity	7.1	Everett TS	2023
		Barrie TS	2027
		Waubaushene	2027
		Midhurst TS	2033/2034
		Minden TS	2036
Supply Capacity	7.2	M6E/M7E (Essa x Midhurst)	2034
		M6E/M7E (Minden x Coopers Fls)	2038
Asset Renewal for Major HV Transmission Equipment	7.3.1	M6E/M7E (Orillia x Coopers Fls)	2026
		E8V/E9V (Orangeville TS x Essa Jct)	2027
		D1M/D2M (Otter Creek Jct x Minden TS)	2028
	7.3.2	Wallace TS (T3/T4)	2025
		Midhurst TS (T4)	2026
		Orillia TS (T2)	2025
		Bracebridge TS (T1)	2026
		Waubaushene TS (T5/T6)	2027
		Alliston TS (T3/T4)	2030
Load Security/Restoration	7.4	None Identified in this planning cycle	-

7.1 Station Capacity Needs

7.1.1 Everett TS

Everett TS is 230/44kV 50/83MVA transformer station with a summer and winter 10-Day LTR of 86MW. Load at this station is forecasted to increase up to 105MW by the end of 2032. Supply capacity is presently limited by a current transformer (CT) ratio setting on the transformer breaker bushing, thereby restricting the ability to utilize the full supply capability of the transformers.

Table 7-2 Everett TS Load Forecast

Station	LTR (MW)		Load Forecast									
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Everett TS	86	85	86	87	88	90	92	93	95	97	100	105

The following alternatives were considered to address Everett TS capacity need:

Alternative 1 - Maintain Status Quo: This alternative was considered and rejected as it does not provide supply capacity to area customers during the study period. Under this scenario load cannot be increased at this station.

Alternative 2 – Replace and upgrade T1/T2 with new 75/125MVA units: Under this alternative the existing T1/T2 transformers will be replaced with new 75/125MVA transformers. This was considered and rejected as this would result in additional cost of approximately $10M and prematurely retire the T1/T2 transformers. These transformers remain in acceptable condition are not scheduled to be replaced by Hydro One within the study period.

Alternative 3 – Modify the CT Ratio: This alternative would require modifying the CT ratio of the low voltage transformer breaker CTs to realize the full supply capacity of the transformers.

The TWG recommends Alternative 3 as the preferred and cost effective alternative for addressing the need. CT ratios are established based on expected loading at a station and typically lower when transformer stations are initially constructed. As the load increases these ratios must be adjusted to ensure protection, control and metering continue to operate as intended. This solution utilizes existing assets without incurring additional high capital expenditures and will allow the station LTR to increase to 108MW (summer) and 177MW (winter) once completed. The budgetary cost for this alternative is expected to be $0.5M

7.1.2 Barrie TS

The Barrie Area Transmission Upgrade (BATU) project is presently underway and scheduled to be in-service in 2023. Barrie TS will be upgraded to a new 230/44kV 125MVA transformer station with 8 feeder positions (six for Alectra Utilities and two for Hydro One Distribution with InnPower as an embedded customer).

Barrie TS will have a 10-Day LTR of 162MW and the forecasted load will exceed its normal supply capacity in 2028 based on the summer demand forecast (see Table 7-3 below). Coincident with the station capacity violation, Hydro One distribution and its embedded LDC (InnPower) will also see a supply capacity constraint on their two 44kV feeders in 2028. Minor capacity increases can be accommodated on the 44kV system, but only on an emergency basis and cannot be used as a permanent supply solution for increased load growth. InnPower will need new supply capacity into the Innisfil service territory to service its load growth beyond the 2-feeder capacity that Barrie TS can supply.

An Innisfil supply study was completed to evaluate supply options for InnPower and consequently help to offload demand from Barrie TS. Results of this study are described in the alternatives below.

Table 7-3 Barrie TS Load Forecast

Station	LTR (MW)		Load Forecast									
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Barrie TS	162	98	119	128	141	154	161	163	164	167	170	174

Alternative 1 - Maintain Status Quo:

This alternative was considered and rejected as it does not address future station capacity restrictions at Barrie TS, nor does it provide InnPower with the mid-term supply capacity required for load growth in their service territory.

Alternative 2 – Inn Power to connect to existing Alectra Feeder as embedded customer:

This solution was initially discussed by the TWG in the first planning cycle to provide increased supply to InnPower without additional station work at Barrie TS. Spare feeder capacity is not available and thus, this alternative fails to meet the full supply needs within the study period and will need to be combined with alternate solutions. This alternative was rejected on this basis, and thus costs have not been explored further.

Alternative 3 – Install an Additional 44kV feeder position from Barrie TS:

This solution was discussed with the TWG and closely relates to Alternative 2. A new dedicated feeder position for InnPower will provide up to 25MW supply capacity, however this solution would still fail to meet the full supply needs of InnPower within the study period, and the increased load will still be seen at Barrie TS triggering a capacity need in 2028. This solution will need to be combined with alternate solutions to relieve Barrie TS. The combined transmission and distribution costs to install and construct a new distribution line from Barrie TS is estimated to cost $20M, however this alternative is rejected as it does address capacity needs at Barrie TS.

Alternative 4 – Load existing 44kV supply feeders beyond normal capacity

This alternative was explored by the TWG to increase supply on the two 44kV feeders from Barrie TS beyond the normal supply capacity. This solution requires increased voltage support on the distribution system along the feeders and will provide up to 20MW increased supply capacity (10MW/feeder). Distribution costs to facilitate increased feeder loading is estimated to cost $8M, however this alternative is rejected as it still does address Capacity needs at Barrie TS.

Alternative 5 – Provide 230kV tap connection to Innisfil service territory for new transformer station

This alternative involves construction of a 230/27.6kV 50/83MVA transformer station in Innisfil to supply the increased load demand forecast. This station will connect directly to the 230kV E28B/E29B circuits which will be completed in 2023 as part of the Barrie Area Transmission Upgrade project. A new 9km double circuit 230kV transmission line will be constructed to connect this new transformer station.

This alternative will provide increased supply capacity for InnPower within the study period and allow for load growth in the future. This alternative can be utilized as a standalone solution to meet the needs without additional interim investments or in conjunction with other alternatives presented above. This solution also allows InnPower to transfer load to this station which would otherwise be connected to Alliston TS. This transfer of load helps to mitigate a capacity need during the study period which would see an additional expenditure to increase supply capacity on the T3/T4 DESN at Alliston TS.

The estimated cost for this investment is expected to be $44M which is comprised of $14M for transmission line construction and $30M for a new transformer station.

The TWG recommends proceeding with Alternative 5. This alternative provides a robust transmission solution to meet InnPower's demand forecast and will also allow for future load growth beyond the study period. This solution will also help to relieve Barrie TS which will see a capacity need in 2028. Based on findings in the Needs Assessment and IRRP, Hydro One and InnPower have commenced development work on this alternative to meet the 2028 need date and TWG recommends continuing with this work.

7.1.3 Waubaushene TS

Waubaushene TS presently has 230/44 83MVA transformers (T5/T6) with a summer LTR of 94MW. This station will exceed its normal supply capacity in 2028 (see Table 7-4 below).

Summer overloading at this station continues to be of concern and the TWG agrees that a solution is required to address this need. Hydro One Distribution has permanently transferred 10MW of load from Waubaushene TS to Midhurst TS to help with recent summer loading concerns, however a solution is required to further address the upcoming supply capacity need.

Table 7-4 Waubaushene TS Load Forecast

Station	LTR (MW)	Load Forecast										
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Waubaushene TS	94	90	90	91	92	93	94	96	97	99	100	102

Alternative 1 - Maintain Status Quo: This solution is not recommended as it does not address the supply capacity need at the station. This solution will prevent load growth at this station beyond 2027.

Alternative 2 – Load Transfer to neighboring stations

This solution was explored during the NA and IRRP phase. Hydro One distribution assessed transfer capability to other stations and determined that a maximum of 10MW of load could be transferred, and this was completed in Q1 2022. Further transfers are not feasible without significant distribution construction costs and regulators on the low voltage network estimated to be $ 5-10 M depending on feeder construction and voltage regulation.

Alternative 3 – Replace End-of-Life Waubaushene TS T5/T6 transformers with upgraded 125MVA units.

Replace and upgrade existing T5/T6 transformers with larger 75/125MVA units. This solution will increase supply capacity to allow load to continue to grow as per the demand forecast.

The TWG recommends Alternative 3 as the preferred and cost-effective alternative for addressing the need. The existing T5/T6 transformers at Waubaushene TS have been identified by Hydro One as requiring replacement based on their asset condition and is planned for replacement in 2027. This date coincides with the supply capacity need timing as shown in Table 7.4 and thus the TWG agrees this is the ideal scenario to address the capacity need and right size the transformers. The budgetary cost for the replacement and upgrade of the transformers is expected to be $20M. Hydro One will follow Ontario Energy Board (OEB) approved procedures to determine appropriate cost allocation as this project addresses both a sustainment and capacity upgrade need.

7.1.4 Midhurst TS and Minden TS

As identified in Table 7-1, the stations listed below will require capacity relief beyond 2032. Based on the long-term horizon of these needs the load at these stations will be reviewed in the next regional planning cycle. The timing for capacity relief of these stations is shown below:

- Midhurst TS T1/T2: 2033 and Midhurst TS T3/T4: 2034
- Minden TS T3/T4: 2036

7.2 Supply Capacity Needs

The M6E/M7E circuits are a 230kV double circuit transmission line forming a critical path between Essa TS and Minden TS. These circuits are approximately 120 km long and serve to provide connection to load serving stations and provide a path for network flows. Based on the coincident load forecast of the stations in the region, sections of this line will start to experience supply capacity violations at the end of the study period and will require mitigating solutions to allow for increased flows. The two circuit sections are described below:

1. Essa TS x Midhurst TS (10km) – For the loss of M6E or M7E, the companion circuit will exceed its Long-Term Emergency (LTE) rating as early as 2034 based on theload forecast.

2. Minden TS x Coopers Falls JCT (51km) – This section of transmission line will experience Long-Term Emergency (LTE) rating violations as early as 2038 for a Minden TS HL7 breaker failure, and Essa T3 contingency with M7E out of service.

Based on the long-term horizon of these needs solutions to address them will be further explored in the next regional planning cycle. Flows on this line and its violations are heavily influenced by area resource assumptions and demand forecast of the transformer stations connected to this circuits. IESO has also identified that incremental cost effective CDM, storage and other non-wires alternatives will be explored to address this need. The TWG will review this need in the next regionalplanning cycle and initiate an investment should this violation be advanced due to changing system conditions.

7.3 Asset Renewal Needs for Major HV Transmission Equipment

A number of Hydro One facilities in the South Georgian Bay-Muskoka Region will require replacement over the 2022-2032 study period. Hydro One is the only Transmission Asset Owner (TAO) in the Region.

The asset renewal assessment considers options for right sizing the equipment such as:

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

7.3.1 Transmission Line Refurbishment

The following transmission line sections were identified by Hydro One as requiring refurbishment over the study period based on asset condition assessment:

1. M6E/M7E Orillia x Coopers Fls – This is a 50km 230kV line section that was in-serviced in 1950. Based on asset condition assessment, this line section requires like for like refurbishment to ensure supply reliability and safety is maintained. The planned in-service date for this investment is 2026.

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

3. D1M / D2M Otter Creek JCT x Minden TS – This is a 124km 230kV line section that was in-serviced in 1950. Based on asset condition assessment, this line section requires like for like refurbishment to ensure supply reliability and safety is maintained. The planned in-service date for this investment is 2028.

7.3.2 Transmission Station Refurbishment

Hydro One identified a number of step-down transformers as requiring replacement over the study period based on asset condition assessment. Details of the planned work as recommended by the TWG are given in Table 7-5 below.

Table 7-5 Asset Renewal Plan-Transmission Stations

No.	Station	Planned In-Service Date*
	In Execution/Construction	
1	Barrie TS Replace and upgrade existing 115/44kV 83MVA transformers (T1/T2) with new 230kV/44kV 125MVA transformers. Remove Essa TS T1/T2 autotransformers and convert Barrie TS supply circuits (E3B/E4B) from 115kV to 230kV. This investment is also known as Barrie Area Transmission Upgrade (BATU) and will include replacement of end of life equipment at Essa TS, in addition to increasing both station and supply capacity to the area.	2023
2	Orangeville TS Replace and upgrade existing 230/44kV 83MVA transformers (T3/T4) with new 230/44kV 125MVA units. Replace and upgrade existing nonstandard three winding 230/44/27.6 125MVA transformers (T1/T2) with new dual winding 230/27.6 83MVA units. Reconfigure low voltage equipment and transfer existing 44kV feeders from T1/T2 DESN to the T3/T4 DESN. This replacement plan will decrease the risk of equipment failure and contribute to maintaining supply reliability to Orangeville Hydro and Hydro One Distribution customers in the Orangeville area.	2023
3	Parry Sound TS Replace existing 230/44kV 42MVA transformers (T1/T2) with new 230/44kV 83MVA units and replace station protection and station service equipment. Replacement of these power transformers will help to maintain the reliability of supply and provide increased supply capacity to customers in the area by right sizing to 83MVA units.	2024
	In Development	
4	Wallace TS Replace existing 230/44kV 42MVA transformers (T3/T4) with new 230/44kV 42MVA units. Replacement of Oil circuit breakers will also be part of this investment. This investment will help maintaining reliability of supply to Hydro One Distribution customers and reduce the risk of interruptions caused by station equipment failure.	2025

5	Midhurst TS Replace existing 230/44kV 125MVA T4 transformer with a new like-for-like unit. The T3/T4 DESN presently supplies load to Alectra though 8 x 44kV feeders. T4 is the sole unit that has been identified as requiring replacement due to poor asset condition. This investment will help maintain reliability of supply to area customers and reduce the risk of interruptions caused by transformer asset failure. Load growth in the area will be reviewed in the next regional planning cycle. The TWG will ensure solutions to increase supply capacity in the region are explored in advance of the need date.	2026
6	Orillia TS Replace existing 230/44kV 125MVA T2 transformer with a new like-for-like 230/44kV 125MVA unit. The T1 transformer was replaced in 2015 after failure and does not require replacement during this study period. This investment will help maintain reliability of supply to Hydro One Distribution customersand decrease the risk of interruptions caused by failure of transformer T2.	2025
7	Bracebridge TS Replace existing 230/44kV 83MVA transformer (T1) with new like-for-like 230/44kV 83MVA unit. Bracebridge TS presently has one transformer (T1) and is used to supply 2 x 44kV feeders and a backup for industrial pipeline operation. The load at this station is not expected to trigger installation of a second transformer and thus like-for-like replacement of T1 will be sufficient during the study period. This investment will help maintain reliability of supply to area customers and reduce the risk of interruptions caused by transformer asset failure.	2026
8	Waubaushene TS Replace existing 230/44 83MVA transformers (T5/T6) with new 125MVA units. This investment will help to maintain reliability of supply to area customers and provide increased supply capacity to meet demand forecast.	2027
9	Alliston TS Replace existing 230/44kV 83MVA transformers (T3/T4) with new like-for-like 230/44kV 83MVA units.	2030

	This investment will help maintain reliability of supply to area customers and reduce the risk of interruptions caused by transformer asset failure and removal of legacy obsolete equipment.	

*The planned in-service year is tentative and is subject to change.

The above asset replacement plans have taken “right sizing” into consideration. All transformer replacements in the development phase are planned to be replacewith like-for-like units based on the load forecast in the study period and Hydro One standard equipment. The TWG recommends that Hydro One proceed with the above station sustainment work to ensure system reliability is maintained.

7.4 Load Security / Restoration

As indicated in section 6.4 there are no load security or restoration violations in the SGB-Muskoka region over the study period. The TWG will continue to monitor and take corrective action as needed.

7.5 Long Term Considerations

Like many other regions in Ontario, load growth in the SGB-Muskoka region will be directly impacted by new energy programs specifically those which help drive electrification. In addition, it is anticipated large market participants will also have incentive programs to modify operations/technologies to reduce greenhouse emissions. Details of how future programs will impact demand is unknown at this time thus the TWG will continue to monitor these trends throughout planning cycles to identify areas in need of investment.

8. CONCLUSION AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE SOUTH GEORGIAN BAY-MUSKOKA REGION.

The major infrastructure investments recommended by the Technical Working Group (TWG) in the near and medium-term planning horizon (2022-2032) are provided in Table 8-1 below, along with their planned in-service dates and budgetary estimates for planning purposes.

Table 8-1 Recommended Plans in Region over the Next 10 Years

Need	Station / Circuit	Investment Description	Lead	Planned In-Service Date[5]	Cost ($M)[6]
Station Capacity	Everett TS	Modify current transformer (CT) ratio setting the low voltage 44kV transformer breakers	HONI	2023	0.5
	Barrie TS	Construct new 230/27.6kV 83MVA transformer station and extend and connect to 230kV E28B/E29B circuits	HONI / Inn Power	2027	44
	Waubaushene TS	Replace and upgrade existing end-of-life 230/44kV 83MVA transformers (T5/T6) with new 230/44kV 125MVA units.	HONI / Hydro One Dx	2027	20
Asset Renewal Needs for Major HV Transmission Equipment	M6E / M7E (Orillia TS x Coopers Fls)	Replace transmission line conductor and associated assets. (25km)	HONI	2026	30
	E8V / E9V (Orangeville TS x Essa JCT)	Replace transmission line conductor and associated assets. (56km)	HONI	2027	70
	D1M / D2M (Minden TS x Otter Creek JCT)	Replace transmission line conductor and associated assets. (62km)	HONI	2028	70
	Wallace TS	Replace existing 230/44kV 42MVA transformers (T3/T4) with new 230/44kV 42MVA units.	HONI	2030	25
	Midhurst TS	Replace existing 230/44kV 125MVA transformer (T4) with a new 230/44kV 125MVA unit.	HONI	2026	12
	Orillia TS	Replace existing 230/44kV 125MVA transformer (T2) with new 230/44kV 125MVA unit	HONI	2025	12
	Bracebridge TS	Replace existing 230/44kV 83MVA transformer (T1) with new 230/44kV 83MVA unit	HONI	2026	10
	Alliston TS	Replace existing 230/44kV 83MVA transformer (T3/T4) with new 230/44kV 83MVA units	HONI	2030	16

[5] The planned in-service dates are tentative and subject to change.

[6] Costs are based on budgetary planning estimates and excludes the cost for distribution infrastructure (if required).

The South Georgian Bay-Muskoka TWG recommends Hydro One and LDCs continue with the implementation of infrastructure investments listed in Table 8-1. All the other identified needs/options in the long-term will be further reviewed by the TWG in the next regional planning cycle.

9. REFERENCES

[1] Independent Electricity System Operator, Barrie/Innisfil IRRP (2022)

[2] Independent Electricity System Operator, Parry Sound Muskoka IRRP (2022)

[3] Hydro One, South Georgian Bay/Muskoka Needs Assessment (2020)

[4] Hydro One, South Georgian Bay/Muskoka RIP (2017)

[5] Independent Electricity System Operator, Barrie/Innisfil IRRP (2016)

[6] Independent Electricity System Operator, Parry Sound/Muskoka IRRP (2016)

[7] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0 August 07, 2007

[8] Ontario Energy Board, Transmission System Code (2018)

[9] Ontario Energy Board, Distribution system Code (2022)

APPENDIX A. SOUTH GEORGIAN BAY-MUSKOKA REGION - STATIONS

No.	Transformer Stations	Voltages (kV)
1.	Alliston TS	230/44
2.	Barrie TS	115/44
3.	Beaverton TS	230/44
4.	Bracebridge TS	230/44
5.	Essa TS	500/230/115
6.	Everett TS	230/44
7.	Lindsay TS	230/44
8.	Meaford TS	230/44
9.	Midhurst TS	230/44
10.	Minden TS	230/44
11.	Muskoka TS	230/44
12.	Orangeville TS	230/44/27.6
13.	Orillia TS	230/44
14.	Parry Sound TS	230/44
15.	Stayner TS	230/115/44
16.	Wallace TS	230/44
17.	Waubaushene TS	230/44

APPENDIX B. SOUTH GEORGIAN BAY-MUSKOKA REGION - TRANSMISSION LINES

Sr. No.	Circuit ID	From Station	To Station	Voltage (kV)
1.	E20/E21S	Essa TS	Stayner TS	230
2.	E26/E27	Essa TS	Parry Sound TS	230
3.	M6E/M7E	Essa TS	Minden TS	230
4.	D1M/D2M	Minden TS	Des Joachims TS	230
5.	D3M/D4M	Minden TS	Des Joachims TS	230
6.	M80B/M81B	Minden TS	Brown Hill TS	230
7.	E3B/E4B	Essa TS	Barrie TS	115
8.	S2S	Stayner TS	Owen Sound TS	115

APPENDIX C. SOUTH GEORGIAN BAY-MUSKOKA REGION - DISTRIBUTORS

Sr. No.	Company	Connection Type (TX/DX)
1.	Hydro One Distribution	TX
2.	Alectra Utilities	TX/DX
3.	InnPower	DX
4.	Orangeville Hydro	DX
5	Elexicon Energy	DX
6.	Lakeland Power	DX
7.	EPCOR Electricity Dist. Ontario Inc.	DX
8.	Newmarket-Tay Power Distribution Ltd.	DX
9.	Wasaga Distribution Inc.	DX

APPENDIX D. SOUTH GEORGIAN BAY-MUSKOKA REGION - STATIONS LOAD FORECAST

Summer Net Non-Coincident Load Forecast

Station	DESN ID	LTR (MVA)	LTR(MW)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Alliston TS	T2	83	74.7	44	44	44	44	45	45	45	45	46	46	47	48	48	49	50	51	51	52	53	54	55
Alliston TS	T3/T4	112	100.8	76	80	83	86	90	93	91	91	91	92	92	93	93	93	93	93	94	94	94	94	94
Barrie TS	T1/T2	170	162.0	98	119	128	141	154	161	163	164	167	170	174	178	183	189	195	203	213	222	232	233	233
Beaverton TS	T3/T4	204	193.8	69	69	69	69	70	70	71	71	71	72	73	75	78	82	82	83	83	86	87	87	87
Bracebridge TS	T1	83	74.7	27	27	27	27	27	27	27	27	28	28	28	28	28	29	29	29	29	29	29	30	30
Everett TS	T1/T2	86	77.4	85	86	87	88	90	92	93	95	97	100	105	111	119	130	140	149	156	164	171	171	172
Lindsay TS	T1/T2	169	160.6	84	85	85	85	86	87	88	89	89	90	92	94	97	100	101	101	102	103	104	105	105
Meaford TS	T1/T2	55	52.3	33	33	33	33	33	34	34	34	34	35	37	38	38	38	38	38	39	39	39	40	40
Midhurst TS	T1/T2	171	163	150	151	153	154	156	157	159	160	162	162	163	166	167	169	170	171	173	174	175	176	176
Midhurst TS	T3/T4	166	149.4	123	107	111	115	118	122	125	129	133	136	140	144	151	156	160	163	167	171	175	176	176
Minden TS	T1/T2	58	52	44	44	44	44	44	45	45	45	46	46	46	47	47	48	48	52	52	53	53	53	53
Muskoka TS	T1/T2	179	170.1	113	114	113	113	114	115	116	117	125	125	126	127	130	132	133	134	135	136	137	137	137
Orangeville TS	T1/T2	113	101.7	49	49	52	53	53	54	55	55	56	57	59	60	62	62	63	64	65	65	66	67	67
Orangeville TS	T3/T4	170	161.5	90	91	97	98	99	100	102	103	104	106	110	111	114	116	117	119	120	122	123	124	124
Orillia TS	T1/T2	162	153.9	105	106	106	107	107	108	109	119	120	121	122	123	128	130	131	132	133	134	135	135	135
Parry Sound TS	T1/T2	113	101.7	45	46	45	47	48	50	50	51	54	54	55	55	56	56	56	57	57	58	58	58	59
Stayner TS	T3/T4	191	181.5	129	130	130	131	133	135	136	138	140	143	145	147	150	152	159	161	163	166	168	170	171
Wallace TS	T3/T4	54	48.6	36	36	36	36	36	36	36	36	36	37	37	37	37	38	38	38	38	38	38	39	40
Waubaushene TS	T5/T6	99	94.1	90	90	91	92	93	94	96	97	99	100	102	107	108	111	113	114	115	116	117	117	117

Winter Net Non-Coincident Load Forecast

Station	DESN ID	LTR (MVA)	LV Cap	LTR(MW)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Alliston TS	T2	83	N	74.7	32	32	32	32	32	33	33	33	34	34	35	35	36	36	37	37	38	38	39	40	40
Alliston TS	T3/T4	128	N	115.2	80	69	74	78	81	85	88	87	86	87	87	87	88	88	88	88	88	89	89	89	88
Barrie TS	T1/T2	200	Y	190.0	74	88	97	109	119	127	127	129	131	133	136	140	144	149	153	160	168	176	184	185	186
Beaverton TS	T3/T4	224	Y	212.8	77	78	78	78	79	79	80	80	81	81	81	82	82	83	84	84	85	88	88	89	90
Bracebridge TS	T1	83	N	74.7	34	34	34	34	34	34	34	35	35	35	35	35	35	35	36	36	36	36	36	37	38
Everett TS	T1/T2	95	N	85.5	60	61	62	63	64	65	66	67	69	71	75	81	88	99	109	118	125	132	139	139	140
Lindsay TS	T1/T2	192	Y	182.4	92	93	94	94	95	96	97	98	98	99	100	101	102	102	103	104	105	105	107	106	107
Meaford TS	T1/T2	62	Y	58.9	43	44	44	44	44	44	44	45	45	45	52	52	53	53	53	54	54	54	54	55	56
Midhurst TS	T1/T2	194	Y	184.3	116	116	117	118	119	120	121	122	123	124	125	126	127	128	128	129	130	131	132	132	133
Midhurst TS	T3/T4	191	N	171.9	96	85	88	90	93	95	98	101	103	106	108	111	114	117	119	122	125	127	130	131	132
Minden TS	T1/T2	64	N	58	55	55	55	55	55	56	56	56	57	57	57	58	58	58	59	63	63	63	64	64	65
Muskoka TS	T1/T2	209	Y	198.6	146	146	146	147	148	150	151	151	158	159	160	161	162	163	164	165	166	167	168	168	169
Orangeville TS	T1/T2	133	N	119.7	42	42	45	46	46	46	47	47	47	48	52	52	55	55	56	56	56	57	57	58	58
Orangeville TS	T3/T4	200	Y	190.0	78	78	84	85	86	86	87	87	88	89	97	97	102	103	103	104	104	105	106	107	107
Orillia TS	T1/T2	184	Y	174.8	108	109	110	111	112	112	113	123	123	124	125	126	127	128	129	130	131	132	133	133	134
Parry Sound TS	T1/T2	133	N	119.7	59	60	60	62	64	65	66	66	69	69	70	70	71	71	72	73	73	74	74	75	76
Stayner TS	T3/T4	213	Y	202.4	135	136	137	138	139	141	142	144	145	147	148	150	152	154	167	169	171	173	175	176	178
Wallace TS	T3/T4	60	N	54.0	38	38	38	38	39	39	39	39	39	39	39	40	40	40	40	40	41	41	41	42	42
Waubaushene TS	T5/T6	109	Y	103.6	74	75	76	76	77	78	79	80	80	81	82	83	84	85	86	86	87	88	89	89	90

APPENDIX E. LIST OF ACRONYMS

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
GS	Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DER	Distributed Energy Resource
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme

Appendix B: 2022 OEB Scorecard

Scorecard - Wasaga Distribution Inc.

8/30/2023

Performance Outcomes	Performance Categories	Measures		2018	2019	2020	2021	2022	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		100.00%	100.00%	100.00%	100.00%	100.00%		90.00%	
		Scheduled Appointments Met On Time		100.00%	100.00%	100.00%	100.00%	100.00%		90.00%	
		Telephone Calls Answered On Time		99.99%	99.98%	99.97%	99.91%	99.83%		65.00%	
	Customer Satisfaction	First Contact Resolution		0.128	.045%	99.9	99.9	99.9			
		Billing Accuracy		99.92%	99.97%	99.95%	99.98%	99.69%		98.00%	
		Customer Satisfaction Survey Results		81.6	81.8	81%	81	81			
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		85.60%	84.20%	84.20%	84.10%	84.10%			
		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]		0.78	1.39	2.86	1.23	0.48			1.32
		Average Number of Times that Power to a Customer is Interrupted [2]		0.62	0.61	2.39	0.63	0.46			1.09
	Asset Management	Distribution System Plan Implementation Progress		Completed	Completed	Completed	Completed	Completed			
	Cost Control	Efficiency Assessment		1	1	1	1	1			
		Total Cost per Customer [3]		$435	$468	$459	$427	$514			
		Total Cost per Km of Line [3]		$21,430	$22,913	$22,464	$21,189	$25,485			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time [4]				100.00%					
		New Micro-embedded Generation Facilities Connected On Time		100.00%	100.00%					90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		2.89	1.53	1.70	1.11	1.05			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		0.30	0.29	0.40	0.39	0.55			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.19%	9.19%	9.19%	9.19%	9.19%			
			Achieved	9.38%	7.14%	6.72%	10.70%	10.85%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor 's reported information.
4. Value displayed for 2021 reflects data from the first quarter, as the filing requirement was subsequently removed from the Reporting and Record-keeping Requirements (RRR).

Legend:

5-year trend: up, down, flat

Current year: target met, target not met

2022 Scorecard Management Discussion and Analysis ("2022 Scorecard MD&A")

The link below provides a document titled "Scorecard - Performance Measure Descriptions" that has the technical definition, plain language description and how the measure may be compared for each of the Scorecard's measures in the 2022 Scorecard MD&A: **http://www.ontarioenergyboard.ca/OEB/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf**

Scorecard MD&A - General Overview

- 2022 was an exciting and transformative year for Wasaga Distribution Inc. (WDI), marked by significant achievements and steadfast commitment to enhancing our services and infrastructure.

  Addressing the challenge of aging infrastructure remained a key priority in 2022. We recognize the importance of ensuring the reliability and resilience of our distribution system in the face of external uncontrollable events, such as adverse weather conditions. Throughout the year, we made substantial progress in our efforts to replace aging infrastructure, enhancing the overall stability of our utility network.

  WDI recognizes that our employees are the driving force behind our success. In 2022, we made strategic investments in our workforce, hiring new engineering and finance staff to further enhance our already talented team. The skilled professionals brought fresh perspectives and expertise, contributing to the continued growth and improvement of our operations.

  Throughout 2022, WDI set a new milestone with record-breaking capital investments. These investments were directed toward enhancing our infrastructure and modernizing our systems and technologies. One of the highlights of the year was the successful completion of a new sub-station. This undertaking expanded our operational capacity, ensuring that we can meet the increasing demand for electricity while maintaining the high standard of reliability that our customers expect from us.

  Our customers remain at the core of everything we do, and we continue to prioritize their needs and expectations. As part of our ongoing dedication to enhancing our customers' experience, we took significant strides in improving our communication channels through the implementation of a new website that provides user-friendly interfaces, comprehensive information and easy to use tools. Looking ahead, we remain committed to investing in initiatives that enhance customer experience, promote environmental sustainability, and deliver reliable and cost-effective electricity.

Service Quality

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

In 2022, WDI connected 395 low voltage (connections under 750 volts) new residential and small business customers within the five-day timeline as prescribed by the Ontario Energy Board. This represents an increase of 33.40% in the number of connections over 2021. WDI considers “New Services Connected on Time” as an important form of customer engagement as it is the utility’s first opportunity to meet 2022 Scorecard MD&A and/or exceed new customers’ expectations, which in turn affects the level of customer satisfaction within a utility’s territory. Consistent with 2021, in 2022 WDI connected 100% of these customers on time, which exceeds the Ontario Energy Board’s mandated target of 90% for this measure. WDI expects this trend to continue into the foreseeable future.

- ### Scheduled Appointments Met On Time

WDI scheduled 42 appointments in 2022 to connect services, disconnect services, or otherwise complete work requested by the customers. WDI considers “Scheduled Appointments Met” as an important form of customer engagement as customer preference is required for all types of appointments. While the number of scheduled appointments decreased 6.67% over the previous year, WDI met 100% of these appointments on time in 2022, which significantly exceeds the Ontario Energy Board’s mandated target of 90% for this measure. WDI expects this trend to continue into the foreseeable future.

- ### Telephone Calls Answered On Time

In 2022, WDI received 14,181 telephone calls from its customers. This represents a decrease of 17.14% in the number of calls over 2021. WDI considers “Telephone Calls” to be an important communication tool for identifying and responding to customers’ needs and preferences. Consistent with prior years, Customer Service Representatives answered 99.83% of these calls in 30 seconds or less, which significantly exceeds the Ontario Energy Board mandated target of 65% for this measure. WDI expects to see this trend continue into the foreseeable future.

Customer Satisfaction

- ### First Contact Resolution

First Contact Resolution is a scorecard measure that was first introduced for tracking by utilities in 2014. The Ontario Energy Board has not yet issued a common definition for this measure. As a result, this measure may differ from other utilities in the province. Historically, WDI defines First Contact Resolution as the number of customer inquiries that are not resolved by the first contact at the utility, resulting in the inquiry being escalated to an alternate contact at the utility, typically a senior staff member. For 2022, the First Contact Resolution was reported as the number of customer inquiries that are resolved the first time they contact the utility, not resulting in the enquiring being escalated to a supervisor or manager. This updated definition is consistent with industry reporting. WDI considers the ability to address customer inquiries quickly and accurately to be an essential component of customer satisfaction. For 2022 WDI received 14,181 inquiries from customers and 99.9% were successfully resolved during first contact.

- ### Billing Accuracy

Billing accuracy is defined as the number of accurate bills issued expressed as a percentage of total bills issued. WDI considers timely and accurate billing to be an essential component of customer satisfaction. For 2022, WDI achieved a billing accuracy of 99.69% which is within the Ontario Energy Board mandated target of 98%.

- **Customer Satisfaction Survey Results**

As with First Contact Resolution and Billing Accuracy, this Customer Satisfaction Survey Results were first tracked in 2014. The Ontario Energy Board has not yet issued a common definition for this measure. As a result, this measure may differ from other utilities in the province. The Customer Satisfaction Survey is completed every two years, the last one occurring in 2021, which WDI attained a score of 81%. WDI will complete its next survey in 2023.

Safety

- **Public Safety**

  The Public Safety measure is generated by the Electrical Safety Authority and is comprised of three components: Public Awareness of Electrical Safety, Compliance with Ontario Regulation 22/04, and the Serious Electrical Incident Index. A breakdown of the three components is as follows:

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

    The component gauges the public's awareness of key electrical safety concepts related to electrical distribution equipment found in a utility's territory. The survey also provides a benchmark of the levels of awareness including identifying gaps where additional education and awareness efforts may be required. In 2022, WDI along with the other CHEC Utilities retained Redhead Media to perform a standardized survey utilized by all utilities. WDI received a survey result of 84.10% which was slightly above the CHEC survey average. WDI will continue to concentrate on education in future years in several areas, including customers requesting locates, overhead powerline safe distances and downed powerline safe distances.

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

    Component B consists of a utility's compliance with Ontario Regulation 22/04 – Electrical Distribution Safety. Ontario Regulation 22/04 establishes the safety requirements for the design, construction, and maintenance of electrical distribution systems, particularly in relation to the approvals and inspections required prior to putting electrical equipment into service. Over the past five years, WDI was found to be compliant with Ontario Regulation 22/04 (Electrical Distribution Safety). This was achieved by WDI's strong commitment to safety and adherence to company policy and procedures.

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

    Component C consists of the number of serious electrical incidents, including fatalities, which occur in a utility's territory. In 2022, WDI had no fatalities or serious incidents within its' territory. This was achieved by WDI's strong commitment to safety and adherence to company policy and procedures.

System Reliability

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

The average number of hours that the power to a customer is interrupted is a measure of system reliability or the ability of a system to perform its required function. WDI views the reliability of electrical service as a high priority for its customers and constantly monitors its system for signs of reliability degradation. WDI also regularly maintains its distribution system to ensure its level of reliability is kept as high as possible. The Ontario Energy Board typically requires a utility to keep its hours of interruption within the range of its historical performance, however, outside factors such as severe weather, defective equipment, or even regularly scheduled maintenance can greatly impact this measure. For 2022, WDI achieved 0.48 hours of interrupted power. This is an improvement in performance over 2021 (1.23).

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

The average number of times that power to a customer is interrupted is also a measure of system reliability and is also a high priority for WDI. As outlined above, the Ontario Energy Board typically requires a utility to keep this measure within a certain range of its historical performance and outside factors can also greatly impact this measure. WDI experienced interrupted power 0.46 times during 2022. This is an improvement in performance over 2021 of 0.63. The weather events commented on above in “Average Number of Hours that Power to a Customer is Interrupted” were also major contributors to this outcome.

Asset Management

- **Distribution System Plan Implementation Progress**

The Distribution System Plan outlines WDI’s forecasted capital expenditures, over a five-year period, which are required to maintain and expand the utilities electrical system to serve its current and future customers. The Distribution System Plan Implementation Progress measure is intended to assess WDI’s effectiveness at planning and implementing these capital expenditures. Consistent with other new measures, utilities were given an opportunity to define this measure in the manner that best fits their organization. As a result, this measure may differ from other utilities in the province. WDI defines this measure as the tracking of actual capital projects to planned capital projects, expressed as a percentage. In 2015, WDI successfully completed the Distribution System Plan as part of its’ 2016 Rate Application. The plan was developed for the period covering 2016-2020 with an average annual spend of $1.23m. WDI's focus was to provide the resources needed to support infrastructure growth and capital renewal projects to continue to ensure a safe and reliable system. WDI is currently in the process of developing a new DSP, however, no quantitative forecasts or estimates are available. WDI continues to experience increased development in Wasaga Beach with a new gaming facility, several large subdivisions, and a new Substation. In 2022, additional resources were added and will continue to be added in the coming years to replace and repair aged and falling infrastructure.

Cost Control

- **Efficiency Assessment**

On an annual basis, each utility in Ontario is assigned an efficiency ranking based on its performance. To determine a ranking, electrical distributors are divided into five groups based on the magnitude of the difference between their actual costs and predicted costs. For 2022, WDI placed in Cohort I, in terms of efficiency. Cohort I is considered excellent and is defined as having actual costs less than 25% of predicted costs. Overall, our ranking was the same as last year and our goal is to remain in Cohort I.

- **Total Cost per Customer**

Total cost per customer is calculated as the sum of WDI’s capital and operating costs and dividing this cost figure by the total number of customers that WDI serves. On average, WDI’s total cost per customer has increased by $19.75 per annum for the period 2018 – 2022. The total cost performance result for 2022 is $514/customer which is an increase of 20% over its 2021 result. This increase was largely the result of increased investments in infrastructure, including the completion of a new sub-station. Going forward, costs are expected to increase due to inflationary cost pressures along with further investment in infrastructure to support growth and maintain the reliability of the utility. WDI will keep pace with economic fluctuations to ensure manageable and sustainable growth.

- **Total Cost per km of Line**

This measure uses the same total cost that is used in the Cost per Customer calculation above. Based on this, WDI's rate is $25,485 per km of line which is a 20% increase over its 2021 rate. WDI's growth rate for its territory is relatively high. In addition, WDI faces supply chain issues and rising inflation. As a result, the cost per km of line is expected to increase as capital and operating costs also increase. As we progress into the future, WDI will continue to seek innovative solutions to help ensure cost/km of line remains competitive and within acceptable limits to our customers.

Connection of Renewable Generation

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

Electricity distributors are required to conduct Connection Impact Assessments (CIA's) on all renewable generation connections within 60 days of receiving the completed application. WDI has developed and implemented an internal procedure to ensure compliance with this regulation. In 2022, WDI did not have any Connection Impact Assessments requested, therefore; no CIAs were done in 2022.

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

Micro-embedded generation facilities consist of solar, wind or other clean energy projects of less than 10 kW that are typically installed by homeowners, farms, or small businesses. In 2022, WDI did not connect to a net-metered generation facility within its territory.

Financial Ratios

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

As an indicator of financial health, a current ratio indicates a company's ability to pay its short-term debts and financial obligations. Typically, the current ratio between 1 and 1.5 is considered good. If the current ratio is below 1, then a company may have problems meeting its current financial obligations. If the current ratio is too high (higher than 1.5) then the company may be inefficient at using its current assets or its short-term financing facilities. WDI's current ratio decreased from 1.11 in 2021 to 1.05 in 2022. This ratio indicates that WDI is a financially healthy organization in the use of its current assets. WDI will strive to maintain a current ratio between 1 and 1.5 going forward.

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

The debt-to-equity ratio is a financial ratio indicating the relative proportion of shareholder's equity and debt used to finance a company's assets. The Ontario Energy Board uses a capital structure of 60% debt and 40% equity (a debt-to-equity ratio of 60/40 or 1.5) when setting rates for an electricity utility. A high debt-to-equity ratio may indicate that an electricity distributor may have difficulty generating sufficient cash flows to make its debt payments, while a low debt-to-equity ratio may indicate that an electricity distributor is not taking advantage of the increased profits that may be had through increased financial debt. In 2022, WDI's debt-to-equity ratio was 0.55 (a change from 0.39 in 2021), which is lower than the ratio used for rate setting purposes by the Ontario Energy Board. WDI expects that its debt-to-equity ratio will change over the next several years as Wasaga Distribution delivers on our capital investment program.

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

Return on equity (ROE) measures the rate of return on shareholder equity. ROE demonstrates an organization's profitability or how well a company uses its investments to generate earnings growth. WDI's current distribution rates were approved by the OEB and include an expected (deemed) regulatory return of 9.19%. The OEB allows a distributor to earn within +/- 3% of the expected return on equity. If a utility 2022 Scorecard MD&A performs outside this range, it may trigger a regulatory review of the distributor's financial structure by the OEB.

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

WDI achieved a ROE of 10.85% in 2022, which is within the +/- 3% range allowed by the OEB (see above paragraph).

Note to Readers of 2022 Scorecard MD&A

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to several risks, uncertainties and other factors that may cause actual events, conditions, or results to differ materially from historical results or those contemplated by the distributor regarding their future performance. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, general economic conditions, and the weather. For these reasons, the information on future performance is intended to be management's best judgement on the reporting date of the performance scorecard and could be markedly different in the future.

1 # Appendix C: 2021 Asset Condition Assessment Report

WASAGA DISTRIBUTION INC.
2021 ASSET CONDITION ASSESSMENT

Kinectrics Report: K-814284-RA-0001-R01

June 17, 2022

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DISCLAIMER

WASAGA DISTRIBUTION INC.
2021 ASSET CONDITION ASSESSMENT

Kinectrics Report: K-814284-RA-0001-R01

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Revision History

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EXECUTIVE SUMMARY

In 2021 Wasaga Distribution Inc. (WD) determined a need to perform a condition assessment of its key distribution assets. WD selected and engaged Kinectrics Inc. (Kinectrics) to assist with this work. This report presents the results of 2021 Asset Condition Assessment (ACA) study, based on the available condition data as of the end of December 2021.

Asset Categories Considered

The 9 asset categories (13 sub-categories in total) include in the 2021 ACA are as follows:

- MS Transformers
- MS Switchgear
- OH Conductors (Primary + 44 kV, Secondary)
- OH 44 kV Load Break Switches
- Pole Mounted Transformers (1-Phase, 3-Phase)
- Wood Poles
- Pad Mounted Transformers (1-Phase, 3-Phase)
- Pad Mounted Switchgear
- UG Cables (Primary + 44 kV, Secondary + Service)

Another asset group, Meters, are maintained and replaced in compliance with Measurement Canada requirements. Such operation and maintenance are pre-set. This asset group is not included in the 2021 ACA study.

For each asset category, available data are assessed, Health Index distribution is determined, and condition-based Flagged-for-action plan is developed.

For asset categories inside substations, specifically MS transformers and MS switchgear, assets are typically replaced *proactively*, i.e., before they fail, while for the rest of the asset categories assets are typically run to failure and replaced *reactively*. For the asset categories with assets replaced *proactively* a risk-based prioritized list is developed identifying specific units and required action timing for each. For assets replaced *reactively*, number of units expected to be replaced each year is estimated without identifying specific units.

Overall Health Index Distribution

In general, 6 of the 13 sub-categories have over 70% of their units classified as “good” or “very good” and with an average Health Index score of greater than 80%.

With respect to the asset categories of concern, OH Conductors (Secondary), Pole Mounted Transformers (1-Ph and 3-Ph) and Wood Poles have 30% or more of units classified as “poor” or “very poor” condition.

Flagged-for-action plans

Flagged-for-action plan refers to a 10-year plan identifying how many units within each asset category require some action. In most cases the required action is replacement, however, for the asset categories replaced proactively other options are available, e.g., refurbishment, enhanced maintenance, operating solution, real time monitoring, or even “do nothing”. For that reason, the numbers presented in the Flagged-for-action plan are not necessarily equal to the number of assets to be replaced as units to be replaced represent a subset of the Flagged-for-action units.

None of asset category have a backlog in terms of flagged-for-action units and all flagged-for-action plans show smooth projections throughout the next 10 years.

It is worth noting that within the next 10 years, over one third of Pole Mounted Transformers (1-Ph and 3-Ph) and UG Cables (Primary + 44 kV) are expected to require some action to be taken to address their condition.

Data Availability

All the asset categories have basic information to develop health index scores.

MS Transformers and Wood Poles have relatively complete data sets, with both test, inspection and loading data available in addition to age information.

The remaining asset categories have age information only.

Wood Poles and Pole/Pad Mounted Transformers have historic removal data available for developing WD specific degradation curves.

Recommendations

As a long-term goal, it is recommended that WD enhance data collection in the following areas:

- Start collecting inspection data for MS Switchgear, OH Conductors, Pole Mounted Transformers, Pad Mounted Transformers, Pad Mounted Switchgear and UG Primary Cables. This is important even for the newer units to establish long-term degradation trends.

- Start collecting loading data for the distribution transformers. Although these transformers are usually sized with some margin to meet forecasted load, the expected proliferation of EVs will results in reduced margins and different loading patterns.

- Create a single file (instead of separate files) for storing inspection and test data for all the individual units collected for an asset category.

- Start recording removal and failure records for OH Conductors and UG Cables to enable development of WD specific asset degradation curves.

- Start tracking of OH Conductors and UG Cables failures by location in the outage database. Once sufficient data are available, they could be incorporated in ACA.

Findings and recommendations of this study are based on asset condition only as determined from available data and information. Note that there are numerous other considerations that may influence WD's planning process, such as obsolescence, system growth, corporate priorities, technological advancements, etc.

It is also important to note that the Flagged-for-action plans are based solely on asset condition using a probabilistic, non-deterministic, approach and, as such, can only show expected failures or probable number of units that are expected to be candidates for replacement or other action. While this condition-based Flagged-for-action plan can be used as a guide for Renewal Investment category within Distribution System Plan, it is not expected that it be followed directly or as the final deciding factor in making investment decisions. There are numerous other factors and considerations that will influence WD's Asset Management decisions, such as obsolescence, system expansion, regulatory requirements, municipal projects, customer preferences, etc.

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DEFINITIONS

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

Terminology	Acronym	Definition
Data Availability Indicator	DAI	A measure of the amount of condition parameter data that an asset has, as measured against the full data sets that are practically available and included in the HI formula. It is determined by the weighted ratio of the condition parameters availability of an individual unit, over the maximum condition parameters availability of an asset category.
Data Gap		A data gap is the case where none of the units in an asset category has data for a particular item as requested by “ideal” data sets. A data gap means the data is either unavailable or not in a useable format.
De-rating Multiplier	DR	Multipliers used to adjust a condition or sub-condition parameter score or calculated Health Index to reflect certain conditions.
Flagged-for-action plan	FFA Plan	Number of units that are expected to require attention annually.
Flagged-for-action Year	FFA Year	The year that a particular unit is flagged for action.
Health Index	HI	Health Indexing quantifies equipment condition-based on numerous condition parameters that are related to the factors that cumulatively lead to an asset’s end of life. HI is given in terms of a percentage range of 0%-100%, with 100% representing as new condition.
Probability Density Function	PDF	Probability density function. Assumed in this methodology as the Weibull function representing the likelihood that an asset will be removed from service when its age is within a particular range.
Removal Rate		Weibull hazard function. Assumed in this methodology as the rate of removal (removals per year for given age, including failures, proactively replaced, removal for non-condition reasons).
Risk		Product of likelihood of removal and consequence of failure.
Sample Size		Subset of an asset population with enough data (i.e., age or condition data) to calculate the HI.

Terminology	Acronym	Definition
Sub-Condition Parameter Score	SCPS	Score of an asset for a particular sub-condition parameter. In this study, the scoring system used ranges from 0 through 4 (0 = worst; 4 = best).
Sub-Condition Parameters	CP	Asset characteristics or properties that are used to derive the HI. Each condition parameter can be comprised of multiple sub-condition parameters.
Weibull Distribution		Continuous function used, in this methodology to model, the removal rates of assets.
Weight of Condition Parameter	WCP	In the HI formula, condition parameters are assigned a weight that is based on the degree of contribution or relevance to asset degradation.
Weight of Sub-Condition Parameter	WSCP	In the HI formula, condition parameters are assigned a weight that is based on the degree of contribution or relevance to asset degradation.

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I INTRODUCTION

Wasaga Distribution Inc. (WD) engaged Kinectrics Inc (Kinectrics) in 2021 to perform an Asset Condition Assessment (ACA) on selected distribution assets. ACA produces a quantifiable evaluation of asset condition and aids in prioritizing and allocating sustainment investments. This undertaking, if done continuously over time, would allow WD to monitor trends in the condition of its assets and to continuously improve its ACA process and asset management practices. This ACA covers WD's asset population as of December 2021. This report presents results based on the available data. Year 0 shown in all figures is for 2022, year 1 for 2023, year 2 for 2024 etc.

I.1 Objective and Scope of Work

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

- MS Transformers
- MS Switchgear
- OH Conductors (Primary + 44 kV, Secondary)
- OH 44 kV Load Break Switches
- Pole Mounted Transformers (1-Phase, 3-Phase)
- Wood Poles
- Pad Mounted Transformers (1-Phase, 3-Phase)
- Pad Mounted Switchgear
- UG Cables (Primary + 44 kV, Secondary + Service)

Another asset group, Meters, is maintained and replaced in compliance with Measurement Canada requirements. Since such maintenance and replacement are pre-set, this asset group is not included in this study.

I.2 Deliverables

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

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

- Additionally, prioritized risk-based lists are provided for MS transformers, whose assets are typically replaced before they fail.

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II ASSET CONDITION ASSESSMENT METHODOLOGY

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

II.1 Health Index

Health Indexing quantifies equipment condition-based on numerous condition parameters that are related to the degradation factors leading to an asset's end of service life. The Health Index is an indicator of the asset's overall health and is typically given in terms of percentage, with 100% representing an asset in brand new condition and 0 asset at the end of its life. Health Indexing provides a measure of long-term degradation and, thus, differs from defect management, whose objective is finding defects and deficiencies that need correction or remediation to keep an asset operating prior to reaching its end of life.

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

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

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

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

Equation 1

where

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

Equation 2

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

The scale that is used to determine an asset's score for a particular parameter is called the *condition criteria*. For this project, a condition criterion scoring system of 0 through 4 is used. A score of 0 represents the worst score while 4 represents the best score, i.e., $CPF_{max} = 4$.

De-Rating multipliers are applied to the calculated HI. These may be used to represent the impact of non-condition issues such as design or operating environment.

II.1.1 Health Index Results

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

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

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

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

II.2 **Condition-Based Flagged-for-action plan**

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

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

II.2.1 Removal Rate and Probability of Removal

Based on Kinectrics' experience in removal rate studies of multiple power system asset categories, Weibull equation is used to model the removal curves. The Weibull function has no specific characteristic shape and, as such, can model the exponentially increasing removal rate using empirically derived parameters.

The Weibull removal density function is defined as:

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

Equation 3

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

The corresponding cumulative removal distribution also sometimes referred to as Probability of Failure is:

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

Equation 4

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

Finally, the removal rate function also known as hazard function) is:

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

Equation 5

$\lambda(t)$	= hazard function (removals per year)

Different asset categories have different removal rates corresponding to different removal distributions. The parameters α and β are determine the shapes of these curves. For each asset category, the values of these constant parameters are selected to reflect typical useful lives for assets in this asset category.

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

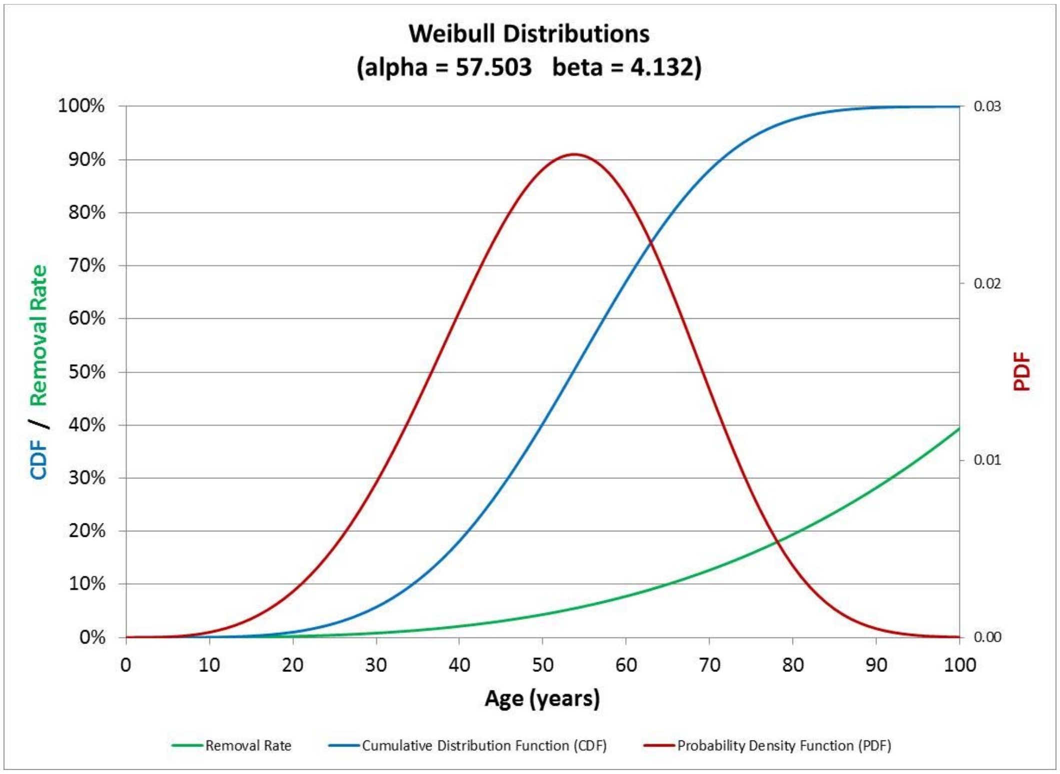

Figure 1 Removal rate vs. Age

II.2.2 Projected Flagged-for-action plan Using a Probabilistic Approach

For assets that have low consequences of failure that are run to failure and are replaced *reactively*, a probabilistic approach is taken to estimate the number of units that are expected to fail and flagged-for-action in each year.

For these asset categories, the number of units expected to be replaced in a given year is determined based on the asset's failure rates. The number of failures per year is given by Equation 5.

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

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

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

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

- OH Conductors
- OH Switches
- Wood Poles
- Distribution transformers (pole mounted, pad mounted)
- Pad mounted switchgear
- UG Cables

II.2.3 Projected Flagged-for-action plan Using a Prioritized Risk Approach

For some asset categories costs of replacement and/or consequences of failure are more substantial, and they are typically replaced *proactively*, i.e., before they fail. For such assets planning for replacement requires a risk-based approach when developing the FFA Plan. This risk-based methodology considers both the asset likelihood of removal (as related to HI) and its consequence of failure (criticality). The product of likelihood or removal and consequence of failure determines asset risk.

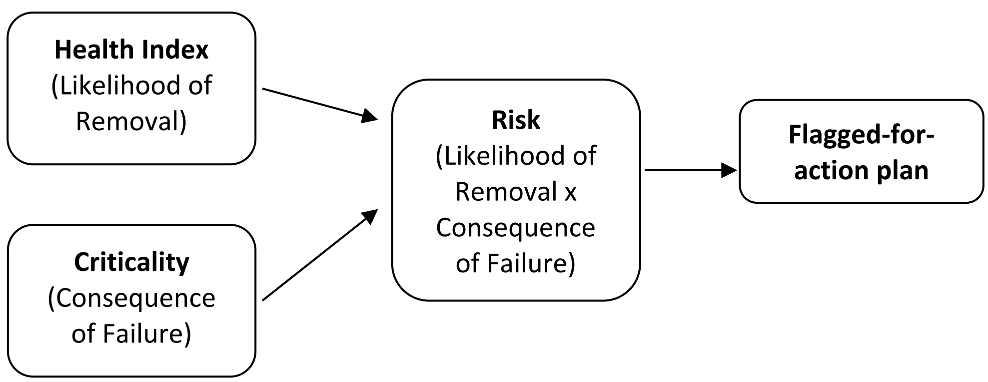

Figure 2 Risk Assessment Procedure

Relating Health Index and Probability of Removal

Typically, a stress asset is exposed is not constant and has normal frequency distribution. This is illustrated by the probability density curve of the stress below. The vertical lines in the figure represent condition or strength (Health Index) of an asset and bell-shaped curved stress distribution.

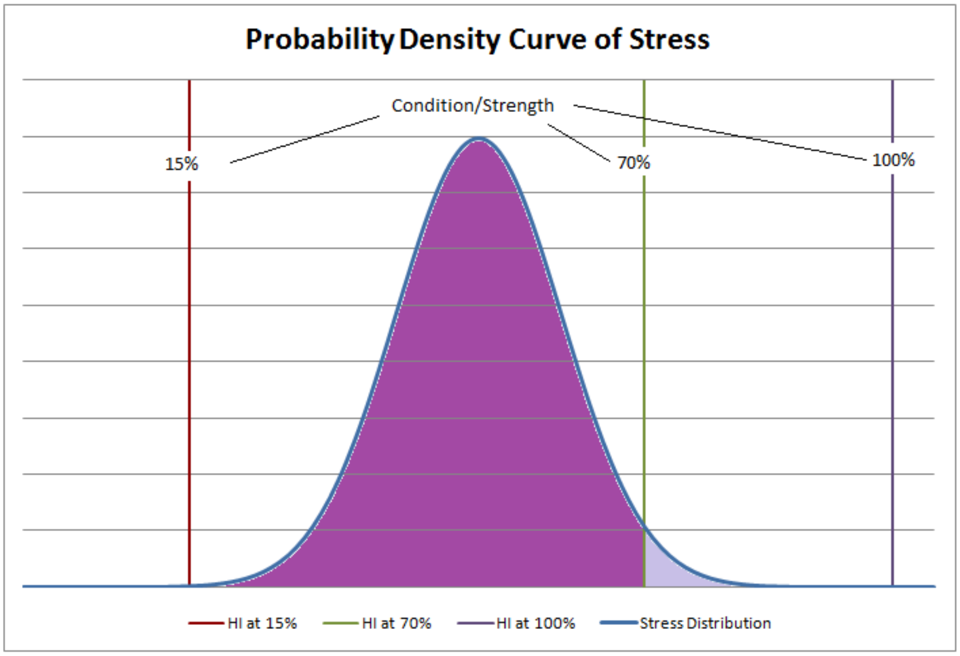

Figure 3 Stress Curve

An asset is in as-new condition (100% strength) should be able to withstand all levels of stress. As the condition of the asset deteriorates, it may be less able to withstand higher levels of stress. Consider, for example, the green vertical line that represents 70% condition/strength. The asset should be able to withstand magnitudes of stress to left of the green line. If, however, the stress is of a magnitude to the right of the green line, the asset will fail.

To create a relationship between the Health Index and likelihood of removal, assume two "points" on the stress curve that correspond to two different Health Index values. In this example, assume that an asset that has a condition/strength (Health Index) of 100% can withstand all magnitudes of stress to the left of the purple line. It then follows that probability that an asset in 100% condition will fail is the probability that the magnitude of stress is at levels to the right of the purple line. This corresponds to the area under the stress density curve to the right of the purple line. Similarly, if it assumed that an asset with a condition of 15% will fail if subjected to stress at magnitudes to the right of the red line, the probability of failure at 15% condition is the area under the stress density curve to the right of the red line.

The likelihood of removal at a particular Health Index is found from plotting the Health Index on X-axis and the area under the probability density curve to the right of the Health Index line on Y-axis, as shown on the graph of the figure below.

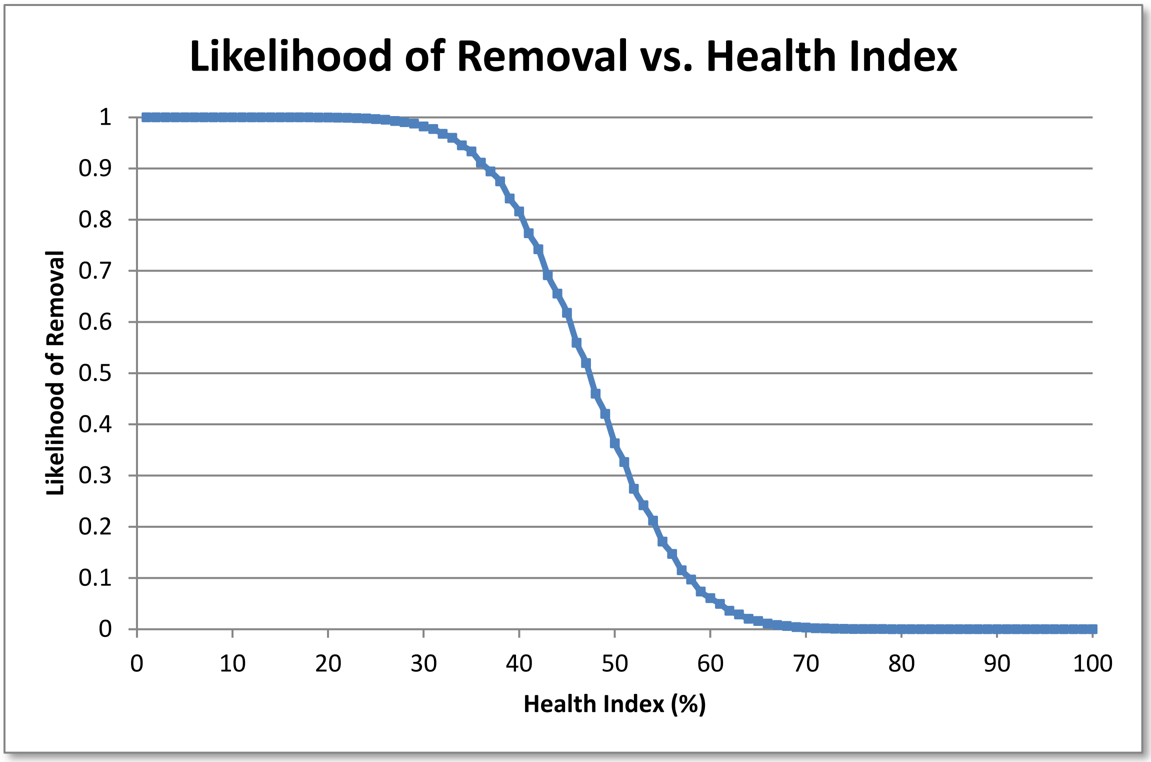

Figure 4 Likelihood of Removal vs. Health Index

Condition-Based Flagged-for-action plan

The metric used to measure consequence of failure is referred to as *Criticality*. Criticality may be determined in numerous ways, with monetary consequence or degree of risk to corporate business values being examples. The higher the criticality value assigned to a unit, the higher it's consequence of failure.

Risk-based prioritization using both estimated probability of failure related to the calculated condition and impact of failure using criticality are used for MS Transformers only. As per feedback from WD, all units within these asset categories are of equal criticality, so the prioritized list is based on their condition.

To develop a Flagged-for-action plan, the risk of removal of each unit must be quantified. Risk is the product of a unit's likelihood of removal and its consequence of failure. An asset is flagged for action when the calculated risk value exceeds a pre-set threshold.

For MS Transformers, the risk-based approach is used to estimate the FFA Plan.

With this approach, the FFA Year (i.e., the years that a particular unit is flagged for action) is determined for each asset.

II.3 Data Assessment

The condition data used in this study include the following:

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

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

II.3.1 Data Availability Indicator (DAI)

The Data Availability Indicator (DAI) is a measure of the amount of condition parameter data that an asset has, as measured against the full data sets that are available for at least one unit. It is determined by the weighted ratio of the condition parameters availability of an individual unit, over the maximum condition parameters availability for this asset category. The formula is given by:

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

Equation 6

where

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

Equation 7

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

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

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

The Data Availability Indicator is calculated as follows:

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

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

An asset with all available condition parameter data represented will, by definition, have a DAI value of 100%. In this case, an asset will have a DAI of 100% regardless of its Health Index score. Bear in mind that a DAI of 100% does not mean there is no data gaps (to be discussed in the following section). What it really indicates is that, at the time of study, an asset has information on all the condition parameters available for ACA calculations. For other units with fewer input data points available the DAI will be less and calculated as shown above.

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

II.3.2 Data Gap

The Health Index formulae developed and used in this study are based only on WD's available data. There are additional parameters or tests that WD may not collect at the present time but that are important indicators in determining the extent of assets degradation. While these will not be included in the HI formula, they are referred to as data gaps. A data gap is the case where none of the units in an asset category has data for a particular item as requested by "ideal" data sets.

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

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

When closing data gaps, it is generally recommended that data collection be initiated for the items marked with higher priority because when more impactive and important data are included in the Health Index formula the higher is confidence in the calculated Health Index score.

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

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

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

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

III RESULTS

This section summarizes the findings of this study.

III.1 Health Index Results

A summary of the Health Index results is shown in Table 1. For each asset category the population, sample size (number of assets with sufficient data for Health Indexing), average age, age availability and average DAI are given. The average Health Index and distribution are also shown. A summary of the Health Index distribution for all asset categories are also graphically shown in Figure 5. Note that the Health Index distribution percentages are based on the asset category's sample size.

It can be observed that out of the 13 sub-categories, 6 of them have over 70% of their units classified as "good" or "very good". Besides, all of them have an average Health Index score of greater than 80%.

The only asset categories that have all the units in "very good" condition are OH 44 kV Load Break Switches.

The results show that compared to other asset categories, Pole Mounted Transformers (3-Ph) have higher percentage of assets classified as "poor" or "very poor", being 75% of the entire population. Given the fact that the entire fleet has 24 assets in total, this represented only 18 assets.

Other asset categories having over 30% of assets classified as "poor" or "very poor" include OH Conductors (Secondary), Pole Mounted Transformers (1-Ph) and Wood Poles.

Table 1 Health Index Results Summary

Asset Category	Population	Sample Size	Average Health Index	Health Index Distribution					Average Age	Average DAI	Age Availability
				Very Poor (< 25%)	Poor (25 - <50%)	Fair (50 - <70%)	Good (70 - <85%)	Very Good (>= 85%)			
MS Transformers	5	5	92%	0	0	0	1	4	22	83%	100.0%
MS Switchgear	19	17							18		89.5%
OH Conductors (Primary + 44 kV)	350.2	350.2	74%	34.8	48.8	30.2	55.2	181.2	39	Age Only	100.0%
OH Conductors (Secondary)	121.5	19.8	64%	4.4	2.1	3.3	1.1	8.9	41	Age Only	16.3%
OH 44 kV Load Break Switches	7	7	100%	0	0	0	0	7	16	Age Only	100.0%
Pole Mounted Transformers (1-Ph)	757	756	66%	223	39	19	65	410	27	Age Only	99.9%
Pole Mounted Transformers (3-Ph)	24	24	46%	3	15	0	1	5	38	Age Only	100.0%
Wood Poles	5090	5086	57%	573	1945	687	633	1248	40	72%	99.9%
Pad Mounted Transformers (1-Ph)	800	800	86%	5	18	132	105	540	20	Age Only	100.0%
Pad Mounted Transformers (3-Ph)	79	77	85%	0	10	3	14	50	21	Age Only	97.5%
Pad Mounted Switchgear	19	19	91%	0	0	0	3	16	13	Age Only	100.0%
UG Cables (Primary + 44 kV)	226.3	226.3	79%	12.2	40.4	20.5	12.2	141.0	20	Age Only	100.0%
UG Cables (Secondary + Service)	481.0	323.7	96%	0.6	1.8	0.0	13.1	308.2	20	Age Only	67.3%

0% 100%

Age Only No information other than age

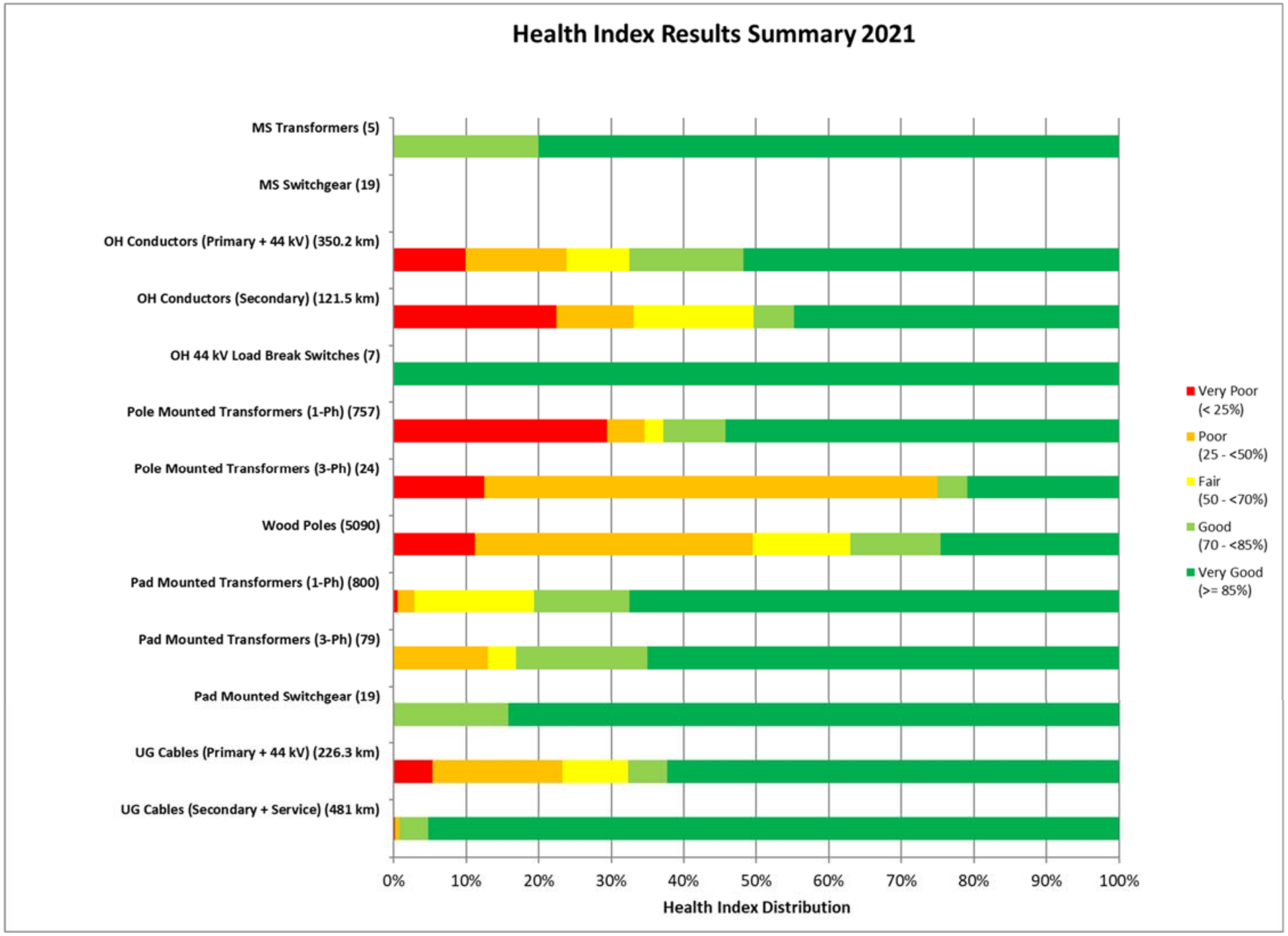

Figure 5 Health Index Results Summary

III.2 Condition-Based Flagged-for-action plan

The Flagged-for-action plan estimates the number of units expected to require attention in a given year, with the attention being replacement or other actions as described earlier in this document.

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

Table 2 shows the Year 0 (year 2022) and 10 Year cumulative Flagged-for-action plan. Table 3 shows annual 10 Year Flagged-for-action plan.

Table 2 Summary of Flagged-for-action

Asset Category	1st Year Action		10 Year Action in Total	
	Quantity	Percentage	Quantity	Percentage
MS Transformers	0	0.0%	0	0.0%
MS Switchgear				
OH Conductors (Primary+44 kV)	12.4	3.5%	103.6	29.6%
OH Conductors (Secondary)	3.1	2.6%	25.8	21.2%
OH 44 kV Load Break Switches	0	0.0%	0	0.0%
Pole Mounted Transformers (1-Ph)	35	4.6%	257	33.9%
Pole Mounted Transformers (3-Ph)	2	8.3%	11	45.8%
Wood Poles	143	2.8%	1192	23.4%
Pad Mounted Transformers (1-Ph)	17	2.1%	171	21.4%
Pad Mounted Transformers (3-Ph)	2	2.5%	20	25.3%
Pad Mounted Switchgear	0	0.0%	4	21.1%
UG Cables (Primary + 44 kV)	13.7	6.1%	87.4	38.6%
UG Cables (Secondary + Service)	4.6	1.0%	85.0	17.7%

High Low

Table 3 Ten Year Flagged-for-action plan

Asset Category	Flagged for Action Plan by Year									
	0	1	2	3	4	5	6	7	8	9
MS Transformers	0	0	0	0	0	0	0	0	0	0
MS Switchgear										
OH Conductors (Primary+44 kV)	12.4	11.7	10.9	10.7	10.7	10	9.4	9.2	9	9.6
OH Conductors (Secondary)	3.1	3.7	3.6	3.1	1.2	1.9	3.1	2.4	1.9	1.8
OH 44 kV Load Break Switches	0	0	0	0	0	0	0	0	0	0
Pole Mounted Transformers (1-Ph)	35	28	26	24	24	24	24	24	24	24
Pole Mounted Transformers (3-Ph)	2	1	1	1	1	1	1	1	1	1
Wood Poles	143	118	121	118	117	115	115	115	115	115
Pad Mounted Transformers (1-Ph)	17	15	16	16	17	17	18	18	18	19
Pad Mounted Transformers (3-Ph)	2	2	2	2	2	2	2	2	2	2
Pad Mounted Switchgear	0	0	0	1	0	0	1	1	1	0
UG Cables (Primary + 44 kV)	13.7	12.0	11.1	9.9	9.0	8.0	6.8	6.2	5.7	5.0
UG Cables (Secondary + Service)	4.6	5.2	5.8	7.3	8.0	9.2	10.0	10.5	11.9	12.5

* Year 0 = 2022, year 1 = 2023, year 2 = 2024 … etc.

km for OH Conductors and UG Cables

III.3 **Data Assessment Results**

Data assessment determines the data availability of each asset category and identifies data gaps for each asset category. Data availability is a measure of the amount of data that an individual unit has in comparison with the set of data currently available for its asset category. Data gaps are data that are not collected or available for any asset in an asset category. The higher the DAI and the fewer the data gaps, the higher the quality of Health Index results.

Data for MS Transformers include age, loading, oil and Furan test results. Data gaps are test and inspection records for windings/bushings and cooling systems.

Data for OH Conductors and UG Cables include age only. Data gaps include inspection records and failure rate records at segment level.

Data for OH Switches and Pad Mounted Switchgear include age only. Data gaps include inspection records.

Data for Pole mounted Transformers and Pad Mounted Transformers include age only. Data gaps include inspection and loading records.

Data for Wood Poles include age and test/inspection results. There are no pressing data gaps for this asset category.

IV CONCLUSIONS

An Asset Condition Assessment is conducted for 9 distribution asset categories of WD (13 sub-categories in total). For each asset category, the Health Index distribution is determined, and a condition-based Flagged-for-action plan is developed.

Risk-based prioritized lists are developed for MS Transformers. These lists indicate the projected flagged-for-action year for each individual unit.

Flagged-for-action plan presented in this study is based solely on available asset condition data and there are other considerations that may influence WD's Asset Management Plan, such as obsolescence, system growth, regulatory requirements, municipal initiatives, etc.

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

1) In general, WD's assets are in good condition, with 6 out of 13 sub-categories having an average Health Index score of greater than 80%.

2) Among all the asset categories, OH Switches are in the best condition, having all the units classified as "very good".

3) Pole Mounted Transformers (3-Ph) have 75% of its assets in "poor" or "very poor" condition. Given the fact that there are in total 24 Pole Mounted Transformers (3-Ph), this represents only 18 assets.

4) Wood Poles have 50% of its assets in "poor" or "very poor" condition. This is mainly due to its aged units.

5) In terms of flagged-for-action plans, no asset category has major backlog.

6) For 10-year long term flagged-for-action plans, Pole Mounted Transformers (3-Ph) have the highest portion of the population to be addressed, while Wood Poles have the highest number of assets to be addressed.

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V RECOMMENDATIONS

The following recommendations are made based on the study results:

a) Continue collecting asset removal records for all the asset categories, to improve the accuracy of asset degradation curves.

b) Start collecting routine inspection records for MS Transformers.

c) Start collecting Inspection records for all the asset categories outside the substations.

d) Start tracking failure records at segment level for OH Conductors and UG Cables, to improve the input granularity for better assessment of component condition status.

e) Start collecting loading data for both pole mounted and pad mounted distribution transformers.

f) For MS transformers and MS switchgear merge Inspection and test data for the individual units in one data file for each asset category.

g) Standardize inspection forms to ensure consistency of inspections records collected in the field.

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VI APPENDIX A: RESULTS FOR EACH ASSET CATEGORY

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1 MS Transformers

1.1 Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

1.1.1 Condition and Sub-Condition Parameters

Table 1-1 Main Tank Condition Parameter and Weights – MS Transformers

m	Condition Parameter	WCP_m	Sub-Condition Parameters
1	Internals	5	Table 1-2
2	Insulation Oil	4	Table 1-3
3	Paper	4	Table 1-4
4	Service Record	5	Table 1-5
	Age Limiting	Overall Multiplier	Figure 1-1

Table 1-2 Internals Sub-Condition Parameters and Weights (m=1) – MS Transformers

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	H2	5	Table 1-6
2	CH4	3	Table 1-6
3	C2H6	3	Table 1-6
4	C2H4	3	Table 1-6
5	C2H2	5	Table 1-6

Table 1-3 Insulation Oil Sub-Condition Parameters and Weights (m=2) – MS Transformers

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Moisture	4	Table 1-7
2	IFT	3	Table 1-7
3	Acid Number	2	Table 1-7

Table 1-4 Paper Sub-Condition Parameters and Weights (m=3) – MS Transformers

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	CO	2	Table 1-6
2	CO2	1	Table 1-6
3	DP	3	Table 1-8

Table 1-5 Service Record Sub-Condition Parameters and Weights (m=4) – MS Transformers

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Loading	1	Table 1-9

1.1.2 Condition Criteria

<u>Oil DGA – Transformer Oil</u>

Table 1-6 DGA Criteria – Transformers

	Dissolved Gas	**Scores**					
		4	**3.2**	**2.4**	**1.6**	**0.8**	**0**
Mineral Oil 2.5 MVA to 10 MVA	**H2 (Hydrogen)**	X ≤ 70	70 < X ≤ 100	100 < X ≤ 200	200 < X ≤ 400	400 < X ≤ 1000	X >1000
	CH4 (Methane)	X ≤ 70	70 < X ≤ 120	120 < X ≤ 200	200 < X ≤ 400	400 < X ≤ 600	X > 600
	C2H6 (Ethane)	X ≤ 75	75 < X ≤ 100	100 < X ≤ 150	150 < X ≤ 250	250 < X ≤ 500	X > 500
	C2H4 (Ethylene)	X ≤ 60	60 < X ≤ 100	100 < X ≤ 150	150 < X ≤ 250	250 < X ≤ 500	X > 500
	C2H2 (Acetylene)	X ≤ 3	3 < X ≤ 7	7 < X ≤ 35	35 < X ≤ 50	50 < X ≤ 100	X > 100
	CO (Carbon Monoxide)	X ≤ 750	750 < X ≤ 1000	1000 < X ≤ 1300	1300 < X ≤ 1500	1500 < X ≤ 1700	X > 1700
	CO2 (Carbon Dioxide)	X ≤ 7500	7500 < X ≤ 8500	8500 < X ≤ 9000	9000 < X ≤ 12000	12000 < X ≤ 15000	X > 15000
Mineral Oil >10 MVA	**H2 (Hydrogen)**	X ≤40	40 < X ≤ 100	100 < X ≤ 300	300 < X ≤ 500	500 < X ≤ 1000	X >1000
	CH4 (Methane)	X ≤ 80	80 < X ≤ 150	150 < X ≤ 200	200 < X ≤ 500	500 < X ≤ 700	X > 700
	C2H6 (Ethane)	X ≤ 70	70 < X ≤ 100	100 < X ≤ 150	150 < X ≤ 250	250 < X ≤ 500	X > 500
	C2H4 (Ethylene)	X ≤ 60	60 < X ≤ 100	100 < X ≤ 150	150 < X ≤ 250	250 < X ≤ 500	X > 500
	C2H2 (Acetylene)	X ≤ 3	3 < X ≤ 7	7 < X ≤ 35	35 < X ≤ 50	50 < X ≤ 80	X > 80
	CO (Carbon Monoxide)	X ≤ 350	350 < X ≤ 500	500 < X ≤ 600	600 < X ≤ 1000	1000 < X ≤ 1500	X > 1500
	CO2 (Carbon Dioxide)	X ≤ 3000	3000 < X ≤ 4500	4500 < X ≤ 5700	5700 < X ≤ 7500	7500 < X ≤ 10000	X > 10000
FR3	**H2 (Hydrogen)**	X ≤75	75 < X ≤ 105	105 < X ≤ 118	118 < X ≤ 250	250 < X ≤ 500	X >500
	CH4 (Methane)	X ≤ 15	15 < X ≤ 19	19 < X ≤ 22	22 < X ≤ 30	30 < X ≤ 50	X > 50
	C2H6 (Ethane)	X ≤ 150	150 < X ≤ 219	219 < X ≤ 247	247 < X ≤ 400	400 < X ≤ 600	X >600
	C2H4 (Ethylene)	X ≤ 14	14 < X ≤ 17	17 < X ≤ 20	20 < X ≤ 25	25 < X ≤ 40	X > 40
	C2H2 (Acetylene)	X ≤ 1					X > 1
	CO (Carbon Monoxide)	X ≤ 120	120 < X ≤ 150	150 < X ≤ 179	179 < X ≤ 225	225 < X ≤ 400	X > 400
	CO2 (Carbon Dioxide)	X ≤ 7500	7500 < X ≤ 8500	8500 < X ≤ 9000	9000 < X ≤ 12000	12000 < X ≤ 15000	X > 15000

General Oil Quality

Table 1-7 Oil Quality Test Criteria

Oil Quality Test		Voltage Class [kV]	Score				
			4	3	2	1	0
Mineral Oil							
Water Content (D1533) [ppm]		V ≤ 69	< 30	[30, 33.3)	[33.3, 36.6)	[36.6, 40)	> =40
		69 < V < 230	< 20	[20, 25)	[25, 30)	[30, 35)	>= 35
		V ≥ 230	< 15	[15, 18.3)	[18.3, 21.6)	[20, 25)	> = 25
IFT (D971) [dynes/cm]		V ≤ 69	> 25	(21.6, 25]	(18.3, 21.6]	(15, 18.3]	< = 15
		69 < V < 230	> 30	(26, 30]	(22, 26]	(18, 22]	< = 18
		V ≥ 230	> 32	(28, 32]	(24, 28]	(20, 24]	< = 20
Acid Number (D974) [mg KOH/g]		V ≤ 69	< 0.05	[0.05, 0.1)	[0.1, 0.15)	[0.15, 0.2)	> = 0.2
		69 < V < 230	< 0.04	[0.04,.077)	[0.077,0.113)	[0.113,0.15)	> = 0.15
		V ≥ 230	< 0.03	[0.03,0.053)	[0.053,0.076)	[0.076,0.1)	> = 0.1
FR3							
Water Content (D1533) [ppm]			< 300	[300, 531)	[531, 763)	[763, 994)	> = 994
Acid Number (D974) [mg KOH/g]			< 0.06	[0.06, 0.2)	[0.2, 0.35)	[0.35, 0.5)	> = 0.5

Furan

Table 1-8 Furan Criteria

Score	Description
4	2FAL < 100
3	100 <= 2FAL < 200
2	200 <= 2FAL < 600
1	600 <= 2FAL < 1000
0	2FAL >= 1000

Loading History

Table 1-9 Loading History - MS Transformers

Data: S1, S2, S3, …, Si recorded data (average daily loading)
SB= rated MVA NA=Number of Si/SB which is lower than 0.6 NB= Number of Si/SB which is between 0.6 and 0.8 NC= Number of Si/SB which is between 0.8 and 1.0 ND= Number of Si/SB which is between 1 and 1.2 NE= Number of Si/SB which is greater than 1.2 Score = $\frac{NA \times 4 + NB \times 3 + NC \times 2 + ND \times 1}{N}$

Age Limiting Factor

Age is used as a limiting factor to reflect the degradation of asset over time.

The calculated overall HI result (after considering all the possible de-rating multipliers) is then compared with an age limiting factor.

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

The age derating is the Weibull survival function (1 – cumulative distribution function).

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

Equation 1-1

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

The parameters of MS Transformers age limiting curve are shown in the following table and are based on industry information.

Table 1-10 Age Limiting Curve Parameters - MS Transformers

Asset Type	α	β
MS Transformers	**60.7246**	**7.7187**

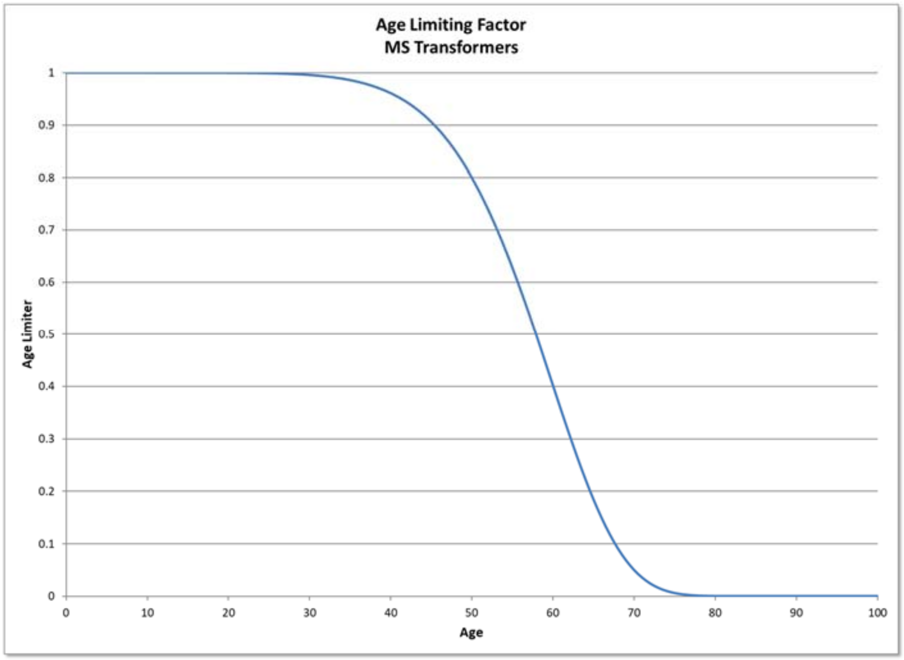

Figure 1-1 Age Limiting Factor Criteria - - MS Transformers

De-Rating Multiplier

The de-rating is based on the following equation and DR is described in the subsequent table.

$$DR = \min(DR_1, DR_2)$$

Equation 1-2

Where DR_1 and DR_2 are as follows:

Table 1-11 De-Rating Multiplier Based on Oil Quality Score

$DR_1 = \min(DR\_Score_{Moisture}, DR\_Score_{Dielectric\ Strength})$	
DR_Score	**$Score_{Oil\ Quality\ Test}$** $Score_{Oil\ Quality}$ is defined in Table 1-7
0.25	$0 \leq Score_{Oil\ Quality\ Test} < 1$
0.5	$1 \leq Score_{Oil\ Quality\ Test} < 2$
1	$Score_{Oil\ Quality\ Test} \geq 2$

DR$_2$: Dissolved Gas Trend

DR$_2$ is based on total dissolved combustible gas (TDCG) concentration daily rate increase.

Table 1-12 De-Rating Multiplier Based on TDCG Trend

Daily Increase (ppm/day)	**IEEE C57.104 Condition Codes for TDCG**			
	Condition 1	Condition 2	Condition 3	Condition 4
	$0 \leq TDCG \leq 720$	$720 \leq TDCG < 1920$	$1920 \leq TDCG < 4630$	$TDCG > 4630$
	DR_Score			
$0 \leq X < 0.33$	1	1	1	1
$0.33 \leq X < 1$	0.9	0.9	0.85	0.75
$1 \leq X < 1.43$	0.9	0.9	0.75	0.75
$1.43 \leq X < 4.29$	0.9	0.9	0.75	0.5
$X \geq 4.29$	0.9	0.9	0.5	0.25

1.2 Age Distribution

The average age is 22 for MS Transformers. The age distribution is as follows.

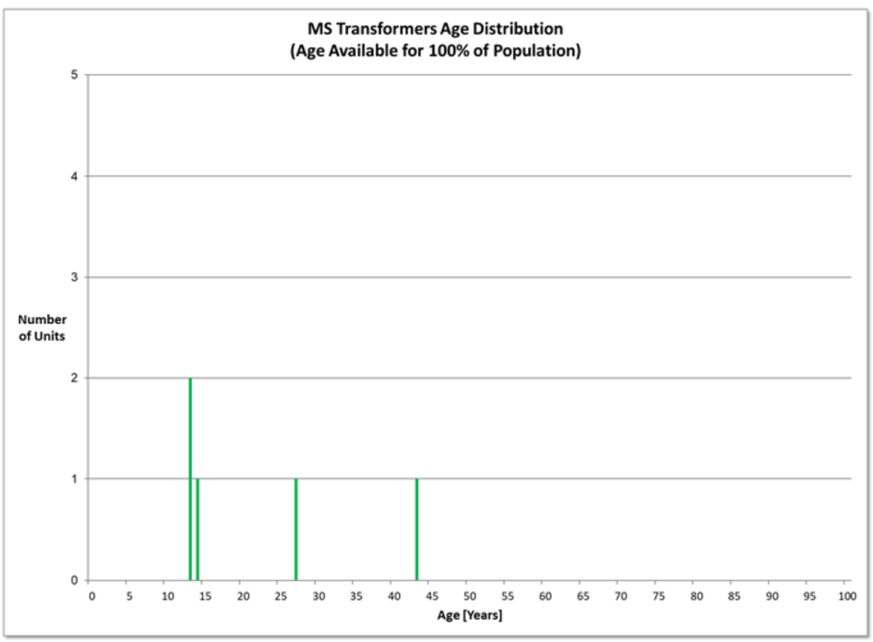

Figure 1-2 Age Distribution –MS Transformers

1.3 Health Index Results

There are 5 units of MS Transformers. The average Health Index is 88%.

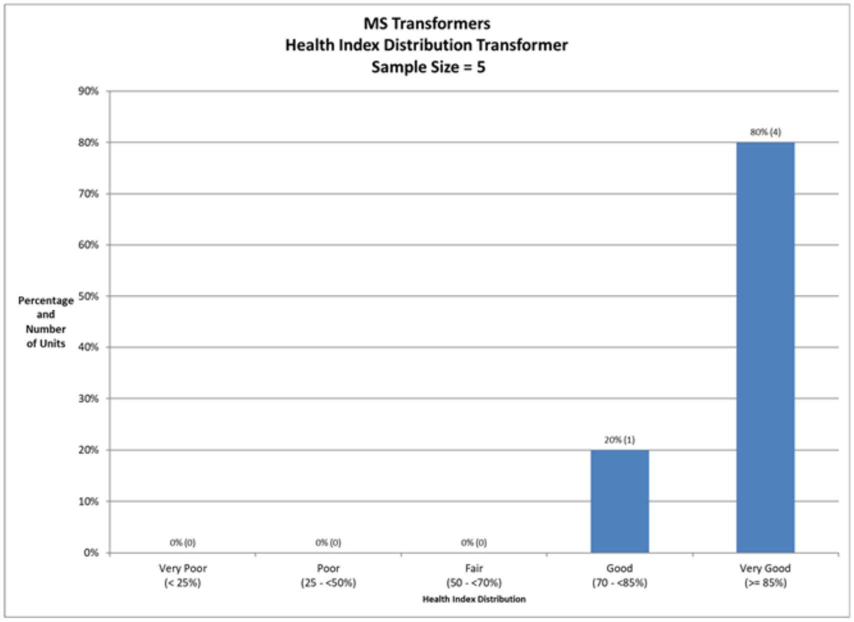

Figure 1-3 Health Index Distribution –MS Transformers

1.4 Flagged-for-Action Plan

MS Transformers are proactively replaced and the risk assessment and methodology described in Section II.2.3 is used to develop flagged-for-action plan.

Minimum criticality value is assigned for each of MS Transformers asset so that a unit becomes a candidate for action when its cumulative probability of failure is greater than or equal to 80%.

Based on health index results and criticality information, no asset is flagged for action in the next 10 years.

1.5 Risk-Based Prioritized List

The following table shows the risk-based prioritization list if units.

Table 1-13 Risk-Based Prioritization List - MS Transformers

Rank	ID	Substation	Position	MVA	Age	DAI	HI by condition	HI	FFA Year
1	MS5-T1	5	1	10	27	86%	85%	85%	>20
2	MS4-T1	4	1	10	13	86%	92%	92%	>20
3	MS3-T1	3	1	10	43	86%	95%	93%	>20
4	MS1-T1	1	1	7.5	14	79%	96%	96%	>20
5	MS2-T1	2	1	5	13	79%	95%	95%	>20

1.6 Data Gaps

Available data for MS Transformers include age, loading, oil and DGA test results. The following table shows the data gaps.

Table 1-14 Data Gap for MS Transformers

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Description**	**Source of Data**
TTR, Excitation Current, Winding Resistance	Winding	✰✰	Winding degradation	Testing
Bushing PF, Dielectric Loss, Capacitance	Bushings	✰✰	Insulation degradation or defects for bushings	Testing
Oil Level, Conservator, Tank Breather	Oil Storage	✰	Defect due to installation or lack of maintenance	Maintenance and/or Inspection records
Radiators, Coolers Fans	Cooling System	✰	Defect due to installation or lack of maintenance	Maintenance and/or Inspection records

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2 MS Switchgear

2.1 Health Index Formula

Given the fact that the all the MS switchgear at Wasaga Distribution is relatively new, no ACA is conducted for this asset category.

2.2 Age Distribution

In total there are 19 MS switchgear. All of them having age information. The average age is 19. The age distribution is as follows.

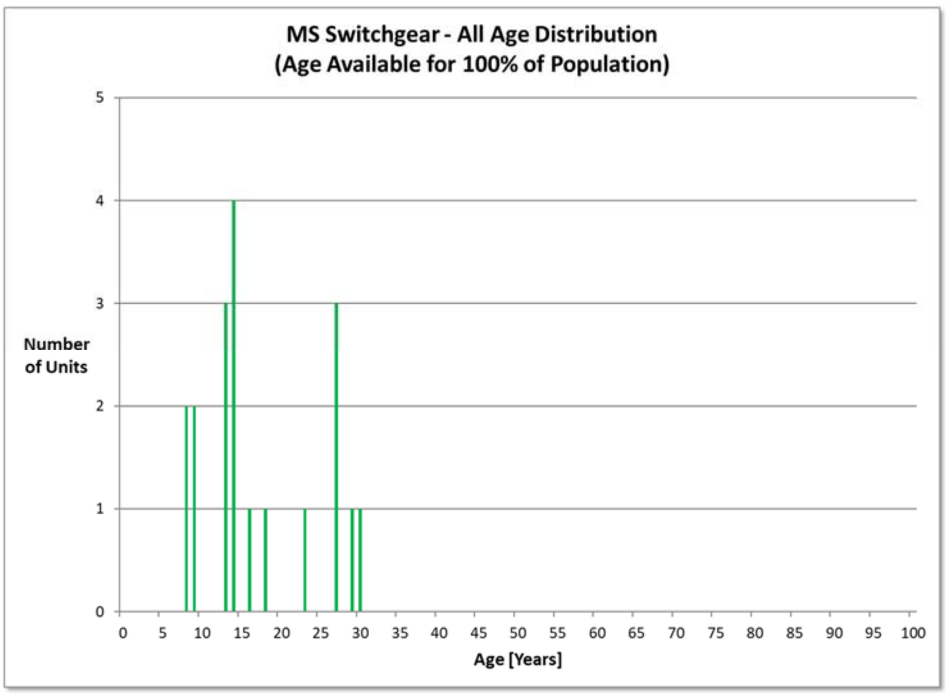

Figure 2-1 Age Distribution –MS Switchgear

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3 OH CONDUCTORS

3.1 Health Index Formula

The HI assessment for this asset category is based on age and the cumulative likelihood of survival at a given age.

Age is used as a limiting factor to reflect the degradation over time as described in section 1.1.2.

3.1.1 Condition and Sub-Condition Parameters

Table 3-1 Condition Parameter and Weights – OH Conductors

m	Condition Parameter	WCP_m	Sub-Condition Parameters
	De-rating Factor		Equation 3-1
	Age Limiting		Figure 3-1

3.1.2 Condition Criteria

De-rating Factor

The de-rating is based on the following equation:

$$DR = \min(DR_1, DR_2)$$

Equation 3-1

Where de-rating parameters (DRP) are as described in Table 3-2.

Table 3-2 De-Rating Multiplier

DR	Conductor Type	De-Rating Multiplier
DR_1	#4 Cu conductor	0.49
DR_2	#6 Cu conductor	0.24
	All Other Type	1

Age Limiting Factor

The parameters of OH Conductors age limiting curve are shown in the following table and are based on industry information.

Table 3-3 Age Limiting Curve Parameters - OH Conductors

Asset Type	α	β
OH Conductors	**59.2788**	**4.364**

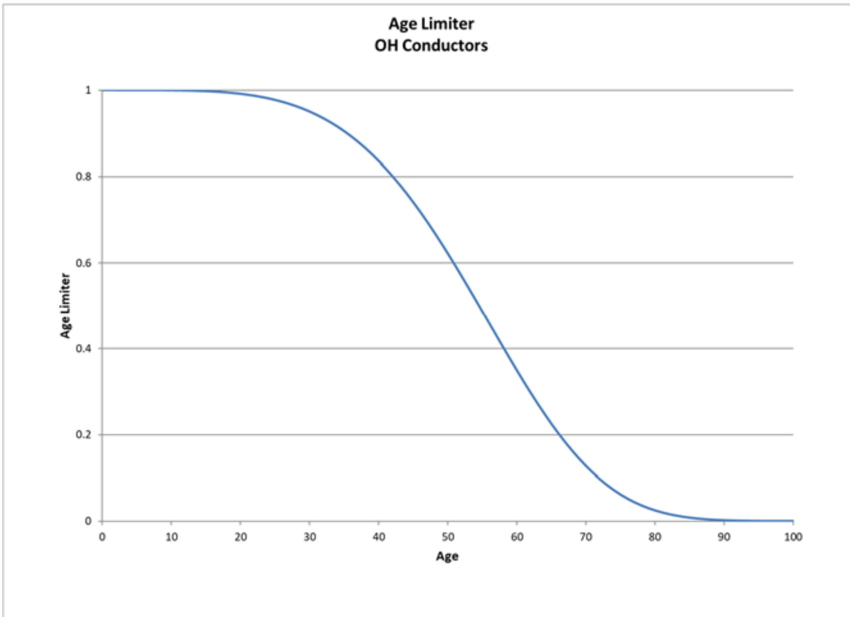


Figure 3-1 Age Limiting Factor Criteria - - OH Conductors

3.2 Age Distribution

The average age of primary and 44 kV conductor segments is 39 years. The average age of secondary conductor segments is 41 years.

The age distributions for OH Conductors are as follows:

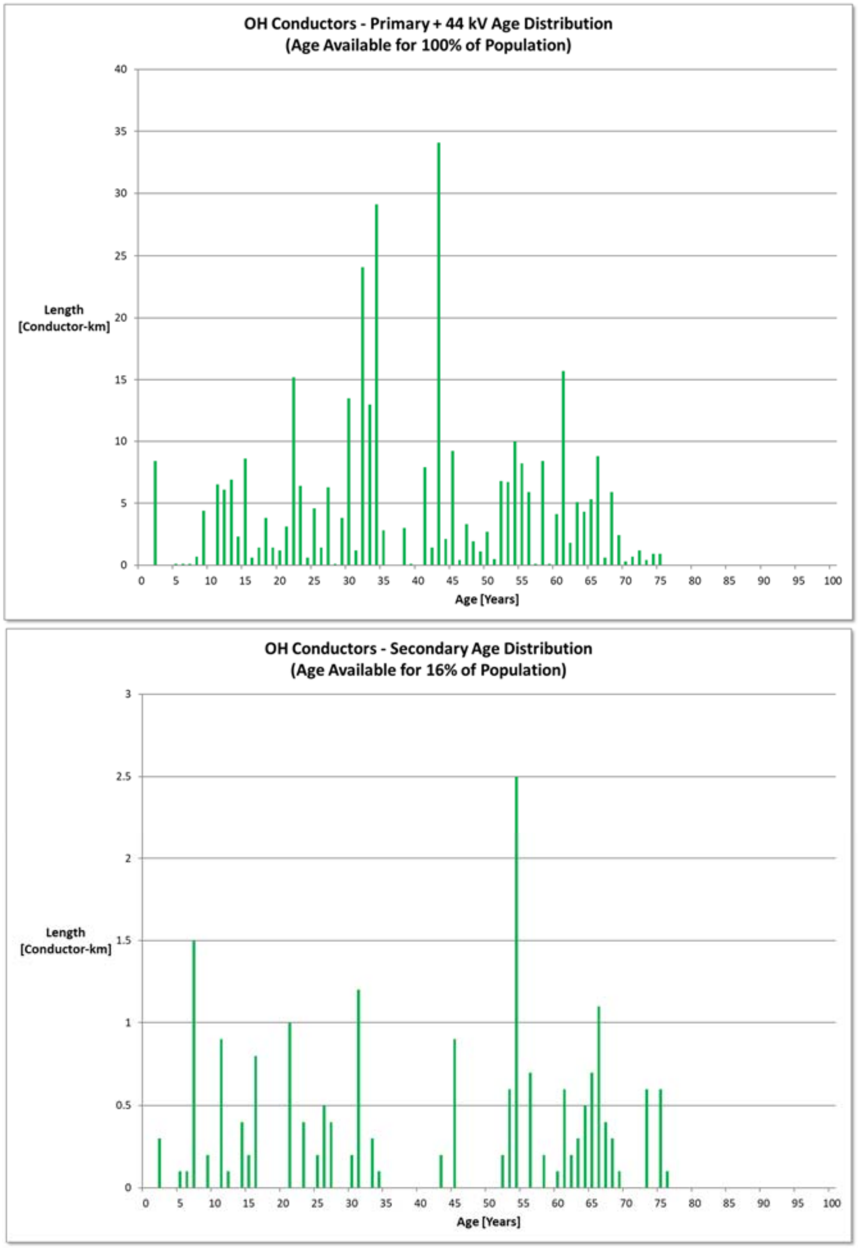


Figure 3-2 Age Distribution - OH Conductors

3.3 Health Index Results

There are 350 km primary and 44 kV OH Conductors. All of them have age data used for Health Indexing and the average Health Index for this asset category is 74%.

There are 121 km secondary OH Conductors. Among them, 19.8 km have age data used for Health Indexing and the average Health Index for this asset category is 64%.

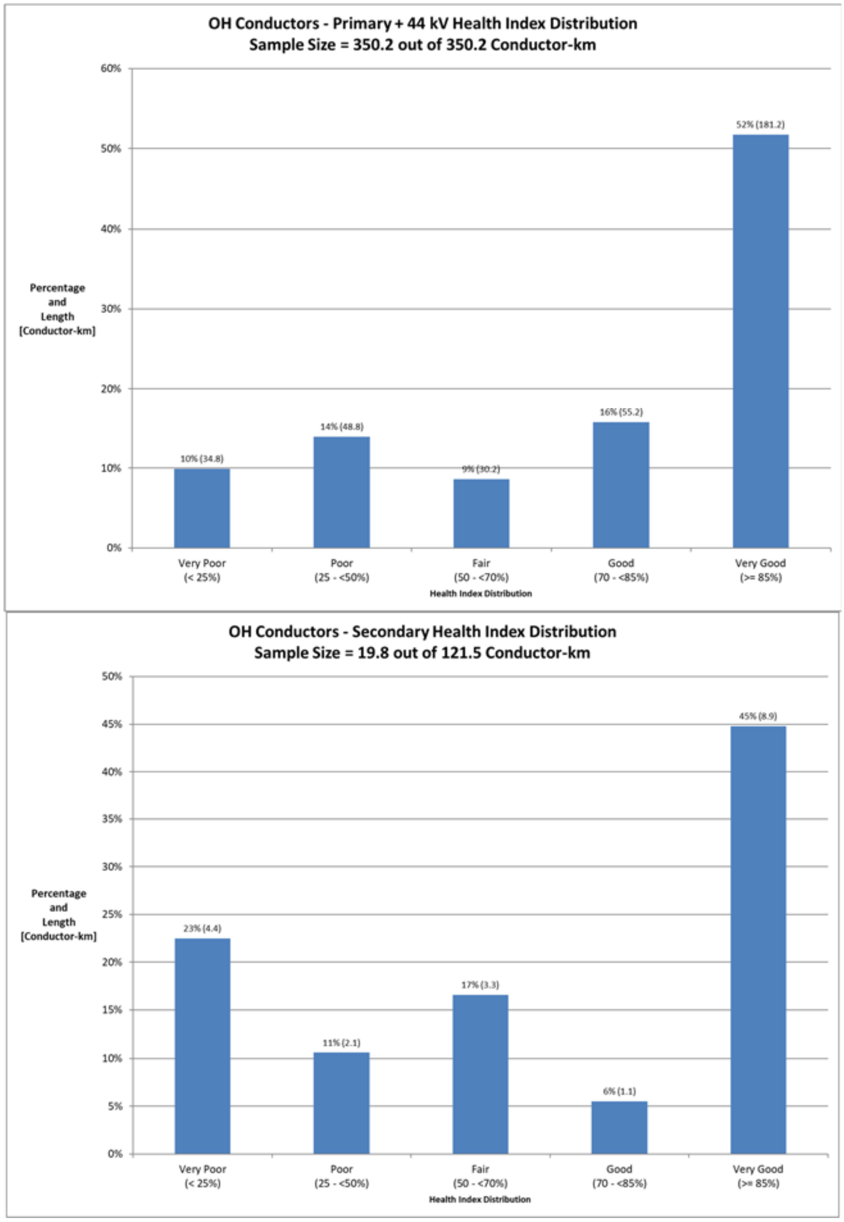
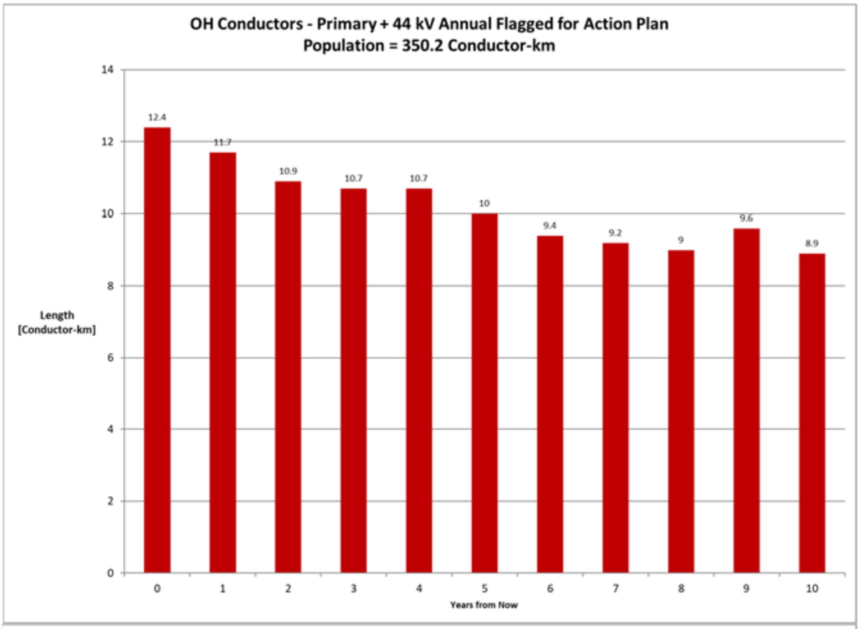


Figure 3-3 Health Index Distribution - OH Conductors

3.4 Flagged-for-action plan

The flagged-for-action plan for OH Conductors is based on asset removal rate and age distribution and is extrapolated to the entire population.



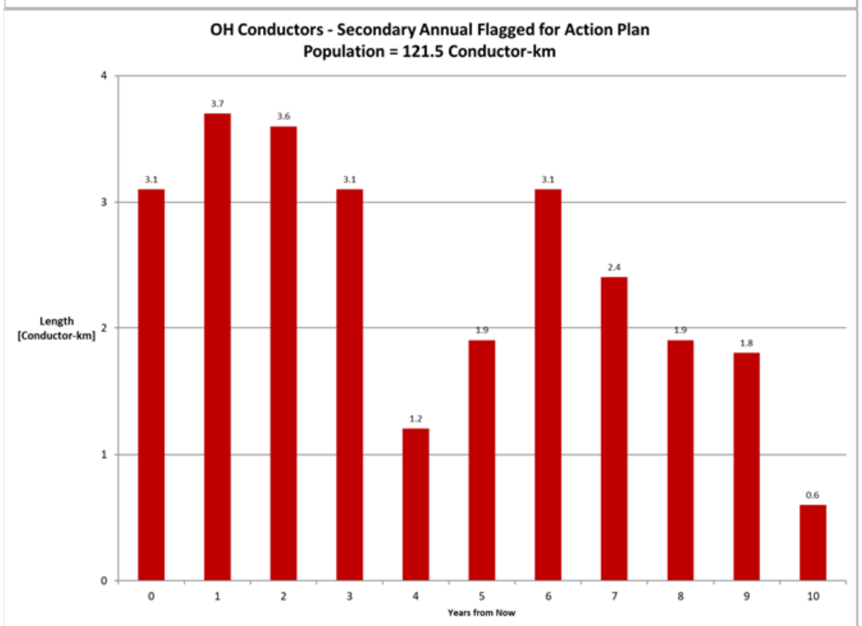


Figure 3-4 Flagged-for-action plan – OH Conductors

3.5 Data Gaps

The data used for assessing condition of OH Conductors assessment include age only.

The data gaps are as follows:

Table 3-4 Data Gap for OH Conductors

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Splices & Termination	Physical Condition	☆ ☆	Conductor Connection	Connection defect	Inspection & Maintenance Records
Clamp & Insulator		☆	Hardware	Loose installation & crack	
Fault rate at Segment Level	Service Record	☆ ☆	Conductor	Failure records	Historic records

4 OH 44 kV Load Break Switches

4.1 Health Index Formula

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

Age is used as a limiting factor to reflect the degradation of asset over time, refer to section 1.1.2 for the description.

4.1.1 Condition and Sub-Condition Parameters

Table 4-1 Condition Parameter and Weights – OH 44 kV Load Break Switches

m	Condition Parameter	WCP_m	Sub-Condition Parameters
	Age Limiting		Figure 4-1

4.1.2 Condition Criteria

<u>Age Limiting Factor</u>

The parameters of OH 44 kV Load Break Switches age limiting curve are shown in the following table and are based on industry information.

Table 4-2 Age Limiting Curve Parameters - OH 44 kV Load Break Switches

Asset Type	α	β
OH 44 kV Load Break Switches	**55.55**	**14.24**

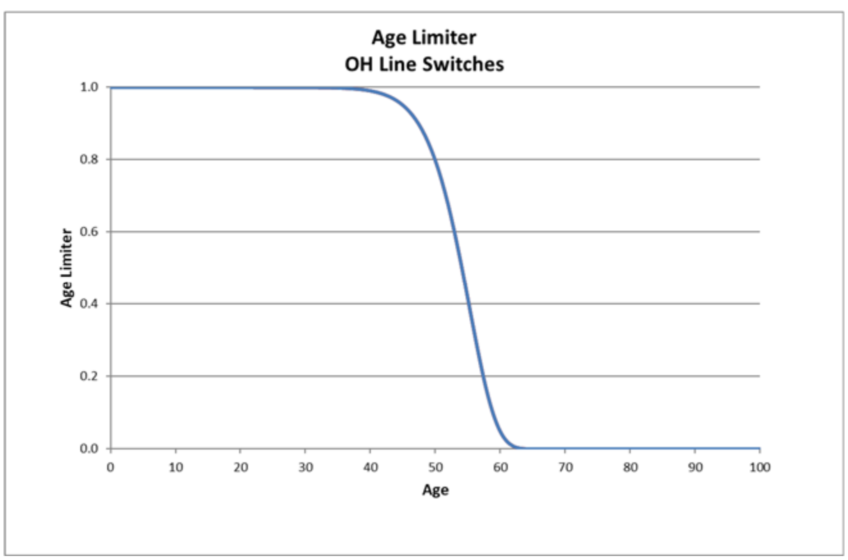


Figure 4-1 Age Limiting Factor Criteria - - OH 44 kV Load Break Switches

4.2 Age Distribution

The average age of all units is 16 years for OH 44 kV Load Break Switches.

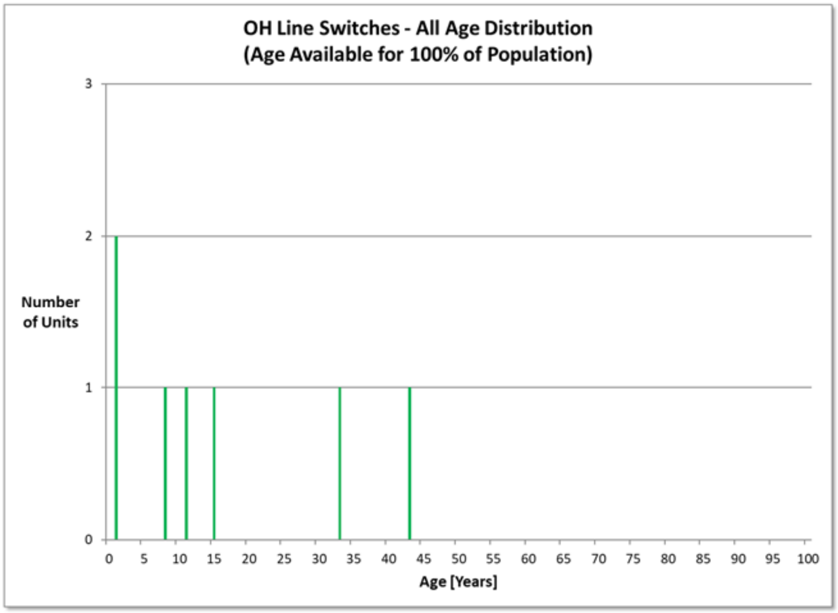


Figure 4-2 Age Distribution – OH 44 kV Load Break Switches

4.3 Health Index Results

There are 7 OH 44 kV Load Break Switches. All of them have age data for a Health Indexing.

The average Health Index is almost 100% for OH 44 kV Load Break Switches.

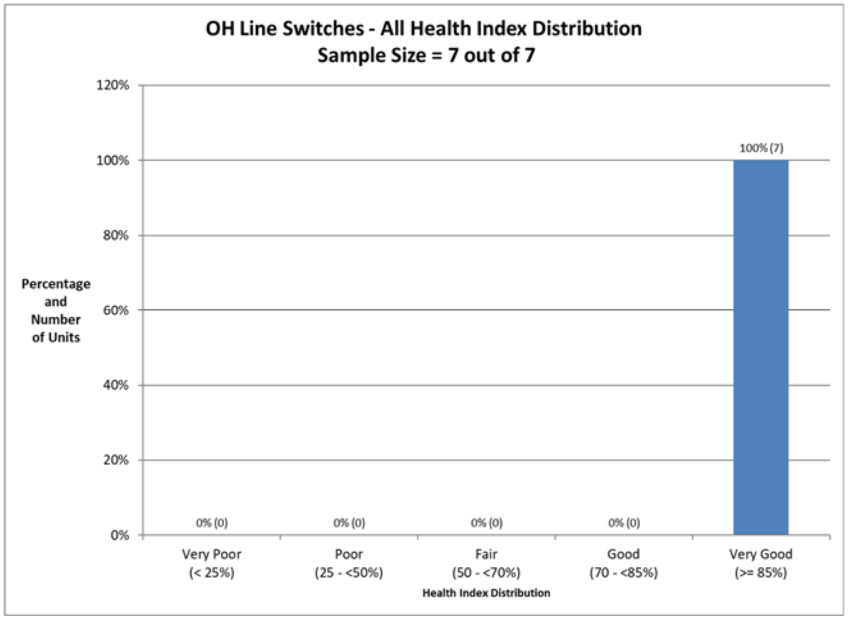


Figure 4-3 Health Index Distribution - OH 44 kV Load Break Switches

4.4 Flagged-for-action plan

The flagged-for-action plan of OH 44 kV Load Break Switches is based on the asset removal rate and age distribution.

Based on health index results and asset removal rate, no asset is flagged for action in the next 10 years.

4.5 Data Gaps

The data used for OH 44 kV Load Break Switches assessment include age only.

The data gaps are as follows.

Table 4-3 Data Gap for OH 44 kV Load Break Switches

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Description**	**Source of Data**
Load Break handle	Operation Mechanism	✯✯	Mechanical part and linkage issue	Inspection/ Maintenance Records
Switch Mounting		✯	Loose installation	
Insulator	**Insulation**	✯	Crack	

5 POLE MOUNTED TRANSFORMERS

5.1 Health Index Formula

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

Age is used as a limiting factor to reflect the degradation of asset over time, refer to section 1.1.2 for the description.

5.1.1 Condition and Sub-Condition Parameters

Table 5-1 Condition Parameter and Weights – Pole Mounted Transformers

m	Condition Parameter	WCP_m	Sub-Condition Parameters
	Age Limiting		Figure 4-1

5.1.2 Condition Criteria

<u>Age Limiting Factor</u>

The parameters for Pole Mounted Transformers age limiting curve are shown in the following table and are based on WD historic removal data.

Table 5-2 Age Limiting Curve Parameters - Pole Mounted Transformers

Asset Type	α	β
Pole Mounted Transformers	**42.01**	**3.51**

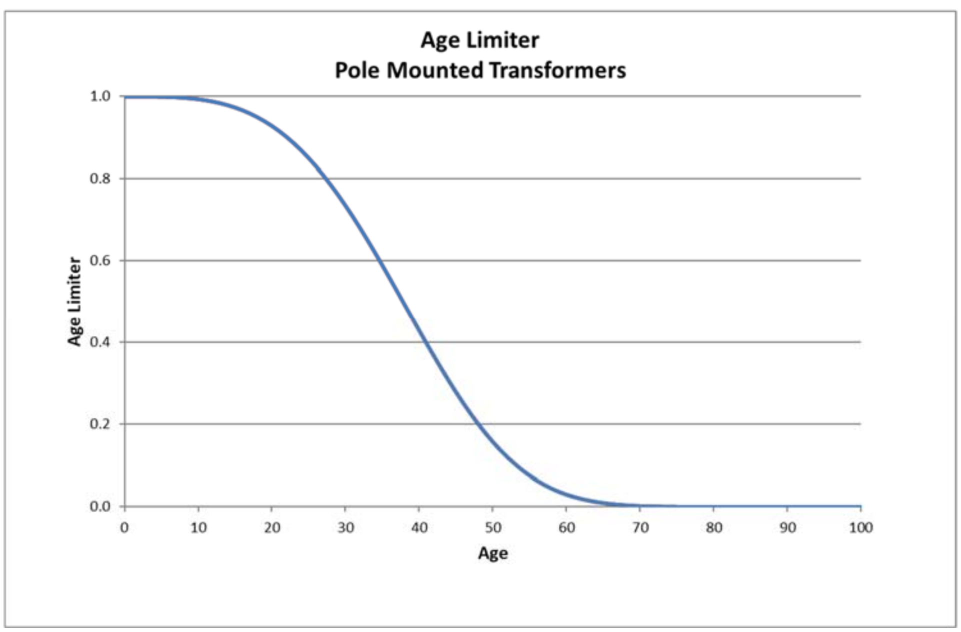


Figure 5-1 Age Limiting Factor Criteria - - Pole Mounted Transformers

5.2 Age Distribution

The average ages of all in service units are 27 and 38, for 1-Ph and 3-Ph Pole Mounted Transformers respectively. The age distribution is as follows.

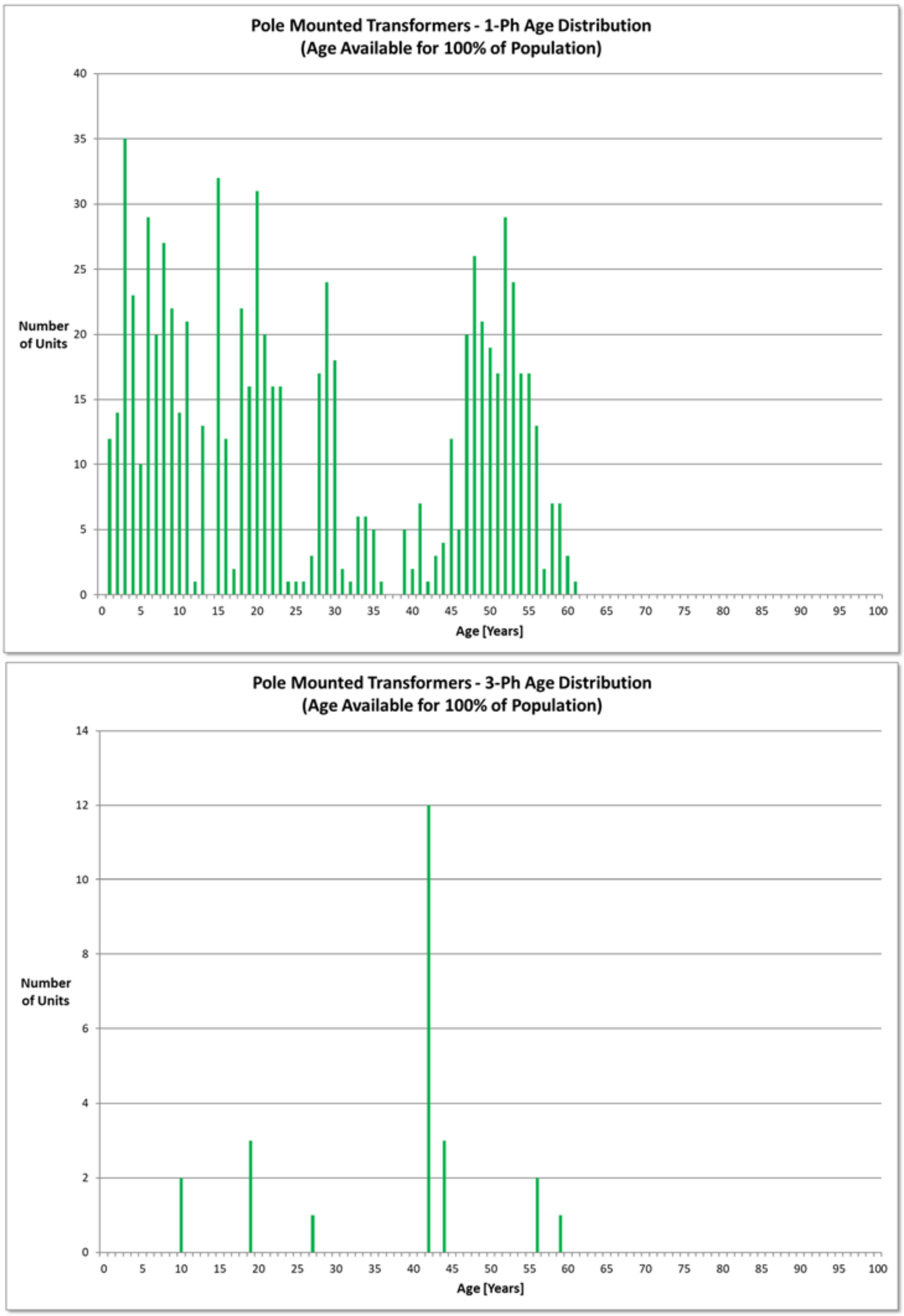


Figure 5-2 Age Distribution - Pole Mounted Transformers

5.3 Health Index Results

There are 757 1-Ph Pole Mounted Transformers. Among them, 756 units have age data for calculating a Health Indexing score.

There are 24 3-Ph Pole Mounted Transformers. All of them have age data for calculating a Health Indexing score.

The average Health Index are 66% and 46%, for 1-Ph and 3-Ph Pole Mounted Transformers respectively.

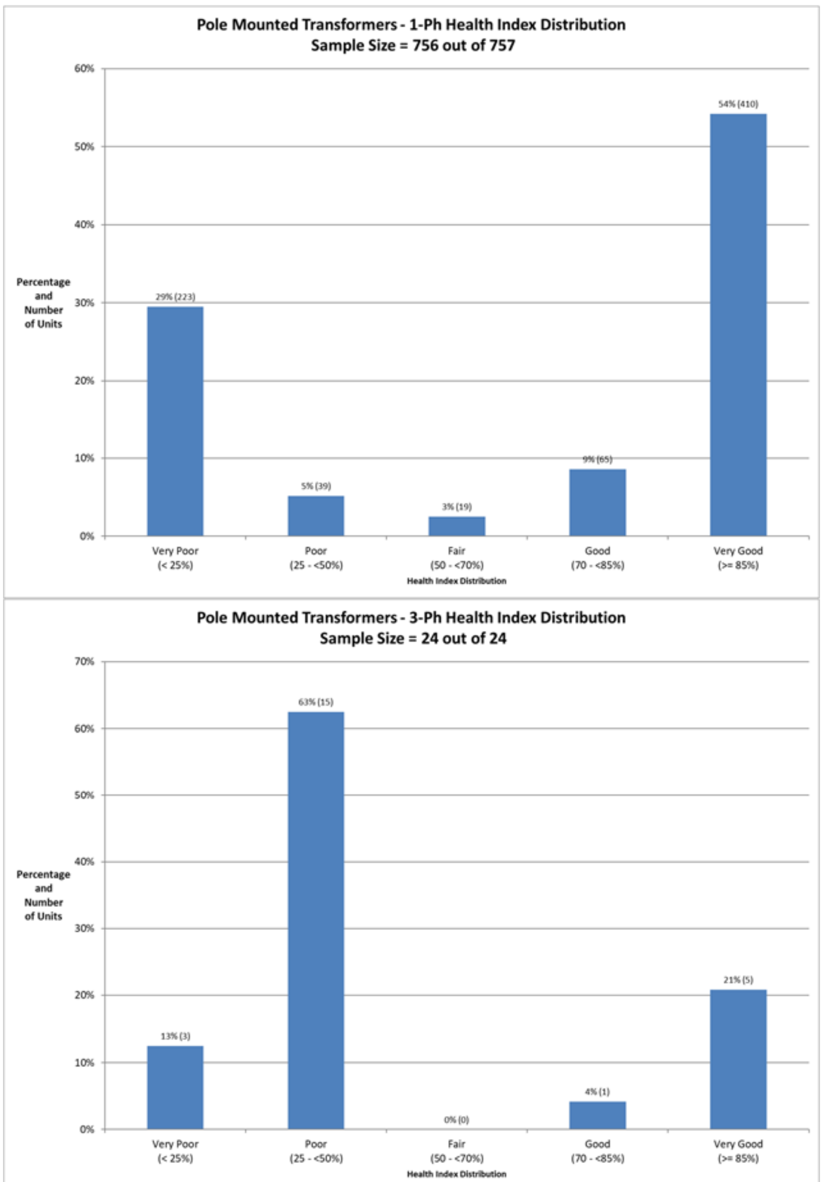


Figure 5-3 Health Index Distribution - Pole Mounted Transformers

5.4 Flagged-for-action plan

The flagged-for-action plan for Pole Mounted Transformers is based on the asset removal rate and age distribution.

The flagged-for-action plan for Pole Mounted Transformers is as follows:

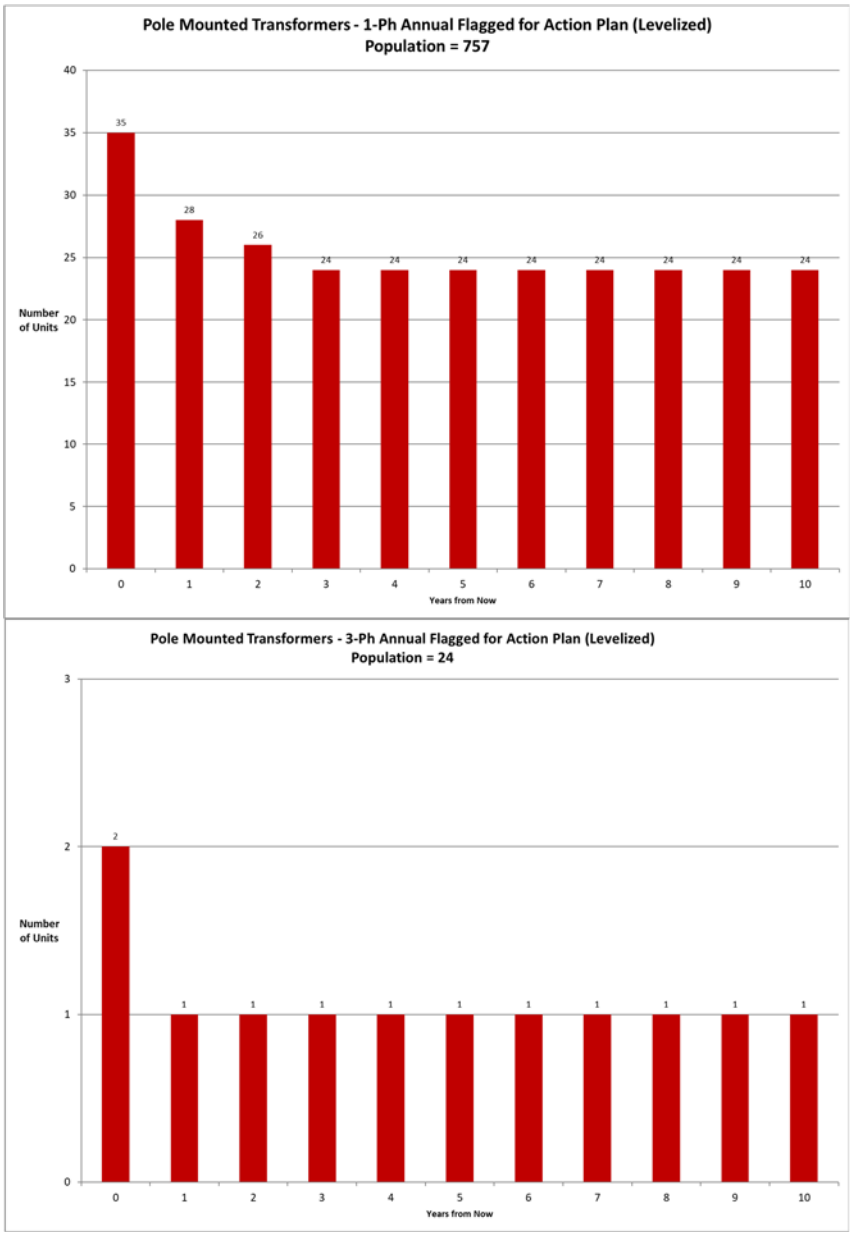


Figure 5-4 Flagged-for-action plan – Pole Mounted Transformers

5.5 Data Gaps

The data for in service Pole Mounted Transformers include age information only.

The data gaps for this asset category are as follows:

Table 5-3 Data Gap for Pole Mounted Transformers

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

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6 WOOD POLES

6.1 Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

6.1.1 Condition and Sub-Condition Parameters

Table 6-1 Condition Parameter and Weights - Wood Poles

m	Condition parameter	WCP_m	Sub-Condition Parameters
1	Pole Strength	7	Table 6-2
2	Pole Condition	5	Table 6-3
3	Pole Accessories	3	Table 6-4
4	Service Record	6	Table 6-5
	Age Limiting		Figure 6-1

Table 6-2 Pole Strength Sub-Condition Parameters and Weights (m=1) - Wood Poles

n	Sub-Condition Parameter	$WSCP_n$	Condition Criteria Table
1	Pole Strength	1	Table 6-7

Table 6-3 Pole Condition Sub-Condition Parameters and Weights (m=2) - Wood Poles

n	Sub-Condition Parameter	$WSCP_n$	Condition Criteria Table
1	Crack	2	Table 6-6
2	Rot	2	Table 6-6
3	Wood Loss	3	Table 6-6
4	Woodpeckers	2	Table 6-6
5	Damage	1	Table 6-6

Table 6-4 Pole Accessories Sub-Condition Parameters and Weights (m=3) - Wood Poles

n	Sub-Condition Parameter	$WSCP_n$	Condition Criteria Table
1	Split	2	Table 6-6
2	Crossarm	3	Table 6-6
3	Leaning	4	Table 6-6

Table 6-5 Service Record Sub-Condition Parameters and Weights (m=4) - Wood Poles

n	Sub-Condition Parameter	$WSCP_n$	Condition Criteria Table
1	Overall	1	Table 6-6

6.1.2 Condition Criteria

Individual Inspection

The score based on individual inspection in the past years is calculated as:

$$Average\ Score = \frac{\sum W_i Score_i}{\sum W_i}$$

Equation 6-1

Where *i* represents the year of inspection

Table 6-6 Individual Inspection Criteria - Wood Poles

Score	Inspection Defect
4	PASS
3	Good
2	Mild, Fair
1	Severe, Marginal, Poor
0	FAIL, Emergency

And the weights for different inspection years are as follows

Year (i)	Weight (W_i)
2021	1
2020	0.9
2019	0.8
2018	0.7
2017	0.6
2016	0.5
2015	0.4
2014	0.3
2013	0.2
2012	0.1
2011	0

Pole Strength

The score based on pole strength data in latest test is calculated as:

Table 6-7 Pole Strength Criteria - Wood Poles

Remaining Strength % Available	Remaining Strength psi Available
$Score = \ Remaining\_Strength\_\% \times 4$	$Score = \dfrac{Remaining\_Strength\_psi \times 4}{Design\_Strength^{*}}$

Where the design strength limits are summarized in the following table

Wood Pole Species	Design Strength (psi) *
Douglas Fir	8000
Lodgepole Pine	6600
Red Pine	6600
Southern Pine	8000
Western Red Cedar	6000

* National wood pole standards (ANSI O5.1-2017)

Age Limiting Factor

Age is used as a limiting factor to reflect the degradation of asset over time. Methodology for applying the degradation survival curve is described in Equation 1-1 of Section 1.1.2.

The parameters of Wood Poles age limiting curve are shown in the following table and based on WD historic pole change records.

Table 6-8 Age Limiting Curve Parameters - Wood Poles

Asset Type	α	β
Wood Poles	**57.07**	**2.26**

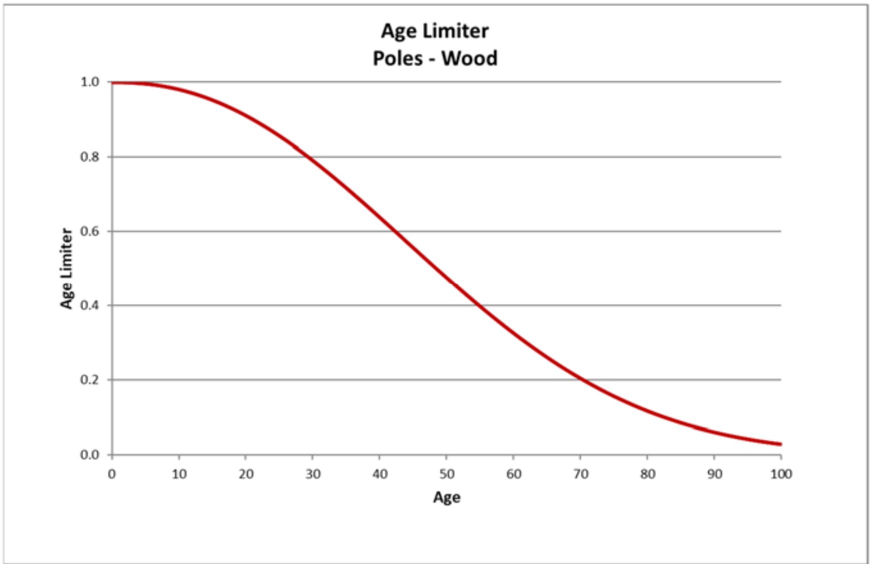


Figure 6-1 Age Limiting Factor Criteria - Wood Poles

6.2 Age Distribution

The average age of all units is 40 years for Wood Poles.

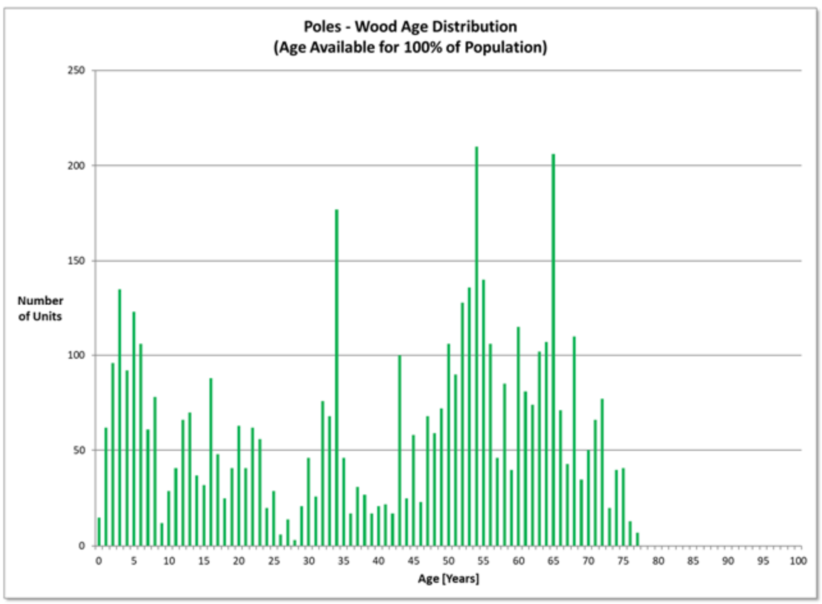


Figure 6-2 Age Distribution – Wood Poles

6.3 Health Index Results

There are 5090 units of Wood Wood Poles. Among them, 5086 units have sufficient data for obtaining Health Indexing results.

The average Health Index score is 57%.

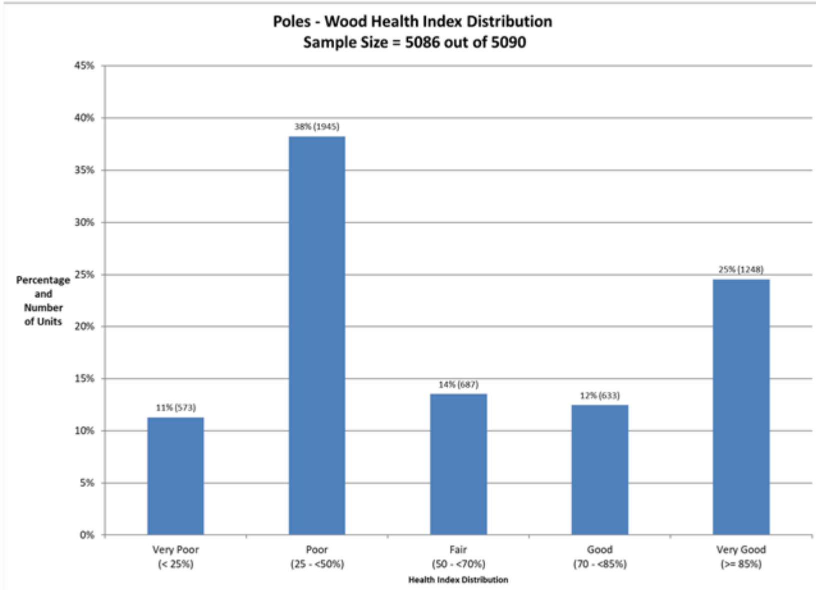


Figure 6-3 Health Index Distribution - Wood Poles

6.4 Flagged-for-Action Plan

The flagged-for-action plan of Wood Poles is based on the asset removal rate and age distribution.

The following diagram shows the flagged-for-action plan:

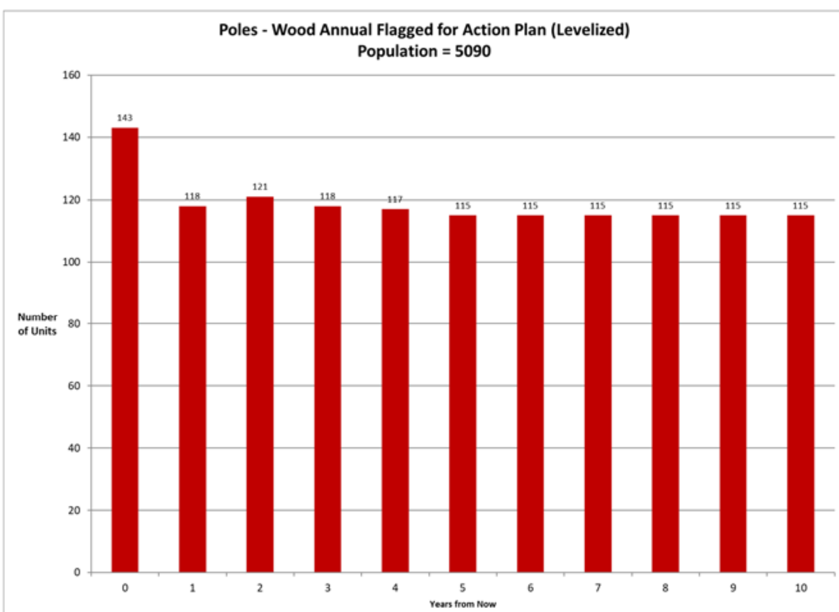


Figure 6-4 Flagged-for-action plan - Wood Poles

6.5 Data Gaps

The data used for Wood Poles assessment include age and pole inspection status condition.

There are no major data gaps for this asset category.

7 Pad Mounted Transformers

7.1 Health Index Formula

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

Age is used as a limiting factor to reflect the degradation of asset over time, refer to section 1.1.2 for the description.

7.1.1 Condition and Sub-Condition Parameters

Table 7-1 Condition Parameter and Weights – Pad Mounted Transformers

m	Condition Parameter	WCP_m	Sub-Condition Parameters
	Age Limiting		Figure 7-1

7.1.2 Condition Criteria

Age Limiting Factor

The parameters of Pad Mounted Transformers age limiting curve are shown in the following table and are based on WD historic removal data.

Table 7-2 Age Limiting Curve Parameters - Pad Mounted Transformers

Asset Type	α	β
Pad Mounted Transformers	**42.01**	**3.51**

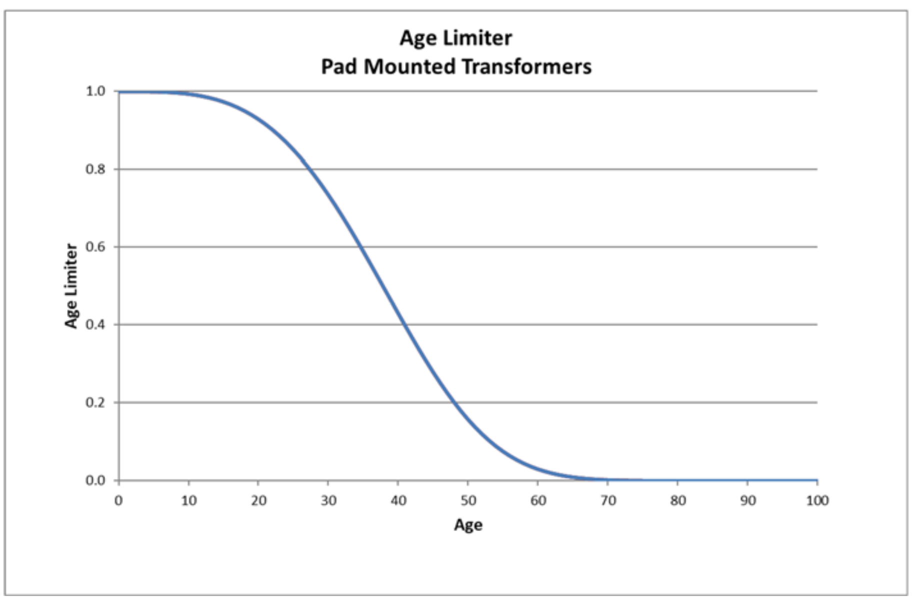


Figure 7-1 Age Limiting Factor Criteria - - Pad Mounted Transformers

7.2 Age Distribution

The average ages of the asset units are 20 years and 21 years, for 1-Ph and 3-Ph Pad Mounted Transformers respectively.

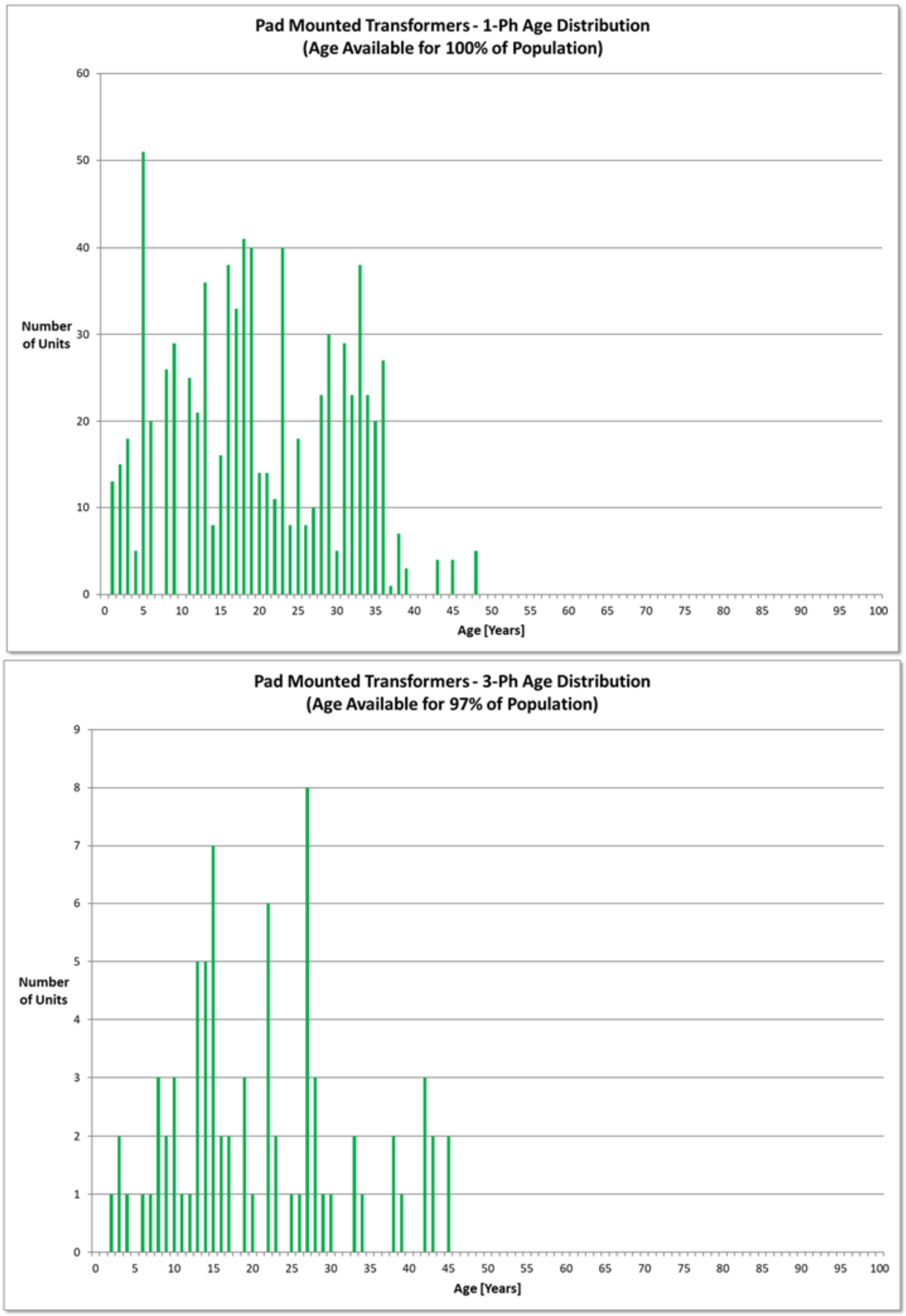


Figure 7-2 Age Distribution - Pad Mounted Transformers

7.3 Health Index Results

There are 800 units of 1-Ph Pad Mounted Transformers. All of them have age data for a Health Indexing.

There are 79 units of 3-Ph Pad Mounted Transformers. Among them, 77 units have age data for a Health Indexing.

The average Health Index scores for this asset category are 86% and 85%, for 1-Ph and 3-Ph Pad Mounted Transformers respectively.

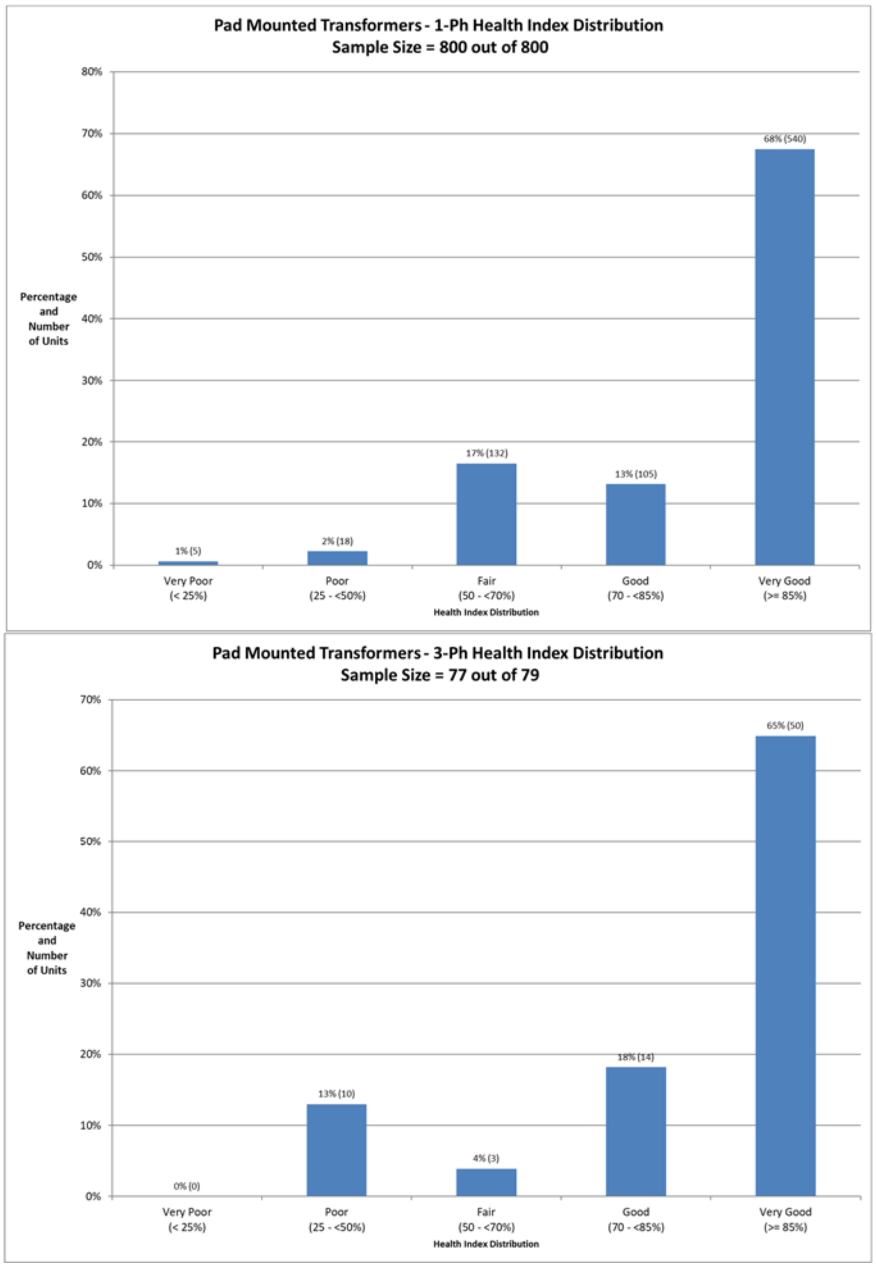
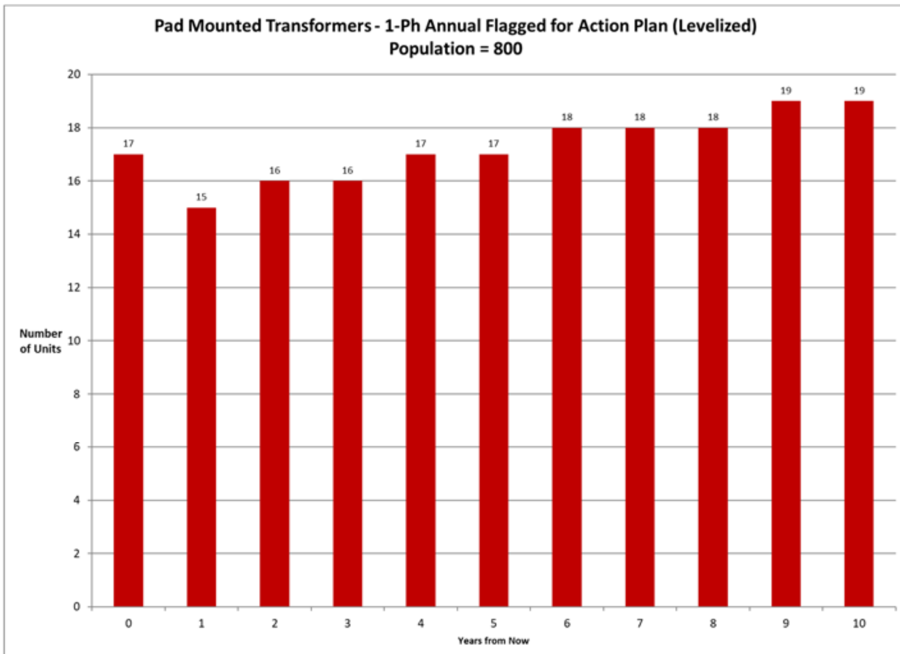


Figure 7-3 Health Index Distribution - Pad Mounted Transformers

7.4 Flagged-for-action plan

The flagged-for-action plan of Pad Mounted Transformers is based on the asset removal rate and age distribution.

The following diagram shows the flagged-for-action plan:



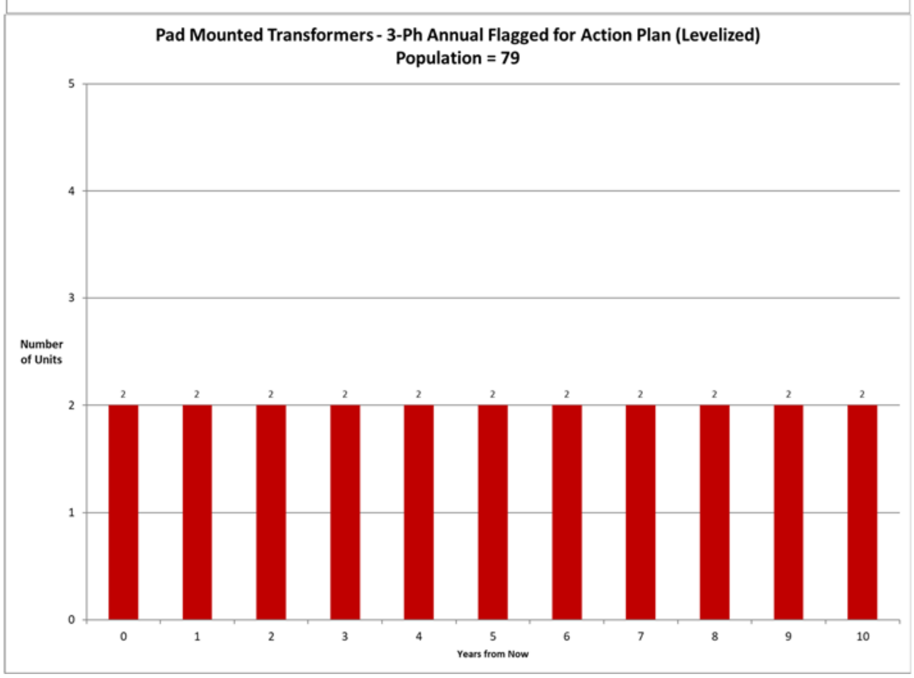


Figure 7-4 Flagged-for-action plan - Pad Mounted Transformers

7.5 Data Gaps

The data used for single phase Pad Mounted Transformers assessment include age and inspection results for some individual components.

The data gaps are as follows.

Table 7-3 Data Gap for Pad Mounted Transformers

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

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8 PAD MOUNTED SWITCHGEAR

8.1 Health Index Formula

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

Age is used as a limiting factor to reflect the degradation of asset over time, refer to section 1.1.2 for the description.

8.1.1 Condition and Sub-Condition Parameters

Table 8-1 Condition Parameter and Weights – Pad Mounted Switchgear

m	Condition Parameter	WCP_m	Sub-Condition Parameters
	Age Limiting		Figure 8-1

8.1.2 Condition Criteria

<u>Age Limiting Factor</u>

The parameters of Pad Mounted Switchgear age limiting curve are shown in the following table and are based on industry information.

Table 8-2 Age Limiting Curve Parameters - Pad Mounted Switchgear

Asset Type	α	β
Pad Mounted Switchgear	**38.54**	**2.47**

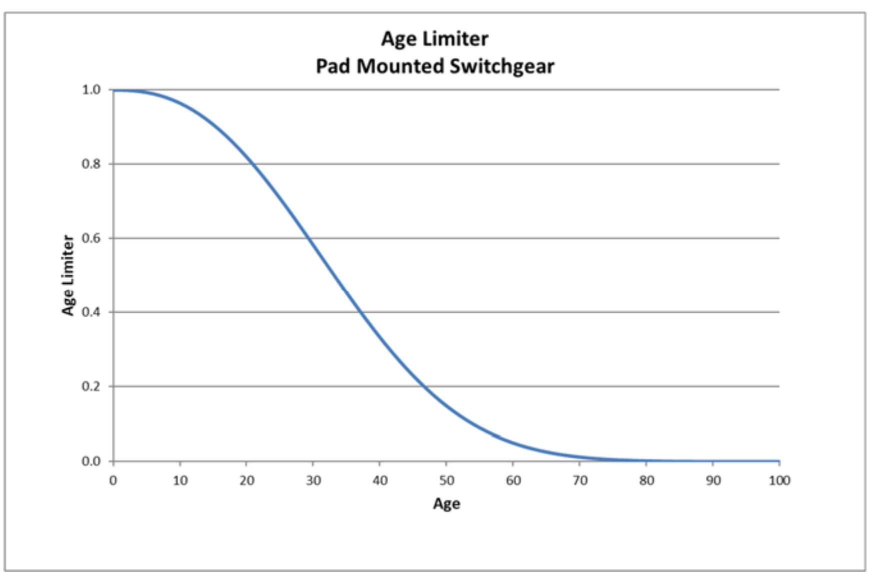


Figure 8-1 Age Limiting Factor Criteria - - Pad Mounted Switchgear

8.2 Age Distribution

The average age of the units is 13 years for Pad Mounted Switchgear.

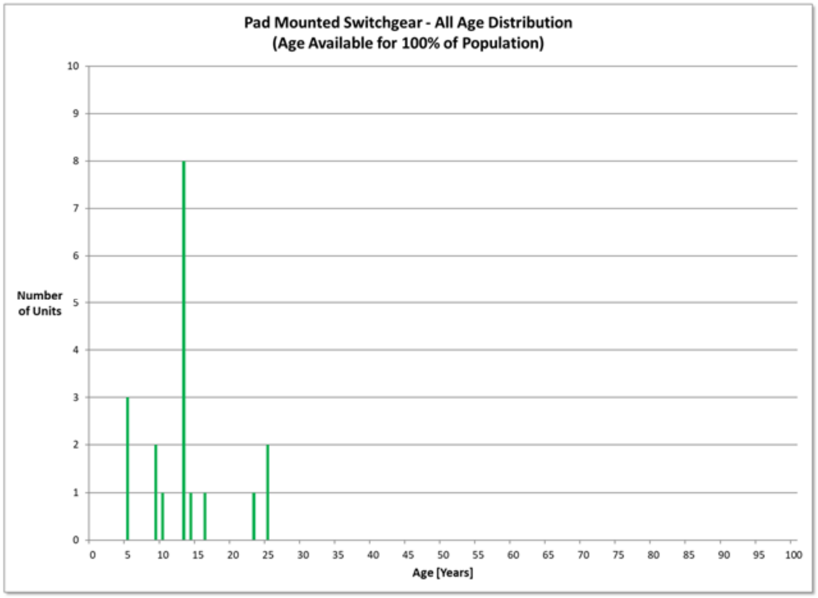


Figure 8-2 Age Distribution - Pad Mounted Switchgear

8.3 Health Index Results

There are a total of 19 units of Pad Mounted Switchgear. All the units have age data for deriving Health Indexing results.

The average Health Index score for this asset category is 91%.

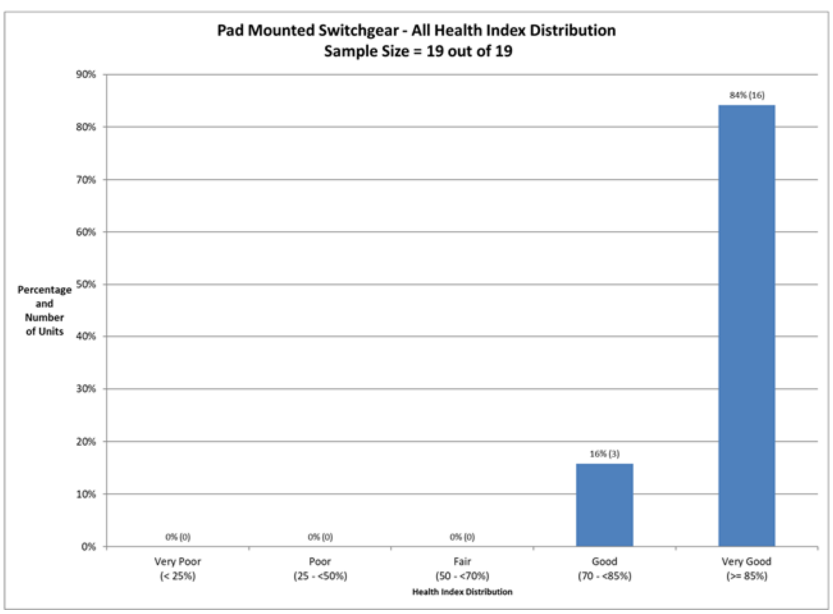


Figure 8-3 Health Index Distribution - Pad Mounted Switchgear

8.4 Flagged-for-action plan

The flagged-for-action plan of Pad Mounted Switchgear is based on the asset removal rate and age distribution.

The following diagram shows the flagged-for-action plan:

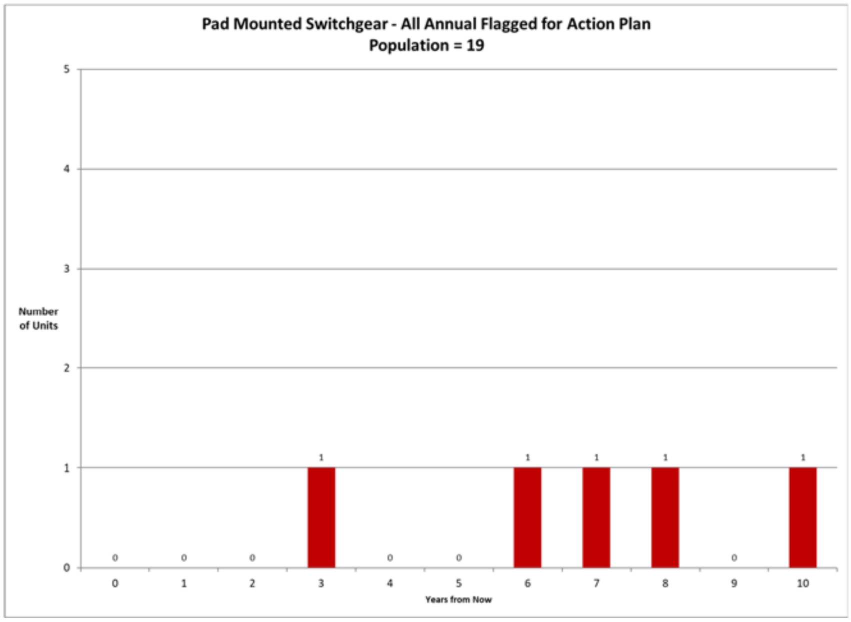


Figure 8-4 Flagged-for-action plan - Pad Mounted Switchgear

8.5 Data Gaps

The data used for Pad Mounted Switchgear assessment include age only.

The data gaps are as follows.

Table 8-3 Data Gap for Pad Mounted Switchgear

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Concrete Pad	Physical Condition	☆	Foundation	Physically worn-out	On-site visual inspection
Corrosion		☆☆	External status	Physically worn-out	On-site visual inspection
Excess Moisture		☆	Environment	Humid operating condition	On-site visual inspection
Fuse Holder	Switch/Fuse Condition	☆☆☆	Fuse	Abnormal breaking performance	On-site visual inspection
Grounding		☆	Grounding	Grounding connection	On-site visual inspection
Insulators	Insulation Condition	☆☆	Insulation	Insulation defect	On-site visual inspection
Barriers		☆☆			On-site visual inspection
Cable Terminations		☆☆	Cabling	Loose connection or overheating	On-site visual inspection
Connections		☆☆	Connection		On-site visual inspection

9 UG CABLES

9.1 Health Index Formula

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

9.1.1 Condition and Sub-Condition Parameters

Table 9-1 Condition Parameter and Weights – UG Cables

m	Condition Parameter	WCP_m	Sub-Condition Parameters
	Age Limiting		Figure 9-1

9.1.2 Condition Criteria

<u>Age Limiting Factor</u>

The parameters of UG Cables age limiting curve are shown in the following table and are based on industry information.

Table 9-2 Age Limiting Curve Parameters - UG Cables

Asset Type	α	β
TR XLPE cables (In Duct)	**53.13**	**9.03**
TR XLPE cables (Direct Buried)	**37.92**	**6.41**
Non-TR XLPE cables	**32.80**	**5.53**
Other type cables	**43.00**	**7.30**

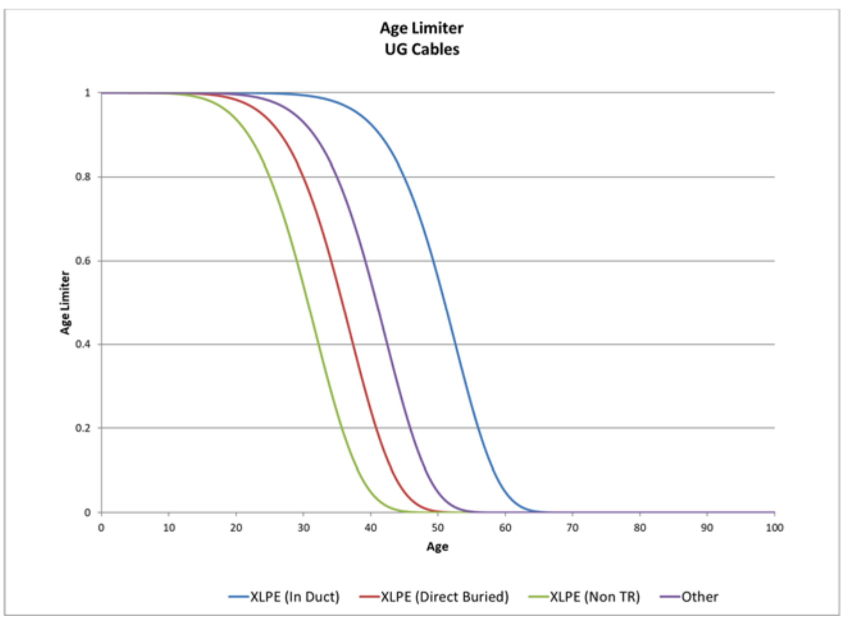


Figure 9-1 Age Limiting Factor Criteria - - UG Cables

9.2 Age Distribution

The average ages of primary and 44 kV UG Cables segments is 20 years.

The average ages of secondary and service UG Cables segments is 20 years.

The age distributions for UG Cables is as follows:

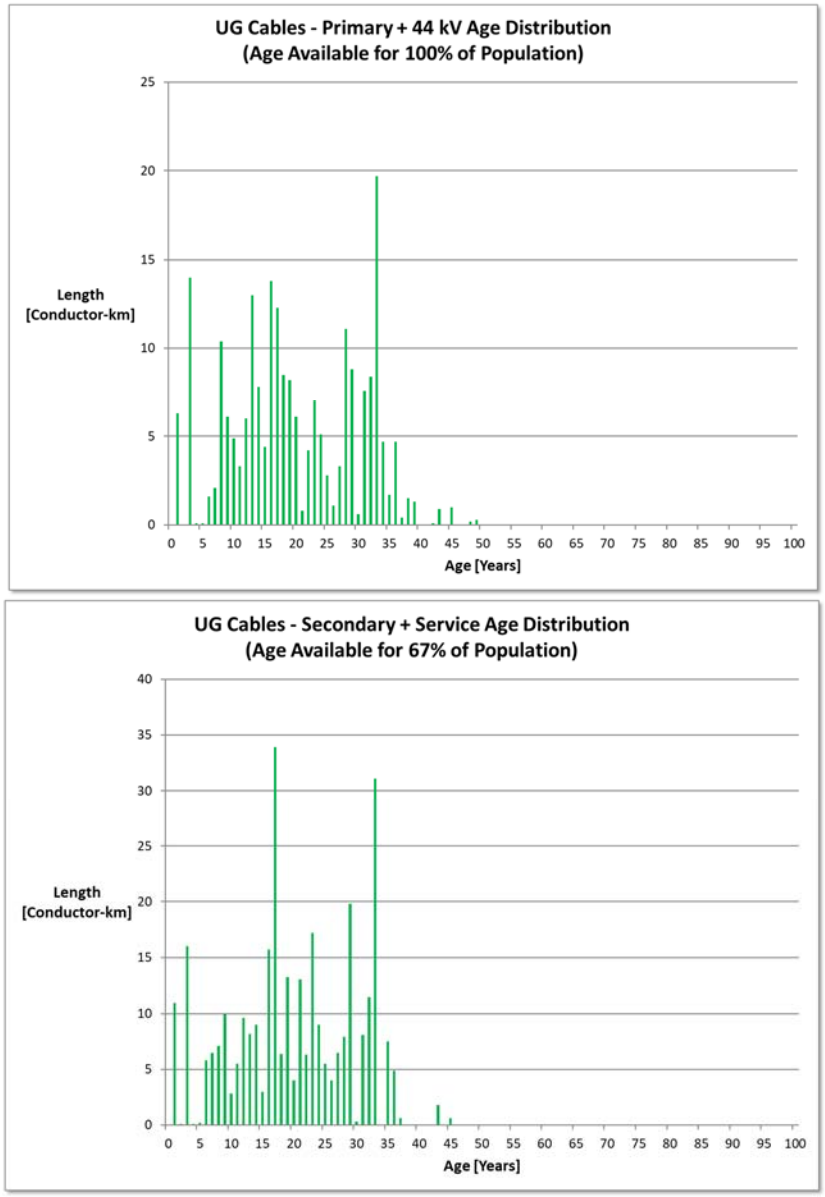


Figure 9-2 Age Distribution - UG Cables

9.3 Health Index Results

There are 226 km primary and 44 kV UG Cables. All of them have age data used for Health Indexing. The average Health Index for this asset category is 79%.

There are 481 km secondary and service UG Cables. Among them, 323 km have age data used for Health Indexing. The average Health Index for this asset category is 96%.

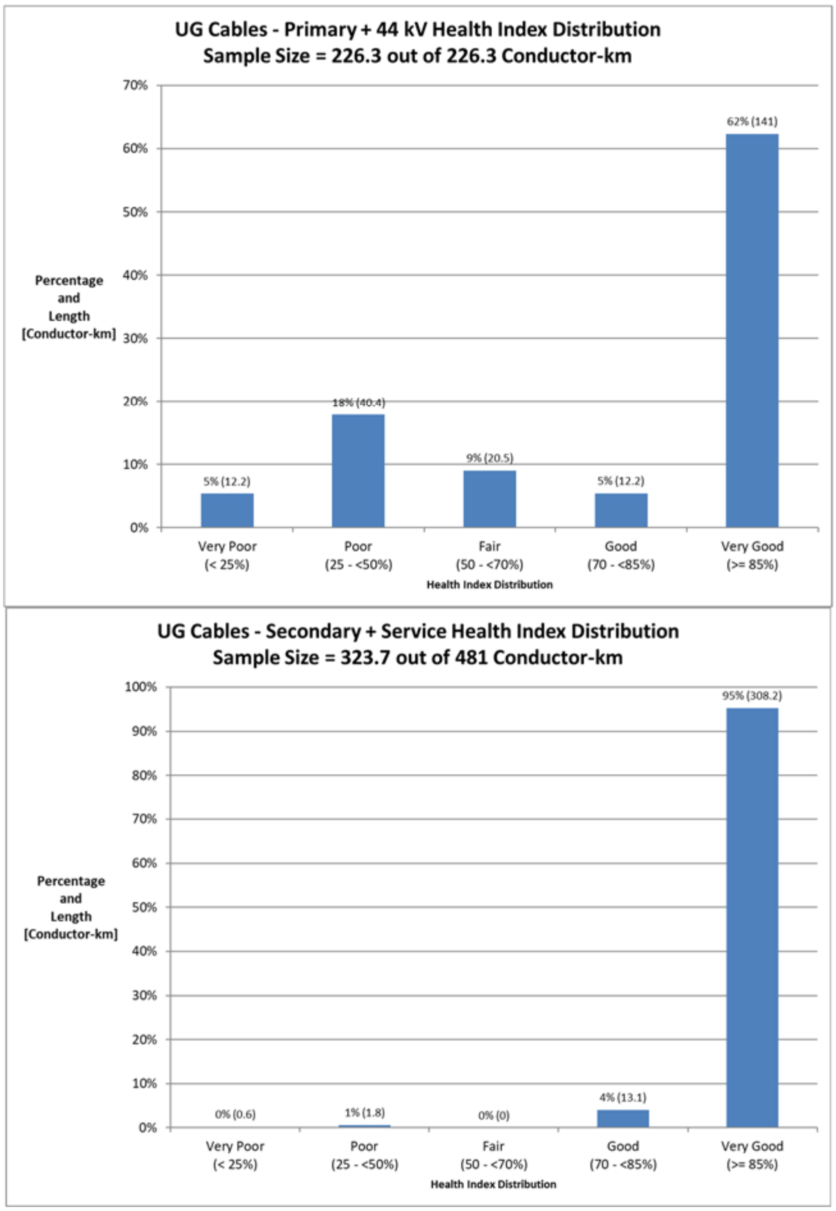
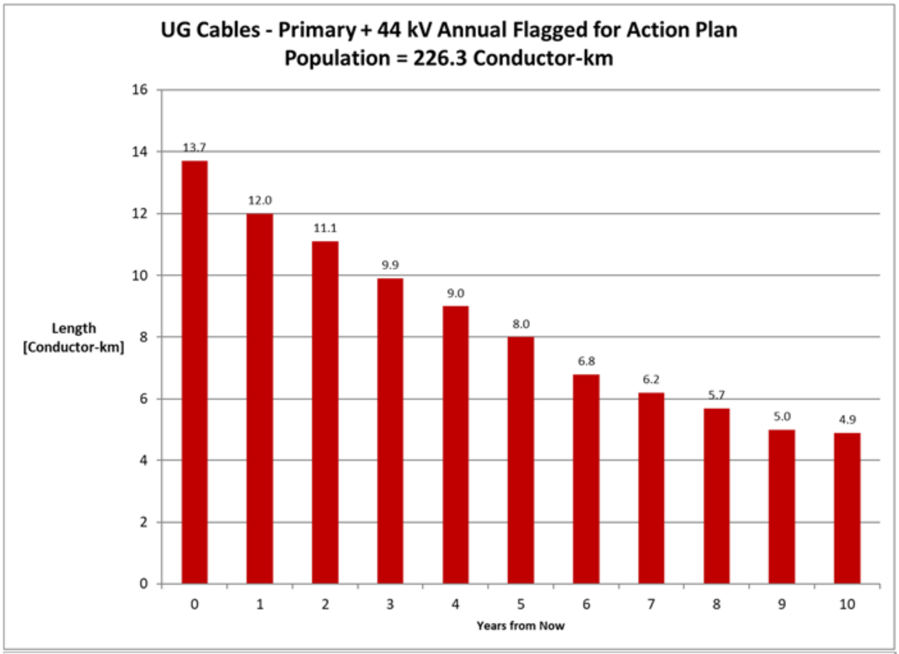


Figure 9-3 Health Index Distribution - UG Cables

9.4 Flagged-for-action plan

The flagged-for-action plan for UG Cables is based on asset removal rate and age distribution and is extrapolated to the entire population.



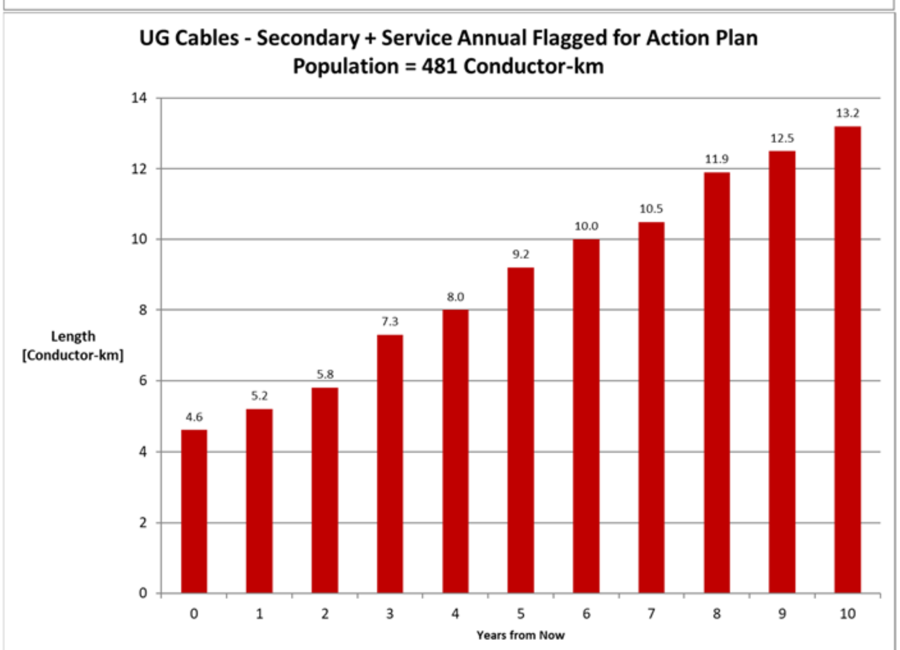


Figure 9-4 Flagged-for-action plan – UG Cables

9.5 Data Gaps

The data used for assessing condition of UG Cables assessment include age only.

The data gaps are as follows:

Table 9-3 Data Gap for UG Cables

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Dielectric Loss	Insulation	☆ ☆	Cable	Insulation defect	Off-line test
Splices & Terminations	Accessories	☆ ☆	Cable Connection	Connection defect	Inspection & Maintenance Records
Neutral Corrosion		☆	Other Component	Neutral defect	
Fault rate at Segment Level	Service Record	☆ ☆	Cable	Failure records	Historic records

1 # Appendix D: Load Growth Analysis Report

Load Growth Analysis

Wasaga Distribution Inc.

Prepared for:
Wasaga Distribution Inc.
10/11/2023

Table of Contents

Document Summary

Client: Wasaga Distribution Inc.
Document Name: Wasaga Distribution Inc.

Versions

VERSION	DATE	AUTHOR	COMMENTS
1.0	10/11/23	Imtiaz Ahmed	

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Executive Summary

This study assesses the impact of adding new loads to the Wasaga Distribution Inc. distribution system.

An overview of the key findings is as follows:

- Some substations are near the peak limit with the addition of new loads. Due to the amount of potential load, installation of BESS wouldn't be an optimal solution, but a new substation installation is recommended to handle load growth.
- Breaker pickup settings may require changes for some feeders.
- Some conductors become overloaded with additional peak loads. Load should be distributed accordingly.
- Distribution system planning needs to consider Building and Transportation Electrification and develop near-term/longer-term strategies.

Scope of Assessment

This report aims to analyze the impact of load growth on the Wasaga Distribution Inc. distribution system. The following potentially high-impact issues are considered:

- Equipment Thermal Loading
- System Voltage
- Breaker Settings
- Building and Transportation Electrification Analysis

System Data

The assessment findings are based on a series of load flow studies performed using DESS v7 software. The assessment was performed with the following assumptions:

- All loading and voltage data were validated based on SCADA and station inspection reports.
- The effect of load growth includes the normal system configuration and peak loading conditions.
- Load growth was projected based on planned and potential developments of subdivisions, and commercial and town strategies as shown in the tables below.
- It was assumed that the peak demand load at each condo, townhome/semi, and detached units are 2kW, 3kW, and 4kW respectively. Loading for some commercial units was distributed based on assigned transformer sizes.

Subdivision Plans:

Feeder	#Townhouse Units	#Detached Units	#Semi-detached Units	Est. Load kW
1F3	307			921
2F1	62		11	219
2F2	35			105
3F1	102			306
3F3		156		624
3F4	338	210	62	2,040
4F1	292	891	228	5,124
4F2			40	120
4F3	21			63
5F2	31			93
5F3	46			138
5F4	31			93
6F1	40			120
6F2	104	398	48	2,048
6F3	100	369	14	1,818
6F3,6F4	57	259	8	1,231
6F4	79	72	106	843
BF1	268	7	48	976
BF2	116		10	378
Total	**2,029**	**2,362**	**575**	**17,260**

Commercial Plans:

Feeder	#Commercial Units	#Condo Units	Est. Load kW
2F1	4	120	340
3F1	1		20
3F3	3	0	75
44kV	2	392	834
4F1	3	140	355
4F2	2	0	50
4F4	37	495	1,915
5F3	3	33	201
5F4	10	32	314
6F2		30	980
6F4	1		200
BF1	1	0	25
BF2	5	269	663
Total	**70**	**1,511**	**5,972**

Town Growth Strategy:

Feeder	# Residential +Commercial Units	Est. Load kW
1F1	501	1,503
1F2	198	594
1F3	999	2,451
3F1	253	773
3F3	50	238
4F1	109	591
5F3	355	1,182
5F4	6	18
Total	**2,470**	**7,350**

Equipment Thermal Loading

The results below show the impact of load growth at the line and station.

44kV System loading

	P (MW)	Q (MVAr)	MVA	PF	Curr (A)	Line Type @Boundary	Line Loading %
Existing System loading							
2M5	13.1	4.4	13.8	0.95	178	336 AL	33%
2M4	22.4	6.7	23.2	0.96	300	336 AL	55%
Planned + Potential Load Growth (50%)							
2M5	17.8	6.4	18.9	0.94	243	336 AL	45%
2M4	32.5	10	34	0.96	441	336 AL	80%
Planned + Potential Load Growth (100%)							
2M5	22.3	8.5	23.8	0.93	306	336 AL	56%
2M4	42.2	13.7	44.2	0.95	577	336 AL	105%

Comments: The highlighted section of the conductor peaks at 100% of capacity with the inclusion of planned and potential loads. Conductor upgrade or partial load transfer should be considered with the load increase.

Substation Loading

Station Name	Name Plate Limit	Existing peak MVA	Planned + Potential Load Growth (50%) MVA	Planned + Potential Load Growth (100%) MVA
MS1	7.5 MVA	4.2	7	9.7
MS2	5 MVA	2.4	2.7	3
MS3	10 MVA	7.8	10	11.9
MS4	10 MVA	10.5	14.6	18.7
MS5	10 MVA	9.9	10.9	11.8
Brocks Beach DS	5 MVA	0.45	1.5	2.5
MS6	10 MVA	N/A	3.7	7.4

Comments: Highlighted stations at over 100% of capacity, including planned and potential loads. It is recommended that a new 10MVA substation be installed, tapping into the 2M5 supply. More to be reviewed in the "Results and Discussion" section below.

System Voltage

Voltages were observed at SCADA points between ~1.03 pu (see appendix). Station tap settings were adjusted to output similar voltages during voltage drop analysis. The table below shows the impact on voltages due to the load growth.

System Condition	Existing loading		Planned + Potential Load Growth (50%)		Planned + Potential Load Growth (100%)	
Station	**Max Volt pu**	**Min Volt pu**	**Max Volt pu**	**Min Volt pu**	**Max Volt pu**	**Min Volt pu**
M2 @ 44kV	1.02	1.0	1.02	1.0	1.02	0.987
M4 @ 44kV	1.02	1.0	1.02	1.0	1.02	0.988
MS1 @8.32kV	1.035	1.007	1.03	0.993	1.015	0.966
MS2 @8.32kV	1.026	1.003	1.011	0.992	1.001	0.981
MS3 @8.32kV	1.025	0.975	1.021	0.963	1.02	0.947
MS4 @8.32kV	1.028	0.982	1.025	0.967	1.0	0.95
MS5 @8.32kV	1.036	0.998	1.029	0.988	1.02	0.975
Brocks Beach DS @8.32kV	1.021	1.019	1.017	1.012	1.017	1.012
MS6 @8.32kV	N/A	N/A	1.023	1.011	1.023	1.008

Comments: The existing operating voltages at all substations are sufficient for all feeders to maintain acceptable Voltages (between 0.94pu – 1.06pu). However, with the inclusion of new loads, some feeders may experience voltage drops closer to the 0.94pu threshold which shall be mitigated by the inclusion of a new substation as mentioned in the previous section.

Line Loading

Feeder	Cable Type	Rated Current	Existing Peak Load	Loading %	Planned + Potential Load Growth (50%)	Loading %	Planned + Potential Load Growth (100%)	Loading %
					Max Current (A)		Max Current (A)	
MS1-F1	500 kcmil Cu-UG	414	162	39.13%	215	51.93%	270	65.22%
MS1-F2	500 kcmil Cu-UG	414	85	20.53%	106	25.60%	126	30.43%
MS1-F3	500 kcmil Cu-UG	414	82	19.81%	202	48.79%	255	61.59%
MS2-F1	500 kcmil Cu-UG	414	154	37.20%	174	42.03%	193	46.62%
MS2-F2	500 kcmil Cu-UG	414	31	7.49%	35	8.45%	38	9.18%
MS3-F1	250 kcmil Cu-UG	344	260	75.58%	296	86.05%	376	109.30%
MS3-F2	250 kcmil Cu-UG	344	NA	NA	NA	NA	NA	NA
MS3-F3	250 kcmil Cu-UG	344	246	71.51%	280	81.40%	314	91.28%
MS3-F4	250 kcmil Cu-UG	344	126	36.63%	198	57.56%	269	78.20%
MS4-F1	500 kcmil Cu-UG	414	264	63.77%	527	127.29%	784	189.37%
MS4-F2	500 kcmil Cu-UG	414	216	52.17%	221	53.38%	225	54.35%
MS4-F3	500 kcmil Cu-UG	414	205	49.52%	205	49.52%	205	49.52%
MS4-F4	500 kcmil Cu-UG	414	151	36.47%	220	53.14%	287	69.32%
MS5-F1	500 kcmil Cu-UG	414	199	48.07%	199	48.07%	199	48.07%
MS5-F2	500 kcmil Cu-UG	414	261	63.04%	264	60.63%	266	64.25%
MS5-F3	500 kcmil Cu-UG	414	184	44.44%	237	57.25%	289	69.81%
MS5-F4	500 kcmil Cu-UG	414	117	28.26%	131	31.64%	145	35.02%
MS6-F1	500 kcmil Cu-UG	414	NA	NA	4	0.97%	8.6	2.08%
MS6-F2	500 kcmil Cu-UG	414	NA	NA	109	26.33%	217	52.42%
MS6-F3	500 kcmil Cu-UG	414	NA	NA	88	21.26%	175	42.27%
MS6-F4	500 kcmil Cu-UG	414	NA	NA	60	14.49%	119	28.74%

Comments: Most conductors near stations are within capacity except near MS-3 and MS-4 which are observed to be over 100% threshold with all planned load inclusion. Some loads from MS-3 can be transferred into the MS-6 feeder to avoid overloading. Most of the planned loads at the MS4-F1 feeder are in the River Rd West area and a new substation should be able to offset the overloading concern.

Breaker Settings

Breaker	Element	Breaker Settings	Planned + Potential Load Growth (50%)	Planned + Potential Load Growth (100%)
		Pickup (A)	Max Current (A)	Max Current (A)
MS1-F1	Phase Timed	400	215	270
MS1-F2	Phase Timed	400	106	126
MS1-F3	Phase Timed	400	170	255
MS2-F1	Phase Timed	400	174	193
MS2-F2	Phase Timed	400	35	38
MS3-F1	Phase Timed	400	296	376
MS3-F2		NA	NA	NA
MS3-F3	Phase Timed	400	280	314
MS3-F4	Phase Timed	400	198	269
MS4-F1	Phase Timed	400	527	784
MS4-F2	Phase Timed	400	221	225
MS4-F3	Phase Timed	400	205	205
MS4-F4	Phase Timed	400	220	287
MS5-F1	Phase Timed	400	199	199
MS5-F2	Phase Timed	400	264	266
MS5-F3	Phase Timed	400	237	289
MS5-F4	Phase Timed	400	131	145
MS6-F1	Phase Timed	600	4	8.6
MS6-F2	Phase Timed	600	109	217
MS6-F3	Phase Timed	600	88	175
MS6-F4	Phase Timed	600	30	59

Comments: Peak loading on some feeders is greater than breaker pickup Normal settings or closer to the safe threshold (pickup ~ 2.4X peak load). Alternate breaker pickup settings should be considered with the load growth.

EV Growth

- The federal government set a mandatory target for all sales of new light-duty cars and passenger trucks to have zero emissions by 2035, with an interim target of 6 percent by 2030, and the IESO assumes that these targets will be achieved.

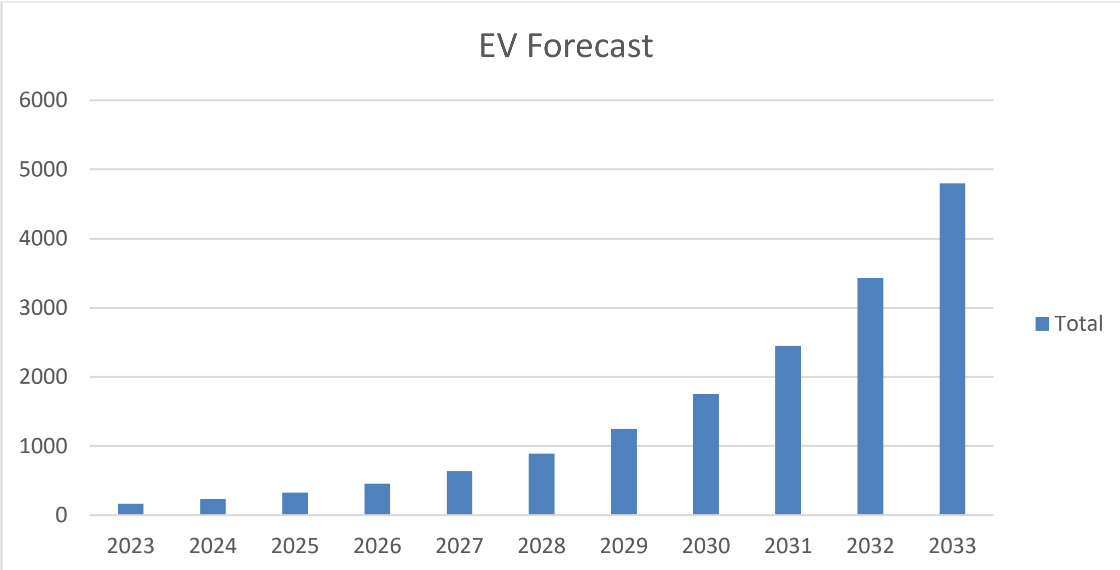
- At the end of 2022, there were 104,093 EVs registered in Ontario. The 2022 IESO Annual Planning Outlook Report (https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook) projects 1.7 million EVs (~16x growth) in Ontario by 2030, with an annual charging demand of 6.2TWH.

Methodology of EV growth in Wasaga:

- Identify EVs at each feeder from the ESA registered list (table below)
- Identify % growth of EVs/Year from registered EVs in Ontario by postcode and apply in the table below.
    - There seems to be an increase of 40% in #EVs since 2022

#EV Growth (40%/year)

Feeder	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
1F1	14	20	28	40	55	77	108	152	213	298	417
1F2	8	11	15	21	29	40	56	79	111	155	217
1F3	8	11	15	21	29	40	56	79	111	155	217
2F1	8	11	15	21	29	40	56	79	111	155	217
2F2	8	11	15	21	29	40	56	79	111	155	217
3F1	10	14	20	27	38	54	75	105	148	207	289
3F3	13	18	25	34	48	67	94	132	184	258	362
3F4	13	18	25	34	48	67	94	132	184	258	362
4F1	8	11	15	21	29	40	56	79	111	155	217
4F2	8	11	15	21	29	40	56	79	111	155	217
4F3	13	18	25	34	48	67	94	132	184	258	362
4F4	8	11	15	21	29	40	56	79	111	155	217
5F1	8	11	15	21	29	40	56	79	111	155	217
5F2	10	14	20	27	38	54	75	105	148	207	289
5F3	13	18	25	34	48	67	94	132	184	258	362
5F4	10	14	20	27	38	54	75	105	148	207	289
6F1	1	1	2	3	4	5	8	11	15	21	29
6F2	1	1	2	3	4	5	8	11	15	21	29
6F3	1	1	2	3	4	5	8	11	15	21	29
6F4	1	1	2	3	4	5	8	11	15	21	29
BF2	8	11	15	21	29	40	56	79	111	155	217
Total	**166**	**232**	**325**	**455**	**637**	**892**	**1,249**	**1,749**	**2,448**	**3,428**	**4,799**



#EV Growth by year

EVs to # WDI customers ratio

#Existing Accounts	# Existing Accounts +50% planned	# Existing Accounts +100% planned
15,000	**19,731**	**24,462**
	%Accounts with EV	
1.1%	**4.52%**	**19.62%**

Comments: It seems that 19.6% of households will own an EV by 2033, while currently there are on average 1.1% of households that own an EV. WDI had 128 registered EVs and the projected number of EVs by 2030 is 1,749 (~14x growth) which seems to be closely aligned with the IESO's forecast.

Source IESO's Annual Planning Outlook 2022: Canadian Vehicle Survey shows that an average car in Ontario drives about 16,000 km per year. Natural Resources Canada manages a database of vehicle fuel efficiency including EVs. Based on data from dozens of EV models, the average 0.2 KWh per km is estimated and used in the IESO's annual planning outlook forecast. In addition, the charger efficiency is assumed at 85%. Based on the numbers the annual charging demand of WDI EV is estimated to be 6.5 GWh by 2030.

Results and Discussion

The following table shows the total loading including planned and potential developments. Also, the estimated load due to building electrification (electric water heaters, resistive electric heaters, etc.) is calculated with an assumption of a **5%** adoption rate. Charging demand was calculated assuming a 7kW/EV demand load.

Substation total load growth

Existing System peak MVA	Development Load MVA	Electrification load MVA	Unmanaged EV Charging Demand at Peak Hour MVA	Total Peak Demand MVA	Existing Substation Capacity MVA
Existing+ Potential Load Growth (50%) by 2028					
35.25	15	2.5	6.2	59	57.5
Existing+ Potential Load Growth (100%) by 2033					
35.25	30	4.9	33.5	103.6	57.5

Comments: With the planned and potential development of 50% completed, 5% Electrification adoption, and 40% EV growth rate the peak demand will surpass existing station capacity.

Development load:
The highest loaded substation is MS#4 and most of the new developments planned are around the River Road West area. Therefore, a new 10MVA substation is recommended to install tapping from the 2M5 feeder to supply the new developments.

Building and Transportation Electrification:
In the table above, the EV charging load was assumed to be at a peak state when all EVs are being charged simultaneously. However, EVs can be charged any time when not on the move, which represents over 90% of the time. Customer preference, battery size, and status, driving conditions, time-of-use electricity rate, and active EV charging load management programs are among the factors affecting charging profiles. A managed EV charging system with visibility of EVs and time-differentiated rates can reduce the peak by 50% or more.

Also, with Canada's GHG reduction goal, adopting net-zero build codes, and transformation of space and water heating it is expected that there will be an increase in electricity demand during winter peak.

Wasaga Distribution System Electrification Readiness Recommendations:

Studies suggest that utilities should begin to prepare now for future electrification demands and there are metrics created for electrification readiness. The following metric is analyzed for Wasaga Distribution's electrification readiness:

Operation Capability	Present State	Suggested State Near-Term	Costs
Load forecasting	Relies on historical demand data at substation SCADA level, with no granular visibility of loads in real-time	Implementing tools i.e. line monitors, and MDMS that utilize AMI 1.0 with improved data analytics and meter data management to have increased visibility to the grid.	MDMS Software and analytics development that can incorporate existing Smart Meter data. Software maintenance, operation, and training cost
Advanced Metering Infrastructure	Basic Smart meter (AMI 1.0)	Develop next-generation smart meters AMI 2.0 deployment strategy. Consider a pilot program with a few AMI 2.0 capable meters on the system.	Pilot costs. (Advanced MDMS tool described in Load forecasting shall use existing Smart Meters for data analysis)
EV Charging Management	Currently, there is no visibility or control over customer-owned EVs.	Consider EV observability utilizing smart meter data (MDMS as described above) for existing connections. For new EV connection, the customer can submit charger specifications and charging schedule, V2G capability to utilities such that nearby transformer and grid limitation can be identified.	Advanced MDMS tool described in Load forecasting shall use existing Smart Meters for EV Detection
Load Management	Monthly meter readings on the billing system, usage snapshot for load flow model.	Implement a data analytics tool that utilizes AMI 1.0 and develop a predictive load model to assess features of customer loads including DER and EV detection.	Advanced MDMS tool described in Load forecasting shall use existing Smart Meters for near real-time visibility of customer load and detect DERs, and EVs on the system.

Operation Capability	Suggested State Longer Term	Costs
Load forecasting	Implement Short-term load/DER forecasting at the feeder level utilizing AMI 2.0 which includes enhancing the existing model for loads as well as electric space heating and various DER resources including EVs, Solar PV, and energy storage.	Capital costs to build tool and system
Advanced Metering Infrastructure	Implement AMI 2.0 meters in the entire system	Capital costs for equipment and installation
EV Charging Management	Implement direct Controllability of EV chargers or have indirect control by allowing customers to follow instructions to charge their EVs during off-peak hours. This will require tools compatible with Open Charge Point Protocol (OCPP 2.0.1), Smart Meter with granular data, and analytics tools.	API costs Potential incentives to customers or charger vendors. Increased O&M cost
Load Management	Implement data analytics with machine learning capability that utilizes granular smart meter (AMI 2.0) data and analyzes customer usage to generate load profiles. Incorporate forecasts with system planning. Develop a demand response management system initiative to enable the capability for customers to participate in dynamic pricing and receiving dispatch signals for major electrification equipment.	Capital costs for software Home automation controller Incentives to participants cost

Other considerations:

Operation Capability	Present State	Suggested State Near-Term	Suggested State Longer Term	Costs
Grid Modernization	Reclosers at feeder boundary.	Implement SCADA controllable switches/reclosers at feeder tie points.	Implement feeder automation by utilizing centralized controllers and smart switches.	Feasibility Study Capital cost upgrading existing switch. Implement SCADA software and communication. Cost of automation controller and developing logic program.
Non-wire alternatives	No DER visibility and alternative investment models	Enhanced DER visibility as described above. Consider alternative model planning such as Utility as Distribution System Operator (DSO) to enable near real-time electricity market. Enable collaboration between stakeholders and identify opportunities for synergies.	Enhanced grid operation by demonstrating the ability to manage and settle grid service transactions between utility and DERs	Capital costs for business case development and pilot projects.

In summary, Wasaga Distribution must initiate plans for the incorporation of a new substation, geared towards accommodating forthcoming developments and ensuring grid operations readiness. This strategic approach will enable the utility to operate at an advanced level, achieved through the integration of cutting-edge systems such as Advanced Meter Data Management, Distributed Energy Resource Management (DERMS), and innovative load management services.

Appendix and References

https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook

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