SYNERGY NORTH CORPORATION

EXHIBIT 2

RATE BASE

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2.1 RATE BASE

2.1.1 OVERVIEW

The following Exhibit provides details and analysis of the Rate Base forecast for SNC.

SNC has prepared its Rate Base to calculate the revenue requirement in this Application following Chapter 2 of the Filing Requirements for Electricity Distribution Rate Applications – 2023 Edition for 2024 Rates Applications issued on December 15, 2022 (“Filing Requirements”).

According to the Filing Requirements, SNC has calculated its Rate Base on the average 2024 Test Year opening and 2024 Test Year closing balances of gross fixed assets net of accumulated depreciation, plus a working capital allowance of 7.5% of the sum of the Cost of Power and controllable expenses.

SNC has not completed a lead-lag study or equivalent analysis to support a different rate and has submitted this application using the default value of 7.5%. The use of a 7.5% rate is consistent with the Ontario Energy Board’s (“OEB”) letter dated June 3, 2015, and the Chapter 2 Filing Requirements as issued by the OEB.

Net fixed assets include those distribution assets that are in-service and associated with activities that enable the conveyance of electricity for distribution purposes. The rate base calculation excludes any non-distribution assets. SNC’s capital expenditures are equivalent to in-service additions, and the variance analysis below is based on these in-service additions. SNC has not applied for or received any Incremental Capital Module (“ICM”) adjustments. Controllable expenses include operations and maintenance, billing and collecting and administration expenses.

SNC has calculated its 2024 Rate Base as $159,570,594, an increase over the 2017 OEB Approved Rate Base Proxy of $119,888,205. This increase in the Rate Base of $39,682,389 is primarily due to an increase in the Average Net Book Value of Capital Assets of $41,718,900.

2.1.2 2017 BOARD-APPROVED PROXY

On January 1, 2019, the former Thunder Bay Hydro (“TBHEDI”) and the former Kenora Hydro Electric Corporation (“KHEC”) legally amalgamated to become SNC.

The last Board Approved amounts were established for each of the entities in the Decisions for the following Applications:

- TBHEDI – 2017 Rate Rebasing, EB-2016-0105
- KHEC– 2011 Rate Rebasing, EB-2010-0135

As a result of the amalgamation, and in light of the fact that each of the former utilities had different rate rebasing years, SNC has developed 2017 Board Approved Proxy figures for comparative purposes. For purposes of this Exhibit, the 2017 Board Approved Proxy was calculated as the aggregate of:

- Former TBHEDI Board Approved Rate Base, as approved in EB-2016-0105; and
- Former KHEC Board Approved Rate Base for 2011, as approved in EB-2010-0135, inflated for the years 2012 to 2017 utilizing the Board Incentive Rate-making Mechanism ("IRM") inflation factors for each of those years for the purpose of the working capital allowance. The average net capital assets are as approved for 2011.

SNC uses the 2017 Board Approved Proxy to facilitate a comparison of Rate Base in a manner consistent with the current SNC corporate structure and Board Filing Requirements.

Table 2.1 (A), Table 2.1 (B) and Table 2.1 (C) summarize the 2017 Board Approved Proxy for purposes of this Exhibit.

TABLE 2-1 (A): COMPUTATION OF KHEC BOARD APPROVED PROXY – WORKING CAPITAL ALLOWANCE

		Proxy 2012	Proxy 2013	Proxy 2014	Proxy 2015	Proxy 2016	Proxy 2017
Distribution Expenses	2011 Board Approved	IRM Factor	IRM Factor	IRM Factor	IRM Factor	IRM Factor	IRM Factor
		0.88%	0.48%	1.10%	1.00%	1.50%	1.30%
Distribution Expenses - Operation	$ 198,090	$ 199,833	$ 200,792	$ 203,001	$ 205,031	$ 208,107	$ 210,812
Distribution Expenses - Maintenance	$ 395,649	$ 399,131	$ 401,047	$ 405,458	$ 409,513	$ 415,655	$ 421,059
Billing and Collecting	$ 536,508	$ 541,229	$ 543,827	$ 549,809	$ 555,307	$ 563,637	$ 570,964
Community Relations	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Administrative and General Expenses	$ 837,121	$ 844,488	$ 848,541	$ 857,875	$ 866,454	$ 879,451	$ 890,884
Donations - LEAP	$ 3,688	$ 3,720	$ 3,738	$ 3,779	$ 3,817	$ 3,874	$ 3,925
Taxes Other than Income Taxes	$ 13,260	$ 13,377	$ 13,441	$ 13,589	$ 13,725	$ 13,931	$ 14,112
Total Eligible Distribution Expenses	**$ 1,984,316**	**$ 2,001,778**	**$ 2,011,387**	**$ 2,033,512**	**$ 2,053,847**	**$ 2,084,655**	**$ 2,111,755**
Power Supply Expenses	$ 9,504,645	$ 9,588,286	$ 9,634,310	$ 9,740,287	$ 9,837,690	$ 9,985,255	$ 10,115,064
Total Working Capital Expenses	**$ 11,488,961**	**$ 11,590,064**	**$ 11,645,696**	**$ 11,773,799**	**$ 11,891,537**	**$ 12,069,910**	**$ 12,226,819**
Working Capital Allowance @ 15%	**$ 1,723,344**	**$ 1,738,510**	**$ 1,746,854**	**$ 1,766,070**	**$ 1,783,731**	**$ 1,810,486**	**$ 1,834,023**

TABLE 2-1 (B): COMPUTATION OF SNC BOARD APPROVED PROXY – WORKING CAPITAL ALLOWANCE

Distribution Expenses	2017 Board Approved (TBHEDI)	2017 Board Approved Proxy (KHEC)	2017 Board Approved Proxy (Combined)
Distribution Expenses - Operation	$ 3,327,377	$ 210,812	$ 3,538,189
Distribution Expenses - Maintenance	$ 4,292,372	$ 421,059	$ 4,713,431
Billing and Collecting	$ 2,306,460	$ 570,964	$ 2,877,424
Community Relations	$ 163,559	$ 3,925	$ 167,483
Administrative and General Expenses	$ 5,120,233	$ 890,884	$ 6,011,116
Taxes Other than Income Taxes	$ 6,700	$ 14,112	$ 20,812
Less Allocated Depreciation	-$ 529,843		-$ 529,843
Total Eligible Distribution Expenses	**$ 14,686,857**	**$ 2,111,755**	**$ 16,798,612**
Power Supply Expenses	$119,143,000	$ 10,115,064	$129,258,064
Total Working Capital Expenses	**$133,829,857**	**$ 12,226,819**	**$146,056,676**
Working Capital Factor	**7.50%**	**15.00%**	**8.13%**
Working Capital Allowance	**$ 10,037,239**	**$ 1,834,023**	**$ 11,871,262**

TABLE 2-1 (C): COMPUTATION OF SNC BOARD APPROVED PROXY – RATE BASE

Description	2017 Board Approved (TBHEDI)	2017 Board Approved Proxy (KHEC)	2017 Board Approved Proxy
Gross Fixed Assets Opening	$199,495,959	$14,701,190	$214,197,149
Gross Fixed Assets Closing	$207,386,883	$15,609,690	$222,996,573
Average Gross Fixed Assets	**$203,441,421**	**$15,155,440**	**$218,596,861**
Accumulated Depreciation Opening	$102,480,653	$6,582,136	$109,062,789
Accumulated Depreciation Closing	$104,930,815	$7,166,232	$112,097,047
Average Accumulated Depreciation	**$103,705,734**	**$6,874,184**	**$110,579,918**
Average Net Book Value	**$99,735,687**	**$8,281,256**	**$108,016,943**
Working Capital	$133,829,857	$12,226,819	$146,056,676
Working Capital Allowance Factor	7.50%	15.00%	8.13%
Working Capital Allowance	**$10,037,239**	**$1,834,023**	**$11,871,262**
Rate Base	**$109,772,926**	**$10,115,279**	**$119,888,205**

2.1.3 PRESENTATION OF CONSOLIDATED RATE BASE

For comparative purposes, and throughout this Exhibit, the actual results for the 2017 and 2018 years represent the combined actual results for the former TBHEDI and KHEDI. The 2019 through 2024 Test Year figures represent SNC.

2.1.4 SUMMARY OF RATE BASE

The following table compares SNC 2017 Board Approved Proxy to this application's proposed 2024 Test Year.

TABLE 2-2: SNC 2017 RATE BASE BOARD APPROVED PROXY TO 2024 TEST YEAR

Description	2017 Board Approved Proxy	2024 Test Year
Gross Fixed Assets Opening	$214,197,149	$277,432,903
Gross Fixed Assets Closing	$222,996,573	$290,050,344
Average Gross Fixed Assets	**$218,596,861**	**$283,741,623**
Accumulated Depreciation Opening	$109,062,789	$131,592,580
Accumulated Depreciation Closing	$112,097,047	$136,418,980
Average Accumulated Depreciation	**$110,579,918**	**$134,005,780**
Average Net Book Value	**$108,016,943**	**$149,735,843**
Working Capital	$146,056,676	$131,130,010
Working Capital Allowance Factor	8.13%	7.50%
Working Capital Allowance	**$11,871,262**	**$9,834,751**
Rate Base	**$119,888,205**	**$159,570,594**
Rate Base Year Over Year Increase		**33.10%**

The main components that make up the increase in rate base for the 2024 Test year include capital additions from 2017 to 2023 (which are on track with SNC's last DSP, covering the 2017 to 2021 historical period, adjusted as per the OEB approved settlement proposal in EB-2016-0105), Kenora's asset management plans, and 2024 Test Year Capital Additions.

Per the MAAD agreement, SNC decided to defer rebasing for five years; therefore, a board-approved DSP was not in place for 2021 and beyond. For this period, SNC increased the DSP-approved figures for 2021 by the Board Incentive Rate-making Mechanism ("IRM") inflation factors for planning purposes for 2022 and 2023.

The following table compares historical data for 2017 to 2022 with the 2023 Bridge Year and 2024 Test Year.

SNC has calculated its 2024 Test Year rate base to be $159,570,594. SNC has provided its rate base continuity schedule for the 2017 Board Approved Proxy, 2017 to 2022 Actuals, 2023 Bridge Year and 2024 Test Year in Table 2-3 below.

TABLE 2-3: RATE BASE CONTINUITY SCHEDULE

Description	2017 Board Approved Proxy	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Bridge Year	2024 Test Year
Gross Fixed Assets Opening	$214,197,149	$210,167,874	$218,359,694	$227,790,432	$236,589,757	$242,757,874	$254,246,571	$265,243,412	$277,432,903
Gross Fixed Assets Closing	$222,996,573	$218,359,694	$227,790,432	$236,589,757	$242,757,874	$254,246,571	$265,243,412	$277,432,903	$290,050,344
Average Gross Fixed Assets	**$218,596,861**	**$214,263,784**	**$223,075,063**	**$232,190,094**	**$239,673,815**	**$248,502,222**	**$259,744,991**	**$271,338,158**	**$283,741,623**
Accumulated Depreciation Opening	$109,062,789	$104,582,875	$107,366,196	$110,886,060	$113,462,448	$117,895,077	$121,960,835	$126,776,931	$131,592,580
Accumulated Depreciation Closing	$112,097,047	$107,366,196	$110,886,060	$113,462,448	$117,895,077	$121,960,835	$126,776,931	$131,592,580	$136,418,980
Average Accumulated Depreciation	**$110,579,918**	**$105,974,535**	**$109,126,128**	**$112,174,254**	**$115,678,762**	**$119,927,956**	**$124,368,883**	**$129,184,755**	**$134,005,780**
Average Net Book Value	**$108,016,943**	**$108,289,249**	**$113,948,935**	**$120,015,840**	**$123,995,053**	**$128,574,266**	**$135,376,109**	**$142,153,402**	**$149,735,843**
Working Capital	$146,056,676	$135,372,497	$128,436,394	$134,930,909	$145,898,069	$129,706,103	$135,700,890	$140,363,831	$131,130,010
Working Capital Allowance Factor	8.13%	8.25%	8.27%	8.13%	8.13%	8.13%	8.13%	8.13%	7.50%
Working Capital Allowance	**$11,871,262**	**$11,171,104**	**$10,622,020**	**$10,969,883**	**$11,861,513**	**$10,545,106**	**$11,032,482**	**$11,411,579**	**$9,834,751**
Rate Base	**$119,888,205**	**$119,460,353**	**$124,570,956**	**$130,985,723**	**$135,856,566**	**$139,119,372**	**$146,408,591**	**$153,564,981**	**$159,570,594**

SNC's assets fall into two broad categories – The first is the Distribution Plant, which includes assets such as distribution, substation buildings, poles, conductors, overhead and underground electricity distribution infrastructure, transformers, meters, and substation equipment. The second is the General Plant which includes assets such as the operations/service center building, office furniture, transportation equipment, communications technology, computer equipment and software, general equipment, and tools.

SNC currently has Rooftop Solar Generation non-distribution assets. For this application, all associated amounts (including the assets, accumulated depreciation, revenues, and costs) from these non-distribution assets have been excluded from Rate Base and all other calculations.

2.1.5 RATE BASE VARIANCE ANALYSIS

SNC has prepared the following table to illustrate the rate base variances between the last OEB-approved rate base proxy and the 2024 test year rate base. The overall changes in the rate base can be attributed to either Gross Assets or Working Capital Allowance.

TABLE 2-4: RATE BASE VARIANCE SUMMARY

Description		2017 Board Approved vs. 2017 Actual	2017 Actual vs. 2018 Actual	2018 Actual vs. 2019 Actual	2019 Actual vs. 2020 Actual	2020 Actual vs. 2021 Actual	2021 Actual vs. 2022 Actual	2022 Actual vs. 2023 Bridge Year	2023 Bridge vs. 2024 Test Year
Gross Fixed Assets Opening		($4,029,275)	$8,191,820	$9,430,737	$8,799,325	$6,168,117	$11,488,697	$10,996,842	$12,189,491
Gross Fixed Assets Closing		($4,636,879)	$9,430,738	$8,799,325	$6,168,117	$11,488,697	$10,996,842	$12,189,491	$12,617,441
Average Gross Fixed Assets		**($4,333,077)**	**$8,811,279**	**$9,115,031**	**$7,483,721**	**$8,828,407**	**$11,242,769**	**$11,593,166**	**$12,403,466**
Accumulated Depreciation Opening		($4,479,913)	$2,783,320	$3,519,865	$2,576,387	$4,432,630	$4,065,758	$4,816,096	$4,815,650
Accumulated Depreciation Closing		($4,730,851)	$3,519,865	$2,576,387	$4,432,630	$4,065,758	$4,816,096	$4,815,650	$4,826,399
Average Accumulated Depreciation		**($4,605,382)**	**$3,151,593**	**$3,048,126**	**$3,504,508**	**$4,249,194**	**$4,440,927**	**$4,815,873**	**$4,821,024**
Average Net Book Value		**$272,306**	**$5,659,686**	**$6,066,905**	**$3,979,213**	**$4,579,213**	**$6,801,842**	**$6,777,293**	**$7,582,441**
Working Capital		($10,684,179)	($6,936,103)	$6,494,515	$10,967,160	($16,191,966)	$5,994,787	$4,662,941	($9,233,821)
Working Capital Allowance Factor		0.1%	0.0%	-0.1%	0.0%	0.0%	0.0%	0.0%	-0.6%
Working Capital Allowance		**($700,158)**	**($549,083)**	**$347,862**	**$891,630**	**($1,316,407)**	**$487,376**	**$379,097**	**($1,576,829)**
Rate Base		**($427,853)**	**$5,110,603**	**$6,414,768**	**$4,870,843**	**$3,262,806**	**$7,289,219**	**$7,156,391**	**$6,005,613**

2024 Test Year vs. 2023 Bridge Year

The 2024 Test Year rate base is forecasted to be $6,005,613 higher than the 2023 Bridge Year. The increase is primarily related to higher net fixed asset additions from capital additions in 2024, offset by a lower Working Capital Allowance due to a decrease in working capital factor from 8.13% (weighted average of KHEC at 15% and TBHEDI at 7.5%) to 7.5% in 2023.

2023 Bridge Year vs. 2022 Actual

The 2023 Bridge Year rate base is forecasted to be $7,156,391 higher than the 2022 Actual. The increase is primarily attributable to higher net fixed asset additions from capital additions in 2022.

2022 Actual Vs. 2021 Actual

The total rate base for the 2022 Actual was $7,289,219, higher than the 2021 Actual. The increase is due to higher net fixed asset additions in 2022 and increased Working Capital Allowance due to an increase in controllable costs and cost of power (COP) expenses.

2021 Actual Vs. 2020 Actual

The total rate base for the 2021 Actual was $3,262,806 higher than 2020 Actual. The increase is primarily attributable to higher net fixed asset additions from capital additions in 2021, offset by a significant decrease in COP expenses.

2020 Actual Vs. 2019 Actual

The total rate base for the 2020 Actual was $4,870,843 higher than 2019 Actual. The increase is primarily attributable to both net fixed asset additions from capital additions and a significant rise in COP expenses.

2019 Actual Vs. 2018 Actual

The total rate base for the 2019 Actual was $6,414,768 higher than 2018 Actual. The increase is primarily attributable to both net fixed asset additions from capital additions and a significant rise in COP expenses.

2018 Actual Vs. 2017 Actual

The total rate base for 2018 Actual was $5,110,603 higher than 2017 Actual. The increase is primarily attributable to net fixed asset additions from the capital offset by decreased COP expenses.

2017 OEB Approved Proxy Vs. 2017 Actual

The total rate base for the 2017 Actual was $427,853 lower than the 2017 Board Approved Proxy. The decrease is primarily attributable to net fixed asset additions not fully materializing in Kenora Rate Zone from 2011 to 2017 and a significant decrease in actual COP expenses from what was forecasted.

2.1.6 ACCOUNTING POLICY CHANGES

In accordance with the Board's letter dated July 12, 2012, each of the former TBHEDI and KHECI adopted capitalization and depreciation policies under CGAAP that were compliant with International Financial Reporting Standards.

The former TBHEDI adopted the required accounting changes for depreciation and capitalization policies on January 1, 2013, which were included in the former TBHEDI's 2017 Cost of Service Application. As a result, there were no additional impacts to expensing overheads or amortization expenses in the Thunder Bay service territory.

The former KHEC adopted the required accounting changes for depreciation and capitalization policies on January 1, 2013. The impact of the capitalization and depreciation changes related to the former KHEC are detailed in Exhibit 9, Deferral and Variance Accounts (Account 1576).

Upon amalgamation on January 1, 2019, the accounting policies for depreciation and capitalization policies for SNC were harmonized to be consistent with the policies of the former TBHEDI.

2.2 FIXED ASSET CONTINUITY SCHEDULES

Opening and closing balances of gross assets and accumulated depreciation correspond to the fixed asset continuity statements. The net book value balances, excluding construction work in progress and asset retirement obligations, are the balances included in the rate base calculation.

SNC has completed the Fixed Asset Continuity Schedules (Board Appendix 2-BA) for the historical actuals for 2017 through 2022, the 2023 Bridge Year and the 2024 Test Year, provided below in Table 2-5 to Table 2-14, and has also been filed in live Excel format.

The Capital Cost Allowance ("CCA") class for fixed assets agrees with the CCA Class used for tax purposes in SNC's tax returns.

Upon the date of IFRS adoption, customer contributions are no longer recorded in Account 1995 Contributions & Grants, but are recorded in Account 2440, Deferred Revenue and amortized to revenue over the service life of the related asset. Additionally, historical amounts recorded in Account 1995 prior to the transition year are to be netted against the assets in Property, Plant and Equipment ("PP&E") that they relate to and no longer accounted separately as an offset to PP&E. SNC has included Account 2440 in the continuity schedules to track contributed capital forecast for the 2022 Bridge Year and the 2023 Test Year. SNC has included the amortization considered revenue for accounting periods as depreciation in Uniform System of Accounts ("USoA") 2440 in its continuity schedules.

Depreciation is explained in further detail in Section 2.4 - Depreciation, Amortization and Depletion.

TABLE 2-5: APPENDIX 2-BA 2017 ACTUAL (TBHEDI)

Accounting Standard: MIFRS
Year: 2017
TBHEDI

			Cost					Accumulated Depreciation				
CCA Class [2]	OEB Account [3]	Description [3]	Opening Balance [8]	Additions [4]	Disposals [6]	Closing Balance	RRR DATA	Opening Balance [8]	Additions	Disposals [6]	Closing Balance	Net Book Value
	1609	Capital Contributions Paid	$ 1,272,321	$ -	$ -	$ 1,272,321	$ -	$ 340,597	$ 50,893	$ -	$ 391,490	$ 880,831
12	1611	Computer Software (Formally known as Account 1925)	$ 1,325,017	$ 2,691	$ -	$ 1,327,708	$ -	$ 1,274,718	$ 29,336	$ -	$ 1,304,054	$ 23,655
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 133,038	$ -	-$ 1,852	$ 131,186	$ -	$ -	$ -	$ -	$ -	$ 131,186
47	1808	Buildings	$ 7,456,455	$ 100,100	$ -	$ 7,556,555	$ -	$ 2,515,757	$ 201,134	$ -	$ 2,716,891	$ 4,839,664
13	1810	Leasehold Improvements	$ 63,262	$ -	$ -	$ 63,262	$ -	$ 63,262	$ -	$ -	$ 63,262	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 8,319,236	$ 38,000	$ -	$ 8,357,236	$ -	$ 7,122,683	$ 159,691	$ -	$ 7,282,374	$ 1,074,862
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 44,895,096	$ 4,284,800	-$ 619,969	$ 48,559,926	$ -	$ 12,599,135	$ 1,040,075	-$ 408,402	$ 13,230,808	$ 35,329,118
47	1835	Overhead Conductors & Devices	$ 40,698,870	$ 3,477,099	-$ 569,980	$ 43,605,989	$ -	$ 17,454,701	$ 566,489	-$ 520,247	$ 17,500,942	$ 26,105,047
47	1840	Underground Conduit	$ 15,628,647	$ 325,644	-$ 12,017	$ 15,942,275	$ -	$ 7,976,152	$ 128,883	-$ 11,506	$ 8,093,529	$ 7,848,745
47	1845	Underground Conductors & Devices	$ 21,215,363	$ 486,306	-$ 43,470	$ 21,658,200	$ -	$ 10,685,632	$ 407,400	-$ 20,172	$ 11,072,860	$ 10,585,340
47	1850	Line Transformers	$ 33,246,913	$ 1,259,945	-$ 528,360	$ 33,978,497	$ -	$ 15,724,434	$ 625,547	-$ 443,224	$ 15,906,757	$ 18,071,740
47	1855	Services (Overhead & Underground)	$ 23,093,575	$ 40,286	$ -	$ 23,133,861	$ -	$ 15,419,450	$ 256,937	$ -	$ 15,676,387	$ 7,457,474
47	1860	Meters				$ -	$ -				$ -	$ -
47	1860	Meters (Smart Meters)	$ 10,108,568	$ 358,508	-$ 174,495	$ 10,292,582	$ -	$ 4,811,768	$ 604,516	-$ 45,756	$ 5,370,529	$ 4,922,053
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 1,604,188	$ 65,375	$ -	$ 1,669,563	$ -	$ 1,328,645	$ 57,230	$ -	$ 1,385,875	$ 283,688
8	1915	Office Furniture & Equipment (5 years)			$ -	$ -	$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 3,311,159	$ 139,695	-$ 1,025	$ 3,449,830	$ -	$ 3,094,830	$ 98,565	-$ 1,025	$ 3,192,370	$ 257,459
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -	$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -	$ -				$ -	$ -
10	1930	Transportation Equipment	$ 7,997,105	$ 426,323	-$ 610,606	$ 7,812,822	$ -	$ 4,441,414	$ 339,299	-$ 585,593	$ 4,195,120	$ 3,617,702
8	1935	Stores Equipment	$ 63,417	$ 34,380	$ -	$ 97,797	$ -	$ 63,417	$ -	$ -	$ 63,417	$ 34,380
8	1940	Tools, Shop & Garage Equipment	$ 2,929,380	$ 50,373	$ -	$ 2,979,753	$ -	$ 2,453,231	$ 71,778	$ -	$ 2,525,009	$ 454,744
8	1945	Measurement & Testing Equipment	$ 374,179	$ 75,859	$ -	$ 450,038	$ -	$ 258,188	$ 25,710	$ -	$ 283,898	$ 166,140
8	1950	Power Operated Equipment	$ 412,564	$ 13,227	$ -	$ 425,791	$ -	$ 165,193	$ 35,549	$ -	$ 200,742	$ 225,049
8	1955	Communications Equipment	$ 283,980	$ 2,438	$ -	$ 286,418	$ -	$ 262,238	$ 11,945	$ -	$ 274,183	$ 12,235
8	1955	Communication Equipment (Smart Meters)				$ -	$ -				$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 800,438	$ -	$ -	$ 800,438	$ -	$ 206,544	$ 83,392	$ -	$ 289,936	$ 510,502
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 18,542,289	$ -	$ -	-$ 18,542,289	$ -	-$ 5,404,531	-$ 432,680	$ -	-$ 5,837,211	-$ 12,705,078
47	2440	Deferred Revenue[5]	-$ 6,859,552	-$ 973,179	$ -	-$ 7,832,731	$ -	-$ 221,514	-$ 173,038	$ -	-$ 394,552	-$ 7,438,179
	2005	Property Under Finance Lease[7]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 199,830,930**	**$ 10,207,872**	**-$ 2,561,774**	**$ 207,477,027**	**$ -**	**$ 102,635,944**	**$ 4,188,650**	**-$ 2,035,925**	**$ 104,788,669**	**$ 102,688,358**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -					$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -					$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 199,830,930**	**$ 10,207,872**	**-$ 2,561,774**	**$ 207,477,027**		**$ 102,635,944**	**$ 4,188,650**	**-$ 2,035,925**	**$ 104,788,669**	**$ 102,688,358**
		Construction Work In Progress	$ 2,690,402	$ 1,793,333	-$ 1,888,074	$ 2,595,661	$ -				$ -	$ 2,595,661
		Total PP&E	**$ 202,521,332**	**$ 12,001,204**	**-$ 4,449,848**	**$ 210,072,688**	**$ -**	**$ 102,635,944**	**$ 4,188,650**	**-$ 2,035,925**	**$ 104,788,669**	**$ 105,284,019**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]										
		Total							**$ 4,188,650**			

			Less: *Fully Allocated Depreciation*	
10			ARO's	
8			Overhead Depts & Information System	$ 642,814
47			Deferred Revenue	-$ 173,038
			Net Depreciation	**$ 3,718,875**

TABLE 2-6: APPENDIX 2-BA 2017 ACTUAL (KHEC)

Accounting Standard: MIFRS
Year: 2017
KHEC

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance [8]	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance [8]	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
	1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 30,009	$ -	$ -	$ 30,009	$ 30,009	$ -	$ -	$ 30,009	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 2,366	$ -	$ -	$ 2,366	$ -	$ -	$ -	$ -	$ 2,366
47	1808	Buildings	$ 33,698	$ -	$ -	$ 33,698	$ 5,321	$ 1,774	$ -	$ 7,094	$ 26,604
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 2,778,226	$ 10,691	$ -	$ 2,788,918	$ 325,884	$ 110,645	$ -	$ 436,529	$ 2,352,389
47	1820	Distribution Station Equipment <50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 2,742,449	$ 316,207	$ -	$ 3,058,656	$ 466,137	$ 174,101	$ -	$ 640,238	$ 2,418,418
47	1835	Overhead Conductors & Devices	$ 970,010	$ 48,973	$ -	$ 1,018,982	$ 95,341	$ 36,674	$ -	$ 132,015	$ 886,967
47	1840	Underground Conduit	$ 130,843	$ 8,302	$ -	$ 139,144	$ 44,341	$ 15,102	$ -	$ 59,443	$ 79,701
47	1845	Underground Conductors & Devices	$ 333,760	$ 4,260	$ -	$ 338,020	$ 106,890	$ 36,645	$ -	$ 143,535	$ 194,485
47	1850	Line Transformers	$ 1,124,891	$ 109,932	$ -	$ 1,234,823	$ 168,109	$ 68,745	$ -	$ 236,853	$ 997,970
47	1855	Services (Overhead & Underground)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1860	Meters				$ -	$ -	$ -	$ -	$ -	$ -
47	1860	Meters (Smart Meters)	$ 689,797	$ 70,152	$ -	$ 759,949	$ 202,643	$ 72,842	$ -	$ 275,485	$ 484,464
N/A	1905	Land	$ 16,562	$ -	$ -	$ 16,562	$ -	$ -	$ -	$ -	$ 16,562
47	1908	Buildings & Fixtures	$ 634,008	$ -	$ -	$ 634,008	$ 105,814	$ 35,296	$ -	$ 141,110	$ 492,898
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 25,177	$ -	$ -	$ 25,177	$ 11,867	$ 3,982	$ -	$ 15,849	$ 9,327
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 19,012	$ 1,351	$ -	$ 20,363	$ 13,440	$ 3,371	$ -	$ 16,811	$ 3,552
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
10	1930	Transportation Equipment	$ 554,966	$ 705	$ -	$ 555,671	$ 249,522	$ 40,194	$ -	$ 289,716	$ 265,955
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1945	Measurement & Testing Equipment	$ 72,058	$ -	$ -	$ 72,058	$ 27,856	$ 6,809	$ -	$ 34,665	$ 37,392
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)				$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment	$ 35,709	$ 16,099	$ -	$ 51,809	$ 20,496	$ 3,664	$ -	$ 24,160	$ 27,649
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 313,374	$ 2,469	$ -	$ 315,843	$ 81,989	$ 28,028	$ -	$ 110,017	$ 205,826
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue[5]	-$ 169,970	-$ 43,418	$ -	-$ 213,388	-$ 8,728	-$ 7,276	$ -	-$ 16,005	-$ 197,384
	2005	Property Under Finance Lease[7]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 10,336,944**	**$ 545,723**	**$ -**	**$ 10,882,667**	**$ 1,946,931**	**$ 630,595**	**$ -**	**$ 2,577,526**	**$ 8,305,141**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 10,336,944**	**$ 545,723**	**$ -**	**$ 10,882,667**	**$ 1,946,931**	**$ 630,595**	**$ -**	**$ 2,577,526**	**$ 8,305,141**
		Construction Work In Progress				$ -				$ -	$ -
		Total PP&E	**$ 10,336,944**	**$ 545,723**	**$ -**	**$ 10,882,667**	**$ 1,946,931**	**$ 630,595**	**$ -**	**$ 2,577,526**	**$ 8,305,141**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**$ 630,595**			

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Deferred Revenue	-$ 7,276
Net Depreciation	**$ 637,871**

TABLE 2-7: APPENDIX 2-BA 2018 ACTUAL (TBHEDI)

Accounting Standard: MIFRS
Year: 2018 **TBHEDI**

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance [8]	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance [8]	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
	1609	Capital Contributions Paid	$ 1,272,321	$ -	$ -	$ 1,272,321	$ 391,490	$ 50,893	$ -	$ 442,383	$ 829,938
12	1611	Computer Software (Formally known as Account 1925)	$ 1,327,708	$ -	$ -	$ 1,327,708	$ 1,304,054	$ 7,726	$ -	$ 1,311,780	$ 15,929
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 131,186	$ -	$ -	$ 131,186	$ -	$ -	$ -	$ -	$ 131,186
47	1808	Buildings	$ 7,556,555	$ 86,036	$ -	$ 7,642,591	$ 2,716,891	$ 207,416	$ -	$ 2,924,307	$ 4,718,284
13	1810	Leasehold Improvements	$ 63,262	$ -	$ -	$ 63,262	$ 63,262	$ -	$ -	$ 63,262	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 8,357,236	$ 141,255	$ -	$ 8,498,490	$ 7,282,374	$ 160,466	$ -	$ 7,442,840	$ 1,055,650
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 48,559,926	$ 4,439,850	-$ 339,440	$ 52,660,336	$ 13,230,808	$ 1,108,697	-$ 259,135	$ 14,080,370	$ 38,579,966
47	1835	Overhead Conductors & Devices	$ 43,605,989	$ 3,197,239	-$ 711,564	$ 46,091,664	$ 17,500,942	$ 605,854	-$ 588,074	$ 17,518,723	$ 28,572,942
47	1840	Underground Conduit	$ 15,942,275	$ 147,995	-$ 94,343	$ 15,995,927	$ 8,093,529	$ 128,613	-$ 73,619	$ 8,148,523	$ 7,847,404
47	1845	Underground Conductors & Devices	$ 21,658,200	$ 729,991	$ -	$ 22,388,191	$ 11,072,860	$ 392,398	$ -	$ 11,465,258	$ 10,922,933
47	1850	Line Transformers	$ 33,978,497	$ 1,293,757	-$ 345,496	$ 34,926,759	$ 15,906,757	$ 577,315	-$ 290,970	$ 16,193,103	$ 18,733,656
47	1855	Services (Overhead & Underground)	$ 23,133,861	$ 234,027	-$ 78,678	$ 23,289,210	$ 15,676,387	$ 232,104	-$ 69,465	$ 15,839,026	$ 7,450,184
47	1860	Meters				$ -				$ -	$ -
47	1860	Meters (Smart Meters)	$ 10,292,582	$ 537,771	-$ 119,705	$ 10,710,648	$ 5,370,529	$ 610,275	$ -	$ 5,980,804	$ 4,729,844
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 1,669,563	$ 21,685	$ -	$ 1,691,248	$ 1,385,875	$ 59,080	$ -	$ 1,444,956	$ 246,292
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 3,449,830	$ 108,673	-$ 44,784	$ 3,513,719	$ 3,192,370	$ 107,079	-$ 44,784	$ 3,254,666	$ 259,053
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
10	1930	Transportation Equipment	$ 7,812,822	$ 611,013	$ -	$ 8,423,834	$ 4,195,120	$ 398,035	$ -	$ 4,593,155	$ 3,830,680
8	1935	Stores Equipment	$ 97,797	$ -	$ -	$ 97,797	$ 63,417	$ 2,579	$ -	$ 65,996	$ 31,802
8	1940	Tools, Shop & Garage Equipment	$ 2,979,753	$ 148,624	$ -	$ 3,128,377	$ 2,525,009	$ 77,010	$ -	$ 2,602,019	$ 526,358
8	1945	Measurement & Testing Equipment	$ 450,038	$ 88,031	$ -	$ 538,069	$ 283,898	$ 33,655	$ -	$ 317,553	$ 220,516
8	1950	Power Operated Equipment	$ 425,791	$ -	$ -	$ 425,791	$ 200,742	$ 35,007	$ -	$ 235,749	$ 190,042
8	1955	Communications Equipment	$ 286,418	$ 1,092	$ -	$ 287,510	$ 274,183	$ 8,579	$ -	$ 282,763	$ 4,748
8	1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 800,438	$ 63,021	$ -	$ 863,460	$ 289,936	$ 76,887	$ -	$ 366,823	$ 496,637
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 18,542,289	$ -	$ -	-$ 18,542,289	-$ 5,837,211	-$ 432,680	$ -	-$ 6,269,891	-$ 12,272,398
47	2440	Deferred Revenue[5]	-$ 7,832,731	-$ 1,243,211	$ -	-$ 9,075,942	-$ 394,552	-$ 186,096	$ -	-$ 580,649	-$ 8,495,293
	2005	Property Under Finance Lease[7]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 207,477,027**	**$ 10,606,849**	**-$ 1,734,010**	**$ 216,349,867**	**$ 104,788,669**	**$ 4,260,892**	**-$ 1,326,046**	**$ 107,723,516**	**$ 108,626,352**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 207,477,027**	**$ 10,606,849**	**-$ 1,734,010**	**$ 216,349,867**	**$ 104,788,669**	**$ 4,260,892**	**-$ 1,326,046**	**$ 107,723,516**	**$ 108,626,352**
		Construction Work In Progress	$ 2,595,661	-$ 3,815	$ -	$ 2,591,846				$ -	$ 2,591,846
		Total PP&E	**$ 210,072,688**	**$ 10,603,034**	**-$ 1,734,010**	**$ 218,941,713**	**$ 104,788,669**	**$ 4,260,892**	**-$ 1,326,046**	**$ 107,723,516**	**$ 111,218,198**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**$ 4,260,892**			

Less: *Fully Allocated Depreciation*	
ARO's	-$ 66,115
Overhead Depts & Information Systems	$ 723,038
Deferred Revenue	-$ 186,096
Net Depreciation	**$ 3,790,066**

TABLE 2-8: APPENDIX 2-BA 2018 ACTUAL (KHEC)

Accounting Standard: MIFRS
Year: 2018 KHEC

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance [8]	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance [8]	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
	1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 30,009	$ -	-$ 30,009	$ -	$ 30,009	$ -	-$ 30,009	$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 2,366	$ -	$ -	$ 2,366	$ -	$ -	$ -	$ -	$ 2,366
47	1808	Buildings	$ 33,698	$ -	$ -	$ 33,698	$ 7,094	$ 1,774	$ -	$ 8,868	$ 24,830
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 2,788,918	$ 24,197	$ -	$ 2,813,115	$ 436,529	$ 115,485	$ -	$ 552,014	$ 2,261,101
47	1820	Distribution Station Equipment <50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 3,058,656	$ 161,654	$ -	$ 3,220,309	$ 640,238	$ 178,916	$ -	$ 819,154	$ 2,401,155
47	1835	Overhead Conductors & Devices	$ 1,018,982	$ 45,314	$ -	$ 1,064,296	$ 132,015	$ 37,580	$ -	$ 169,596	$ 894,700
47	1840	Underground Conduit	$ 139,144	$ 6,642	$ -	$ 145,786	$ 59,443	$ 15,292	$ -	$ 74,735	$ 71,052
47	1845	Underground Conductors & Devices	$ 338,020	$ 7,861	$ -	$ 345,881	$ 143,535	$ 36,930	$ -	$ 180,465	$ 165,415
47	1850	Line Transformers	$ 1,234,823	$ 310,799	-$ 10,863	$ 1,534,759	$ 236,853	$ 71,085	-$ 3,621	$ 304,317	$ 1,230,442
47	1855	Services (Overhead & Underground)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1860	Meters	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1860	Meters (Smart Meters)	$ 759,949	$ 12,625	-$ 27,728	$ 744,846	$ 275,485	$ 45,955	$ -	$ 321,440	$ 423,406
N/A	1905	Land	$ 16,562	$ -	$ -	$ 16,562	$ -	$ -	$ -	$ -	$ 16,562
47	1908	Buildings & Fixtures	$ 634,008	$ -	$ -	$ 634,008	$ 141,110	$ 35,296	$ -	$ 176,407	$ 457,602
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 25,177	$ -	$ -	$ 25,177	$ 15,849	$ 3,982	$ -	$ 19,832	$ 5,345
8	1915	Office Furniture & Equipment (5 years)			$ -	$ -					
10	1920	Computer Equipment - Hardware	$ 20,363	$ 2,492	$ -	$ 22,855	$ 16,811	$ 2,578	$ -	$ 19,389	$ 3,466
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)			$ -	$ -					
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)			$ -	$ -					
10	1930	Transportation Equipment	$ 555,671	$ 11,110	$ -	$ 566,781	$ 289,716	$ 38,403	$ -	$ 328,119	$ 238,661
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1945	Measurement & Testing Equipment	$ 72,058	$ -	$ -	$ 72,058	$ 34,665	$ 6,809	$ -	$ 41,474	$ 30,583
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ 30,124	$ -	$ 30,124	$ -	$ 3,012	$ -	$ 3,012	$ 27,112
8	1955	Communication Equipment (Smart Meters)			$ -	$ -				$ -	$ -
8	1960	Miscellaneous Equipment	$ 51,809	$ 6,660	$ -	$ 58,469	$ 24,160	$ 4,330	$ -	$ 28,490	$ 29,979
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 315,843	$ 7,020	$ -	$ 322,863	$ 110,017	$ 28,496	$ -	$ 138,514	$ 184,349
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue[5]	-$ 213,388	$ -	$ -	-$ 213,388	-$ 16,004	-$ 7,276	$ -	-$ 23,281	-$ 190,108
	2005	Property Under Finance Lease[7]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 10,882,667**	**$ 626,498**	**-$ 68,600**	**$ 11,440,564**	**$ 2,577,526**	**$ 618,648**	**-$ 33,630**	**$ 3,162,545**	**$ 8,278,019**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 10,882,667**	**$ 626,498**	**-$ 68,600**	**$ 11,440,564**	**$ 2,577,526**	**$ 618,648**	**-$ 33,630**	**$ 3,162,545**	**$ 8,278,019**
		Construction Work In Progress				$ -				$ -	$ -
		Total PP&E	**$ 10,882,667**	**$ 626,498**	**-$ 68,600**	**$ 11,440,564**	**$ 2,577,526**	**$ 618,648**	**-$ 33,630**	**$ 3,162,545**	**$ 8,278,019**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**$ 618,648**			

Less: *Fully Allocated Depreciation*	
ARO's	
Overhead Depts & Information Systems	
Deferred Revenue	-$ 7,276
Net Depreciation	**$ 625,925**

TABLE 2-9: APPENDIX 2-BA 2019 ACTUAL (SNC)

Accounting Standard: MIFRS
Year: 2019 SNC

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance (TBHEDI) [8]	Cost: Opening Balance (KHEC) [8]	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance (TBHEDI) [8]	Accumulated Depreciation: Opening Balance (KHEC) [8]	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
	1609	Capital Contributions Paid	$ 1,272,321	$ -	$ -	$ -	$ 1,272,321	$ 442,383	$ -	$ 50,893	$ -	$ 493,276	$ 779,045
12	1611	Computer Software (Formally known as Account 1925)	$ 1,327,708	$ -	$ 14,735	$ -	$ 1,342,443	$ 1,311,780	$ -	$ 6,122	$ -	$ 1,317,901	$ 24,542
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 131,186	$ 18,928	$ -	$ -	$ 150,114	$ -	$ -	$ -	$ -	$ -	$ 150,114
47	1808	Buildings	$ 7,642,591	$ 667,707	$ 40,996	$ -	$ 8,351,294	$ 2,924,307	$ 185,275	$ 246,695	$ -	$ 3,356,278	$ 4,995,016
13	1810	Leasehold Improvements	$ 63,262	$ -	$ -	$ -	$ 63,262	$ 63,262	$ -	$ -	$ -	$ 63,262	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ 2,736,397	$ -	$ -	$ 2,736,397	$ -	$ 457,671	$ 91,914	$ -	$ 549,585	$ 2,186,812
47	1820	Distribution Station Equipment <50 kV	$ 8,498,490	$ -	$ -	$ -	$ 8,498,490	$ 7,442,840	$ 41,559	$ 168,068	$ -	$ 7,652,467	$ 846,023
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 52,660,336	$ 2,538,751	$ 4,689,958	-$ 369,542	$ 59,519,503	$ 14,080,370	$ 680,955	$ 1,346,959	-$ 271,196	$ 15,837,089	$ 43,682,415
47	1835	Overhead Conductors & Devices	$ 46,091,664	$ 1,745,854	$ 2,663,301	-$ 463,973	$ 50,036,846	$ 17,518,723	$ 307,797	$ 717,060	-$ 378,608	$ 18,164,972	$ 31,871,874
47	1840	Underground Conduit	$ 15,995,927	$ -	$ 1,296,028	-$ 37,968	$ 17,253,986	$ 8,148,523	$ 74,735	$ 132,166	-$ 36,367	$ 8,319,056	$ 8,934,931
47	1845	Underground Conductors & Devices	$ 22,388,191	$ 532,494	$ 1,584,252	-$ 148,967	$ 24,355,970	$ 11,465,258	$ 180,465	$ 425,540	-$ 132,573	$ 11,938,690	$ 12,417,280
47	1850	Line Transformers	$ 34,926,759	$ 1,493,932	$ 2,126,682	-$ 547,820	$ 37,999,554	$ 16,193,103	$ 304,314	$ 659,952	-$ 356,041	$ 16,801,327	$ 21,198,227
47	1855	Services (Overhead & Underground)	$ 23,289,210	$ -	$ 205,960	-$ 334	$ 23,494,836	$ 15,839,026	$ -	$ 237,566	-$ 317	$ 16,076,274	$ 7,418,562
47	1860	Meters					$ -					$ -	$ -
47	1860	Meters (Smart Meters)	$ 10,710,648	$ 821,565	$ 503,430	-$ 107,636	$ 11,928,007	$ 5,980,804	$ 374,224	$ 684,808	-$ 1,134	$ 7,038,702	$ 4,889,305
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 1,691,248	$ 25,177	$ 20,799	$ -	$ 1,737,223	$ 1,444,956	$ 19,832	$ 60,652	$ -	$ 1,525,439	$ 211,784
8	1915	Office Furniture & Equipment (5 years)					$ -					$ -	$ -
10	1920	Computer Equipment - Hardware	$ 3,513,719	$ 22,855	$ 448,241	$ -	$ 3,984,815	$ 3,254,666	$ 19,389	$ 155,664	$ -	$ 3,429,720	$ 555,095
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)					$ -					$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)					$ -					$ -	$ -
10	1930	Transportation Equipment	$ 8,423,834	$ 566,781	$ 439,982	-$ 1,435,148	$ 7,995,449	$ 4,593,155	$ 328,120	$ 463,865	-$ 1,328,608	$ 4,056,531	$ 3,938,918
8	1935	Stores Equipment	$ 97,797	$ -	$ -	$ -	$ 97,797	$ 65,996	$ -	$ 3,438	$ -	$ 69,434	$ 28,364
8	1940	Tools, Shop & Garage Equipment	$ 3,128,377	$ 58,468	$ 34,848	$ -	$ 3,221,693	$ 2,602,019	$ 28,490	$ 89,399	$ -	$ 2,719,908	$ 501,785
8	1945	Measurement & Testing Equipment	$ 538,069	$ 72,058	$ 31,673	$ -	$ 641,799	$ 317,553	$ 41,474	$ 40,712	$ -	$ 399,739	$ 242,060
8	1950	Power Operated Equipment	$ 425,791	$ -	$ -	$ -	$ 425,791	$ 235,749	$ -	$ 34,678	$ -	$ 270,428	$ 155,364
8	1955	Communications Equipment	$ 287,510	$ 30,124	$ 41,522	$ -	$ 359,156	$ 282,763	$ 3,012	$ 15,109	$ -	$ 300,884	$ 58,272
8	1955	Communication Equipment (Smart Meters)				$ -	$ -				$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 863,460	$ 322,863	$ 285,529	$ -	$ 1,471,851	$ 366,823	$ 138,514	$ 109,302	$ -	$ 614,638	$ 857,213
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 18,542,289	$ -	$ -	$ -	-$ 18,542,289	-$ 6,269,891	$ -	-$ 432,680	$ -	-$ 6,702,571	-$ 11,839,718
47	2440	Deferred Revenue[5]	-$ 9,075,942	-$ 213,388	-$ 2,517,223	$ -	-$ 11,806,553	-$ 580,649	-$ 23,281	-$ 226,650	$ -	-$ 830,580	-$ 10,975,973
	2005	Property Under Finance Lease[7]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 216,349,867**	**$ 11,440,564**	**$ 11,910,712**	**-$ 3,111,387**	**$ 236,589,757**	**$ 107,723,516**	**$ 3,162,545**	**$ 5,081,231**	**-$ 2,504,844**	**$ 113,462,448**	**$ 123,127,309**
		Less Socialized Renewable Energy Generation Investments (input as negative)					$ -					$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)					$ -					$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 216,349,867**	**$ 11,440,564**	**$ 11,910,712**	**-$ 3,111,387**	**$ 236,589,757**	**$ 107,723,516**	**$ 3,162,545**	**$ 5,081,231**	**-$ 2,504,844**	**$ 113,462,448**	**$ 123,127,309**
		Construction Work In Progress	$ 2,591,846	$ 2,593	$ 82,380	$ -	$ 2,676,819					$ -	$ 2,676,819
		Total PP&E	**$ 218,941,713**	**$ 11,443,157**	**$ 11,993,092**	**-$ 3,111,387**	**$ 239,266,576**	**$ 107,723,516**	**$ 3,162,545**	**$ 5,081,231**	**-$ 2,504,844**	**$ 113,462,448**	**$ 125,804,128**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]											
		Total								**$ 5,081,231**			

Less: *Fully Allocated Depreciation*

ARO's	-$ 34,857
Overhead Depts & Information Systems	$ 837,907
Deferred Revenue	-$ 226,650
Net Depreciation	**$ 4,504,831**

TABLE 2-10: APPENDIX 2-BA 2020 ACTUAL (SNC)

Accounting Standard: MIFRS
Year: 2020 **SNC**

			Cost				Accumulated Depreciation				
CCA Class [2]	OEB Account [3]	Description [3]	Opening Balance [8]	Additions [4]	Disposals [6]	Closing Balance	Opening Balance [8]	Additions	Disposals [6]	Closing Balance	Net Book Value
	1609	Capital Contributions Paid	$ 1,272,321	$ -	$ -	$ 1,272,321	$ 493,276	$ 50,893	$ -	$ 544,169	$ 728,152
12	1611	Computer Software (Formally known as Account 1925)	$ 1,342,443	$ 14,290	$ -	$ 1,356,733	$ 1,317,901	$ 9,990	$ -	$ 1,327,892	$ 28,841
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 150,114	$ -	$ -	$ 150,114	$ -	$ -	$ -	$ -	$ 150,114
47	1808	Buildings	$ 8,351,294	$ 26,061	$ -	$ 8,377,355	$ 3,356,278	$ 248,253	$ -	$ 3,604,531	$ 4,772,823
13	1810	Leasehold Improvements	$ 63,262	$ -	$ -	$ 63,262	$ 63,262	$ -	$ -	$ 63,262	$ -
47	1815	Transformer Station Equipment >50 kV	$ 2,736,397	$ -	$ -	$ 2,736,397	$ 549,585	$ 122,054	$ -	$ 671,639	$ 2,064,758
47	1820	Distribution Station Equipment <50 kV	$ 8,498,490	$ -	$ -	$ 8,498,490	$ 7,652,467	$ 121,161	$ -	$ 7,773,628	$ 724,862
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 59,519,503	$ 3,778,014	-$ 377,747	$ 62,919,771	$ 15,837,089	$ 1,460,459	-$ 285,145	$ 17,012,403	$ 45,907,368
47	1835	Overhead Conductors & Devices	$ 50,036,846	$ 1,555,859	-$ 345,214	$ 51,247,491	$ 18,164,972	$ 759,764	-$ 327,368	$ 18,597,367	$ 32,650,123
47	1840	Underground Conduit	$ 17,253,986	$ 733,915	$ -	$ 17,987,902	$ 8,319,056	$ 147,471	$ -	$ 8,466,527	$ 9,521,375
47	1845	Underground Conductors & Devices	$ 24,355,970	$ 764,589	-$ 36,033	$ 25,084,525	$ 11,938,690	$ 460,558	-$ 28,895	$ 12,370,353	$ 12,714,172
47	1850	Line Transformers	$ 37,999,554	$ 1,628,063	-$ 202,172	$ 39,425,445	$ 16,801,327	$ 698,423	-$ 218,791	$ 17,280,960	$ 22,144,485
47	1855	Services (Overhead & Underground)	$ 23,494,836	$ 226,701	-$ 938	$ 23,720,599	$ 16,076,274	$ 242,634	-$ 474	$ 16,318,434	$ 7,402,165
47	1860	Meters							$ -		$ -
47	1860	Meters (Smart Meters)	$ 11,928,007	$ 599,370	-$ 128,143	$ 12,399,234	$ 7,038,702	$ 723,563	$ -	$ 7,762,265	$ 4,636,968
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 1,737,223	$ 28,692	$ -	$ 1,765,915	$ 1,525,439	$ 57,719	$ -	$ 1,583,158	$ 182,757
8	1915	Office Furniture & Equipment (5 years)				$ -			$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ 3,984,815	$ 176,819	$ -	$ 4,161,634	$ 3,429,720	$ 176,423	$ -	$ 3,606,143	$ 555,491
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)			$ -	$ -			$ -	$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)			$ -	$ -			$ -	$ -	$ -
10	1930	Transportation Equipment	$ 7,995,449	$ 491,899	-$ 52,746	$ 8,434,603	$ 4,056,531	$ 447,450	-$ 42,639	$ 4,461,341	$ 3,973,261
8	1935	Stores Equipment	$ 97,797	$ -	$ -	$ 97,797	$ 69,434	$ 3,438	$ -	$ 72,872	$ 24,926
8	1940	Tools, Shop & Garage Equipment	$ 3,221,693	$ 112,542	$ -	$ 3,334,234	$ 2,719,908	$ 94,998	$ -	$ 2,814,906	$ 519,329
8	1945	Measurement & Testing Equipment	$ 641,799	$ 13,150	$ -	$ 654,949	$ 399,739	$ 43,279	$ -	$ 443,018	$ 211,931
8	1950	Power Operated Equipment	$ 425,791	$ -	$ -	$ 425,791	$ 270,428	$ 21,620	$ -	$ 292,048	$ 133,744
8	1955	Communications Equipment	$ 359,156	$ -	$ -	$ 359,156	$ 300,884	$ 15,483	$ -	$ 316,367	$ 42,789
8	1955	Communication Equipment (Smart Meters)			$ -	$ -			$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 1,471,851	$ 83,670	$ -	$ 1,555,522	$ 614,638	$ 112,285	$ -	$ 726,923	$ 828,598
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 18,542,289	$ -	$ -	-$ 18,542,289	-$ 6,702,571	-$ 432,680	$ -	-$ 7,135,251	-$ 11,407,038
47	2440	Deferred Revenue[5]	-$ 11,806,553	-$ 2,922,524	$ -	-$ 14,729,077	-$ 830,580	-$ 249,298	$ -	-$ 1,079,878	-$ 13,649,199
	2005	Property Under Finance Lease[7]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 236,589,757**	**$ 7,311,110**	**-$ 1,142,993**	**$ 242,757,874**	**$ 113,462,448**	**$ 5,335,942**	**-$ 903,313**	**$ 117,895,077**	**$ 124,862,797**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 236,589,757**	**$ 7,311,110**	**-$ 1,142,993**	**$ 242,757,874**	**$ 113,462,448**	**$ 5,335,942**	**-$ 903,313**	**$ 117,895,077**	**$ 124,862,797**
		Construction Work In Progress	$ 2,676,819	$ 2,689,972		$ 5,366,791				$ -	$ 5,366,791
		Total PP&E	**$ 239,266,576**	**$ 10,001,082**	**-$ 1,142,993**	**$ 248,124,664**	**$ 113,462,448**	**$ 5,335,942**	**-$ 903,313**	**$ 117,895,077**	**$ 130,229,587**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**$ 5,335,942**			

Less: *Fully Allocated Depreciation*	
ARO's	-$ 24,202
Overhead Depts & Information Systems	$ 799,435
Deferred Revenue	-$ 249,298
Net Depreciation	**$ 4,810,007**

TABLE 2-11: APPENDIX 2-BA 2021 ACTUAL (SNC)

Accounting Standard: MIFRS
Year: 2021
SNC

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance [8]	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance [8]	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
	1609	Capital Contributions Paid	$ 1,272,321	$ -	$ -	$ 1,272,321	$ 544,169	$ 50,893	$ -	$ 595,061	$ 677,260
12	1611	Computer Software (Formally known as Account 1925)	$ 1,356,733	$ 29,072	$ -	$ 1,385,804	$ 1,327,892	$ 16,271	$ -	$ 1,344,162	$ 41,642
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 150,114	$ -	-$ 1,441	$ 148,673	$ -	$ -	$ -	$ -	$ 148,673
47	1808	Buildings	$ 8,377,355	$ 44,365	$ -	$ 8,421,719	$ 3,604,531	$ 249,587	$ -	$ 3,854,118	$ 4,567,601
13	1810	Leasehold Improvements	$ 63,262	$ -	$ -	$ 63,262	$ 63,262	$ -	$ -	$ 63,262	$ -
47	1815	Transformer Station Equipment >50 kV	$ 2,736,397	$ -	$ -	$ 2,736,397	$ 671,639	$ 114,943	$ -	$ 786,582	$ 1,949,815
47	1820	Distribution Station Equipment <50 kV	$ 8,498,490	$ 5,055	$ -	$ 8,503,545	$ 7,773,628	$ 67,343	$ -	$ 7,840,972	$ 662,574
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 62,919,771	$ 6,872,912	-$ 593,643	$ 69,199,039	$ 17,012,403	$ 1,592,872	-$ 432,594	$ 18,172,680	$ 51,026,359
47	1835	Overhead Conductors & Devices	$ 51,247,491	$ 3,149,821	-$ 694,535	$ 53,702,777	$ 18,597,367	$ 792,328	-$ 536,700	$ 18,852,995	$ 34,849,781
47	1840	Underground Conduit	$ 17,987,902	$ 944,967	-$ 18,984	$ 18,913,885	$ 8,466,527	$ 159,613	-$ 18,231	$ 8,607,910	$ 10,305,975
47	1845	Underground Conductors & Devices	$ 25,084,525	$ 1,173,468	-$ 73,725	$ 26,184,267	$ 12,370,353	$ 484,694	-$ 71,682	$ 12,783,365	$ 13,400,903
47	1850	Line Transformers	$ 39,425,445	$ 1,951,091	-$ 279,423	$ 41,097,113	$ 17,280,960	$ 736,875	-$ 369,467	$ 17,648,367	$ 23,448,746
47	1855	Services (Overhead & Underground)	$ 23,720,599	$ 209,063	-$ 98,915	$ 23,830,747	$ 16,318,434	$ 248,403	-$ 97,624	$ 16,469,213	$ 7,361,534
47	1860	Meters				$ -			$ -	$ -	$ -
47	1860	Meters (Smart Meters)	$ 12,399,234	$ 390,957	-$ 123,713	$ 12,666,477	$ 7,762,265	$ 735,372	$ -	$ 8,497,637	$ 4,168,840
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 1,765,915	$ 2,799	$ -	$ 1,768,714	$ 1,583,158	$ 50,331	$ -	$ 1,633,489	$ 135,225
8	1915	Office Furniture & Equipment (5 years)			$ -	$ -			$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ 4,161,634	$ 422,671	$ -	$ 4,584,305	$ 3,606,143	$ 217,644	$ -	$ 3,823,787	$ 760,518
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)			$ -	$ -			$ -	$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)			$ -	$ -			$ -	$ -	$ -
10	1930	Transportation Equipment	$ 8,434,603	$ 689,798	$ -	$ 9,124,401	$ 4,461,341	$ 473,323	$ -	$ 4,934,664	$ 4,189,737
8	1935	Stores Equipment	$ 97,797	$ -	$ -	$ 97,797	$ 72,872	$ 3,438	$ -	$ 76,310	$ 21,488
8	1940	Tools, Shop & Garage Equipment	$ 3,334,234	$ 64,714	$ -	$ 3,398,948	$ 2,814,906	$ 99,906	$ -	$ 2,914,812	$ 484,137
8	1945	Measurement & Testing Equipment	$ 654,949	$ 19,891	$ -	$ 674,841	$ 443,018	$ 41,401	$ -	$ 484,419	$ 190,421
8	1950	Power Operated Equipment	$ 425,791	$ -	$ -	$ 425,791	$ 292,048	$ 15,574	$ -	$ 307,622	$ 118,169
8	1955	Communications Equipment	$ 359,156	$ -	$ -	$ 359,156	$ 316,367	$ 14,791	$ -	$ 331,158	$ 27,998
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 1,555,522	$ 144,028	$ -	$ 1,699,549	$ 726,923	$ 126,732	$ -	$ 853,655	$ 845,894
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 18,542,289	$ -	$ -	-$ 18,542,289	-$ 7,135,251	-$ 432,680	$ -	-$ 7,567,931	-$ 10,974,358
47	2440	Deferred Revenue[5]	-$ 14,729,077	-$ 2,741,595	$ -	-$ 17,470,672	-$ 1,079,878	-$ 267,599	$ -	-$ 1,347,476	-$ 16,123,195
	2005	Property Under Finance Lease[7]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 242,757,874**	**$ 13,373,076**	**-$ 1,884,379**	**$ 254,246,571**	**$ 117,895,077**	**$ 5,592,056**	**-$ 1,526,298**	**$ 121,960,835**	**$ 132,285,736**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 242,757,874**	**$ 13,373,076**	**-$ 1,884,379**	**$ 254,246,571**	**$ 117,895,077**	**$ 5,592,056**	**-$ 1,526,298**	**$ 121,960,835**	**$ 132,285,736**
		Construction Work In Progress	$ 5,366,791	-$ 1,011,139		$ 4,355,651				$ -	$ 4,355,651
		Total PP&E	**$ 248,124,664**	**$ 12,361,936**	**-$ 1,884,379**	**$ 258,602,222**	**$ 117,895,077**	**$ 5,592,056**	**-$ 1,526,298**	**$ 121,960,835**	**$ 136,641,387**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**$ 5,592,056**			

Less: *Fully Allocated Depreciation*	
ARO's	-$ 24,059
Overhead Depts & Information Systems	$ 809,426
Deferred Revenue	-$ 267,599
Net Depreciation	**$ 5,074,288**

TABLE 2-12: APPENDIX 2-BA 2022 ACTUAL (SNC)

Accounting Standard: MIFRS
Year: 2022 **SNC**

			Cost				Accumulated Depreciation				
CCA Class [2]	OEB Account [3]	Description [3]	Opening Balance [8]	Additions [4]	Disposals [6]	Closing Balance	Opening Balance [8]	Additions	Disposals [6]	Closing Balance	Net Book Value
	1609	Capital Contributions Paid	$ 1,272,321	$ -	$ -	$ 1,272,321	$ 595,061	$ 50,893	$ -	$ 645,954	$ 626,367
12	1611	Computer Software (Formally known as Account 1925)	$ 1,385,804	$ 161,300	$ -	$ 1,547,104	$ 1,344,162	$ 50,269	$ -	$ 1,394,431	$ 152,673
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 148,673	$ -	$ -	$ 148,673	$ -	$ -	$ -	$ -	$ 148,673
47	1808	Buildings	$ 8,421,719	$ 55,400	$ -	$ 8,477,119	$ 3,854,118	$ 251,856	$ -	$ 4,105,974	$ 4,371,145
13	1810	Leasehold Improvements	$ 63,262	$ -	$ -	$ 63,262	$ 63,262	$ -	$ -	$ 63,262	$ -
47	1815	Transformer Station Equipment >50 kV	$ 2,736,397	$ 106,497	$ -	$ 2,842,894	$ 786,582	$ 116,216	$ -	$ 902,799	$ 1,940,095
47	1820	Distribution Station Equipment <50 kV	$ 8,503,545	$ -	$ -	$ 8,503,545	$ 7,840,972	$ 64,271	$ -	$ 7,905,243	$ 598,302
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 69,199,039	$ 6,245,854	-$ 427,489	$ 75,017,405	$ 18,172,680	$ 1,755,399	-$ 330,869	$ 19,597,211	$ 55,420,194
47	1835	Overhead Conductors & Devices	$ 53,702,777	$ 3,341,974	-$ 483,485	$ 56,561,265	$ 18,852,995	$ 847,834	-$ 388,735	$ 19,312,094	$ 37,249,171
47	1840	Underground Conduit	$ 18,913,885	$ 801,224	$ -	$ 19,715,109	$ 8,607,910	$ 171,279	$ -	$ 8,779,189	$ 10,935,921
47	1845	Underground Conductors & Devices	$ 26,184,267	$ 1,074,215	-$ 115,379	$ 27,143,103	$ 12,783,365	$ 507,287	-$ 110,782	$ 13,179,869	$ 13,963,234
47	1850	Line Transformers	$ 41,097,113	$ 1,956,066	-$ 324,440	$ 42,728,740	$ 17,648,367	$ 778,563	-$ 264,320	$ 18,162,610	$ 24,566,130
47	1855	Services (Overhead & Underground)	$ 23,830,747	$ 209,445	-$ 691	$ 24,039,501	$ 16,469,213	$ 254,373	-$ 691	$ 16,722,895	$ 7,316,606
47	1860	Meters				$ -				$ -	$ -
47	1860	Meters (Smart Meters)	$ 12,666,477	$ 597,630	-$ 153,043	$ 13,111,064	$ 8,497,637	$ 752,132	-$ 450	$ 9,249,319	$ 3,861,745
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 1,768,714	$ 14,664	$ -	$ 1,783,378	$ 1,633,489	$ 33,500	$ -	$ 1,666,990	$ 116,388
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 4,584,305	$ 317,152	$ -	$ 4,901,457	$ 3,823,787	$ 289,539	$ -	$ 4,113,326	$ 788,131
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
10	1930	Transportation Equipment	$ 9,124,401	$ 787,954	-$ 113,486	$ 9,798,868	$ 4,934,664	$ 514,458	-$ 108,071	$ 5,341,051	$ 4,457,817
8	1935	Stores Equipment	$ 97,797	$ 14,567	$ -	$ 112,364	$ 76,310	$ 3,681	$ -	$ 79,990	$ 32,373
8	1940	Tools, Shop & Garage Equipment	$ 3,398,948	$ 133,868	$ -	$ 3,532,816	$ 2,914,812	$ 106,577	$ -	$ 3,021,389	$ 511,427
8	1945	Measurement & Testing Equipment	$ 674,841	$ 2,793	$ -	$ 677,634	$ 484,419	$ 33,940	$ -	$ 518,360	$ 159,275
8	1950	Power Operated Equipment	$ 425,791	$ -	$ -	$ 425,791	$ 307,622	$ 15,574	$ -	$ 323,196	$ 102,595
8	1955	Communications Equipment	$ 359,156	$ 41,473	$ -	$ 400,629	$ 331,158	$ 19,776	$ -	$ 350,935	$ 49,694
8	1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 1,699,549	$ 168,261	$ -	$ 1,867,811	$ 853,655	$ 121,312	$ -	$ 974,967	$ 892,844
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 18,542,289	$ -	$ -	-$ 18,542,289	-$ 7,567,931	-$ 432,680	$ -	-$ 8,000,611	-$ 10,541,678
47	2440	Deferred Revenue[5]	-$ 17,470,672	-$ 3,415,481	$ -	-$ 20,886,152	-$ 1,347,476	-$ 286,035	$ -	-$ 1,633,511	-$ 19,252,641
	2005	Property Under Finance Lease[7]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 254,246,571**	**$ 12,614,854**	**-$ 1,618,013**	**$ 265,243,412**	**$ 121,960,835**	**$ 6,020,014**	**-$ 1,203,918**	**$ 126,776,931**	**$ 138,466,482**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 254,246,571**	**$ 12,614,854**	**-$ 1,618,013**	**$ 265,243,412**	**$ 121,960,835**	**$ 6,020,014**	**-$ 1,203,918**	**$ 126,776,931**	**$ 138,466,482**
		Construction Work In Progress	$ 4,355,651	$ 1,157,235		$ 5,512,886				$ -	$ 5,512,886
		Total PP&E	**$ 258,602,222**	**$ 13,772,089**	**-$ 1,618,013**	**$ 270,756,298**	**$ 121,960,835**	**$ 6,020,014**	**-$ 1,203,918**	**$ 126,776,931**	**$ 143,979,368**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**$ 6,020,014**			

			Less: *Fully Allocated Depreciation*	
10			ARO's	-$ 25,646
8			Overhead Depts & Information Systems	$ 866,640
47			Deferred Revenue	-$ 286,035
			Net Depreciation	**$ 5,465,055**

TABLE 2-13: APPENDIX 2-BA 2023 BRIDGE(SNC)

Accounting Standard: MIFRS
Year: 2023
SNC

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance [8]	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance [8]	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
	1609	Capital Contributions Paid	$ 1,272,321	$ -	$ -	$ 1,272,321	$ 645,954	$ 50,893	$ -	$ 696,847	$ 575,474
12	1611	Computer Software (Formally known as Account 1925)	$ 1,547,104	$ 61,000	$ -	$ 1,608,104	$ 1,394,431	$ 73,441	$ -	$ 1,467,872	$ 140,232
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 148,673	$ -	$ -	$ 148,673	$ -	$ -	$ -	$ -	$ 148,673
47	1808	Buildings	$ 8,477,119	$ 80,000	$ -	$ 8,557,119	$ 4,105,974	$ 242,757	$ -	$ 4,348,732	$ 4,208,388
13	1810	Leasehold Improvements	$ 63,262	$ -	$ -	$ 63,262	$ 63,262	$ -	$ -	$ 63,262	$ -
47	1815	Transformer Station Equipment >50 kV	$ 2,842,894	$ -	$ -	$ 2,842,894	$ 902,799	$ 126,058	$ -	$ 1,028,857	$ 1,814,037
47	1820	Distribution Station Equipment <50 kV	$ 8,503,545	$ -	$ -	$ 8,503,545	$ 7,905,243	$ 73,856	$ -	$ 7,979,099	$ 524,447
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 75,017,405	$ 7,972,667	-$ 354,510	$ 82,635,561	$ 19,597,211	$ 1,848,950	-$ 323,994	$ 21,122,167	$ 61,513,394
47	1835	Overhead Conductors & Devices	$ 56,561,265	$ 3,203,584	-$ 640,536	$ 59,124,313	$ 19,312,094	$ 896,284	-$ 557,409	$ 19,650,969	$ 39,473,343
47	1840	Underground Conduit	$ 19,715,109	$ 281,580	-$ 88,669	$ 19,908,021	$ 8,779,189	$ 179,167	-$ 63,603	$ 8,894,753	$ 11,013,268
47	1845	Underground Conductors & Devices	$ 27,143,103	$ 461,023	-$ 157,873	$ 27,446,252	$ 13,179,869	$ 537,466	-$ 132,690	$ 13,584,646	$ 13,861,607
47	1850	Line Transformers	$ 42,728,740	$ 1,584,646	-$ 445,532	$ 43,867,854	$ 18,162,610	$ 823,226	-$ 347,375	$ 18,638,461	$ 25,229,394
47	1855	Services (Overhead & Underground)	$ 24,039,501	$ 236,221	$ -	$ 24,275,723	$ 16,722,895	$ 275,156	$ -	$ 16,998,051	$ 7,277,671
47	1860	Meters				$ -				$ -	$ -
47	1860	Meters (Smart Meters)	$ 13,111,064	$ 277,785	-$ 122,032	$ 13,266,818	$ 9,249,319	$ 812,174	-$ 1,909	$ 10,059,583	$ 3,207,234
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 1,783,378	$ 194,000	$ -	$ 1,977,378	$ 1,666,990	$ 62,167	$ -	$ 1,729,157	$ 248,221
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 4,901,457	$ 358,500	$ -	$ 5,259,957	$ 4,113,326	$ 320,699	$ -	$ 4,434,025	$ 825,932
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
10	1930	Transportation Equipment	$ 9,798,868	$ 185,000	$ -	$ 9,983,868	$ 5,341,051	$ 545,666	$ -	$ 5,886,717	$ 4,097,151
8	1935	Stores Equipment	$ 112,364	$ -	$ -	$ 112,364	$ 79,990	$ 3,438	$ -	$ 83,428	$ 28,935
8	1940	Tools, Shop & Garage Equipment	$ 3,532,816	$ 145,000	$ -	$ 3,677,816	$ 3,021,389	$ 143,053	$ -	$ 3,164,442	$ 513,374
8	1945	Measurement & Testing Equipment	$ 677,634	$ -	$ -	$ 677,634	$ 518,360	$ 11,652	$ -	$ 530,011	$ 147,623
8	1950	Power Operated Equipment	$ 425,791	$ -	$ -	$ 425,791	$ 323,196	$ 15,574	$ -	$ 338,770	$ 87,021
8	1955	Communications Equipment	$ 400,629	$ 132,645	$ -	$ 533,274	$ 350,935	$ 31,816	$ -	$ 382,750	$ 150,523
8	1955	Communication Equipment (Smart Meters)				$ -		$ -		$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 1,867,811	$ 246,559	$ -	$ 2,114,370	$ 974,967	$ 85,894	$ -	$ 1,060,861	$ 1,053,509
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 18,542,289	$ -	$ -	-$ 18,542,289	-$ 8,000,611	-$ 432,680	$ -	-$ 8,433,291	-$ 10,108,998
47	2440	Deferred Revenue[5]	-$ 20,886,152	-$ 1,421,569	$ -	-$ 22,307,721	-$ 1,633,511	-$ 484,078	$ -	-$ 2,117,590	-$ 20,190,131
	2005	Property Under Finance Lease[7]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 265,243,412**	**$ 13,998,642**	**-$ 1,809,152**	**$ 277,432,903**	**$ 126,776,931**	**$ 6,242,630**	**-$ 1,426,980**	**$ 131,592,580**	**$ 145,840,323**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 265,243,412**	**$ 13,998,642**	**-$ 1,809,152**	**$ 277,432,903**	**$ 126,776,931**	**$ 6,242,630**	**-$ 1,426,980**	**$ 131,592,580**	**$ 145,840,323**
		Construction Work In Progress	$ 5,512,886	$ -	$ -	$ 5,512,886				$ -	$ 5,512,886
		Total PP&E	**$ 270,756,298**	**$ 13,998,642**	**-$ 1,809,152**	**$ 282,945,789**	**$ 126,776,931**	**$ 6,242,630**	**-$ 1,426,980**	**$ 131,592,580**	**$ 151,353,208**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**$ 6,242,630**			

Less: *Fully Allocated Depreciation*

CCA Class				
10			ARO's	-$ 25,175
8			Overhead Depts & Information Systems	$ 909,971
47			Deferred Revenue	-$ 484,078
			Net Depreciation	**$ 5,841,912**

TABLE 2-14: APPENDIX 2-BA 2024 TEST (SNC)

Accounting Standard MIFRS
Year 2024 **SNC**

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account** [3]	**Description** [3]	**Opening Balance** [8]	**Additions** [4]	**Disposals** [6]	**Closing Balance**	**Opening Balance** [8]	**Additions**	**Disposals** [6]	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ 1,272,321	$ -	$ -	$ 1,272,321	$ 696,847	$ 50,893	$ -	$ 747,740	$ 524,581
12	1611	Computer Software (Formally known as Account 1925)	$ 1,608,104	$ 85,000	$ -	$ 1,693,104	$ 1,467,872	$ 114,774	$ -	$ 1,582,647	$ 110,457
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 148,673	$ -	$ -	$ 148,673	$ -	$ -	$ -	$ -	$ 148,673
47	1808	Buildings	$ 8,557,119	$ 155,250	$ -	$ 8,712,369	$ 4,348,732	$ 244,975	$ -	$ 4,593,707	$ 4,118,662
13	1810	Leasehold Improvements	$ 63,262	$ -	$ -	$ 63,262	$ 63,262	$ -	$ -	$ 63,262	$ -
47	1815	Transformer Station Equipment >50 kV	$ 2,842,894	$ -	$ -	$ 2,842,894	$ 1,028,857	$ 129,395	$ -	$ 1,158,252	$ 1,684,642
47	1820	Distribution Station Equipment <50 kV	$ 8,503,545	$ -	$ -	$ 8,503,545	$ 7,979,099	$ 75,811	$ -	$ 8,054,909	$ 448,636
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 82,635,561	$ 4,388,231	-$ 339,511	$ 86,684,281	$ 21,122,167	$ 1,954,665	-$ 304,273	$ 22,772,559	$ 63,911,722
47	1835	Overhead Conductors & Devices	$ 59,124,313	$ 5,458,830	-$ 843,345	$ 63,739,798	$ 19,650,969	$ 967,679	-$ 599,568	$ 20,019,081	$ 43,720,717
47	1840	Underground Conduit	$ 19,908,021	$ 496,017	-$ 170,871	$ 20,233,167	$ 8,894,753	$ 191,291	-$ 142,979	$ 8,943,066	$ 11,290,101
47	1845	Underground Conductors & Devices	$ 27,446,252	$ 840,020	-$ 225,406	$ 28,060,866	$ 13,584,646	$ 562,443	-$ 196,701	$ 13,950,388	$ 14,110,478
47	1850	Line Transformers	$ 43,867,854	$ 2,663,469	-$ 558,176	$ 45,973,147	$ 18,638,461	$ 877,645	-$ 462,021	$ 19,054,085	$ 26,919,062
47	1855	Services (Overhead & Underground)	$ 24,275,723	$ 628,195	$ -	$ 24,903,917	$ 16,998,051	$ 288,921	$ -	$ 17,286,973	$ 7,616,945
47	1860	Meters				$ -				$ -	$ -
47	1860	Meters (Smart Meters)	$ 13,266,818	$ 389,941	-$ 122,031	$ 13,534,728	$ 10,059,583	$ 841,673	-$ 1,993	$ 10,899,263	$ 2,635,464
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 1,977,378	$ 51,000	$ -	$ 2,028,378	$ 1,729,157	$ 61,370	$ -	$ 1,790,527	$ 237,851
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 5,259,957	$ 220,000	$ -	$ 5,479,957	$ 4,434,025	$ 267,600	$ -	$ 4,701,625	$ 778,332
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
10	1930	Transportation Equipment	$ 9,983,868	$ 600,000	$ -	$ 10,583,868	$ 5,886,717	$ 556,133	$ -	$ 6,442,850	$ 4,141,019
8	1935	Stores Equipment	$ 112,364	$ -	$ -	$ 112,364	$ 83,428	$ 3,438	$ -	$ 86,866	$ 25,497
8	1940	Tools, Shop & Garage Equipment	$ 3,677,816	$ 120,000	$ -	$ 3,797,816	$ 3,164,442	$ 142,592	$ -	$ 3,307,034	$ 490,782
8	1945	Measurement & Testing Equipment	$ 677,634	$ 51,170	$ -	$ 728,804	$ 530,011	$ 11,394	$ -	$ 541,405	$ 187,399
8	1950	Power Operated Equipment	$ 425,791	$ -	$ -	$ 425,791	$ 338,770	$ 15,574	$ -	$ 354,344	$ 71,447
8	1955	Communications Equipment	$ 533,274	$ -	$ -	$ 533,274	$ 382,750	$ 32,154	$ -	$ 414,904	$ 118,370
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 2,114,370	$ 264,081	$ -	$ 2,378,451	$ 1,060,861	$ 92,338	$ -	$ 1,153,199	$ 1,225,252
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 18,542,289	$ -	$ -	-$ 18,542,289	-$ 8,433,291	-$ 432,680	$ -	-$ 8,865,971	-$ 9,676,318
47	2440	Deferred Revenue[5]	-$ 22,307,721	-$ 1,534,422	$ -	-$ 23,842,143	-$ 2,117,590	-$ 516,145	$ -	-$ 2,633,735	-$ 21,208,408
	2005	Property Under Finance Lease[7]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 277,432,903**	**$ 14,876,780**	**-$ 2,259,340**	**$ 290,050,344**	**$ 131,592,580**	**$ 6,533,934**	**-$ 1,707,534**	**$ 136,418,980**	**$ 153,631,364**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 277,432,903**	**$ 14,876,780**	**-$ 2,259,340**	**$ 290,050,344**	**$ 131,592,580**	**$ 6,533,934**	**-$ 1,707,534**	**$ 136,418,980**	**$ 153,631,364**
		Construction Work In Progress	$ 5,512,886	$ -	$ -	$ 5,512,886				$ -	$ 5,512,886
		Total PP&E	**$ 282,945,789**	**$ 14,876,780**	**-$ 2,259,340**	**$ 295,563,230**	**$ 131,592,580**	**$ 6,533,934**	**-$ 1,707,534**	**$ 136,418,980**	**$ 159,144,250**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**$ 6,533,934**			

			Less: *Fully Allocated Depreciation*	
10			ARO's	-$ 25,175
8			Overhead Depts & Information Systems	$ 937,105
47			Deferred Revenue	-$ 516,145
			Net Depreciation	**$ 6,138,149**

2.3 GROSS ASSETS – PROPERTY, PLANT & EQUIPMENT AND DEPRECIATION

2.3.1 BREAKDOWN BY FUNCTION

The tables below categorizes SNC's assets into four categories: Distribution Plant, General Plant, Contributions and Grants and Intangible Assets. In accordance with the Uniform System of Accounts ("USoA"), SNC has included gross assets as follows:

- Intangible Plant Assets – includes USoA accounts 1606 to 1611; these accounts capture assets such as software.
- Distribution Plant Assets – includes USoA accounts 1805 to 1860; these accounts capture assets such as substation equipment, poles, wires, transformers, and meters.
- General Plant Assets – includes USoA accounts 1905 to 1990; these accounts capture assets such as operation service center buildings, computer hardware, transportation equipment and tools.
- Contribution and Grants – includes USoA account 1995; this account captures all contributions in aid of capital that SNC has received or forecasted to be received as per the Distribution System Code. SNC has presented USoA account 1995 and 2440 on a net basis in this application. Details of 1995 Capital Contributions and 2440 Deferred Revenues have been shown in Table 2-15 below.

TABLE 2-15: CONTRIBUTIONS – DEFERRED REVENUE

	OEB Account	Opening Net Balance	Contributions/ Deferred Revenue	Amortization of Contributions /Revenue	Closing Balance Net Balance
2017					
Contributions	1995	(13,137,758)		432,680	(12,705,078)
Deferred Revenues	2440	(6,851,426)	(973,179)	189,042	(7,635,563)
		(19,989,184)	(973,179)	621,722	(20,340,641)
2018					
Contributions	1995	(12,705,078)		432,680	(12,272,398)
Deferred Revenues	2440	(7,635,563)	(1,243,211)	193,373	(8,685,400)
		(20,340,641)	(1,243,211)	626,053	(20,957,798)
2019					
Contributions	1995	(12,272,398)		432,680	(11,839,718)
Deferred Revenues	2440	(8,685,400)	(2,517,223)	226,650	(10,975,973)
		(20,957,798)	(2,517,223)	659,330	(22,815,691)
2020					
Contributions	1995	(11,839,718)		432,680	(11,407,038)
Deferred Revenues	2440	(10,975,973)	(2,922,524)	249,298	(13,649,199)
		(22,815,691)	(2,922,524)	681,978	(25,056,237)
2021					
Contributions	1995	(11,407,038)		432,680	(10,974,358)
Deferred Revenues	2440	(13,649,199)	(2,741,595)	267,599	(16,123,195)
		(25,056,237)	(2,741,595)	700,279	(27,097,553)
2022					
Contributions	1995	(10,974,358)		432,680	(10,541,678)
Deferred Revenues	2440	(16,123,195)	(3,415,481)	286,035	(19,252,641)
		(27,097,553)	(3,415,481)	718,715	(29,794,319)
2023					
Contributions	1995	(10,541,678)		432,680	(10,108,998)
Deferred Revenues	2440	(19,252,641)	(1,421,569)	484,078	(20,190,131)
		(29,794,319)	(1,421,569)	916,758	(30,299,129)
2024					
Contributions	1995	(10,108,998)		432,680	(9,676,318)
Deferred Revenues	2440	(20,190,131)	(1,534,422)	516,145	(21,208,408)
		(30,299,129)	(1,534,422)	948,825	(30,884,726)

The variance analysis on gross assets in Section 2.3.2 below includes a detailed breakdown by major plant accounts.

2.3.2 VARIANCE ANALYSIS ON GROSS ASSET ADDITIONS

The following variance analysis has been prepared based on SNC's materiality threshold, per the materiality calculation noted in Exhibit 1, Section 1.4.7 of this Application. Accordingly, SNC has chosen to use $178,000 as its basis for the variance analysis of Gross Asset Additions.

In SNC's daily operations, it forecasts, reports, and analyzes gross asset additions on a project categorization basis. SNC has prepared its variance analysis herein on the same basis.

2017 TBHEDI Board Approved versus 2017 TBEHDI Actual

The previous TBHEDI experienced an overall increase in gross assets between the 2017 Board Approved and 2017 Actual of $90,144, as seen in Table 2-16.

TABLE 2-16: 2017 BOARD APPROVED TBHEDI VERSUS 2017 ACTUAL TBHEDI

Line No.	USoA	Description	2017 Board Approved	2017 Actual	Variance
1	**Intangible Plant**				
2	1609	Capital Contribution Pd - Gate Stn	$1,272,321	$1,272,321	($0)
3		**Sub-total**	**$1,272,321**	**$1,272,321**	**($0)**
4	**Distribution Plant**				
5	1805	Land	$129,852	$131,186	$1,335
6	1806	Land Rights	$0	$0	$0
7	1808	Buildings and Fixtures	$7,538,455	$7,556,555	$18,100
8	1810	Leasehold Improvements	$63,262	$63,262	($0)
9	1815	Transformer Station Equipment > 50 kV	$0	$0	$0
10	1820	Distribution Station Equipment < 50 kV	$8,315,333	$8,357,236	$41,903
11	1830	Poles, Towers and Fixtures	$47,922,250	$48,559,926	$637,676
12	1835	Overhead Conductors and Devices	$43,663,163	$43,605,989	($57,174)
13	1840	Underground Conduit	$15,626,382	$15,942,275	$315,893
14	1845	Underground Conductors and Devices	$21,554,384	$21,658,200	$103,816
15	1850	Line Transformers	$34,239,036	$33,978,497	($260,538)
16	1855	Services (Overhead & Underground)	$23,187,570	$23,133,861	($53,710)
17	1860	Meters	$10,426,166	$10,292,582	($133,584)
18		**Sub-total**	**$212,665,852**	**$213,279,569**	**$613,716**
19	**General Plant**				
24	1915	Office Furniture and Equipment	$1,662,188	$1,669,563	$7,375
25	1920	Computer Equipment - Hardware	$3,459,659	$3,449,830	($9,829)
26	1611	Computer Software	$1,387,517	$1,327,708	($59,809)
27	1930	Transportation Equipment	$7,952,689	$7,812,822	($139,867)
28	1935	Stores Equipment	$63,417	$97,797	$34,380
29	1940	Tools, Shop and Garage Equipment	$3,022,880	$2,979,753	($43,127)
30	1945	Measurement and Testing Equipment	$449,179	$450,038	$859
31	1950	Power Operated Equipment	$412,564	$425,791	$13,227
32	1955	Communication Equipment	$283,980	$286,418	$2,438
33	1980	System Supervisory Equipment	$808,771	$800,438	($8,333)
36		**Sub-total**	**$19,502,845**	**$19,300,158**	**($202,687)**
37	**Contribution and Grants**				
38	1995	Contributions and Grants	($18,542,289)	($18,542,289)	$0
39	2440	Deferred Revenue	($7,511,846)	($7,832,731)	($320,885)
40		**Sub-total**	**($26,054,135)**	**($26,375,020)**	**($320,885)**
41		**Grand Total**	**$207,386,883**	**$207,477,027**	**$90,144**

DISTRIBUTION PLANT

The variance was mainly due to the increased scope of the MacDougall Court 25kV project. The original budgeted amount for the project was $397,000. Due to the amount of bedrock discovered in the area and additional poles added to the scope, there was significantly more rock boring required to install poles during the project which amounted to cost overruns of approximately $400,000.

ACCOUNT 1830 – POLES, TOWERS, & FIXTURES $637,676

Most of the increase was attributed to the MacDougall Court 25kV project, mainly due to the rock boring of an addition of 14 poles from the original scope. The MacDougall Court project area generally included several poles that consisted of 4kV and 25kV circuits. The 4kV portion of the work was deferred due to capital reductions from the Cost of Service. In addition to the increased scope of pole installations on the 25kV circuits, many of the poles and anchoring associated with them required rock boring and drilling, resulting in the majority of the increased spend on Poles, Towers, and Fixtures account.

ACCOUNT 1840 – UNDERGROUND CONDUIT $315,893

Most of the increase in underground conduit resulted from 3 subdivision expansions that began in previous years and were completed in 2017.

ACCOUNT 1850 – LINE TRANSFORMERS ($260,538)

Residential and General Service Connections were below expected levels for 2017. Similarly, Subdivision expansions that were expected were not completed in 2017.

CONTRIBUTIONS AND GRANTS

An increase in contributions of $320,885 was experienced due to a high level of Joint Use Attachments in Thunder Bay, where the local telecommunications company Tbaytel continued working on its fibre to the home program and contributed 100% of the work required.

2017 KN BOARD APPROVED PROXY VERSUS 2017 KN ACTUAL

The previous KHEC's OEB Approved Capital budget was set in the 2011 Cost of Service. The following Table 2-17 provides the movement in capital asset accounts, tracking the impact of the following:

- The 2013 componentization of assets and the impact of IFRS conversion (removing the fully amortized assets from the cost), in column E. Removing the impact of componentization and IFRS conversion from the balances provides a 2017 Budget adjusted for those impacts (column F).
- In addition, column G is required to account for the differences in the 2011 Board Approved capital asset balances to the actual 2010 ending capital balances. The Cost of Service Application was completed using the estimated balances in capital accounts, prior to the completion of the 2010 year end. This timing difference created differences between the

approved and the actual 2010 ending balances. By accounting for these differences (column G), the variance created by these differences is removed from this analysis.

- Column H provides the actual balances at year end 2017, compared to the adjusted capital 2017 Budget (columns F – G).

Material variances in column I are explained below.

TABLE 2-17: 2017 BOARD APPROVED KHEC VERSUS 2017 ACTUAL KHEC

Line No.	USoA	Description	2011 Board Approved	Annual Capital Budget Approved (Included in 2011 Board Approved)	Budget * 6 Years (2012 – 2017)	2017 Ending Capital Balance Anticipated	2013 Componentized and 2014 IFRS Remove Fully Amortized	2017 Budget Adjusted for Componentization and IFRS Conversion	Adjust for 2010 Ending Actual vs OEB Approved 2011 Opening	2017 Actual	Variance
1	**Intangible Plant**		A	B	C	D	E	F	G	H	I
2	1609	Capital Contribution Pd - Gate Stn	$0	$0	$0	$0	$0	$0	$0	$0	$0
3		**Sub-total**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
4	**Distribution Plant**										
5	1805	Land	$18,928	$0	$0	$18,928	$0	$0	$0	$18,928	$0
6	1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0
7	1808	Buildings and Fixtures	$827,050	$155,000	$930,000	$1,757,050	($231,883)	$1,525,167	**$9,224**	$667,707	($848,236)
8	1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0		$0	$0
9	1815	Transformer Station Equipment > 50 kV	$3,538,115	$302,500	$1,815,000	$5,353,115	($1,038,336)	$4,314,779	**$3,827**	$2,788,918	($1,522,034)
10	1820	Distribution Station Equipment < 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0
11	1830	Poles, Towers and Fixtures	$4,742,513	$60,000	$360,000	$5,102,513	($2,902,462)	$2,200,051	**($32,053)**	$3,058,656	$826,552
12	1835	Overhead Conductors and Devices	$1,554,620	$80,000	$480,000	$2,034,620	($905,696)	$1,128,924	**$13,669**	$1,018,982	($96,273)
13	1840	Underground Conduit	$279,727	$18,000	$108,000	$387,727	($141,649)	$246,078	**$62,000**	$139,144	($44,934)
14	1845	Underground Conductors and Devices	$594,483	$40,000	$240,000	$834,483	($323,409)	$511,074	**$52,274**	$338,020	($120,780)
15	1850	Line Transformers	$1,842,162	$119,000	$714,000	$2,556,162	($1,279,065)	$1,277,097	**$43,402**	$1,234,823	$1,128
16	1855	Services (Overhead & Underground)	$670,902	$35,000	$210,000	$880,902	($800,138)	$80,764	**($10,012)**	$0	($90,776)
17	1860	Meters	$1,030,525	$3,500	$21,000	$1,051,525	($376,029)	$675,496	**$2,390**	$759,949	$86,843
18		**Sub-total**	**$15,099,025**	**$813,000**	**$4,878,000**	**$19,977,025**	**($7,998,667)**	**$11,959,430**	**$144,721**	**$10,025,127**	**($1,808,510)**
19	**General Plant**										
24	1915	Office Furniture and Equipment	$28,042	$1,000	$6,000	$34,042	($26,202)	$7,840	**($1,557)**	$25,177	$15,780
25	1920	Computer Equipment - Hardware	$34,313	$2,000	$12,000	$46,313	($41,302)	$5,011	**($4,874)**	$20,363	$10,478
26	1611	Computer Software	$21,402	$2,000	$12,000	$33,402	($51,660)	($18,258)	**$2,000**	$30,009	$50,267
27	1930	Transportation Equipment	$871,537	$150,000	$900,000	$1,771,537	($701,736)	$1,069,801	**($14,737)**	$555,671	($528,867)
28	1935	Stores Equipment	$0	$0	$0	$0		$0			$0
29	1940	Tools, Shop and Garage Equipment	$79,022	$2,500	$15,000	$94,022	($82,559)	$11,463	**$2,967**	0	($8,496)
30	1945	Measurement and Testing Equipment	$8,982	$2,000	$12,000	$20,982	($16,378)	$4,604	**$2,000**	$72,058	$69,454
31	1950	Power Operated Equipment	$0	$0	$0	$0		$0			$0
32	1955	Communication Equipment	$1,193	$0	$0	$1,193	($1,193)	$0		$0	$0
33	1960	Miscellaneous Equipment	$15,484	$0	$0	$15,484	$1,686	$17,170	**$2,000**	$51,809	$36,639
33	1980	System Supervisory Equipment	$0	$0	$0	$0	$98,334	$98,334	$0	$315,843	$217,509
36		**Sub-total**	**$1,059,975**	**$ 159,500**	**$957,000**	**$2,016,975**	**($821,010)**	**$1,195,965**	**($12,201)**	**$1,070,928**	**($137,238)**
37	**Contribution and Grants**										
38	1995	Contributions and Grants	($549,313)	($64,000)	($384,000)	($933,313)	$577,235	($356,078)	$0	$0	$356,078
39	2440	Deferred Revenue	$0	$0	$0	$0	$0	$0	$0	($213,388)	($213,388)
40		**Sub-total**	**($549,313)**	**($64,000)**	**($384,000)**	**($933,313)**	**$577,235**	**($356,078)**	**$0**	**($213,388)**	**$142,690**
41		**Grand Total**	**$15,609,687**	**$908,500**	**$5,451,000**	**$21,060,687**	**($8,242,442)**	**$12,799,317**	**$132,520**	**$10,882,667**	**($1,803,058)**

A 2011 Ending Capiltal Balances Approved 2011 COS, Includes 2011 Budget.
B Annual Capital Budget Approved 2011 COS.
C 6 Years of Annual Capital Budget Approved 2011 COS.
D 2011 COS Approved Capital Balance Plus 6 Years of Approved Budget.
E Jan 2013, Assets componetized. In the 2015 F/S, retro to 2014 figures, Fully Amortized Assets removed from cost.
F 2011 COS Budget as adjusted for assets componentized and for fully amortized balances removed from cost.
J Capital spending from 2011 through 2017.
K COS 2011 Annual Budget * 7 Years, less actual spending 2011 through 2017.

DISTRIBUTION PLANT

ACCOUNT 1808 – BUILDINGS AND FIXTURES ($848,236)

The 2011 Budget of $155,000 was for a one-time roof replacement and generator purchase, which occurred in 2011 and 2012. A backup generator was installed in 2012 to provide emergency power to the shop and office in the event of an outage to the building. The generator was $45,109. There were no other significant requirements for building improvements or construction during the years 2013 to 2017, resulting in an actual capital balance less than the budget amount of $848,236 in this asset group.

Seven Years of OEB Annual Capital Budget	**$1,085,000**
Capital Spending	
2011 on Roof Repairs	$ 168,026
2012 on Backup Generator	$ 45,109
2012-2017 – Misc Upgrades	$ 23,629
Total Spending	**$ 236,764**
Under-budget	**$ 848,236**

ACCOUNT 1815 – TRANSFORMATION EQUIPMENT ($1,522,034)

The 2011 Budget of $302,500 was approved for a one-time change out for a substation transformer "T1" with a rewound unit. This work was performed during 2011 and 2012 at a cost of $344,984. This was a one-time capital cost. Kenora also installed an Under Frequency Load Shedding system at the substation. This project totalled $160,212. There were no other significant upgrades needed at the substation, the cumulative budget was under-spent.

Seven Years of OEB Annual Capital Budget	**$ 2,117,500**
Capital Spending	
2011/12 on Transformer Changeout	$ 344,984
2013 through 2017 on UFLS Project	$ 160,212
2014 through 2017	$ 90,270
Total Spending	$ 595,466
Under-budget	**$ 1,522,034**

ACCOUNT 1830 – POLES, TOWERS, & FIXTURES $826,552

The 2011 Annual Budget of $60,000 did not include capital additions to install Reclosers, $258,590. In addition, as a result of the Asset Condition Assessment Report, KHEC began a concentrated risk-based pole replacement project starting in 2016, with $269,972 capital spending during that year. The project continued in 2017, $180,591 was spent. Although the annual OEB approved budget of $60,000 exceeded during these years, this was a necessary capital project arising from the Asset Condition Assessment Report.

Seven Years of OEB Annual Capital Budget	**$ 420,000**
Capital Spending	
2011 and 2012 on Pole replacements	$ 155,505
2013 through 2015 on Pole replacements	$ 260,716
2016 Pole replacements	$ 269,972
2017 Pole replacements	$ 180,591
2014 through 2017 on Reclosers	$ 258,590
2013 through 2017 Cross Arms and Switches	$ 121,178
Total Spending	**$ 1,246,552**
Over-budget	**$ 826,552**

General Plant

ACCOUNT 1930 – TRANSPORTATION EQUIPMENT ($528,867)

The 2011 Approved Budget included an approved expenditure of $150,000 for a single bucket truck. Purchases from 2010 to 2017 were $521,133, including a single bucket truck, a double bucket truck, boat and two half ton trucks. The result is an under-budget amount of $528,867 in this asset group.

Seven Years of OEB Annual Capital Budget	**$1,050,000**
Capital Spending	
2011 Single Bucket Truck	$ 120,527
2012 Half Ton Truck	$ 27,685
2015 Double Bucket Truck	$ 283,991
2015 Boat	$ 40,548
2016 Half Ton Truck	$ 36,702
2011 through 2017 – Misc Vehicle Upgrades	$ 11,680
Total Spending	**$ 521,133**
Under-budget	**$ 528,867**

ACCOUNT 1980 – SYSTEM SUPERVISORY EQUIPMENT $217,509

A SCADA system was purchased in 2012 for the Kenora substation, with upgrades to the system from 2013 through 2017. This SCADA system was not in the 2011 capital budget.

Seven Years of OEB Annual Capital Budget	**$ 0**
Capital Spending	
2011-2017 – SCADA system	$ 315,843
Over-budget	**$ 315,843**

1 **2017 TBHEDI ACTUAL VERSUS 2018 TBEHDI ACTUAL**

2 The previous TBHEDI experienced an increase in gross assets between 2017 Actual and 2018 Actual of
3 $8,872,840, as can be seen in the following Table 2-18.

4 **TABLE 2-18: 2017 ACTUAL TBHEDI VERSUS 2018 ACTUAL TBHEDI**

USoA	Description	2017 Actual	2018 Actual	Variance
Intangible Plant				
1609	Capital Contribution Pd - Gate Stn	$1,272,321	$1,272,321	$0
Sub-total		**$1,272,321**	**$1,272,321**	**$0**
Distribution Plant				
1805	Land	$131,186	$131,186	$0
1806	Land Rights	$0	$0	$0
1808	Buildings and Fixtures	$7,556,555	$7,642,591	$86,036
1810	Leasehold Improvements	$63,262	$63,262	$0
1815	Transformer Station Equipment > 50 kV	$0	$0	$0
1820	Distribution Station Equipment < 50 kV	$8,357,236	$8,498,490	$141,255
1830	Poles, Towers and Fixtures	$48,559,926	$52,660,336	$4,100,410
1835	Overhead Conductors and Devices	$43,605,989	$46,091,664	$2,485,675
1840	Underground Conduit	$15,942,275	$15,995,927	$53,652
1845	Underground Conductors and Devices	$21,658,200	$22,388,191	$729,991
1850	Line Transformers	$33,978,497	$34,926,759	$948,262
1855	Services (Overhead & Underground)	$23,133,861	$23,289,210	$155,349
1860	Meters	$10,292,582	$10,710,648	$418,066
Sub-total		**$213,279,569**	**$222,398,264**	**$9,118,696**
General Plant				
1915	Office Furniture and Equipment	$1,669,563	$1,691,248	$21,685
1920	Computer Equipment - Hardware	$3,449,830	$3,513,719	$63,889
1611	Computer Software	$1,327,708	$1,327,708	$0
1930	Transportation Equipment	$7,812,822	$8,423,834	$611,013
1935	Stores Equipment	$97,797	$97,797	$0
1940	Tools, Shop and Garage Equipment	$2,979,753	$3,128,377	$148,624
1945	Measurement and Testing Equipment	$450,038	$538,069	$88,031
1950	Power Operated Equipment	$425,791	$425,791	$0
1955	Communication Equipment	$286,418	$287,510	$1,092
1980	System Supervisory Equipment	$800,438	$863,460	$63,021
Sub-total		**$19,300,158**	**$20,297,513**	**$997,355**
Contribution and Grants				
1995	Contributions and Grants	($18,542,289)	($18,542,289)	$0
2440	Deferred Revenue	($7,832,731)	($9,075,942)	($1,243,211)
Sub-total		**($26,375,020)**	**($27,618,231)**	($1,243,211)
Grand Total		**$207,477,027**	**$216,349,867**	**$8,872,840**

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DISTRIBUTION PLANT

SNC distribution asset variance from 2017 to 2018 is due in large part to ongoing system renewal efforts as part of the 4kV to 25kV conversion projects. The main drivers of asset additions included $7 million in overhead line renewal, $1.3 million in underground cable and transformer renewals, $0.155 million in new service connections (both overhead and underground), and $0.420 million in mandated meter replacements.

ACCOUNT 1830 – POLES, TOWERS, & FIXTURES $4,100,410

The voltage conversion program consisted of $2.3 million. This program consists of all work and materials associated with designing and installing new poles, towers, and fixtures for 25kV circuits and removing the existing 4kV circuit poles, towers and fixtures. The assets in these areas are generally in poor health as identified through the asset condition process (Section 5.3.1 of the DSP) and have been scheduled for renewal. This supports SNC's longstanding 4kV conversion program and subsequent substation decommissioning. Project areas completed in 2018 through the voltage conversion program in included the following:

- Donald Mountdale Area (50 Poles),
- McPherson Christie Area (45 Poles),
- Cumming Brodie Area (116 Poles),
- Miles Edward Area (55 Poles).

The overhead renewal program consisted of $0.525 million. Through the asset condition assessment process, 25kV circuits that are found to be in poor condition are scheduled for replacement similarly to the 4kV. Project areas completed in 2018 included the following:

- 106th – 108th St Mission Island (44 Poles),
- Arthur St 25kV Project (45 Poles).

The Lines Safety Reports program consisted of $0.925 million. This program consists of all work and materials associated with the unscheduled, reactive replacement of distribution assets found to be in poor health (through the ACA process or through the Joint Use Attachment permit process) and in need of immediate and/or near-term replacement to ensure either performance or the ability for Joint Use Attachments. As a result, 55 poles were replaced across the service territory.

Construction associated with Joint Use requests for attachment consisted of $0.19 million. SNC processed 1036 new attachments requests from Tbaytel, Shaw, Telus, and Bell, which included make ready work for 10 new poles, guy wires and anchors for approved attachment.

The remainder of additions encompassed several smaller projects below materiality.

ACCOUNT 1835 – OVERHEAD CONDUCTORS AND DEVICES $2,485,675

Voltage conversion program consisted of $1.2 million. This program consists of all work and materials associated with the design and installation of new 25kV overhead conductors the removal of the existing 4kV overhead conductors. Through the same 4kV Conversion Projects identified in Poles Towers and Fixtures, approximately 21 km of overhead conductor was replaced in the system in 2018.

The overhead renewal program consisted of $0.325 million, 106th – 108th St Mission Island and the Arthur St 25kV rebuild; a total of 5.5 km of 25kV overhead conductor was replaced.

The Lines Safety Reports program consisted of $0.189 million. This program consists of all work and materials associated with the unscheduled, reactive replacement of distribution assets found to be in poor health. Through the risk assessment process there were approximately 2 km of 25kV circuits that were found to be in poor condition that were replaced in the system in 2018.

The Grid Modernization program consisted of $0.176 million. SNC installed 4 reclosing devices in 2018, which required overhead conductor and switching devices, these devices were located at:

- HWY61
- Broadway/Mapleward
- High St Substation, and
- Thunder Bay International Airport - This recloser was a collaborative project with NAVCAN and the Thunder Bay Airport Authority and these two parties contributed 2/3 of the capital cost.

Customer Driven expansions consisted of $0.159 million. The expansions in 2018 mainly were for rural residential customer connections and included connections along Riverdale Rd, Dawson Rd, Melbourne Rd, Paquette Rd and Neebing Ave.

The remainder of expenditures encompassed several smaller programs below materiality totaling $0.437 million.

ACCOUNT 1845 – UNDERGROUND CONDUCTORS AND DEVICES $729,991

Voltage conversion program consisted of $0.160 million, which replaced approximately 2.8 km of underground conductor to the system in 2018.

The underground renewal program consisted of $0.327 million. The 10M2 and 10M5 main feeder cables which exit the FWTS (Fort William Transformer Station) were planned for replacement in the DSP and were replaced as a result. The total amount of cable replaced was 1.45 km.

The remainder of expenditures encompassed several smaller programs below materiality.

ACCOUNT 1850 – LINE TRANSFORMERS $948,262

Voltage conversion program consisted of $0.420 million. This program consists of all work and materials associated with designing and installing new 25kV transformers and removing the existing 4kV transformers. Through the 4kV conversion projects in 2018, the following number of line transformers were replaced throughout the system:

Donald Mountdale Area (9 Pole top, 3 Pad mount),

McPherson Christie Area (28 Pole top, 1 Pad mount),

Cumming Brodie Area (54 Pole top, 6 Pad Mount) and,

Miles Edward Area (12 Pole top).

The risk assessment program also replaced immediate need transformers and consisted of $0.344 million and,

- 3 Pole top and 13 Pad mount transformers

The remainder of expenditures encompassed several smaller programs below materiality.

ACCOUNT 1860 – METERS $418,066

New meters consisted of $0.11 million in residential and commercial services, and the meter reverification and sample compliance testing program. In 2018, Thunder Bay Hydro had 663 failed meters that needed replacement and reverified and compliance sampled 298 and 1000 meters respectively.

General Plant

ACCOUNT 1930 – TRANSPORTATION EQUIPMENT $611,013

The variance in this account can be attributed to SNC's annual budgeted replacement of transportation equipment. In 2018, SNC acquired the following significant transportation assets;

- Vehicle #116 F/ Liner
- 5 Light vehicles (Truck #110, Truck #111, Truck #112, Truck #114, Truck #115)
- 2 Space Kap Toppers
- Cargo Locker / Storage
- Truck Topper

Contributions and Grants

Contributions increased compared to 2017 due to an overall increase in customer-driven work. Contributions were largely due to General Service and Residential Connections $0.7 million and Joint Use Attachments $0.25 million, Expansions and Relocations make up the rest of the contribution.

1 ### 2017 KHEC ACTUAL VERSUS 2018 KHEC ACTUAL

2 The previous KHEC experienced an increase in gross assets between 2017 Actual and 2018 Actual of
3 $557,898, as can be seen in the following Table 2-19.

4 ### TABLE 2-19: 2017 ACTUAL KHEC VERSUS 2018 ACTUAL KHEC

USoA	Description	2017 Actual	2018 Actual	Variance
Intangible Plant				
1609	Capital Contribution Pd - Gate Stn			$0
	Sub-total	**$0**	**$0**	**$0**
Distribution Plant				
1805	Land	$18,928	$18,928	$0
1806	Land Rights	$0	$0	$0
1808	Buildings and Fixtures	$667,707	$667,707	$0
1810	Leasehold Improvements	$0	$0	$0
1815	Transformer Station Equipment > 50 kV	$2,788,918	$2,813,115	$24,197
1820	Distribution Station Equipment < 50 kV	$0	$0	$0
1830	Poles, Towers and Fixtures	$3,058,656	$3,220,309	$161,654
1835	Overhead Conductors and Devices	$1,018,982	$1,064,296	$45,314
1840	Underground Conduit	$139,144	$145,786	$6,642
1845	Underground Conductors and Devices	$338,020	$345,881	$7,861
1850	Line Transformers	$1,234,823	$1,534,759	$299,936
1855	Services (Overhead & Underground)	$0	$0	$0
1860	Meters	$759,949	$744,846	($15,103)
	Sub-total	**$10,025,127**	**$10,555,627**	**$530,500**
General Plant				
1915	Office Furniture and Equipment	$25,177	$25,177	$0
1920	Computer Equipment - Hardware	$20,363	$22,855	$2,492
1611	Computer Software	$30,009	$0	($30,009)
1930	Transportation Equipment	$555,671	$566,781	$11,110
1935	Stores Equipment			$0
1940	Tools, Shop and Garage Equipment			$0
1945	Measurement and Testing Equipment	$72,058	$72,058	$0
1950	Power Operated Equipment			$0
1955	Communication Equipment		$30,124	$30,124
1960	Miscellaneous Equipment	$51,809	$58,469	$6,660
1980	System Supervisory Equipment	$315,843	$322,863	$7,020
	Sub-total	**$1,070,928**	**$1,098,325**	**$27,397**
Contribution and Grants				
1995	Contributions and Grants			$0
2440	Deferred Revenue	($213,388)	($213,388)	$0
	Sub-total	**($213,388)**	**($213,388)**	**$0**
Grand Total		**$10,882,667**	**$11,440,564**	**$557,898**

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DISTRIBUTION PLANT

ACCOUNT 1850 – LINE TRANSFORMERS $299,936

The variance in this account can be attributed to all costs associated with replacing 4 pad mount transformers in 2018, 2 on Coney Island, 1 at Gardner Block and 1 at the Lake of the Woods Museum. Including hiring a contractor, Lake of the Woods Electric, to complete the replacement.

KHEC MERGER WITH TBHEDI

Upon merger, there were some differences where KHEC historically grouped some assets versus how the assets were brought into SNC as a merged entity. The total gross assets (before Work In Progress) per KHEC's closing 2018 Fixed Asset Continuity is equal to $11,440,564, which equals the opening 2019 balance of KHEC's assets brought into SNC.

Grouping differences upon merger:

TABLE 2-20: KENORA CAPITAL ACCOUNTS USOA ON MERGER

Account Description	Kenora USoA	Into SN USoA	Cost
Land	1905	1805	$16,562
Admin Building	1908	1808	$634,008
Revenue Meters	1815	1860	$76,719
UG Cable in Duct	1840	1845	$145,786
Cross Arms, Switches, Reclosers	1830	1835	$681,559
Padmount Switchgear	1850	1845	$40,826
Misc Equipment	1960	1940	$58,469

2018 ACTUAL VERSUS 2019 ACTUAL

SNC experienced an overall increase in gross assets between the 2018 Actual (combined historical TBHEDI and KHEC) and 2019 Actual of $8,799,325, as can be seen in the following Table 2-21.

TABLE 2-21: 2018 ACTUAL VERSUS 2019 ACTUAL

USoA	Description	2018 Actual	2019 Actual	Variance
Intangible Plant				
1609	Capital Contribution Pd - Gate Stn	$1,272,321	$1,272,321	$0
Sub-total		**$1,272,321**	**$1,272,321**	**$0**
Distribution Plant				
1805	Land	$150,114	$150,114	$0
1806	Land Rights	$0	$0	$0
1808	Buildings and Fixtures	$8,310,298	$8,351,294	$40,996
1810	Leasehold Improvements	$63,262	$63,262	$0
1815	Transformer Station Equipment > 50 kV	$2,813,115	$2,736,397	($76,718)
1820	Distribution Station Equipment < 50 kV	$8,498,490	$8,498,490	$0
1830	Poles, Towers and Fixtures	$55,880,646	$59,519,503	$3,638,858
1835	Overhead Conductors and Devices	$47,155,960	$50,036,846	$2,880,886
1840	Underground Conduit	$16,141,713	$17,253,986	$1,112,273
1845	Underground Conductors and Devices	$22,734,072	$24,355,970	$1,621,898
1850	Line Transformers	$36,461,518	$37,999,554	$1,538,036
1855	Services (Overhead & Underground)	$23,289,210	$23,494,836	$205,626
1860	Meters	$11,455,494	$11,928,007	$472,513
Sub-total		**$232,953,892**	**$244,388,260**	**$11,434,368**
General Plant				
1915	Office Furniture and Equipment	$1,774,893	$1,737,223	($37,670)
1920	Computer Equipment - Hardware	$3,536,574	$3,984,815	$448,241
1611	Computer Software	$1,327,708	$1,342,443	$14,735
1930	Transportation Equipment	$8,990,615	$7,995,449	($995,166)
1935	Stores Equipment	$97,797	$97,797	$0
1940	Tools, Shop and Garage Equipment	$3,128,377	$3,221,693	$93,316
1945	Measurement and Testing Equipment	$610,126	$641,799	$31,673
1950	Power Operated Equipment	$425,791	$425,791	$0
1955	Communication Equipment	$317,634	$359,156	$41,522
1980	System Supervisory Equipment	$1,186,322	$1,471,851	$285,529
Sub-total		**$21,395,838**	**$21,278,018**	**($117,820)**
Contribution and Grants				
1995	Contributions and Grants	($18,542,289)	($18,542,289)	$0
2440	Deferred Revenue	($9,289,330)	($11,806,553)	($2,517,223)
Sub-total		**($27,831,619)**	**($30,348,842)**	**($2,517,223)**
Grand Total		**$227,790,432**	**$236,589,757**	**$8,799,325**

DISTRIBUTION PLANT

SNC distribution asset variance from 2018 to 2019 is due in large part to ongoing system renewal efforts as part of the 4kV to 25kV conversion projects. The drivers of asset additions included $7.3 million in overhead line renewal, $3.5 million in UG renewal, $200,000 in Services (Overhead and Underground), and $400,000 in Meter replacements, consistent with the asset renewal additions from the previous year.

ACCOUNT 1830 – POLES, TOWERS, & FIXTURES $3,638,858

The voltage conversion program in 2019 replaced $1.481 million in Poles, Towers and Fixtures. This voltage conversion program consisted of all work and materials associated with designing and installing new 25kV poles and removing the existing 4kV poles. Project areas in the voltage conversion program included the following:

- Northern Vickers 4 kV Project Area (144 Poles)
- Ford Walnut Project Area (45 Poles)
- Arundel Strathcona Project Area (56 Poles)

The risk assessment process (Lines Safety Reports projects) also identified poles that needed unscheduled, reactive replacement for $0.860 million, and as a result 77 poles were replaced.

Overhead Renewal Program consisted of $0.607 million. Project areas identified for replacement in SNC's plans included the following:

- Northern Vickers 25kV Project Area (27 Poles)
- Pineview Sycamore Project Area (41 Poles)

Road Construction & Line Relocations Consisted of $0.202 million. This project accounts for SNC's costs to relocate assets based on customer requests. When the City of Kenora requested the work to accommodate road work, 3 new poles were installed, and several were relocated. In 2019 SNC completed the following:

- Third St Pole Relocation to accommodate road work by the City of Kenora (3 new poles)

Construction associated with Joint Use requests for attachment consisted of $0.717 million. SNC processed and connected 867 new attachments in Thunder Bay and 970 in Kenora. In 2019, there were 62 poles which required replacement due to meeting CSA clearance requirements for attachment heights.

The remainder of expenditures encompassed several smaller programs below materiality.

ACCOUNT 1835 – OVERHEAD CONDUCTORS AND DEVICES $2,880,886

Voltage conversion program consisted of $0.813 million. The 4kV Conversion Projects identified above replaced approximately 19.1 km of overhead conductor throughout the system.

The risk assessment process (Lines Safety Reports projects) consisted of $0.395 million. The majority of overhead conductor replaced in the system was completed by reconductoring the Right-of-Way through 10M9-10M9 circuits located off Mapleward Road. Out of the 11.98 km of overhead conductor replaced in the system, 9.2 km was attributed from 10M9/10 circuits through the Right-Of-Way.

The 25kV overhead renewal program consisted of $0.336 million. Overhead conductors in the following

- Northern Vickers 25kV Project Area and the Pineview Sycamore Project Area were renewed, which amounted to 4.34 km of overhead conductor.

58 new residential overhead services were connected in Thunder Bay and Kenora, costing $0.326 million. Work associated with the connection of these services included the installation of new overhead lines. This project accounted for all SNC's costs to connect customer requested services.

The remainder of expenditures encompassed several smaller programs below materiality.

ACCOUNT 1840 – UNDERGROUND CONDUIT $1,112,273

Voltage conversion program consisted of $0.173 million through the projects identified in the voltage conversion program, the following quantities of underground conduit were added to the system:

- Northern Vickers Project Area (2420 ft),
- Ford Walnut Project Area (492 ft),
- Arundel Strathcona Project Area (256 ft).

36 new underground services were connected in the Hutton Park, River Terrace, Whiskey Jack, Gemstone, Tuscany Estates and Fort William First Nation subdivisions which consisted of $0.326 million. Work associated with the connection of these services included the installation of new underground conduit and wire and consisted of $0.175 million. Work associated with a service's connection may include installing new or upgrading existing underground lines, which require conduit.

Road Construction & Line Relocations Consisted of $0.551 million, of which the majority was the reconstruction of Chipman St in Kenora, where the underground conduit was found in a substandard state when the City of Kenora started its road reconstruction work. 2.334 km of new rigid conduit was required to be installed at a greater depth to meet required standards as part of this project.

The remainder of expenditures encompassed several smaller programs below materiality totaling $0.359 million.

ACCOUNT 1845 – UNDERGROUND CONDUCTORS AND DEVICES $1,621,898

Voltage conversion program consisted of $0.378 million, which accounted for approximately 2.11 km of underground replacements in the system in 2019.

36 new underground services were connected in the Hutton Park, River Terrace, Whiskey Jack, Gemstone, Tuscany Estates and Fort William First Nation subdivisions which consisted of $0.182 million of underground conductors and devices.

Road Construction & Line Relocations Consisted of $0.340 million, which again was the Chipman St in Kenora with the 2.334 km of new underground conductor installation in the project.

The remainder of expenditures encompassed several smaller programs below materiality totaling $0.535 million.

ACCOUNT 1850 – LINE TRANSFORMERS $1,538,036

Voltage conversion program consisted of $0.302 million. This program consisted of all work and materials associated with designing and installing new 25kV transformers and removing the existing 4kV transformers. Through the 4kV conversion projects shown below, the following number of line transformers were replaced in the system:

- Northern Vickers Area (41 Pole top, 10 Pad mount),
- Ford Walnut Area (12 Pole top), and
- Arundel Strathcona Area (8 Pole top)

The risk assessment process (Transformer, Switches and Switchgear replacement project) consisted of $0.569 million. This program consists of all work and materials associated with the unscheduled, reactive replacement of 22 Pole top and 23 Pad mount transformers being replaced in the system in 2019.

New Services in 2019 consisted of $0.383 million. A total of 95 Residential Services were connected (9 in Kenora and 86 in Thunder Bay) and 24 Commercial Services (16 in Thunder Bay and 8 in Kenora). Work associated with the connection of a service may include the installation of new or upgrade of existing transformation.

The remainder of expenditures encompassed several smaller programs below materiality totaling $0.324 million.

ACCOUNT 1855 – SERVICES $205,626

A total of 95 new Residential Services were connected (9 in Kenora and 86 in Thunder Bay) and 24 new Commercial Services (16 in Thunder Bay and 8 in Kenora) and of those, $0.175 million was spent on the service. The remaining $0.03 million falls under the materiality threshold.

ACCOUNT 1860 – METERS $472,513

New meters were installed for 95 residential and 24 commercial services. The meter account also consisted of replacing 731 failed meters in the field and the reverification and compliance sampling activities of 833 and 2324 meters respectively.

GENERAL PLANT

ACCOUNT 1920 – COMPUTER EQUIPMENT $448,241

The variance in this account can be attributed to SNC's annual budgeted replacement of computer equipment and the acquisition of the following assets:

- Computer and laptop replacements: $71,000
- Microsoft Windows Server 2019 to replace older unsupported versions $15,000
- NuVoxx Communications – Cust Serv call outs $9,000
- Replace old and or failed printers: $9,500
- BeyondTrust Privileged Remote Access $17,000 – System to improve cyber security for remote access into the network
- Cisco Switches and SFPs, $44,500, - replace old and unsupported network equipment
- Server Replacements $57,000 – replace old and unsupported physical servers IBM Server Replacement $184,000 – replace old IBM i server (Naviline/HTE)
- Replacement UPS for servers $28,500 – replace failed UPSs and deploy new to improve runtime during power outages

- Firewall Clusters with HA for Kenora Networks $10,000 – new firewalls needed for Corp and Scada networks in Kenora
- Kenora Phone System $4,000 – new equipment required to synergize Kenora phones with the Thunder Bay phone system
- 10Zig replacements $5,000 – replace aging terminals

ACCOUNT 1930 – TRANSPORTATION EQUIPMENT ($995,166)

The variance in this account can be attributed to SNC's annual budgeted replacement of transportation equipment and the significant amount of fleet retirements made in 2019. In 2019, SNC acquired the following significant transportation assets:

- Backhoe #957 ($173,000)
- Aerial Device #125 ($120,000 – initial progress payment)
- Truck #124
- Engine Rebuild #85

Further, the following vehicles of were disposed of in 2019:

- Vehicle #65 ($44,000)
- Vehicle #50 ($40,000)
- Vehicle #25 ($41,000)
- Vehicle #38 ($25,000)
- Vehicle #77 ($215,000)
- Backhoe #930 ($91,000)
- Vehicle #12 ($143,000)
- Vehicle #3 ($215,000)
- Vehicle #37 ($180,000)
- Vehicle #87 ($207,000)

CONTRIBUTIONS AND GRANTS

Contributions increased $2,517,223 over 2018. Contributions were largely due to a System Relocation in Kenora ($1.0 million), General Service connections ($0.9 million) and Joint Use Attachments ($0.760 million).

2019 Actual Versus 2020 Actual

SNC experienced an overall increase in gross assets between the 2019 Actual and 2020 Actual of $6,168,117, as can be seen in the following Table 2-22.

Table 2-22: 2019 Actual versus 2020 Actual

USoA	Description	2019 Actual	2020 Actual	Variance
Intangible Plant				
1609	Capital Contribution Pd - Gate Stn	$1,272,321	$1,272,321	$0
Sub-total		**$1,272,321**	**$1,272,321**	**$0**
Distribution Plant				
1805	Land	$150,114	$150,114	$0
1806	Land Rights	$0	$0	$0
1808	Buildings and Fixtures	$8,351,294	$8,377,355	$26,061
1810	Leasehold Improvements	$63,262	$63,262	$0
1815	Transformer Station Equipment > 50 kV	$2,736,397	$2,736,397	$0
1820	Distribution Station Equipment < 50 kV	$8,498,490	$8,498,490	$0
1830	Poles, Towers and Fixtures	$59,519,503	$62,919,771	$3,400,267
1835	Overhead Conductors and Devices	$50,036,846	$51,247,491	$1,210,645
1840	Underground Conduit	$17,253,986	$17,987,902	$733,915
1845	Underground Conductors and Devices	$24,355,970	$25,084,525	$728,555
1850	Line Transformers	$37,999,554	$39,425,445	$1,425,891
1855	Services (Overhead & Underground)	$23,494,836	$23,720,599	$225,763
1860	Meters	$11,928,007	$12,399,234	$471,227
Sub-total		**$244,388,260**	**$252,610,584**	**$8,222,324**
General Plant				
1915	Office Furniture and Equipment	$1,737,223	$1,765,915	$28,692
1920	Computer Equipment - Hardware	$3,984,815	$4,161,634	$176,819
1611	Computer Software	$1,342,443	$1,356,733	$14,290
1930	Transportation Equipment	$7,995,449	$8,434,603	$439,154
1935	Stores Equipment	$97,797	$97,797	$0
1940	Tools, Shop and Garage Equipment	$3,221,693	$3,334,234	$112,542
1945	Measurement and Testing Equipment	$641,799	$654,949	$13,150
1950	Power Operated Equipment	$425,791	$425,791	$0
1955	Communication Equipment	$359,156	$359,156	$0
1980	System Supervisory Equipment	$1,471,851	$1,555,522	$83,670
Sub-total		**$21,278,018**	**$22,146,335**	**$868,317**
Contribution and Grants				
1995	Contributions and Grants	($18,542,289)	($18,542,289)	$0
2440	Deferred Revenue	($11,806,553)	($14,729,077)	($2,922,524)
Sub-total		**($30,348,842)**	**($33,271,366)**	($2,922,524)
Grand Total		**$236,589,757**	**$242,757,874**	**$6,168,117**

DISTRIBUTION PLANT

SNC distribution asset variance from 2019 to 2020 is due in large part to ongoing system renewal efforts as part of the 4kV to 25kV conversion projects. The main drivers of asset additions included $5.5 million in overhead line renewal, $2.0 million in underground renewal, $225,000 in Services (Overhead and Underground), and $471,000 in Meter replacements.

ACCOUNT 1830 – POLES, TOWERS, & FIXTURES $3,400,267

Voltage conversion program consisted of $1.4 million. The voltage conversion program is longstanding and began in 2008, it has been a focus of TBHEDI's historical OEB's approved plans. This program consists of all work and materials associated with designing and installing new 25kV poles, towers & fixtures and supports SNC's longstanding 4kV conversion program and subsequent substation decommissioning. Project areas completed in 2020 included;

- Redmond Egan Project Area (144 Poles),
- Elm Campbell Project Area (68 Poles)

The risk assessment process (Lines Safety Reports) program consisted of $0.701 million. It replaced 72 poles for failure to meet safety standards as assessed by a visual and quantitative testing program and the requirements arising from Joint Use attachment permits.

The 25kV overhead renewal program consisted of $0.646 million. Project areas identified for replacement included the following:

- Carl Dublin 25kV Project Area (72 Poles),
- Tupper St. Project Area (21 Poles)

Construction associated with Joint Use requests for attachment consisted of $0.653 million. In 2020 this was an all-time high for SNC and included 540 joint use attachments in Thunder Bay and 830 in Kenora. Permits in both distribution territories required make-ready work, including 168 pole replacements for Bell Canada, Tbaytel and Shaw.

ACCOUNT 1835 – OVERHEAD CONDUCTORS AND DEVICES $1,210,645

Voltage conversion program consisted of $0.558 million. This program consists of all work and materials associated with designing and installing new 25kV overhead conductors and removing the existing 4kV overhead conductors. The 4kV Conversion Projects identified above replaced approximately 18.25 km of overhead conductor in the system in 2020.

The 25 kV overhead renewal program consisted of $0.410 million and overhead conductors in the Carl Dublin 25kV Project area and the Tupper St. Project area were renewed, which amounted to 5.25 km of overhead conductor.

The remainder of expenditures encompassed several smaller programs below materiality totaling $0.242 million.

ACCOUNT 1840 – UNDERGROUND CONDUIT $733,915

The risk assessment process identified $0.163 million of conduit needing replacement (or addition) depending on the existing conditions. This program consists of all work and materials associated with the system's unscheduled, reactive replacement of conduit.

New underground conduit was installed in 49 new services through the following subdivisions: Fort William First Nation, Mapleward, Foxborough Greens, Gemstone, Maplewood Stage 2, Parkdale Stg 6, and Tuscany Estates, and consisted of $0.326 million. This project accounts for all SNC's costs to install underground conduit for customer requested services.

The remainder of expenditures encompassed several smaller programs below materiality totaling $0.244 million.

ACCOUNT 1845 – UNDERGROUND CONDUCTORS AND DEVICES $728,555

The Lines Safety Reports program consisted of $0.153 million. This program consisted of all work and materials associated with the unscheduled, reactive replacement of conductor to accommodate work being completed on Main St Bridge, 0.97 km of UG conductor was installed to the replace the overhead distribution line and removal of the 16F6 circuit.

New Services in Subdivisions consisted of $0.230 million. As in the above underground conduit which detailed 49 new residential underground services, including the installation of new underground conductors to service those subdivisions.

Residential and Commercial services consisted of 37 residential underground services and 37 commercial services for $0.191 million.

The remainder of expenditures encompassed several smaller programs below materiality totaling $0.154 million.

ACCOUNT 1850 – LINE TRANSFORMERS $1,425,891

Voltage conversion program consisted of $0.187 million and Risk assessment $0.654 million. This includes all work and materials associated with the design and installation of new 25kV transformers and the removal of the existing 4kV transformers. Through the 4kV conversion projects and the risk assessment processes, the following number of line transformers were replaced in the system:

- Redmond Egan Area (34 Pole top),
- Elm Campbell Area (18 Pole top, 1 Pad mount)
- Lines Safety and Transformer, Switch, Switchgear (35 pole top, 10 Pad mount)

37 new commercial service connections (9 in Kenora and 28 in Thunder Bay) were connected. These general service connections typically require the installation of transformation for connection and consisted of $0.489 million.

The remainder of expenditures encompassed several smaller programs below materiality totaling $0.095 million.

ACCOUNT 1855 – SERVICES $225,763

There were 37 new general services and 105 new residential services for SNC that consisted of $0.154 million.

ACCOUNT 1860 – METERS $471,227

New meters were installed for 105 residential and 37 commercial services. The meter account also consisted of the replacement of 1141 failed meters in the field and the reverification activities of 297 meters and consisted of $0.250 million.

General Plant

ACCOUNT 1930 – TRANSPORTATION EQUIPMENT $439,154

The variance in this account can be attributed to SNC's annual budgeted replacement of transportation equipment. In 2020, SNC acquired the following significant transportation assets;

- Aerial Device #125 – ($180,000 – interim payment)

- Vehicle #959 – Pole Trailer ($28,000)
- Washroom trailer build ($52,000)
- Aerial Device #127 ($108,000 – initial progress payment)
- Aerial Device #128 ($108,000 – initial progress payment)
- Flat Utility Deck
- V10 Engine

CONTRIBUTIONS AND GRANTS

Contributions increased in 2020 $2,922,524 over 2019. The primary components of contributions received were $1.15 million for Joint Use Attachments, $700,000 for General Service and Residential connections, and $720,000 for contributions for subdivisions. Expansions make up the rest of the contributions.

2020 Actual Versus 2021 Actual

SNC experienced an overall increase in gross assets between the 2020 Actual and 2021 Actual of $11,488,697, as can be seen in the following Table 2-23.

Table 2-23: 2020 Actual versus 2021 Actual

USoA	Description	2020 Actual	2021 Actual	Variance
Intangible Plant				
1609	Capital Contribution Pd - Gate Stn	$1,272,321	$1,272,321	$0
Sub-total		**$1,272,321**	**$1,272,321**	**$0**
Distribution Plant				
1805	Land	$150,114	$148,673	($1,441)
1806	Land Rights	$0	$0	$0
1808	Buildings and Fixtures	$8,377,355	$8,421,719	$44,365
1810	Leasehold Improvements	$63,262	$63,262	$0
1815	Transformer Station Equipment > 50 kV	$2,736,397	$2,736,397	$0
1820	Distribution Station Equipment < 50 kV	$8,498,490	$8,503,545	$5,055
1830	Poles, Towers and Fixtures	$62,919,771	$69,199,039	$6,279,268
1835	Overhead Conductors and Devices	$51,247,491	$53,702,777	$2,455,286
1840	Underground Conduit	$17,987,902	$18,913,885	$925,983
1845	Underground Conductors and Devices	$25,084,525	$26,184,267	$1,099,742
1850	Line Transformers	$39,425,445	$41,097,113	$1,671,668
1855	Services (Overhead & Underground)	$23,720,599	$23,830,747	$110,149
1860	Meters	$12,399,234	$12,666,477	$267,244
Sub-total		**$252,610,584**	**$265,467,903**	**$12,857,319**
General Plant				
1915	Office Furniture and Equipment	$1,765,915	$1,768,714	$2,799
1920	Computer Equipment - Hardware	$4,161,634	$4,584,305	$422,671
1611	Computer Software	$1,356,733	$1,385,804	$29,072
1930	Transportation Equipment	$8,434,603	$9,124,401	$689,798
1935	Stores Equipment	$97,797	$97,797	$0
1940	Tools, Shop and Garage Equipment	$3,334,234	$3,398,948	$64,714
1945	Measurement and Testing Equipment	$654,949	$674,841	$19,891
1950	Power Operated Equipment	$425,791	$425,791	$0
1955	Communication Equipment	$359,156	$359,156	$0
1980	System Supervisory Equipment	$1,555,522	$1,699,549	$144,028
Sub-total		**$22,146,335**	**$23,519,308**	**$1,372,973**
Contribution and Grants				
1995	Contributions and Grants	($18,542,289)	($18,542,289)	$0
2440	Deferred Revenue	($14,729,077)	($17,470,672)	($2,741,595)
Sub-total		**($33,271,366)**	**($36,012,961)**	**($2,741,595)**
Grand Total		**$242,757,874**	**$254,246,571**	**$11,488,697**

DISTRIBUTION PLANT

SNC distribution asset variance from 2020 to 2021 is due in large part to ongoing system renewal efforts as part of the 4kV to 25kV conversion projects. The main drivers of asset additions included $9.8 million in overhead line renewal, $2.6 million in UG renewal, and $267k in Meter replacements.

ACCOUNT 1830 – POLES, TOWERS, & FIXTURES $6,279,268

Voltage conversion program consisted of $3.204 million. This program consists of all work and materials associated with the design and installation of new 25kV poles, towers & fixtures, and the removal of the existing 4kV poles, towers & fixtures. Project areas completed in the voltage conversion program included the following:

- Court Van Horne Project Area (146 Poles),
- MacDougall Court Phase 1 Project Area (117 Poles),
- MacDougall Court Phase 2 Project Area (71 Poles)
- 21F1 Phase 1 Project Area (100 Poles)

The risk assessment process (Lines Safety Reports) program consisted of $1.277 million and consisted of 147 poles. This was largely due to the poles identified by Joint Use attachment permits in Thunder Bay to be substandard or at the end of the typical useful life and needing replacement.

The 25kV overhead renewal Program consisted of $0.355 million and project areas included the following:

- Walsh St 10M7 Station Exit overhead Line 25kV Project Area (22 Poles),
- FWTS (Fort William Transmission Station) UG Feeder Cable Replacement (1 Pole)

Construction associated with Joint Use requests for attachment consisted of $1.186 million. In 2021 this included 349 joint use attachments in Thunder Bay. Permits in both distribution territories required make-ready work, including 22 pole replacements and many additional guy anchors under Poles, Towers and Fixtures.

The remainder of expenditures encompassed several smaller programs below materiality totaling $0.257 million.

ACCOUNT 1835 – OVERHEAD CONDUCTORS AND DEVICES $2,455,286

Voltage conversion program consisted of $1.708 million. This program consists of all work and materials associated with designing and installing new 25kV circuits and removing the existing 4kV circuits. The 4kV Conversion Projects identified above replaced approximately 41.63 km of overhead conductor in the system.

The 25kV overhead renewal Program consisted of $0.149 million. Through the asset condition assessment process, 25kV circuits in the Walsh St 10M7 Station Exit overhead Line 25kV Project Area and the FWTS (Fort William Transmission Station) UG Feeder Cable Replacement area were renewed, which amounted to 0.53 km of overhead conductor replaced in the system.

The risk assessment process (Lines Safety Reports project) consisted of $0.194 million.

Road Construction & Line Relocations consisted of $0.212 million, which was primarily due to Railway Ave in Kenora (Tenth and Gould Rd).

The remainder of expenditures encompassed several smaller programs below materiality totaling $0.192 million.

ACCOUNT 1840 – UNDERGROUND CONDUIT $925,983

Voltage conversion program consisted of $0.223 million. This program consists of all work and materials associated with the design and installation of new 25kV circuits and the removal of the existing 4kV circuits. Through the projects identified in the voltage conversion program, the following quantities of underground conduit were installed in the system:

- Court Van Horne Project Area (3640 ft),
- MacDougall Court Phase 1 Project Area (586 ft),
- MacDougall Court Phase 2 Project Area (194 ft)
- 21F1 Phase 1 Project Area (853 ft)

UG Renewal Program consisted of $0.337 million. Through the renewal of the FWTS (Fort William Transmission Station) UG Feeder Cable Replacement area, 2025 ft of UG conduit was added to the system.

The remainder of expenditures encompassed several smaller programs below materiality totaling $0.365 million.

ACCOUNT 1845 – UNDERGROUND CONDUCTORS AND DEVICES $1,099,742

Voltage conversion program consisted of $0.254 million. Through the 4kV Conversion Projects identified above, approximately 1.73 km of UG conductor was replaced in the system.

The overhead renewal Program consisted of $0.140 million. Through the renewal of the 25kV circuits in the Walsh St 10M7 Station Exit overhead Line 25kV Project Area, 0.96 km of overhead conductor was replaced.

The underground renewal Program consisted of $0.188 million. Through the renewal of the FWTS (Fort William Transmission Station) UG Feeder Cable Replacement area, 0.96 km of UG Primary Feeder Cable was replaced.

New Services in Subdivisions consisted of 51 new underground residential services comprised of $0.279 million in 2021. This represents connections the following subdivisions: Parkdale 6, Maplewood, Hutton Park, Fort William First Nation, Southpark (Kenora), River Terrace and Gemstone.

The remainder of expenditures encompassed several smaller programs below materiality totaling $0.238 million.

ACCOUNT 1850 – LINE TRANSFORMERS $1,671,668

Voltage conversion and risk assessment programs consisted of $0.748 and $0.447 million respectively. Through the 4kV conversion projects shown below, the following number of line transformers were replaced in the system:

- Court Van Horne Project Area (54 Pole top, 9 Pad mount),
- MacDougall Court Phase 1 Project Area (39 Pole top, 7 Pad mount),
- MacDougall Court Phase 2 Project Area (21 Pole top, 2 Pad mount)
- 21F1 Phase 1 Project Area (19 Pole top).
- Lines Safety Reports (33 Pole top, 22 Pad mount)

New Services in subdivisions in 2021 consisted of $0.257 million. This project accounts for all SNC's costs to connect customer requested services. This represents approximately 107 residential services, 15 general service connections (14 in Thunder Bay and 1 in Kenora).

The remainder of expenditures encompassed several smaller programs below materiality totaling $0.220 million.

ACCOUNT 1860 – METERS $267,244

New meters were installed for 107 residential and 15 commercial services. The meter account also consisted of the replacement of 1130 failed meters in the field and the reverification activities of 438 meters and consisted of $0.267 million.

GENERAL PLANT

ACCOUNT 1920 – COMPUTER EQUIPMENT $422,671

The variance in this account can be attributed to SNC's annual budgeted replacement of computer equipment and the acquisition of the following assets:

- Computer replacements: $96,000
- SAN Solution – Storage System $139,000
- Virtual Tape Library (VTL) for backups $121,000
- Server replacements $31,000
- Air Conditioner for Kenora Server Room $7,000
- Video Conf Unit $18,000
- Firewall replacements $5,000
- Cisco SFPs $10,000

ACCOUNT 1930 – TRANSPORTATION EQUIPMENT $689,798

The variance in this account can be attributed to SNC's annual budgeted replacement of transportation equipment. In 2021, SNC purchased acquired the following significant transportation assets;

- Aerial Device #125 – ($99,000 – final payment)
- Aerial Device #127 ($255,0000)
- Aerial Device #128 ($255,0000)
- Truck #126

- Backhoe Quick Coupler
- Pole Trailer #948 Rebuild
- V8 Engine

CONTRIBUTIONS AND GRANTS

Contributions increased by $2,741,595 in 2021.

Contributions were largely due to Joint Use Attachments ($1,400,000), a System Relocation in Kenora ($800,000), and General Service and Residential connections ($680,000), Expansions make up the rest of the contribution.

2021 Actual Versus 2022 Actual

SNC experienced an overall increase in gross assets between the 2021 Actual and 2022 Actual of $10,996,842, as can be seen in the following Table 2-24.

Table 2-24: 2021 Actual versus 2022 Actual

USoA	Description	2021 Actual	2022 Actual	Variance
Intangible Plant				
1609	Capital Contribution Pd - Gate Stn	$1,272,321	$1,272,321	$0
Sub-total		**$1,272,321**	**$1,272,321**	**$0**
Distribution Plant				
1805	Land	$148,673	$148,673	$0
1806	Land Rights	$0	$0	$0
1808	Buildings and Fixtures	$8,421,719	$8,477,119	$55,400
1810	Leasehold Improvements	$63,262	$63,262	$0
1815	Transformer Station Equipment > 50 kV	$2,736,397	$2,842,894	$106,497
1820	Distribution Station Equipment < 50 kV	$8,503,545	$8,503,545	$0
1830	Poles, Towers and Fixtures	$69,199,039	$75,017,405	$5,818,365
1835	Overhead Conductors and Devices	$53,702,777	$56,561,265	$2,858,488
1840	Underground Conduit	$18,913,885	$19,715,109	$801,224
1845	Underground Conductors and Devices	$26,184,267	$27,143,103	$958,836
1850	Line Transformers	$41,097,113	$42,728,740	$1,631,627
1855	Services (Overhead & Underground)	$23,830,747	$24,039,501	$208,754
1860	Meters	$12,666,477	$13,111,064	$444,587
Sub-total		**$265,467,903**	**$278,351,681**	**$12,883,778**
General Plant				
1915	Office Furniture and Equipment	$1,768,714	$1,783,378	$14,664
1920	Computer Equipment - Hardware	$4,584,305	$4,901,457	$317,152
1611	Computer Software	$1,385,804	$1,547,104	$161,300
1930	Transportation Equipment	$9,124,401	$9,798,868	$674,468
1935	Stores Equipment	$97,797	$112,364	$14,567
1940	Tools, Shop and Garage Equipment	$3,398,948	$3,532,816	$133,868
1945	Measurement and Testing Equipment	$674,841	$677,634	$2,793
1950	Power Operated Equipment	$425,791	$425,791	$0
1955	Communication Equipment	$359,156	$400,629	$41,473
1980	System Supervisory Equipment	$1,699,549	$1,867,811	$168,261
1985	Sentinel Lighting Rental Units	$0	$0	$0
1990	Other Tangible Property	$0	$0	$0
Sub-total		**$23,519,308**	**$25,047,852**	**$1,528,544**
Contribution and Grants				
1995	Contributions and Grants	($18,542,289)	($18,542,289)	$0
2440	Deferred Revenue	($17,470,672)	($20,886,152)	($3,415,481)
Sub-total		**($36,012,961)**	**($39,428,441)**	**($3,415,481)**
Grand Total		**$254,246,571**	**$265,243,412**	**$10,996,842**

Distribution Plant

SNC distribution asset variance from 2021 to 2022 is due in large part to ongoing system renewal efforts as part of the 4kV to 25kV conversion projects.

ACCOUNT 1830 – POLES, TOWERS, & FIXTURES $5,818,365

Voltage conversion program consisted of $1.363 million. Project areas which were completed in the voltage conversion program included the following (with pole additions in brackets):

- Algoma Wolseley Project Area (66 Poles)
- Donald Edward Project Area (93 Poles)

The overhead program consisted of $2.127 million. Through the asset condition assessment process, 25kV circuits that are found to be in poor condition are scheduled for replacement similarly to the 4kV. Project areas identified included the following:

- Northwood 10M7 Agate-Amethyst Project Area (32 Poles),
- Spruce Hemlock Project area (35 Poles),
- Edward William 25kV Project Area (36 Poles),
- Kingsway Walsh 25kV Project Area (65 Poles),
- Central 17M1/17M3 25kV Project Area (37 Poles),

The risk assessment program identified 56 poles for replacement for a total of $0.606 million under Lines Safety Reports projects.

Road Construction & Line Relocations consisted of $0.542 million. This work was requested by the City of Thunder Bay and in 2022 this consisted of;

- River St Culvert Replacement (3 poles)
- Balmoral St between Alloy and Lithium project (Phase 3) (37 new poles)

Construction associated with Joint Use requests in 2022 included 308 joint use attachments in Thunder Bay, which consisted of $0.945 million.

The remainder of expenditures encompassed several smaller programs below materiality totaling $0.369 million.

ACCOUNT 1835 – OVERHEAD CONDUCTORS AND DEVICES $2,858,488

Voltage conversion program consisted of $0.789 million. This program consists of all work and materials associated with the design and installation of new 25kV overhead circuits and the removal of the existing 4kV overhead circuits. Through the 4kV Conversion Projects identified above, approximately 9.56 km of overhead conductor was replaced in the system.

The 25kV overhead renewal Program consisted of $1.311 million. Through the asset condition assessment process, 25kV circuits in the project areas below were replaced and as a result 15.18 km of overhead conductor.

- Northwood 10M7 Agate-Amethyst Project Area (3.63 km),
- Spruce Hemlock 25kV Project area (3.71 km), the Edward William Project Area (2.57 km),
- Kingsway Walsh 25kV Project Area (5.0 km),
- Central 17M1/17M3 25kV Project Area (0.274 km).

Risk assessment process (Lines Safety Reports) program consisted of $0.219 million and approximately 0.513 km of overhead conductor was replaced as well as 428 porcelain insulators, which were identified as a safety hazard to the public.

Road Construction & Line Relocations Consisted of $0.476 million, which required the relocation of overhead conductors and devices on the following projects.

- River St Culvert Replacement for City of Thunder Bay
- Balmoral St between Alloy and Lithium project (Phase 3)

The remainder of expenditures encompassed several smaller programs below materiality totaling $0.135 million.

ACCOUNT 1840 – UNDERGROUND CONDUIT $801,224

The 25 kV overhead renewal Program consisted of $0.157 million. Through the projects identified above in 25kV renewal, 0.583 km of UG conduit was added to the system.

Risk Assessment processes identified 3.49 km of underground conduit which required replacement and consisted of $0.174 million.

New Services in Subdivisions in 2022 consisted of $0.280 million. This project accounted for 19 new underground services in subdivisions in the following subdivisions: Keewatin (Kenora), Parkdale, Whiskey Jack, Hutton Park, River Terrace, and Maplewood.

The remainder of expenditures encompassed several smaller programs below materiality totaling $0.207 million.

ACCOUNT 1845 – UNDERGROUND CONDUCTORS AND DEVICES $958,836

Voltage conversion program consisted of $0.142 million. This program consists of all work and materials associated with the design and installation of new 25kV circuits and the removal of the existing 4kV circuits. Through the 4kV Conversion Projects identified above, approximately 0.681 km of UG conductor was replaced in the system.

The risk assessment process (Lines Safety Reports) consisted of $0.279 million. This program consists of all work and materials associated with the unscheduled, reactive replacement of distribution assets found to be in poor health and in need of immediate and/or near-term replacement to ensure ongoing system performance. As a result, 2.624 km of UG conductor was replaced.

New Services and Subdivisions consisted of $0.240 million for the primary services to the above-mentioned subdivisions in 2022.

Road Construction & Line Relocations consisted of $0.171 million for the River St Culvert Replacement for City of Thunder Bay.

The remainder of expenditures encompassed several smaller programs below materiality totaling $0.149 million.

ACCOUNT 1850 – LINE TRANSFORMERS $1,631,627

Voltage conversion program consisted of $0.340 million. This program consists of all work and materials associated with the design and installation of new 25kV transformers and the removal of the existing 4kV transformers This supports SNC's longstanding 4kV conversion program and subsequent substation decommissioning. Through the 4kV conversion projects shown below, the following number of line transformers were replaced in the system:

- Donald Edward Project Area (25 Pole top, 5 Pad mount),
- Algoma Wolseley Project Area (12 Pole top).

Through the asset condition assessment process, 25kV circuits that are found to be in poor condition are scheduled for replacement similarly to the 4kV. Through the 25 kV overhead renewal Program projects identified below, $0.314 millions of transformers were replaced.

- Northwood 10M7 Agate-Amethyst Project Area (7 Pole top),
- Spruce Hemlock 25kV Project area (8 Pole top),
- Edward William 25kV Project Area (7 Pole top),
- Kingsway Walsh 25kV Project Area (15 Pole top),
- Industrial Park PH3 Project area (3 Pad mount).

The risk assessment process (Lines Safety project) consisted of $0.255 million which included to installation of 20 new pole top and 10 new Pad mount transformers.

New Services and Subdivisions consisted of $0.431 million. This project accounts for all SNC's costs to connect customer requested services. This represents approximately 80 residential services, 31 general service connections (17 in Thunder Bay and 14 in Kenora).

Road Construction & Line Relocations Consisted of $0.191 million in line transformers that were relocated and rewired onto the new poles for the Balmoral St between Alloy and Lithium project (Phase 3).

The remainder of expenditures encompassed several smaller programs below materiality totaling $0.133 million.

ACCOUNT 1855 – SERVICES $208,754

New services in subdivisions consisted of $0.208 million. This project accounts for all of SNC's costs to connect customer requested services.

ACCOUNT 1860 – METERS $444,587

New services consisted of $0.251 million. New meters were installed for 80 residential and 31 commercial services. The meter account also consisted of the replacement of 1141 failed meters in the field and the reverification and compliance sampling activities of 99 meters and 155 meters and consisted of $0.267 million. In order to complete the sampling and reverification program, SNC added inventory which consisted of $0.152 million.

General Plant

ACCOUNT 1920 – COMPUTER EQUIPMENT $317,152

The variance in this account can be attributed to SNC's annual budgeted replacement of computer equipment and the acquisition of the following assets:

- Computer replacements and new iPad purchases: $149,000
- Cisco Switches $17,000
- Wifi access point replacements $9,000
- Video Conf system $24,000
- Firewall replacements and virtual FW $59,000
- Server replacements $24,000
- Computer Monitors $10,000
- VLT shipping costs/customs/duties $7,000
- PRA additional licensing $10,000

ACCOUNT 1930 – TRANSPORTATION EQUIPMENT $674,468

The variance in this account can be attributed to SNC's annual budgeted replacement of transportation equipment. In 2022, SNC purchased six F-150's, one F-250, and made a progress payment for an RBD.

- Truck #129 F250 - $64,669
- Truck #130 F150 - $62,689
- Truck #131 F150 - $62,855
- Truck #132 F150 - $62,855
- Truck #133 F150 - $62,855
- Truck #134 F150 - $62,855
- Truck #135 F150 - $62,855
- RBD #136 ($315,000 – progress payment)
- Flat Deck #120

Contributions and Grants

Contributions increased by $3,415,481 in 2022. Contributions can be broken down into:

- Capital recoverable work of $1,350,000 ($583,000 Government Road Project).
- General Service and Residential connections of $1.41 million.

- System Relocation work of $494,000 (Balmoral $425,000, River St $56,000).
- Developer's costs for subdivision Gemstone Stage 5 of $159,000.

2022 Actual Versus 2023 Bridge

SNC experienced an overall increase in gross assets between the 2022 Actual and 2023 Forecasted Bridge year of $12,189,491, as can be seen in the following Table 2-25.

Table 2-25: 2022 Actual versus 2023 Forecast (Bridge Year)

USoA	Description	2022 Actual	2023 Projected	Variance
Intangible Plant				
1609	Capital Contribution Pd - Gate Stn	$1,272,321	$1,272,321	$0
Sub-total		**$1,272,321**	**$1,272,321**	**$0**
Distribution Plant				
1805	Land	$148,673	$148,673	$0
1806	Land Rights	$0	$0	$0
1808	Buildings and Fixtures	$8,477,119	$8,557,119	$80,000
1810	Leasehold Improvements	$63,262	$63,262	$0
1815	Transformer Station Equipment > 50 kV	$2,842,894	$2,842,894	$0
1820	Distribution Station Equipment < 50 kV	$8,503,545	$8,503,545	$0
1830	Poles, Towers and Fixtures	$75,017,405	$82,635,561	$7,618,157
1835	Overhead Conductors and Devices	$56,561,265	$59,124,313	$2,563,047
1840	Underground Conduit	$19,715,109	$19,908,021	$192,911
1845	Underground Conductors and Devices	$27,143,103	$27,446,252	$303,149
1850	Line Transformers	$42,728,740	$43,867,854	$1,139,115
1855	Services (Overhead & Underground)	$24,039,501	$24,275,723	$236,221
1860	Meters	$13,111,064	$13,266,818	$155,754
Sub-total		**$278,351,681**	**$290,640,035**	**$12,288,355**
General Plant				
1915	Office Furniture and Equipment	$1,783,378	$1,977,378	$194,000
1920	Computer Equipment - Hardware	$4,901,457	$5,259,957	$358,500
1611	Computer Software	$1,547,104	$1,608,104	$61,000
1930	Transportation Equipment	$9,798,868	$9,983,868	$185,000
1935	Stores Equipment	$112,364	$112,364	$0
1940	Tools, Shop and Garage Equipment	$3,532,816	$3,677,816	$145,000
1945	Measurement and Testing Equipment	$677,634	$677,634	$0
1950	Power Operated Equipment	$425,791	$425,791	$0
1955	Communication Equipment	$400,629	$533,274	$132,645
1980	System Supervisory Equipment	$1,867,811	$2,114,370	$246,559
Sub-total		**$25,047,852**	**$26,370,556**	**$1,322,704**
Contribution and Grants				
1995	Contributions and Grants	($18,542,289)	($18,542,289)	$0
2440	Deferred Revenue	($20,886,152)	($22,307,721)	($1,421,569)
Sub-total		**($39,428,441)**	**($40,850,010)**	**($1,421,569)**
Grand Total		**$265,243,412**	**$277,432,903**	**$12,189,491**

Distribution Plant

SNC distribution asset variance from 2022 to 2023 is due in large part to ongoing system renewal efforts as part of the 4kV to 25kV conversion projects.

ACCOUNT 1830 – POLES, TOWERS, & FIXTURES $7,618,157

Voltage conversion program consisted of $4.70 million. This program consists of all work and materials associated with the design and installation of new 25kV poles, towers & fixtures, and the removal of the existing 4kV poles, towers & fixtures. Project areas identified in the voltage conversion program in 2023 include the following:

- College Tupper Project area (134 Poles),
- 21F1 Ph2 Project area (68 Poles)

Risk assessment process (Lines Safety Reports) program consisted of $0.716 million. This program consists of all work and materials associated with the unscheduled, reactive replacement of distribution assets found to be in poor health (through the ACA process) and in need of immediate and/or near-term replacement to ensure ongoing system performance. As a result, 21 Poles are planned for replacement.

The 25kV overhead renewal Program consisted of $1.507 million. Through the asset condition assessment process, 25kV circuits that are found to be in poor condition are scheduled for replacement similarly to the 4kV. Project areas identified for replacement in SNC's ACA included the following:

- Valley Skyline 25kV Project Area (100 Poles),
- Edward ironwood 25kV Project Area (58 Poles),
- University Sherbrooke 25kV Project Area (34 Poles),
- Railway St Phase 3 Project in Kenora (16 Poles).

The remainder of expenditures encompassed several smaller programs below materiality totaling $0.195 million.

ACCOUNT 1835 – OVERHEAD CONDUCTORS AND DEVICES $2,563,047

Voltage conversion program consisted of $0.707 million. This program consists of all work and materials associated with the design and installation of new 25kV circuits and the removal of the existing 4kV circuits. The assets in these areas are generally in poor health as identified through the asset condition process and resulted in approximately 21.57 km of overhead conductor which replaced in the system.

Risk assessment process (Lines Safety Reports) program consisted of $0.773 million. This program consists of all work and materials associated with the unscheduled, reactive replacement of distribution assets found to be in poor health (through the ACA process) and in need of immediate and/or near-term replacement to ensure ongoing system performance. Approximately 200 Locations of porcelain insulators are planned for the replacement.

25kV overhead renewal Program consisted of $0.772 million. Through the asset condition assessment process, 25kV circuits that are found to be in poor condition are scheduled for replacement similarly to the 4kV. 25kV Circuits in the project areas below are scheduled for replacement and as a result there will be replacement of 15.909 km of overhead conductor in the system.

- Valley Skyline 25kV Project Area (9.133 km),
- Edward ironwood 25kV Project Area (3.0 km),
- University Sherbrooke 25kV Project Area (1.376 km),
- Railway St Phase 3 Project in Kenora (2.4 km).

The remainder of expenditures encompassed several smaller programs below materiality totaling $0.309 million.

ACCOUNT 1840 – UNDERGROUND CONDUIT $192,911

The total of expenditures encompassed several smaller programs below materiality totaling $0.192 million.

ACCOUNT 1845 – UNDERGROUND CONDUCTORS AND DEVICES $303,149

The total of expenditures encompassed several smaller programs below materiality totaling $0.303 million.

ACCOUNT 1850 – LINE TRANSFORMERS $1,139,115

The 25kV overhead renewal program consisted of $0.698 million. Through the projects identified as part of the 25kV overhead renewal program, 17 pole top and 18 Pad mount transformers are scheduled for replacement.

UG Renewal Program consisted of $0.500 million. The area identified for replacement as part of the Underground renewal program is James St Subdivision PH2 (Simon Fraser) and consists of the replacement of 13 Single Phase Residential Pad Mount transformers located in backyard utility easement locations.

The remainder of expenditures encompassed several smaller programs below materiality totaling $0.441 million.

ACCOUNT 1855 – SERVICES $236,221

New services in subdivisions consisted of $0.236 million. This project accounts for all SNC's costs to connect customer requested services. This represents approximately 130 residential services, 25 general service connections (20 in Thunder Bay and 5 in Kenora).

General Plant

ACCOUNT 1915 OFFICE FURNITURE EQUIPMENT – $194,000

The variance in this account can be attributed to SNC's office change, leasehold improvements etc.

ACCOUNT 1920 – COMPUTER EQUIPMENT $358,500

The variance in this account can be attributed to SNC's annual budgeted replacement of computer equipment and the acquisition of the following assets:

- Computer replacements and iPads $88,000
- Server replacements $70,000
- Cisco switches $10,000
- UPS $30,000
- High St Data Centre $74,000
- Desk phone replacements $21,000

ACCOUNT 1930 – TRANSPORTATION EQUIPMENT $185,000

The variance in this account can be attributed to SNC's annual budgeted replacement of transportation equipment.

In 2023 SNC plans to purchase

- Electric Vehicle - $100,0000
- RBD #136 ($85,000 – final payment)

ACCOUNT 1980 – SYSTEM SUPERVISORY EQUIPMENT $246,559

The variance in this account can be attributed to SNC's continued installation of automated reclosers. This amount is the labour, trucking and material required to install and commission 2 reclosers in the field.

SNC expects to review and select the worst performing feeders and determine the optional location for these reclosers to sectionalize and reduce outages to customers on an annual basis.

CONTRIBUTIONS AND GRANTS

Contributions are forecasted to increase by $1,421,569 in 2023. It is expected that the capital recoverable work (System Access) work will lower in 2023 and therefore the contributions will also decline.

The contributions that are forecasted to be received are as follows:

- Capital recoverable work of $400,000
- General Service and Residential connections of $868,000
- Contributions for relocations work of $90,000

2023 Bridge Versus 2024 Test

SNC is forecasting an overall increase in gross assets between the 2023 Bridge and 2024 Test year of $12,617,441, as can be seen in the following Table 2-26.

Table 2-26: 2023 Bridge versus 2024 Test Year

USoA	Description	2023 Bridge	2024 Projected	Variance
Intangible Plant				
1609	Capital Contribution Pd - Gate Stn	$1,272,321	$1,272,321	$0
Sub-total		**$1,272,321**	**$1,272,321**	**$0**
Distribution Plant				
1805	Land	$148,673	$148,673	$0
1806	Land Rights	$0	$0	$0
1808	Buildings and Fixtures	$8,557,119	$8,712,369	$155,250
1810	Leasehold Improvements	$63,262	$63,262	$0
1815	Transformer Station Equipment > 50 kV	$2,842,894	$2,842,894	$0
1820	Distribution Station Equipment < 50 kV	$8,503,545	$8,503,545	$0
1830	Poles, Towers and Fixtures	$82,635,561	$86,684,281	$4,048,720
1835	Overhead Conductors and Devices	$59,124,313	$63,739,798	$4,615,485
1840	Underground Conduit	$19,908,021	$20,233,167	$325,146
1845	Underground Conductors and Devices	$27,446,252	$28,060,866	$614,614
1850	Line Transformers	$43,867,854	$45,973,147	$2,105,293
1855	Services (Overhead & Underground)	$24,275,723	$24,903,917	$628,195
1860	Meters	$13,266,818	$13,534,728	$267,910
Sub-total		**$290,640,035**	**$303,400,648**	**$12,760,612**
General Plant				
1915	Office Furniture and Equipment	$1,977,378	$2,028,378	$51,000
1920	Computer Equipment - Hardware	$5,259,957	$5,479,957	$220,000
1611	Computer Software	$1,608,104	$1,693,104	$85,000
1930	Transportation Equipment	$9,983,868	$10,583,868	$600,000
1935	Stores Equipment	$112,364	$112,364	$0
1940	Tools, Shop and Garage Equipment	$3,677,816	$3,797,816	$120,000
1945	Measurement and Testing Equipment	$677,634	$728,804	$51,170
1950	Power Operated Equipment	$425,791	$425,791	$0
1955	Communication Equipment	$533,274	$533,274	$0
1980	System Supervisory Equipment	$2,114,370	$2,378,451	$264,081
Sub-total		**$26,370,556**	**$27,761,807**	**$1,391,251**
Contribution and Grants				
1995	Contributions and Grants	($18,542,289)	($18,542,289)	$0
2440	Deferred Revenue	($22,307,721)	($23,842,143)	($1,534,422)
Sub-total		($40,850,010)	**($42,384,432)**	**($1,534,422)**
Grand Total		**$277,432,903**	**$290,050,344**	**$12,617,441**

Distribution Plant

SNC distribution asset variance from 2023 to 2024 is due in large part to ongoing system renewal efforts as part of the 4kV to 25kV conversion projects.

ACCOUNT 1830 – POLES, TOWERS, & FIXTURES $4,048,720

Voltage conversion program consisted of $2.319 million. This program consists of all work and materials associated with the design and installation of new 25kV circuits and the removal of the existing 4kV circuits. Project areas identified in the voltage conversion program include the following:

- Court Wilson Project Area (102 Poles),
- Donald Vickers Project Area (73 Poles),
- 21F6 PH1 Project Area (115 Poles).

Risk assessment process (Lines Safety Reports) program consisted of $0.560 million. This program consists of all work and materials associated with the unscheduled, reactive replacement of distribution assets found to be in poor health (through the ACA process) and in need of immediate and/or near term replacement to ensure ongoing system performance. As a result, 21 Poles are planned for replacement.

The 25kV overhead renewal program consisted of $0.933 million. Through the asset condition assessment process, 25kV circuits that are found to be in poor condition are scheduled for replacement and areas identified for replacement in SNC’s ACA included the following:

- Inglewood Ashland 25kV Project Area (64 Poles)
- Central 17M5/6/7 25kV Project Area (34 Poles)

The remainder of expenditures encompassed several smaller programs below materiality totaling $0.274 million.

ACCOUNT 1835 – OVERHEAD CONDUCTORS AND DEVICES $4,615,485

Voltage conversion program consisted of $3.106 million. Through the 4kV Conversion Projects identified above, approximately 26.2 km of overhead conductor will be replaced in the system.

The 25kV overhead renewal project listed above will consist of $0.697 million.

The Risk assessment process (Lines Safety Reports) in 2024 will consist of $0.649 million. Through the asset condition assessment process, approximately 200 porcelain insulator's locations are planned for replacement, and an estimated amount of overhead conductors and devices associated with approximately 21 poles.

The remainder of expenditures encompassed several smaller programs below materiality totaling $0.278 million.

ACCOUNT 1840 – UNDERGROUND CONDUIT $325,146

Voltage conversion program consisted of $0.172 million. Through the 4kV conversion project areas identified below, approximately 13,630 ft of conduit will be added to the system.

- Court Wilson Project Area (4989 ft),
- Donald Vickers Project Area (4376 ft),
- 21F6 PH1 Project Area (4265 ft).

The remainder of expenditures encompassed several smaller programs below materiality totaling $0.160 million.

ACCOUNT 1845 – UNDERGROUND CONDUCTORS AND DEVICES $614,614

Voltage conversion program consisted of $0.191 million. Through the 4kV conversion project areas identified below, approximately 6.546 km of underground conductor will be replaced.

- Court Wilson Project Area (4.073 km),
- Donald Vickers Project Area (1.823 km),
- 21F6 PH1 Project Area (.650 km).

The remainder of expenditures encompassed several smaller programs below materiality totaling $0.421 million.

ACCOUNT 1850 – LINE TRANSFORMERS $2,105,293

Voltage conversion program consisted of $0.611 million. Through the 4kV conversion project areas identified below, 105 line transformers will be replaced in the system.

- Court Wilson Project Area (46 Pole top, 6 Pad mount),
- Donald Vickers Project Area (29 Pole top, 3 Pad mount),
- 21F6 PH1 Project Area (21 Pole top).

Risk assessment process (Lines Safety Reports) consisted of $0.679 million. Through the risk assessment program, SNC expects approximately 17 pole top, and 18 Pad mount transformers will be identified for replacement.

The overhead renewal program consisted of $0.456 million. Through the asset condition assessment process, 25kV circuits that are found to be in poor condition are scheduled for replacement similarly to the 4kV. The Inglewood Ashland Project Area Consists of the replacement of 19 Pole top transformers.

The remainder of expenditures encompassed several smaller programs below materiality totaling $0.239 million.

ACCOUNT 1855 – SERVICES $628,195

Voltage conversion program consisted of $0.313 million.

New residential services consisted of $0.198 million. This project accounts for all SNC's costs to connect customer requested services. This represents approximately 130 residential services, 25 general service connections (20 in Thunder Bay and 5 in Kenora).

The remainder of expenditures encompassed several smaller programs below materiality totaling $0.124 million.

ACCOUNT 1860 – METERS $267,910

Total meters consisted of $0.187 million. The remainder of expenditures encompassed several smaller programs below materiality totaling $0.081 million.

GENERAL PLANT

ACCOUNT 1920 – COMPUTER EQUIPMENT $220,000

The variance in this account can be attributed to SNC's annual budgeted replacement of computer equipment and the acquisition of the following assets:

- Computer and tablet replacements $72,500
- Server Replacements $50,000
- SAN Augmentation $30,000
- Intrusion Prevention System $50,000
- Phone System and Load Balancers $30,000

ACCOUNT 1930 – TRANSPORTATION EQUIPMENT $600,000

The variance in this account can be attributed to SNC's annual budgeted replacement of transportation equipment. In 2024 SNC plans to purchase the following:

- F-350 Crew cab truck to replace #86 (2013) - $75,000
- Space Kap for #86's replacement - $25,000
- Electric or gasoline powered SUV to replace #59 (2009) -$90,000
- Light truck to replace #55 (2009) - $70,000
- Light truck to replace #69 (2012) - $70,000
- Space Kap to replace an existing kap -$25,000
- Drop bow type work boat, outboard motor, and trailer to replace #950 (2015)- $250,000

ACCOUNT 1980 – SYSTEM SUPERVISORY EQUIPMENT $264,081

The variance in this account is associated with budgeted grid modernization improvements. In 2024, SNC is proposing to install an additional 2 (two) overhead 3 phase reclosers to sectionalize the distribution system further and provide improved reliability to customers.

CONTRIBUTIONS AND GRANTS

As discussed above, SNC is expecting System Access work to decrease in the forecasted period in comparison to the last few historical years, which in turn lowers the amount of expected contributions.

Contributions are forecasted to increase by $1,534,422 in 2024. The contributions that are forecasted to be received are as follows:

- Capital recoverable work of $412,000
- General Service and Residential connections of $1.04 million
- Expansion work of $55,000

2.4 DEPRECIATION, AMORTIZATION AND DEPLETION

2.4.1 OVERVIEW

As directed by the Board, SNC had modified its capitalization and depreciation policies to be more in line with IFRS effective January 1, 2013. This was referred to as "modified CGAAP" (MCGAAP) in the 2013 Cost of Service Application.

Useful lives were guided by the Kinectrics Report provided by the Board as well as an internal assessment of the remaining service lives for the purposes of determining the computation of depreciation expense on a go-forward basis.

SNC confirms that significant parts or components of each item of PP&E are being depreciated separately. This is discussed in more detail below.

SNC's capital assets and capital contributions are amortized on a straight-line basis, when the item is put into service, over the deemed life of the assets.

Construction in progress assets are amortized once the project is complete and in-service. SNC does not capitalize any interest to the cost of assets constructed as typical life cycle of construction projects are less than one year.

For the purposes of calculating depreciation for this Application, the half-year rule has been applied for all in-service 2024 Test Year capital additions and capital contributions in accordance with Section 2.2.4 of Chapter 2 of the Board's Filing Requirements.

A copy of SNC's Depreciation Policy has been included as Attachment 2-B. The continuity schedules in Tables 2-5 to 2-14 reconcile to the annual recorded depreciation expense.

2.4.2 USEFUL LIFE AND COMPONENTIZATION

The following discussion outlines the depreciation practices used by SNC in this Application and provides a summary of changes since the last Cost of Service Application.

SNC has reviewed the useful life of its assets with the aid of the Asset Depreciation Study by Kinectrics (Kinectrics Report). In addition, SNC's Engineering Department reviewed the condition of its assets and construction practices to determine the applicable depreciation periods for SNC assets.

Attachment 2-C, which is consistent with Board Appendix 2-BB, contains the useful lives by Uniform System of Account. SNC has not changed any amortization periods for its capital assets since the last Cost of Service Application.

SNC is outside of the useful life range for 1930 Transportation Equipment (Vans) and 1611 Computer Software. For both accounts, SNC uses a longer amortization period than was indicated in the Kinectrics Report. These service lives were approved in the EB-2016-0105 proceeding.

No changes have been made to SNC's depreciation policy or service lives since last rebasing. When KHEC merged with TBHEDI, KHEC adopted TBHEDI's historical useful lives and depreciation policy.

2.4.3 Asset Retirement Obligation

SNC continues to carry a constructive obligation related to the decommissioning of SNC's sub-stations. The accrued liability was added to the cost of the sub-station assets and is being amortized over the life of the associated assets ($25,175 annually). This asset has been excluded from Rate Base for purposes of calculating Rate of Return, ARO treatment is in line with TBHEDI's Settlement in EB-2016-0105.

2.4.4 Depreciation Expense Summary and Analysis

Depreciation on capital assets is calculated as follows:

Depreciation is calculated on a straight-line basis over the estimated remaining useful life of the assets. Depreciation commences when the asset has been put in service. Per IAS 16 paragraph 55 "*Depreciation of an asset begins when it is available for use.*" As a result, SNC depreciates an item of PP&E when the asset is available for use.

It is SNC's depreciation policy to commence depreciation when the asset has been put into service; however, the half-year rule has been used for the accounting for depreciation expense for this rate application for both the 2023 Bridge and 2024 Test Years, with the exception of its constructed assets where typically SNC installs a significant portion in the fall and winter months. For constructed assets SNC has assumed they would be put into service between October and December. This basis was used as it should approximate the actual impact to depreciation.

In accordance with the filing requirements, SNC has completed the depreciation and amortization expense Board Appendix 2-C, attached as Attachment 2-D.

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

TABLE 2-27: DEPRECIATION EXPENSE 2017-2024

OEB Account	Description	Last Rebasing Year (2017 Actuals)	2018 Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Actuals	2023 Bridge Year	2024 Test Year
1609	Capital Contributions Paid	$50,893	$50,893	$50,893	$50,893	$50,893	$50,893	$50,893	$50,893
1611	Computer Software (Formally known as Account 1925)	$29,336	$7,726	$6,122	$9,990	$16,271	$50,269	$73,441	$114,774
1808	Buildings	$202,908	$209,190	$246,695	$248,253	$249,587	$251,856	$242,757	$244,975
1815	Transformer Station Equipment >50 kV	$110,645	$115,485	$91,914	$122,054	$114,943	$116,216	$126,058	$129,395
1820	Distribution Station Equipment <50 kV	$159,691	$160,466	$168,068	$121,161	$67,343	$64,271	$73,856	$75,811
1830	Poles, Towers & Fixtures	$1,214,176	$1,287,613	$1,346,959	$1,460,459	$1,592,872	$1,755,399	$1,848,950	$1,954,665
1835	Overhead Conductors & Devices	$603,163	$643,435	$717,060	$759,764	$792,328	$847,834	$896,284	$967,679
1840	Underground Conduit	$143,985	$143,904	$132,166	$147,471	$159,613	$171,279	$179,167	$191,291
1845	Underground Conductors & Devices	$444,045	$429,329	$425,540	$460,558	$484,694	$507,287	$537,466	$562,443
1850	Line Transformers	$694,292	$648,400	$659,952	$698,423	$736,875	$778,563	$823,226	$877,645
1855	Services (Overhead & Underground)	$256,937	$232,104	$237,566	$242,634	$248,403	$254,373	$275,156	$288,921
1860	Meters (Smart Meters)	$677,358	$656,231	$684,808	$723,563	$735,372	$752,132	$812,174	$841,673
1908	Buildings & Fixtures	$35,296	$35,296	$0	$0	$0	$0	$0	$0
1915	Office Furniture & Equipment (10 years)	$61,213	$63,063	$60,652	$57,719	$50,331	$33,500	$62,167	$61,370
1920	Computer Equipment - Hardware	$101,936	$109,658	$155,664	$176,423	$217,644	$289,539	$320,699	$267,600
1930	Transportation Equipment	$379,493	$436,438	$463,865	$447,450	$473,323	$514,458	$545,666	$556,133
1935	Stores Equipment	$0	$2,579	$3,438	$3,438	$3,438	$3,681	$3,438	$3,438
1940	Tools, Shop & Garage Equipment	$71,778	$77,010	$89,399	$94,998	$99,906	$106,577	143,053	$142,592
1945	Measurement & Testing Equipment	$32,519	$40,464	$40,712	$43,279	$41,401	$33,940	$11,652	$11,394
1950	Power Operated Equipment	$35,549	$35,007	$34,678	$21,620	$15,574	$15,574	$15,574	$15,574
1955	Communications Equipment	$11,945	$11,592	$15,109	$15,483	$14,791	$19,776	$31,816	$32,154
1960	Miscellaneous Equipment	$3,664	$4,330	$0	$0	$0	$0	$0	$0
1980	System Supervisor Equipment	$111,420	$105,383	$109,302	$112,285	$126,732	$121,312	$85,894	$92,338
1995	Contributions & Grants	($432,680)	($432,680)	($432,680)	($432,680)	($432,680)	($432,680)	($432,680)	($432,680)
2440	Deferred Revenue[5]	($180,315)	($193,373)	($226,650)	($249,298)	($267,599)	($286,035)	($484,078)	($516,145)
Depreciation Expense Excluding Adjustments		**$ 4,819,246**	**$ 4,879,541**	**$ 5,081,231**	**$ 5,335,942**	**$ 5,592,056**	**$ 6,020,014**	**$ 6,242,630**	**$ 6,533,934**
Adjustments:									
Less: IT		($3,039)	($4,683)	($7,888)	($6,939)	($7,613)	($7,280)	($31,651)	($43,091)
Less: Fleet		($489,078)	($547,898)	($613,246)	($582,824)	($602,318)	($644,566)	($674,765)	($683,797)
Less: Operations Centre		($104,968)	($113,466)	($152,017)	($144,559)	($142,009)	($138,654)	($134,852)	($137,070)
Less: Engineering and Supervisory		($45,461)	($54,562)	($61,182)	($61,538)	($53,359)	($70,662)	($59,185)	($63,284)
Less: Stores		($269)	($2,429)	($3,575)	($3,575)	($4,127)	($5,478)	($9,518)	($9,863)
Less: Capital Contribution		$180,315	$193,373	$226,650	$249,298	$267,599	$286,035	$484,078	$516,145
Add: Amortization of ARO		$0	$66,115	$34,857	$24,202	$24,059	$25,646	$25,175	$25,175
Net Depreciation		**$ 4,356,746**	**$ 4,415,991**	**$ 4,504,831**	**$ 4,810,007**	**$ 5,074,288**	**$ 5,465,055**	**$ 5,841,912**	**$ 6,138,149**

A summary of the annual variances calculated is summarized in Table 2-28 below.

TABLE 2-28: DEPRECIATION AND AMORTIZATION VARIANCE SUMMARY

OEB Account [3]	Description [3]	2017 v 2018 Actuals	2018 v 2019 Actuals	2019 v 2020 Actuals	2021 Actuals	2022 Actuals	2023 Bridge Year	2024 Test Year
1609	Capital Contributions Paid	$0	($0)	$0	$0	$0	$0	$0
1611	Computer Software (Formally known as Account 1925)	($21,610)	($1,604)	$3,868	$6,280	$33,998	$23,173	$41,333
1808	Buildings	$6,282	$37,506	$1,558	$1,333	$2,269	($9,099)	$2,218
1815	Transformer Station Equipment >50 kV	$4,839	($23,571)	$30,140	($7,112)	$1,273	$9,842	$3,337
1820	Distribution Station Equipment <50 kV	$775	$7,602	($46,907)	($53,818)	($3,072)	$9,585	$1,955
1830	Poles, Towers & Fixtures	$73,438	$59,346	$113,500	$132,413	$162,527	$93,551	$105,715
1835	Overhead Conductors & Devices	$40,272	$73,625	$42,704	$32,564	$55,506	$48,450	$71,395
1840	Underground Conduit	($81)	($11,738)	$15,306	$12,142	$11,665	$7,888	$12,124
1845	Underground Conductors & Devices	($14,716)	($3,789)	$35,018	$24,136	$22,593	$30,179	$24,977
1850	Line Transformers	($45,892)	$11,552	$38,472	$38,451	$41,688	$44,663	$54,419
1855	Services (Overhead & Underground)	($24,833)	$5,462	$5,069	$5,769	$5,970	$20,783	$13,765
1860	Meters (Smart Meters)	($21,127)	$28,578	$38,755	$11,809	$16,760	$60,042	$29,499
1908	Buildings & Fixtures	$0	($35,296)	$0	$0	$0	$0	$0
1915	Office Furniture & Equipment (10 years)	$1,850	($2,411)	($2,933)	($7,388)	($16,831)	$28,667	($797)
1920	Computer Equipment - Hardware	$7,722	$46,006	$20,759	$41,221	$71,895	$31,159	($53,099)
1930	Transportation Equipment	$56,945	$27,427	($16,415)	$25,873	$41,135	$31,208	$10,467
1935	Stores Equipment	$2,579	$860	$0	$0	$243	($243)	$0
1940	Tools, Shop & Garage Equipment	$5,232	$12,389	$5,599	$4,908	$6,671	$36,476	($461)
1945	Measurement & Testing Equipment	$7,945	$248	$2,567	($1,877)	($7,461)	($22,288)	($258)
1950	Power Operated Equipment	($542)	($329)	($13,058)	($6,046)	($0)	($0)	$0
1955	Communications Equipment	($353)	$3,517	$374	($692)	$4,985	$12,040	$338
1960	Miscellaneous Equipment	$666	($4,330)	$0	$0	$0	$0	$0
1980	System Supervisor Equipment	($6,037)	$3,919	$2,983	$14,447	($5,420)	($35,418)	$6,444
1995	Contributions & Grants	$0	$0	$0	$0	$0	$0	$0
2440	Deferred Revenue[5]	($13,058)	($33,278)	($22,647)	($18,301)	($18,436)	($198,043)	($32,067)
Depreciation Expense Excluding Adjustments		**$ 60,295**	**$ 201,690**	**$ 254,711**	**$ 256,114**	**$ 427,958**	**$ 222,616**	**$ 291,304**
Adjustments:								
Less: IT		($1,644)	($3,205)	$949	($674)	$333	($24,371)	($11,440)
Less: Fleet		($58,820)	($65,348)	$30,422	($19,494)	($42,248)	($30,199)	($9,032)
Less: Operations Centre		($8,499)	($38,551)	$7,458	$2,551	$3,354	$3,802	($2,218)
Less: Engineering and Supervisory		($9,102)	($6,619)	($356)	$8,179	($17,302)	$11,477	($4,099)
Less: Stores		($2,159)	($1,146)	$0	($553)	($1,350)	($4,040)	($345)
Less: Capital Contribution		$13,058	$33,278	$22,647	$18,301	$18,436	$198,043	$32,067
Add: Amortization of ARO		$66,115	($31,258)	($10,655)	($143)	$1,587	($471)	$0
Net Depreciation		**$ 59,244**	**$ 88,840**	**$ 305,176**	**$ 264,280**	**$ 390,767**	**$ 376,857**	**$ 296,237**

Depreciation on Deferred Revenue in the 2023 bridge year increased by $198,043 based on a review of the Capital Contributions amortization process, and actual contributions being higher than budgeted from 2019 to 2022.

The net depreciation calculation difference on the remaining accounts by account basis was below the materiality threshold. Variances are a result of the following:

- SNC's practice of amortizing assets when they are put into use vs. the use of the half year rule as is done in the Board tables.

- The requirement of componentization and that some Board accounts have multiple components at different amortization periods.

Further information on Depreciation expense is provided in Attachment 2-D which is OEB Appendix 2-C for the years 2017-2024.

2.5 ALLOWANCE FOR WORKING CAPITAL

2.5.1 ALLOWANCE FACTOR OVERVIEW

The Filing Requirements permit applicants to take one of two approaches for the calculation of the allowance for working capital:

- use a default allowance of 7.5% or
- the filing of a lead/lag study.

SNC has not been directed by the Board to undertake a lead\lag study, and accordingly, has chosen to use the Board's default value for working capital.

Power Supply Expenses are provided in App 2-ZB of the Chapter 2 Appendices. SNC confirms that it has split RPP and non RPP based on actual data and includes SME charges. SNC used the RPP supply cost for the period from November 1, 2022, to October 31, 2023, as published in the Regulated Price Plan Price Report, dated October 21, 2022 for the period from November 1, 2022 to October 31, 2023. SNC confirms the 11.7% OER credit is applied to RPP supply costs.

SNC has used the default allowance of 7.5% for the 2024 Test Year in this Application, in accordance with the Filing Requirements.

2.5.2 WORKING CAPITAL ALLOWANCE

SNC is proposing a working capital allowance of $9,834,751 as shown in Table 2-29 below:

TABLE 2-29: WORKING CAPITAL ALLOWANCE

Distribution Expenses	2024 Test Year
Distribution Expenses - Operation	$ 4,326,174
Distribution Expenses - Maintenance	$ 7,452,720
Billing and Collecting	$ 2,473,769
Community Relations	$ 303,172
Administrative and General Expenses	$ 6,876,395
Taxes Other than Income Taxes	$ 2,431
Total Eligible Distribution Expenses	$ 21,434,661
Power Supply Expenses	$ 109,695,350
Total Working Capital Expenses	$ 131,130,010
Working Capital Factor	7.5%
Working Capital Allowance	**$ 9,834,751**

2.6 DISTRIBUTION SYSTEM PLAN

In accordance with the Filing Requirements, SNC is filing its consolidated Distribution System Plan ("DSP") as a stand-alone document in Attachment 2-A to this Exhibit. SNC has organized the information contained in the DSP using the headings indicated in Chapter 5 of the Board's Filing Requirements for Electricity Distribution and Transmission Applications, Consolidated Distribution System Plan Filing Requirements, dated December 15, 2022. The DSP incorporates matters pertaining to asset management, regional planning, and renewable energy generation. A snapshot of the 5-year spending by OEB category is presented in Table 2-30 with the full DSP attached as Attachment 2-A.

TABLE 2-30: DISTRIBUTION SYSTEM PLAN SUMMARY 2024-2028

CATEGORY	Forecast Period (planned)				
	2024	2025	2026	2027	2028
	$ '000				
System Access	2,092	4,323	2,796	2,455	2,329
System Renewal	12,714	12,383	12,068	12,151	12,691
System Service	323	330	336	343	350
General Plant	1,282	1,480	1,473	1,617	1,701
GROSS CAPITAL EXPENDITURE	16,411	18,516	16,673	16,566	17,071
Contributed Capital	(1,534)	(3,437)	(1,865)	(1,596)	(1,628)
Net Capital Expenses after Contributions	14,877	15,079	14,808	14,970	15,443
System O&M	11,779	12,014	12,255	12,500	12,750

2.7 POLICY OPTIONS FOR THE FUNDING OF CAPITAL

SNC has not applied for nor received approval of any ICM assets and therefore has no such asset added to its rate base. Accordingly, SNC has not completed the Board's Capital Model applicable to ACM and

ICM. SNC has identified a constraint in the Kenora service territory that is expected to arise in 2031. Due to the uncertainty of the load growth, as well as the uncertainty of the expected solution cost, and timing, SNC will continue to monitor the situation. There is the possibility that load growth will arise unexpectedly and SNC will at that time determine the appropriate regulatory tool for funding.

2.8 ADDITION OF PREVIOUSLY APPROVED ACM AND ICM PROJECT ASSETS TO RATE BASE

SNC has not applied for nor received approval of any ICM assets and therefore has no such asset added to its rate base. Accordingly, SNC has not completed the Board's Capital Model applicable to ACM and ICM.

2.9 CAPITALIZATION

2.9.1 CAPITALIZATION POLICY

SNC's current capitalization policies and principles are based on International Financial Reporting Standards ("IFRS") and guidelines set out by the Board, where applicable. SNC converted to Modified International Financial Reporting Standards ("MIFRS'') for financial reporting purposes on December 31, 2015, and, as such, the capitalization policy in effect for the 2023 Bridge Year and 2024 Test Year is compliant with MIFRS.

Per the Board's letter dated July 17, 2012, electricity distributors that elected to remain on Canadian generally accepted accounting principles ("CGAAP") in 2012 must have implemented regulatory accounting changes for capitalization and depreciation policies by January 1, 2013. SNC engaged Grant Thornton LLP to assist with determining the level of Property, Plant & Equipment ("PP&E") componentization required under IFRS and identifying whether any changes to overhead capitalization were required. As a result of this analysis, and in accordance with the Board's July 17, 2012, letter, SNC revised its capitalization policy effective January 1, 2013, to align with guidance under IFRS. SNC confirms that the changes to its capitalization policy are consistent with the Board's regulatory accounting policies as set out for MIFRS as contained in the Report of the Board, Transition to International Financial Reporting Standards (EB-2008-0408) (the Board Report and the Board's Accounting Procedures Handbook ("APH").

Capitalization and depreciation policies have remained consistent since the last rebasing in 2017.

IFRS prescribes which costs can be included as part of the cost of an asset and indicates that only costs that are directly attributable to bringing an asset to the location and to a condition necessary for it to operate in a manner intended by management can be capitalized. Indirect overhead costs, such as general and administrative costs that are not directly attributable to an asset, cannot be capitalized under IFRS.

SNC performed an analysis of all costs that were being capitalized under CGAAP in order to determine whether these costs were eligible for capitalization under IFRS. This analysis is summarized below.

Labour Cost

Capitalized labour includes engineering design time and operations construction time, which are recorded on timesheets to capital work orders. The timesheets capture the nature of the activities undertaken and time spent on each task by employee.

As a result, it was determined that any time charged to a capital work order was directly attributable to a particular item of PP&E. Under IFRS, these costs are capitalized since they are directly attributable costs of bringing an asset to the location and to a condition necessary for it to operate in a manner intended by management.

Material Cost

These costs include stocked items taken from SNC's warehouse and issued out to each capital project, as well as direct materials which are purchased and delivered to the job site. These costs represent the purchased price and initial delivery costs of the materials.

Under IFRS, these costs are capitalized since they are directly attributable costs of bringing an asset to the location and to a condition necessary for it to operate in a manner intended by management.

Third Party Cost

Sub-contractor costs are incurred when SNC engages a third party for the construction of SNC's assets. Under IFRS, these costs are capitalized since they are directly attributable costs of bringing an asset to the location and to a condition necessary for it to operate in a manner intended by management.

Capitalization Guidelines

The purpose of capitalizing expenditures is to provide an equitable allocation of costs among current and future customers. As capital assets are expected to provide future economic benefits for more than one year, any expenditure incurred for the acquisition, construction, development, or betterment of the capital assets should be capitalized. These capitalized costs are allocated over the estimated useful life of the assets by amortization.

Capital assets include tangible assets which include property, plant and equipment provided they are held for use in the production or supply of goods and services. A capital expenditure must provide a benefit lasting beyond one year. Intangible assets are also considered capital assets and are identified as assets that lack physical substance.

Repair

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

Capitalization by Components

When parts or components of an item of PP&E have different useful lives, they are accounted for as individual items (major components). Component costs must be significant in relation to the total cost of the item and depreciated separately over the specific component's useful life.

Components with similar useful lives and depreciation methods are grouped in determining the depreciation charge. Parts of the item that are not individually significant (i.e., the remainder of the item) are combined and categorized as a single component best suited for the sum of the parts.

Capitalization Threshold

Theoretically, any expenditure that meets the asset cost and asset recognition criteria would be recorded as a capital asset. However, for practical reasons, a qualifying cost would be capitalized only if the item cost is greater than $1,500.

Spare Transformers

Spare transformers are accounted for as capital assets since they form an integral part of the reliability program for a distribution system. They are not intended for resale and cannot be classified as inventory in accordance with IAS 2, *Inventories*. Transformers are depreciated once they are put into service.

Amortization

IAS 16 requires each part of an item of PP&E with a cost that is significant in relation to the total cost of the item to be depreciated separately. In addition, IAS 16 requires entities perform a review of assets' useful lives, depreciation methods and residual values on an annual basis. SNC reviewed the useful life of its assets with the aid of the Asset Depreciation Study by Kinectrics (Kinectrics Report). This can be seen in Board Appendices 2-BB of Appendix 2-D of this Exhibit.

Capital Contribution Policy

SNC receives capital contributions in compliance with the provisions in the Distribution System Code and SNC's Conditions of Service. Under IFRS, capital contributions are recorded as deferred revenue and amortized into income over the useful life of the asset to which it relates. The Board Report states:

"IFRS requires customer contributions to be recorded as revenue or as deferred revenue (depending on the circumstances) instead of as an offset to capital cost. For regulatory reporting and rate-making purposes, the amount of customer contributions will be treated as deferred revenue to be included as an offset to rate base and amortized over the life of the facility to which it relates. This reclassification is necessary to preserve continuity of the rate base."

Consistent with the Board Report, SNC has continued to include forecast 2023 and 2024 capital contributions as an offset to rate base in Account 2440.

Asset Retirement Policy

IAS 16 requires that the carrying amount of an item of PP&E shall be derecognized on disposal, or when no future economic benefits are expected from its use. The gain or losses arising from derecognition of an item of PP&E shall be included in profit or loss when the item is derecognized.

Asset Retirement Obligation

As a result of adopting IFRS, SNC has determined that a constructive obligation exists with respect to the plan for the decommissioning of its substations. The constructive obligation relating to the unamortized costs of stations scheduled for dismantling has been calculated based on estimated decommissioning costs and expected dates of decommissioning.

SNC continues to carry a constructive obligation related to the decommissioning of SNC's sub-stations. The accrued liability was added to the cost of the sub-station assets and is being amortized over the life of the associated assets ($25,175 annually). This asset has been excluded from Rate Base for purposes of calculating Rate of Return.

2.9.2 CAPITALIZATION OF OVERHEAD

Standard IAS 16 – PP&E states that cost of an item of PP&E includes:

- The purchase price.
- Any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management.
- The initial estimate of the costs of dismantling and removing the item and restoring the site on which it is located.

IAS 16 does not define the term "directly attributable". The specific facts and circumstances surrounding the nature of the costs and the activity associated with it must be considered to determine if it is directly attributable to an item of PP&E. SNC reviews the charges in each of its "Overhead/Burden" departments to determine which costs would be directly attributable and therefore eligible to be capitalized. As a result, overhead rates expensed in operating and maintenance accounts are higher than those allocated to Capital.

All overhead charges are reviewed regularly. Any residual balances remaining after regular distribution are cleared to the applicable capital, operating or maintenance accounts depending on the actual occurrence of the cost allocation relationships. SNC has completed Table 2-31, which provides a summary of OM&A before capitalization and a breakdown of capitalized OM&A, this table is consistent with the Board's Appendix 2-D

Table 2-31 below provides a summary of capitalized OM&A charges before capitalization for the historical years, 2017 through 2022 as well as the 2023 Bridge Year and 2024 Test Year. Over the 7 year period from 2017 to 2024, SNC has capitalized (and expects to capitalize) about $30.95 million or 17.36% of its OM&A costs. In the 2024 Test Year, SNC anticipates that 18.17% of OM&A costs will be capitalized, which is slightly higher than the 7-year average.

The 18.17% of OM&A costs forecast to be capitalized in the 2024 test year represents a 2.93% increase as compared to the 2017 historical year. Similarly, the OM&A costs forecast to be capitalized in the 2024 Test year are slightly higher when compared with the 2023 Bridge year. Overhead Department costs fluctuate annually depending on new or changing projects in overhead departments, inflation, and the fluctuation of the Canadian dollar etc. As a result, amounts eligible for capitalization can fluctuate.

TABLE 2-31: OVERHEAD EXPENSES (APPENDIX 2-D)

	Last Rebasing Year (2017 Board-Approved Proxy)	Last Rebasing Year (2017 Actuals)	2018 Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Actuals	2023 Bridge Year	2024 Test Year	Directly Attributable (Yes/No)	Explanation for Change in Overhead Capitalized
Total OM&A Before Capitalization (B)	**$ 17,307,644**	**$ 21,158,871**	**$ 21,219,193**	**$ 20,939,085**	**$ 20,066,758**	**$ 20,132,198**	**$ 23,831,021**	**$ 24,796,483**	**$ 26,191,523**		
Benefits	$172,988	$124,611	$73,142	$146,492	$105,025	$144,907	$115,101	$144,598	$159,394	Yes	Directly attributable to total labour costs
Downtime	$592,014	$572,167	$533,493	$547,522	$539,755	$419,753	$475,163	$613,294	$614,042	Yes	Directly attributable to total labour costs
Material	$100,910	$107,361	$152,339	$118,644	$117,729	$136,090	$111,344	$126,051	$140,723	Yes	Directly attributable to material costs
Supervisory	$596,441	$534,999	$496,608	$714,598	$663,197	$617,035	$722,714	$759,841	$820,701	Yes	Directly attributable to total labour and subcontractor costs charged to capital
Engineering	$1,062,413	$1,016,451	$973,642	$1,206,768	$1,222,532	$1,420,533	$1,312,084	$1,375,490	$1,487,523	Yes	Directly attributable to total labour and subcontractor costs charged to capital
Trucking	$762,197	$855,564	$1,120,230	$1,062,917	$1,002,169	$1,107,421	$1,170,104	$1,415,761	$1,536,910	Yes	Directly attributable to total fleet costs
Total Capitalized OM&A (A)	**3,286,963**	**3,211,153**	**3,349,454**	**3,796,941**	**3,650,407**	**3,845,739**	**3,906,510**	**4,435,035**	**4,759,293**		
% of Capitalized OM&A (=A/B)	18.99%	15.18%	15.79%	18.13%	18.19%	19.10%	16.39%	17.89%	18.17%		

2.9.3 BURDEN RATES

SNC uses the following "Overhead/Burden" Accounts:

Corporate Benefit Burden

This account accumulates the costs of fringe benefits associated with labour such as dental benefits, medical benefits, long-term disability, vested sick leave, future employee benefit costs and the Employee Assistance Program. These costs are distributed to an employee's Division/Department as a percentage of their wages as they are paid during the year.

Indirect Labour Burden

This account accumulates the related payroll costs for the powerline technician group ("PLT") associated with vacations, statutory holidays, sick leave, other leaves of absence, employee training, safety programs and any other unproductive labour time. These costs are allocated to operating, maintenance or capital expenditures as a % based on powerline technician work order labour costs.

Safety, training, and education expenses are indirect expenses and cannot be capitalized under MIFRS. These expenses include the following:

- In-house training

- Miscellaneous courses and workshops
- Safety consulting
- EUSA
- Safety meetings and training

Material Burden

This account accumulates the related costs associated with the Stores Department. These costs include payroll costs of employees directly related with stores operation cost, as well as property and miscellaneous department charges. These costs are allocated as a percentage of materials issued through stores.

Only the direct labour and benefits of the stores department are considered as directly attributable and therefore eligible for capitalization. The Stores Manager as well as other vehicle charges, information technology and property expenses were considered as general and administrative expenses.

Supervisory Burden

This account accumulates the related payroll and operation costs related to the powerline technician Supervisor group. These costs are allocated to operating, maintenance or capital expenditures as a % based on PLT work order labour costs.

Only labour and benefits associated with the PLT supervisors who provide direct supervision of the PLT staff which are directly attributable to capital were considered as eligible for capitalization. Costs associated with the superintendent, clerks and miscellaneous department expenses were considered as general and administrative expenses.

Engineering Burden

This account accumulates the costs associated with the costs of engineering operations, including engineering staff and their support staff payroll costs, facilities, equipment, and supplies. When working directly on a capital project, engineering staff will time sheet directly to the capital work order. Any remaining engineering department costs are allocated to operating, maintenance or capital expenditures as a % based on powerline technician work order labour costs.

Engineering staff includes the Engineering Manager, a part time Engineering Clerk, Technicians, and Drafting and Design services. It was determined that only the staff costs associated with the technician, drafting and design services were directly attributable to capital projects. Further, miscellaneous charges such as IT expenses, property charges and other miscellaneous department expenses were not considered as directly attributable to capital and therefore are not burdened to capital projects.

Rolling Stock Burden

This account accumulates the costs associated with maintaining trucks, equipment, and trailers etc. These costs include payroll costs related to the mechanics and common rolling stock operation costs such as fuel, lubricants, repairs, parts, insurance as well as office and computer costs directly related to the rolling stock operations. The total cost of operating all vehicles is charged to specific jobs, based on an hourly rate for the time each vehicle is on a job. Timesheets are completed for each truck and therefore the costs are directly attributable to specific jobs.

Only departmental expenses such as depreciation on rolling stock, fuel, and other operating expenses directly attributable to maintaining and operating the rolling stock are considered directly attributable to capital. Wages and benefits of the mechanics and other miscellaneous and property expenses were considered general or administrative under IFRS and therefore are not eligible for capitalization.

2.10 COSTS OF ELIGIBLE INVESTMENTS FOR THE CONNECTION OF QUALIFYING GENERATION FACILITIES

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

EXHIBIT 2

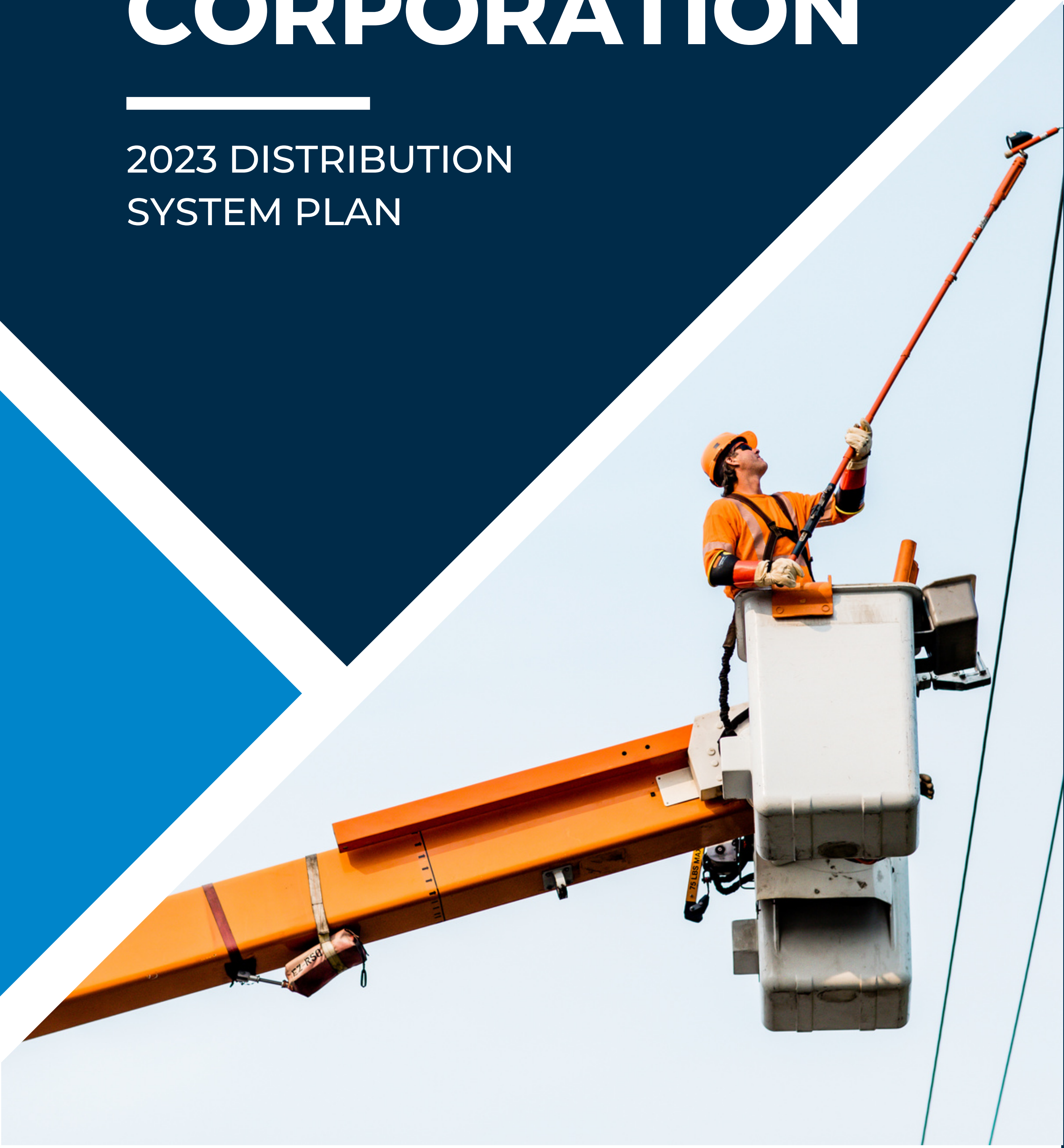
ATTACHMENT 2 - A

SNC 2023 DSP

SYNERGY NORTH CORPORATION

SYNERGY NORTH CORPORATION

2023 DISTRIBUTION SYSTEM PLAN



SYNERGY NORTH Corporation
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Filed: August 16, 2023

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5.2 Distribution System Plan

Synergy North Corporation (SNC) has prepared this Distribution System Plan (DSP) in accordance with the Ontario Energy Board's (OEB) *Chapter 5 Consolidated Distribution System Plan Filing Requirements* dated 15 December 2022 (the Filing Requirements) as part of its 2024 Cost of Service Application (the Application).

Objectives and Scope of Work

The SNC DSP is a stand-alone document and is filed in support of SNC's application. This Distribution System Plan ("DSP") represents the first consolidated capital planning submission of Synergy North Corporation. ("SNC" or "the utility") – the product of a 2018 merger of Thunder Bay Hydro Electric Distribution Inc ("TBHEDI") and Kenora Hydro Electric Corporation Ltd. ("KHECL' or "Kenora") approved by the Ontario Energy Board ("OEB" or "Regulator") on November 15th, 2018.

SNC's DSP describes and demonstrates SNC's Asset Management (AM) processes and capital expenditure plan for 2024-2028. The DSP documents the policies and processes that are in place to ensure that investment decisions support SNC's outcomes balancing cost, risk, and performance to the benefit of our customers.

SNC's DSP has been prepared in support of the four key OEB established Renewed Regulatory Framework (RRF) performance outcomes, namely:

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

Outline of Report

This DSP is organized using the same headings as the Filing Requirements, with the corresponding section number from the Filing Requirements for each heading. It identifies material initiatives and programs to be undertaken during the filed planning period. The DSP spans 12 years, with the historical period covering 2017-2023 (2023 being the Bridge Year) and the forecast period 2024-2028 (2024 being the Test Year).

The report contains three (3) sections including:

- Section 5.2 provides an overview of the DSP, including coordinated planning with Third Parties, and performance measurement for continuous improvement.
- Section 5.3 provides an overview of SNC's AM practices, including asset lifecycle optimization, and capacity for renewable energy generation (REG).

- Section 5.4 provides a summary SNC's capital expenditure plan, including an overview of the capital expenditure planning process, and justification of material projects (above the materiality threshold of $178,000).

In some cases, historical data have been presented for the former Thunder Bay Hydro Electricity Distribution Inc. (TBHEDI), and former Kenora Hydro Electric Corporation Ltd. (KHECL) and consolidated as if the entities were combined since 2017.

5.2.1 Distribution System Plan Overview

5.2.1.1 Description of the Utility Company

5.2.1.1.1 Service territory and corporate structure

SNC is a local distribution company (LDC) in northwestern Ontario, serving approximately 50,000 residential and 6,000 commercial customers located in Thunder Bay and Kenora.

Effective January 1, 2019, the former TBHEDI and KHECL merged[1] pursuant to the provisions of the Ontario Business Corporations Act, to continue to operate as a single entity under the name Synergy North Corporation.

SNC is a jointly owned subsidiary of the Thunder Bay Hydro Corporation (TBHC); which is a wholly owned subsidiary of the Corporation of the City of Thunder Bay, and the Corporation of the City of Kenora. TBHC also wholly owns Thunder Bay Hydro Utility Services Inc. (TBHUSI) and Thunder Bay Hydro Renewable Power Inc. (TBHRPI).

TBHUSI provides back-office systems and support, IT hosted applications; underground locate services and program management that includes conservation programs to other electric utility companies in the district. TBHUSI is also registered with IESO as a Metering Service Provider (MSP) to several large industrial customers in the region. MSPs are the only organizations authorized to undertake the registration of metering installations for operation in the wholesale electricity market.

TBHRPI's strategy is to develop renewal energy generation projects in the Thunder Bay area. The company owns, operates, and manages the Mapleward Generating Station.

The corporate structure in Figure 5.2-1 depicts these relationships.

SNC is responsible for the distribution of electricity in the City of Thunder Bay and the City of Kenora as depicted in Figure 5.2-2 and Figure 5.2-3. These service areas are non-continuous and are approximately 489 km apart. Both service territories are bounded by Hydro One Networks Inc. (HONI).

In Thunder Bay, SNC receives power from three HONI owned transformer stations at 25kV. Here, SNC owns, operates, and maintains approximately 910km of overhead primary distribution circuits, 265km of underground primary distribution circuits, four (4) 12kV distribution

[1] OEB Mergers, Acquisitions, Amalgamations and Divestures (MAADs) – application EB-2018-0124

stations and seven (7) 4kV distribution stations. This includes: twenty-three (23) 25kV feeders; six (6) 12kV feeders; and twenty-three (23) 4kV feeders.

In Kenora, electricity is transmitted through the HONI high voltage network to SNC's Kenora transmission station at 115kV. Here, SNC owns, operates, and maintains approximately 90km of overhead primary distribution, 15km of underground primary distribution circuits, one (1) transmission station and six (6) 12kV feeders.

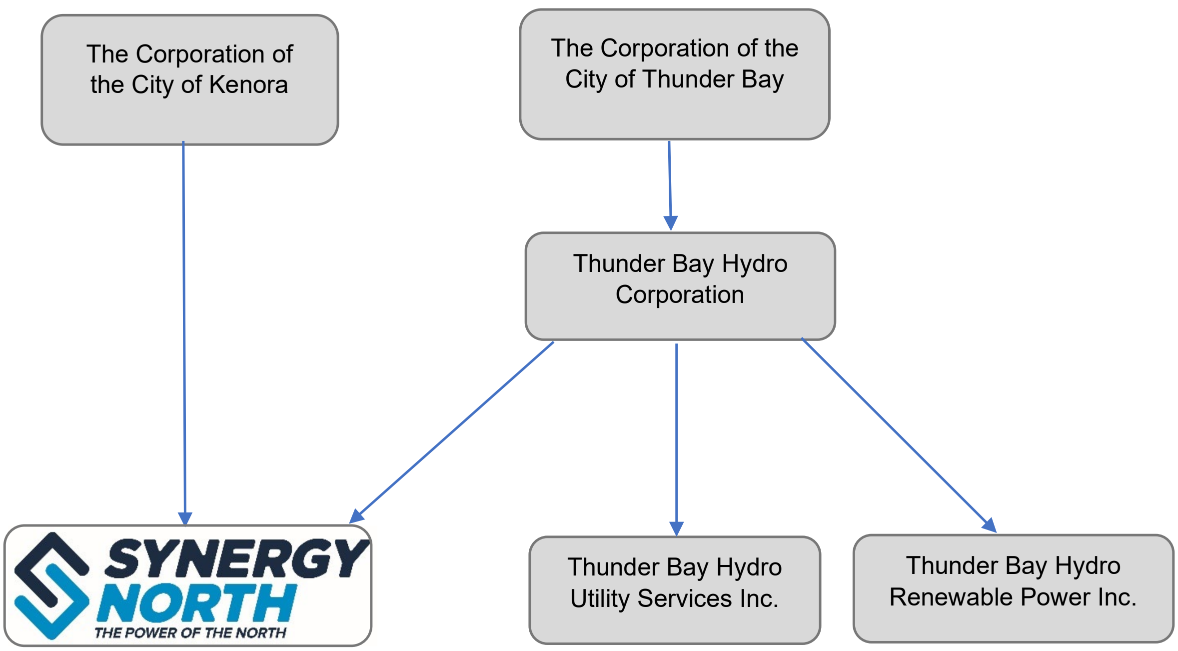
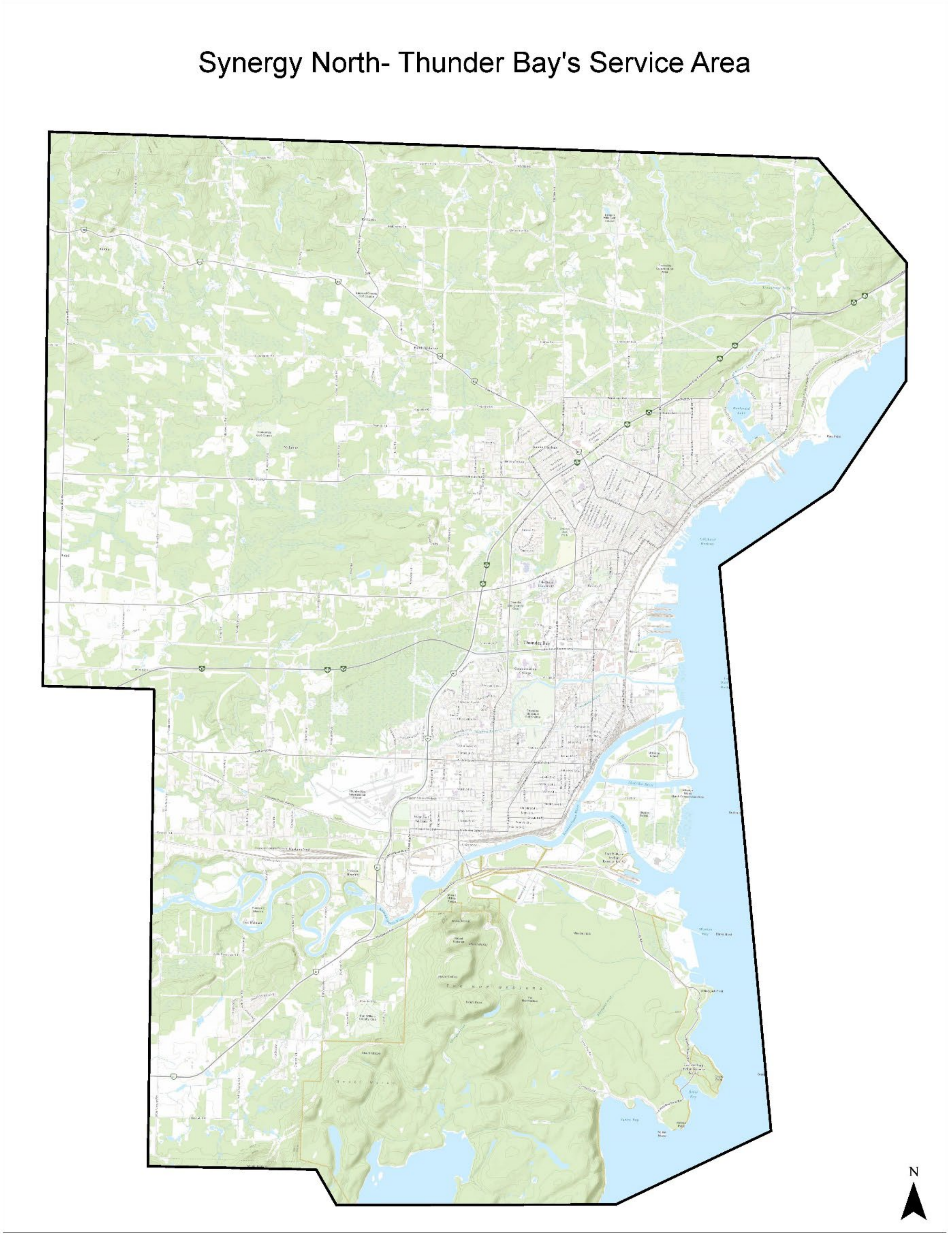


Figure 5.2-1: Corporate Structure



1 *Figure 5.2-2 Thunder Bay Service Territory*

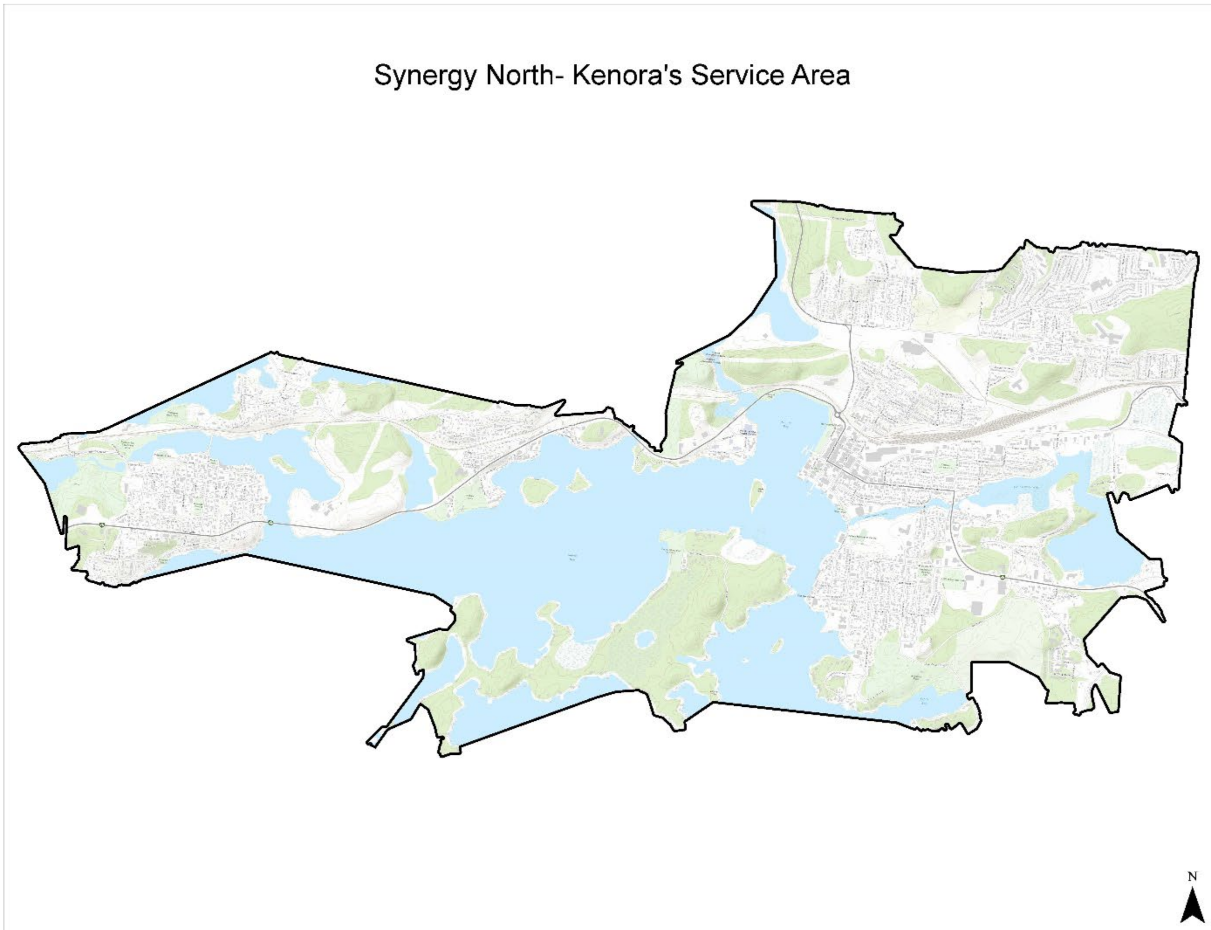


Figure 5.2-3: Kenora Service Territory

5.2.1.1.2 Mission, Vison, Values and Goals

SNC's Board of Directors has approved the following vision, mission, and core values.

Our Mission

The mission of Synergy North is to provide outstanding energy services in a safe, reliable, and trusted manner to our communities in order to power people's lives.

Our Vision

Your trusted partner for energy and related services.

Our Values

Excellence Pursue being better in everything that we do.	Safety Promote, work, and live safely.
Reliable Supply our products and services in a trustworthy, fair, and dependable manner.	Community Lead by example to build a stronger community

Strategy

To create the best direction forward for SYNERGY NORTH's future, the strategic plan is centered around strategic goals that we look to accomplish over the next five years. As we move forward, we remain focused on reaching these goals and delivering on priorities over the next three to five years. The goals that form this strategy dovetail with the OEB's performance outcomes in the renewed regulatory framework for electricity (RRFE). What follows are SNC's strategic goals, categorized by the appropriate performance outcome.

<u>RRFE Performance Outcome: Public Policy Responsiveness</u>

> SNC Strategic Goal: Promote, work and live safety achieving positive health and safety outcomes for employees and the public.

The potential danger associated with the product we work with everyday cannot be overstated. It is critical that the utility's primary focus remain on the safety of our staff and the public and deliver on the obligations mandated by the government.

<u>RRFE Performance Outcome: Financial Performance</u>

> SNC Strategic Goal: Pursue being better in everything we do resulting in increased shareholder and customer value.

SYNERGY NORTH Corporation is a valuable asset, owned by the City of Thunder Bay and the City of Kenora. The owners have the right to expect that the value of this asset will increase. The Board and Management of the utility must make this growth a priority and ensure that the utility remain financially viable.

<u>RRFE Performance Outcome: Operational Effectiveness</u>

SNC Strategic Goal: Supply electricity and related services in a trustworthy, fair and dependable manner supporting our customers in achieving their goals.

The provision of electricity to the residents and businesses in Thunder Bay, Kenora and the Fort William First Nation is our reason for existence and is critical to the economy and the quality of life of residents throughout our service territories. SNC must focus on delivering quality services and reliable electricity to its customers.

RRFE Performance Outcome: Customer Focus

SNC Strategic Goal: Lead where we live and operate as an integral part of the community.

Notwithstanding that SYNERGY NORTH Corporation is a business, we strive to be part of the fabric of the communities we serve, supporting local events, assisting with local initiatives and being present where needed and called upon and providing services in response to customer preferences.

SNC has implemented an integrated approach to planning and investing in its distribution system. All material investments are planned and optimized together. These investments typically include the following:

- Customer driven connections.
- Regulatory requirements.
- System renewal and expansion.
- Renewable generation connections.
- General plant investments.
- Grid modernization assets.
- Regionally planned infrastructure.

For system renewal and expansion projects, each project area is reviewed for wires and non-wires solutions, and innovative technologies that can be incorporated to best serve the long-term needs of our customers.

In the case of this DSP, SNC has planned these investments over a five-year term. This allows SNC to allocate both labour and material resources in a cost-effective and efficient manner to achieve its corporate goals and the evolving needs of its customers; ultimately managing the impacts of these investments on customer rates.

5.2.1.2 Capital Investment Overview

As part of this DSP and in accordance with the Filing Requirements, SNC projects and programs are grouped into the following four investment categories. Representative projects and programs that are applicable to SNC are categorized based on the trigger driver for that particular investment.

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

System Renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of SNC's distribution system to provide customers with electricity services.

System Service investments are modifications to SNC's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements.

General Plant investments are modifications, replacements, or additions to SNC's assets that are not part of its 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.

Table 5.2-1 Historical Actual and Forecast CAPEX and OM&A ($,000)

Category	Historical Period						Bridge Year	Forecast Period				
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System Acces (Gross)	1,942	1,688	4,370	3,299	3,383	4,066	1,985	2,092	4,323	2,796	2,455	2,329
System Renewal (Gross)	8,748	9,403	8,636	8,674	10,205	11,451	11,985	12,714	12,383	12,068	12,151	12,691
System Service (Gross)	151	289	432	87	242	142	277	323	330	336	343	350
General Plant (Gross)	929	1,093	1,073	863	1,273	1,529	1,174	1,282	1,480	1,473	1,617	1,701
Gross Capital Expenditure	11,770	12,473	14,510	12,924	15,104	17,188	15,420	16,411	18,516	16,674	16,566	17,071
Contributed Capital	(1,017)	(1,243)	(2,517)	(2,923)	(2,742)	(3,415)	(1,422)	(1,534)	(3,437)	(1,865)	(1,596)	(1,628)
Net Capital Expenses after Contributions	10,754	11,230	11,993	10,001	12,362	13,772	13,999	14,877	15,079	14,809	14,969	15,442
System O&M	8,785	9,155	8,881	8,317	8,387	11,359	11,253	11,779	12,014	12,255	12,500	12,750

5.2.1.2.1 System Access

SNC will continue to provide access to its system for both residential and commercial; new and upgraded services. SNC does not expect significant electrification of transportation or fuel switching will factor into the next 5-year term. It does expect to see a few early adopters, which will not affect the number of connections that SNC typically experiences (see Appendix B). SNC participates actively in the IESO led Integrated Regional Resource Planning activities and calculated that the forecasted load growth is approximately 0.5% in Thunder Bay, and 1.25% in Kenora. In addition, Synergy North has incorporated feedback from third parties regarding the potential relocations of SNC plant due to road construction. This amount of system access activity will result in a baseline decrease of planned expenditure, which is a decrease from those found during the previous DSP period. The exception to this is in 2025 where an increase in activity is evident. This is further detailed in section 5.2.2.4.

5.2.1.2.2 System Renewal

Infrastructure operating at 4kV is a part of the legacy system first installed in Thunder Bay over 50 years ago. The conversion program began in Thunder Bay in 2007 and has been an ongoing focus for the utility since that time.

The 4kV Conversion program represents the most significant program in the system renewal category (See Appendix H for current program justifications). It has accounted for approximately 49% of asset replacements in the historical period from 2017-2022 (by dollar value, see Figure 5.2-4).

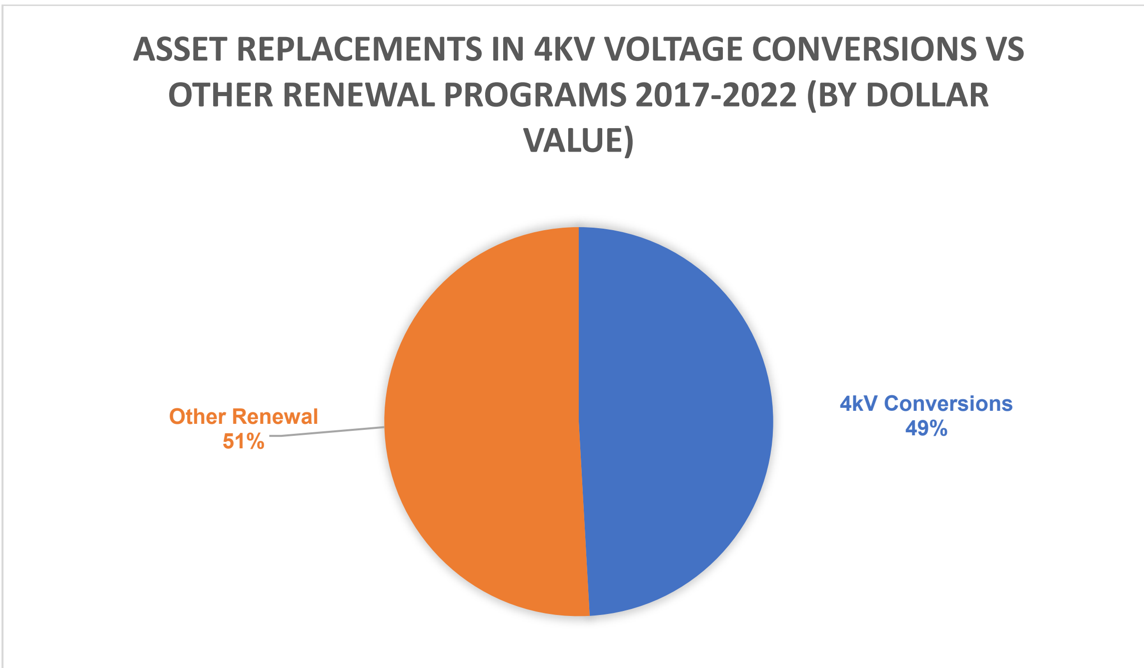


Figure 5.2-4 2017-2022 Asset Replacements in 4kV Conversion Program vs Other Renewal

The practice of upgrading to a higher operating voltage and decommissioning substations has several known benefits such as decreased Operating and Maintenance (O&M) spending costs for substations and reduced system losses, as well, a reduction in inventory due to multiple operating voltages. There is also significant deferral of capital expenses by replacing and converting this end-of-life infrastructure as the substation assets associated with these areas can be decommissioned as opposed to replaced. The following was filed with TBHEDI's rate application in 2013[2]:

Distribution Station Component	*Estimated Cost*
4MVA, 24.94kV/4.16kV, Oil Immersed Power Transformer (Qty 2)	*$250,000*
4kV, 1200A Breaker Lineup (8 Breakers/Substation Average)	*$310,000*
DC Supply Components	*$20,000*

[2] *2013 Cost of Service Application*, EB-2012-0167 – Thunder Bay Hydro Electricity Distribution Inc.

Power and Instrument Transformers	*$28,000*
Protective Relays	*$17,000*
Ground & Test Device	*$55,000*
Power Quality Meters	*$25,000*
Current Transformers	*$20,000*
Infrared Viewing Ports	*$25,000*
Auxiliary Substation Components	*$15,000*
Civil Work	*$200,000*
Engineering and Design	*$100,000*
Labour, Trucking, and Additional Materials	*$225,000*
Total:	*$1,270,000*

Assuming a major substation rebuild takes place annually every year from 2013-2027, the net present cost to TBHEDI represented by these replacements (at a 2% CPI[3]) is $15.4M.

Current estimates received from vendors indicate that the 2023 replacement costs for the first two line items are as follows:

Distribution Station Component	***Estimated Cost***
4MVA, 24.94kV/4.16kV, Oil Immersed Power Transformer (Qty 2)	*$1,648,000*
4kV, 1200A Breaker Lineup (8 Breakers/Substation Average)	*$3,500,000*

These costs are between five and nine times higher than the expected inflated values over this period. Using these estimated costs, without the remaining line items, SNC estimates a net present cost of $33M (at a 2% CPI) to rebuild the seven remaining 4kV substations during this filing period.

This calculation was performed to reaffirm the original financial justification for continuing to convert the 4kV network and decommission the substations. The expenditures proposed as part of this DSP will align the completion timeline of the 4kV substation decommissioning schedule with that previously proposed in the 2013 application.

Additionally, the customers in the 4kV areas benefit from the removal of legacy equipment which is bought to current standards which improves the resilience of the entire grid.

Over the five-year forecast period SNC plans to invest in removing the remainder of the installed 4kV infrastructure, including wood poles, transformers, cables, substation breakers and substation transformers. The forecasted expenditure for this program is approximately $27M.

The Overhead Renewal program includes planned expenditures of $13M over the forecast period. This includes planned renewal efforts on overhead systems (poles, transformers, switches, etc.) that fall outside the 4kV conversion projects.

[3] CPI: Consumer Pricing Index

The Underground Renewal program includes the planned expenditure of approximately $8M. The program encompasses the replacement and rejuvenation of direct buried cables throughout SNC service territory. The program is currently focused on subdivisions that went into service in the 1970's and is based on the inspection and non-destructive testing[4] of those cables. SNC piloted a cable rejuvenation program in 2021 and is investigating the merits of the technology with regards to cost effectiveness and reduced carbon emissions (i.e., reduction in materials, labour, and equipment to return the cable to "as-new" condition should result in decreased environmental impact). Additional information on the potential cost savings can be found in Appendix H.

Additionally, based on condition (as determined through field assessment and testing) SNC plans to test[5] and inspect approximately 6000 poles and, as a result, replace about 150 poles during this period. This represents approximately 1% of the 22,000-pole population, and typically addresses all the poles found to be in very poor condition annually.

5.2.1.2.3 System Service

In the 2016 Grid Modernization plan, SNC included the costs of implementing a fully functional Outage Management System (OMS) and strategically placed reclosers to ensure the system's operability and reliability. SNC plans to continue reviewing the reliability and implementing intelligent devices in the field to work towards a "smart autonomous grid." Additional investments in smart sensors are forecasted in the five years to allow Synergy North to monitor, enable and potentially control loads associated with enhanced electrification and distributed energy resources.

SNC recognizes the need for more DER's to actively participate in energy markets and to provide non-wires alternatives to LDC's. The IESO has also indicated in its Market Vision and Design Project that the enablement of DER participation is to be established in the wholesale market by 2026. In order to progress to providing customer-choice and offering an optimal network SNC is supportive of the Total Distribution System Operator model. As such SNC has planned for SCADA investments to facilitate these services. Refer to Appendix D – FINO Strategy for further information.

Through the IRRP completed with IESO, SNC has identified a system constraint at its Kenora Municipal Transformer Station (KMTS) which will be reached in 2030. SNC will be further exploring both wires and non-wires options for this constraint in coordination with available IESO programming. There are planning activities scheduled in the 5-year term to assist SNC in developing the investment plan for this eventuality.

5.2.1.2.4 General Plant

SNC plans to replace some light-duty vehicles with hybrid and/or fully electric vehicles as they reach their end-of-life during this period with pricing and availability being top of mind. SNC

[4] In 2020, SNC began non-destructive testing of the insulation degradation of approximately 200 cables annually.
[5] In 2019, SNC began non-destructive testing of the remaining strength at the ground-line of approximately 1200 poles annually.

does not expect to replace any heavy-duty vehicles with electric due to the lack of available options, prior to 2028. SNC will continue to invest in infrastructure and monitoring activities to comply with cyber security standards, but we foresee these expenses leveling moving forward. For these reasons, SNC does not anticipate a significant increase in general plant investments over the forecast period. See Appendix E for further information regarding Fleet.

5.2.1.3 Key Changes since Last Filing

- Covid-19 Pandemic – the covid-19 pandemic has presented SNC with challenges that will likely persist over the DSP period 2024-2028. Significant increases in material and equipment costs, a strained labour market, and supply chain constraints may result in execution delays. To avoid significant impacts to our proposed DSP, SNC has taken deliberate steps to ensure these challenges are considered well in advance of the program execution. SNC will continue to take this into consideration in all its formal planning processes until such a time that it is no longer a material risk.
- Merger of TBHEDI and KHECL[6] - In 2019 Thunder Bay Hydro Electricity Distribution Inc. and Kenora Hydro Electricity Corporation Ltd. merged to form Synergy North Corporation. An important objective of which was the creation of opportunities for efficiencies through economies of scale, innovation, realizing competitive advantages throughout the service territories and the sharing of best practices across all facets of the business. The major portion of the efficiency gains have been experienced through the consolidation of administrative practices and economies of scale. This includes the consolidation of management, billing, customer service, finance, and regulatory functions. Refer to Section 1.9 of Exhibit 1 of the filing for further details.
- The energy transition is at the forefront of our discussions with customers and our planning processes. SNC is working diligently to incorporate the choices of customers to electrify transportation and heating sources. These decisions require a deeper understanding of the capacity and availability of wires and non-wires alternatives to service customers and are impacting our planning processes for infrastructure investment.
- Customer engagement processes – In 2021, Synergy North began the process of providing a platform for customers in each project area to meet with Synergy North representatives to understand the work, ask questions, and provide input.
- SNC has continued to utilize the Asset Condition Assessment models provided by Kinectrics from its 2016 DSP filing. However, SNC staff have updated the models from field collected data rather than obtaining consultant services during this rate filing.
- SNC has collaborated with METSCO to refine and establish its program prioritization process. This process is described in detail in the report provided in Appendix K.

5.2.1.4 DSP Objectives

This DSP is a stand-alone document that is filed in support of SNC's Application. The capital investment plan has been crafted around managing mandatory investments in support of

[6] OEB Decision and Order. EB-2018-0124 Thunder Bay Hydro Electricity Distribution Inc. April 12, 2018

customer connections and other regulatory requirements; renewing system infrastructure; controlling risks associated with system constraints and critical infrastructure; and meeting system requirements with regards to future demands. The DSP provides all interested stakeholders with the following information:

- A review of SNC's asset management objectives and goals;
- An overview of SNC's performance over the historical period;
- A forecast of SNC's planned expenditures for the five years starting 2024 and aimed at achieving the four performance outcomes established by the OEB's RRF; and
- Detailed justifications for material investments planned for SNC's Test Year (2024).

By employing a long-term, wholistic approach to planning SNC is better able to consider the future needs of its customers, and how those needs will impact our systems. This approach enhances SNC's ability to provide the level of service our customers expect, when they expect it, and in a manner that minimizes impacts to affordability. This DSP clearly establishes SNC's commitment to providing customers with safe, reliable power by ensuring its processes align with the outcomes established by the OEB's RRFE for electricity:

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

This DSP is designed to support key outcomes of SNC's corporate and asset management objectives. The capital investment plan has been crafted to manage mandatory investments in support of customer connections and other regulatory requirements; renew system infrastructure; control risks associated with system constraints and critical infrastructure; and meet system requirement with regards to future demands (e.g., DER and EV's).

5.2.2 Coordinated Planning with Third Parties

5.2.2.1 Customers

SNC recognizes the importance of coordinating infrastructure planning with its customers. This coordination and feedback provide valuable insight and allows SNC to generate sound financial investments that balance affordability for the ratepayers and the need to provide safe and reliable power. SNC has encouraged feedback from customers through several engagement opportunities. In all cases, SNC initiated the customer consultations using its own staff as well as consultants whose expertise lies in gathering public input. The participants included representatives from all SNC's customer classes.

Synergy North communicated the various proposals in our application to our customers and stakeholders in a variety of ways—both through significant discussion with our Local Advisory Council (LAC), and through additional tailored initiatives specially designed to solicit customer feedback regarding the proposals in this application.

Firstly, SNC hosted detailed information and an expansive investment planning survey on our centralized “Have Your Say” website (https://haveyoursay.synergynorth.ca/) as part of our annual survey touchpoint with customers. We encouraged all customers we contacted to visit the website to educate themselves on our plans and provide feedback. The website provided information about vegetation management, our capital programs, and more.

Figure 5.2-5 Have. Your. Say. SNC Customer Engagement

From June through October 2022, Synergy North hosted and promoted a "Have Your Say" survey on this website. This survey was user-friendly, easily accessible, clearly explained, and designed to be painless for customers to complete. We promoted this survey to our customers through multiple avenues, including a large banner on our website encouraging all our paying customers to "Help shape our future plans."

There were over 2,800 total visitors to the survey, with 925 complete responses submitted in total.

In addition, we sent direct personalized letters to our large commercial customers informing them of our DSP. We met with some of them specifically about their energy plans and how we can work together even better going forward.

SNC's Engineering department sent letters to the following customers (quantity shown in brackets) to understand their future investment plans.

- Class 'A' customers (11)
- Joint Use Attachers (6)
- Developers (7)
- City of Thunder Bay and
- City of Kenora

Through the mailing of letters and follow up emails to its contacts at these organizations, SNC received a request for 6 meetings and a response from an additional 7 customers providing information on scope and timelines regarding their upcoming capital plans. See Figure 5.2-6 for a sample feedback letter.

September 29, 2022

PRIVATE & CONFIDENTIAL

Via: email
[redacted]

Tbaytel
1050 Lithium Dr.
Thunder Bay, Ontario
P7B 6G3

Attention: Director - [redacted] Manager - [redacted]

RE: Capital Plans and Synergy North's Cost-of-Service Rate Application

We at Synergy North are preparing to file a Cost-of-Service application for electricity distribution rates for the upcoming 2024-2028 period. This application includes a Distribution System Plan which lays out the anticipated capital investments needed to accommodate any improvements and growth in the electrical distribution system.

For Synergy North to properly forecast our customer's needs we are formally requesting any information you may be able to share regarding your upcoming capital investment plans. This coordinated planning effort will ensure that Synergy North will be able to accommodate your business and/or investment needs.

Should we not receive any response from you; Synergy North will use historical data and averages from the last five-year period to predict the capital needs of your organization/ corporation.

If you are interested in setting up a meeting, please call [redacted] to arrange an in-person meeting or a Teams meeting with Karla Bailey, Vice President, Asset Management & Engineering. Otherwise, please return your plan(s) by November 30th, 2022, to Nicole Mihalus, Executive Assistant, Asset Management & Engineering - [redacted].

We are also interested in your thoughts on our upcoming investment plans through our online planning survey, the results of which will also be incorporated into our application. The survey can be accessed at haveyoursay.synergynorth.ca .

We look forward to hearing from you.

Sincerely,

Karla Bailey

Karla Bailey, P. Eng, MBA, Vice President Asset Management & Engineering
/nm

Figure 5.2-6 Sample Letter

SNC received email responses from Bell, Shaw, Tbaytel, Telus, Thunder Bay Regional Health Sciences Center, Richardson Terminals, Canada Malting.

In-Person and Virtual Meetings were held with: Confederation College, Lakehead University, Alstrom, City of Thunder Bay Engineering, City of Thunder Bay Facilities and Energy Management and City of Kenora Engineering departments. These meetings provided information on the direction that these customers were heading with respect to electrification, net zero and their future investment and energy demands.

Beyond our survey and personalized data collection efforts, our LAC, which represents the voice of SNC's customers, is paramount in keeping us connected with our community—not only when preparing this application, but on a regular ongoing basis. The proposals, decisions, and direction outlined in this application all stemmed from ongoing discussions with SNC and our LAC.

Many of our LAC meetings over the past few years have been centered around topics that helped to outline our proposals and define our ultimate Cost-of-Service decision making. Key topics covered in LAC meetings throughout 2018-2022 included the following:

- Past Distribution System Plan Evaluations
- Kenora Merger and Rebranding Efforts
- System Control and Outage Response
- Synergy North Public Safety Initiatives
- Past Customer Survey Results
- Business Relationship Coordination and Business Services Evaluation
- Planned Outages
- Capital Engagement
- Cost-of-Service and Customer Engagement Strategy
- Vegetation Management
- "Have Your Say" Survey Planning
- Environmental Social Governance

Following the aforementioned "Have Your Say" survey, the final customer feedback across all the responses was aggregated and used to verify whether most of Synergy North customers agreed or disagreed with our decisions.

SNC customers asked that we prioritize affordability and keep costs down. This understanding, as evidenced by the survey results, was a major factor in defining our application. SNC has responded to this specific consideration by considering the following in our plans to minimize costs and keep our services affordable for our customers:

- Customers in our first survey expressed that our cybersecurity spending is sufficient. With this in mind, SNC did not increase its cybersecurity forecast, choosing instead to proceed with steady state spending.
- Customers were agreeable to our vegetation management spending. Overall, customers chose an option which suggested we spend more on our vegetation program to ensure we are compliant with industry standards. Most customers chose to spend between $1.00 and $1.50 per bill at the speed described in the survey, as opposed to the other choices contained within the survey.

- Customers have consistently told us that they prefer a proactive approach to our capital program, renewing equipment prior to failure to avoid longer outage times.
- Finally, our customers have consistently told us that lower costs are their top priority. This is always the primary concern during the capital planning process, and a priority we understand and take very seriously.

The details of our planning and decision making are by necessity nuanced, however our DSP and capital programs do reflect these customer mandates. SNC has specifically deferred work in its underground renewal program whereby the increased risk of doing so will not jeopardize the near-term reliability of the system.

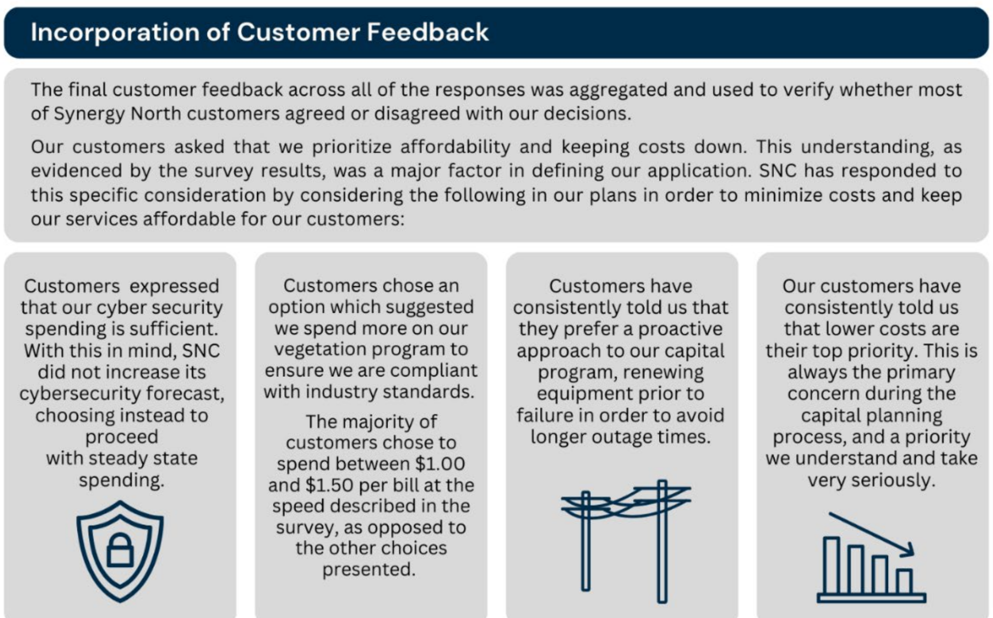


Figure 5.2-7 Incorporating Customer Feedback

SNC hosted a second phase of the investment planning survey and the results have also been incorporated in this DSP. Final results show that when asked, 92% of customers understand the need for SNC to continue replacing assets proactively rather than running them to failure. See Figure 5.2-9 below.

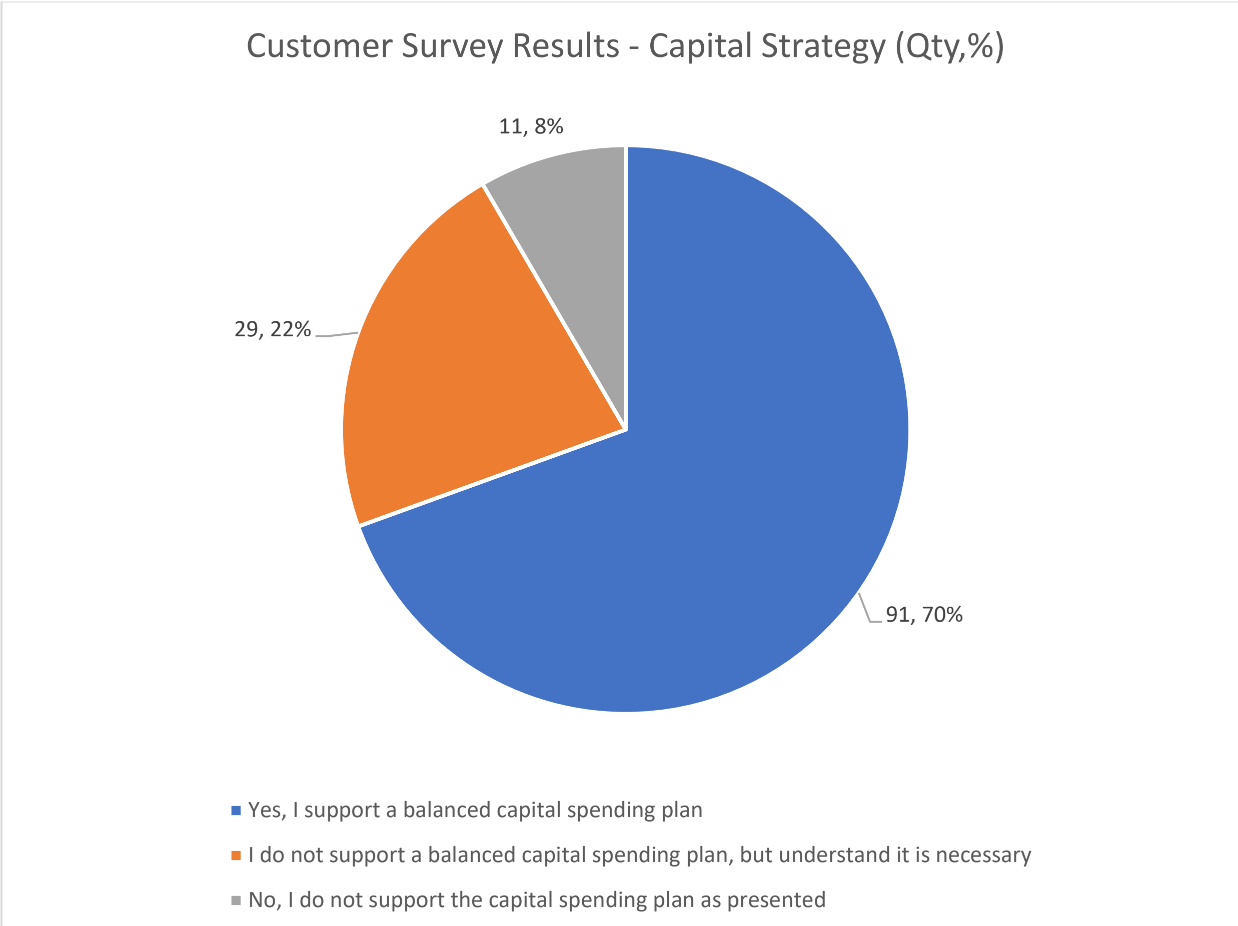


Figure 5.2-8 Customer Survey Results - Capital Strategy

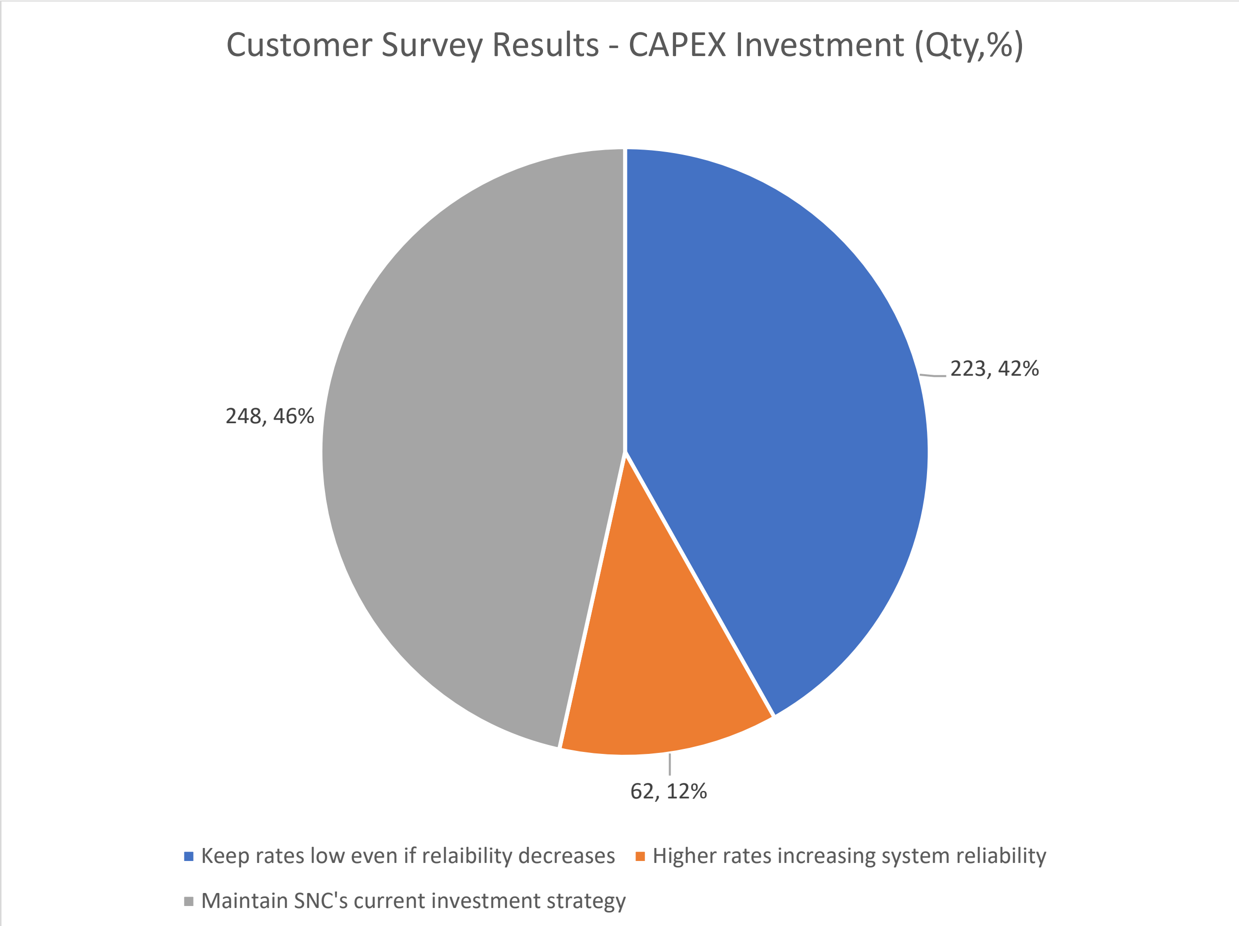


Figure 5.2-9 Customer Survey Results - CAPEX

5.2.2.2 Consultations with regional and Municipal Governments

SNC works closely with the Engineering, Planning and Administrative departments in both Thunder Bay and Kenora.

As a key stakeholder, SNC consults regularly with these departments to ensure it is informed and is provided the opportunity to comment on all major developments (subdivision, road widening, buried infrastructure renewal) during the draft plan and preliminary design stage. Typically, the city initiates the consultation through the opportunity to comment and review all severances and variances which result from the committee of adjustment process. All utility owners are allowed the same opportunity and the consultation results in a coordinated effort of planning. This process is ongoing, and the results of these consultations inform SNC's knowledge of development activity throughout its service territories. SNC's Engineering department attended separate virtual meetings with the City of Thunder Bay's Engineering department, the Facilities, Fleet & Energy Management departments to determine impacts on investments in the DSP. From these meetings, the impacts of fuel switching, transit electrification and road widening projects were incorporated into the DSP. The most significant impact on the capital plans was the forecasted construction of the Northwest arterial, which would require relocation of SNC's plant in several locations, the costs of which have been incorporated into the 2025 and 2026 capital investment budgets. In addition, SNC continues to work closely with the City of Thunder Bay regarding its plans to electrify transit and ensure that where charging is necessary, it can be accommodated.

To this end, Synergy North has partnered with the City of Thunder Bay, Lakehead University and BlueWave AI to develop an artificial intelligence (AI) data-driven simulation platform for the City of Thunder Bay to accelerate the adoption of an electric transit system that supports the city's road map towards meeting the local net-zero (NTZ) carbon goals. This project will also address the electric transit grid integration challenges with novel yet practical charging/ discharging infrastructure placement strategies to minimize peak demand, power loss, and voltage drop impact on the grid.

Consultations with regional departments such as the Ministry of Transportation (“MTO”) and Ministry of the Environment, Conservation and Parks (“MOECP”) have occurred on an as needed basis to address specific project related topics such as permitting requirement and specific details regarding certain projects. The party whose project plans impact the others (e.g., road widening requires movement of poles) initiates the consultation for the purpose of project discussions. The outcome of such specific project discussions include, for example, plans and direction for the project currently being constructed or a request for a concept design and estimate to relocate assets related to an upcoming project. As mentioned, the MTO is intending to proceed with construction of the Northwest arterial and these plans have been incorporated into this planning cycle.

SNC is a member of the local Public Utilities Coordinating Committee (PUCC) and Subdivision Development and Coordinating subcommittee that meet on a semi-annual basis. The meetings are initiated by the City of Thunder Bay and the committee is comprised of representatives from other local infrastructure owners such as telecommunications, gas, and the City of Thunder Bay. The purpose of the PUCC meetings is to coordinate planning and development to the extent possible and share information regarding future endeavors. The purpose of the subdivision sub-committee meetings is to discuss City approved plans and upcoming potential developments within the city. Generally, the outcome of these meetings provides SNC with direction on System Access projects relating to; road widening, line relocations and subdivision creation/expansion. These projects impact the DSP near-term budgeting process for SNC.

SNC has also consulted with the Fort William First Nations (FWFN) regarding subdivision development, line extensions and various other projects that may impact the near-term budgeting process. There are no active projects at the time of writing and thus there is no expected impact on the DSP.

SNC has a mature planning process relating to System Renewal efforts. This often results in a path for several other infrastructure owners to follow during their respective planning processes. These meetings aid in the effective delivery of services throughout the service territory and help prevent miscoordination and increased costs.

5.2.2.3 Regional Planning Process

SNC has been an active participant in the regional planning process (“RPP”). As members of the working group for the Northwest IRRP as well as members of the Local Advisory Committee, SNC developed a load forecast in collaboration with Elenchus for the City of Thunder Bay and City of Kenora. Refer to Exhibit 3 for further details, as well as the narratives and methodologies to support these forecasts.

In addition, SNC developed distribution system options, including non-wires alternatives to address capacity needs. SNC has consulted with stakeholders in its region in preparing this DSP, the Regional Infrastructure Plan (RIP) for the Northwest Region can be found in Appendix J. No inconsistencies have been identified between the DSP and the Regional Plan.

SNC is surrounded on all borders of its service territory by HONI and as such collaborates and shares information on a regular basis via the IRRP meetings established by the IESO, as well as annual HONI stakeholder meetings. While awaiting the IESO’s final report, SNC remains committed to the process and continues to collaborate with HONI where possible. SNC will also continue to participate and attend presentations at IESO municipal engagement events.

The Northwest region IRRP was released to the public January 2023, and was posted on the IESO website[7] and is available for review in Appendix B.

This plan provided recommendations to address the electricity needs of the Northwest region over the next 20 years (2021 to 2040). The Northwest region includes the area roughly bounded by Lake Superior to the south, the Marathon area to the east, and the Manitoba border to the west. It includes the districts of Kenora, Rainy River and Thunder Bay. Northwest regional electricity demand is peaking in winter and, over the last five years, has grown on average by 1.1% per year. Electricity supply to the Northwest region is provided through the 230 kV East-West Tie circuits from Wawa TS, as well as from interconnections with Manitoba and Minnesota. The region is predominantly supplied by hydroelectric and biomass-fueled generation.

The region’s electricity is delivered by five local distribution companies (LDCs): Hydro One Networks Inc., Atikokan Hydro Inc., Fort Frances Power Corporation, Sioux Lookout Hydro Inc., and Synergy North. Hydro One Networks is also the lead transmitter in the region for regional planning purposes. Note that three transmitters own assets in the Northwest region: Hydro One Networks, Nextbridge Infrastructure, and Wataynikaneyap Power. As the lead transmitter, Hydro One Networks coordinates the involvement of other transmitters as necessary. The IRRP report was prepared by the Independent Electricity System Operator (IESO) on behalf of a Working Group composed of the LDCs and Hydro One Networks.

Development of the Northwest IRRP was initiated in Jan 2021 following the publication of the Needs Assessment report in July 2020 by Hydro One and the Scoping Assessment Outcome Report in Jan 2021 by the IESO. The Scoping Assessment identified needs that should be

[7] https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Regional-Electricity-Planning-Northwest-Ontario

further assessed through an IRRP. The Working Group was then formed to gather data, identify near- to long-term needs in the region and develop the recommended actions included in this IRRP.

The outcome of the IRRP was that the infrastructure in the Northwest will be adequate to support forecast growth except for some station capacity and local operational needs. No new transmission projects have been recommended because of this Northwest planning initiative.

One of the near-term recommendations was that the Kenora MTS Station Capacity constraint investment be led by Synergy North and IESO by 2030. Non-wires alternatives (NWAs) can be cost effective depending on distribution system benefits; Kenora MTS will be a potential focus area for the IESO's Local Initiative Program and Synergy North will lead further non-wires analysis in local planning.

Kenora MTS is expected to reach capacity in 2030. There are no upstream supply constraints aside from the station capacity itself. The "wires" options range from installing an additional transformer at the existing station ($5M) to a new station across town ($30M) that would also incrementally improve reliability and provide distribution system benefits. The wires options and distribution benefits are further discussed in Section 7.1.4.1 of the IRRP. Based on the forecast hourly demand and associated energy-not-served profiles, three non-wires alternatives (NWAs) were identified including a 4 MW gas turbine facility, a 6-hour 4 MW battery, and a hybrid option of energy efficiency and demand response. The cost of these NWAs generally falls between the cost of expanding the existing station and a new station. Therefore, the decision to pursue NWAs versus traditional wires options rests on distribution system benefits that can be realized by each option. NWA options analysis is further discussed in Section 7.1.4.2 of the IRRP.

The technologies, regulatory framework, and protocols required to implement dispatchable NWAs to meet local capacity needs are still being tested. The IESO's York Region Non-Wires Alternative Demonstration Project is currently exploring market-based approaches to secure energy and capacity services from distributed energy resources (DERs) for local needs. There is a window of opportunity between today and 2030 when the Kenora MTS capacity need arises to leverage learnings from the York Pilot and further refine NWAs for Kenora MTS.

Therefore, the IRRP recommends that Synergy North lead further NWA analysis and refinement as part of local planning. Synergy North should monitor load growth at Kenora MTS to determine when a firm commitment for additional capacity is required and implement NWAs if they remain feasible and cost-effective. Furthermore, the IESO will consider Kenora MTS as a potential focus area for the Local Initiatives Program under the 2021-2024 Conservation and Demand Management Framework. The IESO will collaborate with Synergy North in 2023 as further details for the next round of the Local Initiatives Program becomes available.

Following the publication of the Northwest IRRP in January of 2023, Synergy North has continued to consult with Hydro One (Lead Transmitter in the region) on the Regional Infrastructure Planning (RIP). The final Regional Infrastructure Plan for the Northwest Region has been provided by Hydro One and is included in Appendix J. During the RIP process in early January, SNC and HONI adjusted the 10-day limited time rating (LTR) of the transformers in

Kenora due to the winter peaking nature of the load. This adjustment has subsequently pushed out the expected constraint on the assets at KMTS by one year from 2029 to 2030.

5.2.2.4 Telecommunication Entities

As previously mentioned SNC sought feedback from the telecommunication companies within its service territory, specifically Bell, Shaw, Tbaytel, and Telus, as these companies represent the major telecom companies within the region and work closely with SNC on a regular basis as part of our joint-use attachment program.

Generally, representatives from these companies attend semi-annual meetings hosted by the City of Thunder Bay where discussion regarding the timing and scope of capital programs is discussed. This allows for opportunities to coordinate work and gain efficiency between organizations.

Although SNC has formally engaged these entities to discuss plans and potential impacts on the DSP, informal discussion occurs routinely throughout the year.

SNC engaged these companies via mail in September of 2022. A sample of this engagement letter can be found in Figure 5.2-6.

The province has mandated improved broadband access which has incentivized many telecommunication companies to expand their infrastructure to allow these services to reach more customers. SNC has seen the impact of this already, as the local telecommunication company (Tbaytel) has installed new fibre infrastructure across the cities of Thunder Bay and Kenora to allow improved access.

The results of these consultations are such that 2 of the 4 telecommunication companies informed SNC they do not have any projects in SNC's service territory that will have a material effect on the DSP historical values and that using data and averages from the last 5-year period will be an accurate predictor of investments. In the last two cases, SNC has received proposed attachments from both Tbaytel and Bell. The cost for Tbaytel's 5-year plan for attachments, as well, Bell's proposed attachments as part of the AHSIP program have been incorporated into the system access investment for the 2024-2028 period.

SNC plans to continue to regularly communicate with the service providers over the forecast period and promote any opportunities for coordination.

5.2.3 Performance Measurement for Continuous Improvement

5.2.3.1 DSP

SNC is committed to meeting its performance targets through close monitoring of its performance indicators which align with the OEB's "Scorecard-Performance Measures" for electricity distributors as follows:

- Service quality,

- Customer satisfaction,
- Safety,
- System reliability,
- Asset management,
- Cost control,
- Connection of renewable generation, and
- Financial ratios.

The scorecard is designed to quickly show SNC's performance over time and benchmark its performance against other utilities. Several performance measures have an established minimum level of performance while others do not.

A summary of SNC's performance over the historical period is present in this DSP as part of SNC's continued effort to achieve the best performance for its customers. Each measure shown in Table 5.2-1 has influenced this DSP as part of SNC's ongoing commitment.

Table 5.2-2 2021 SNC OEB Scorecard Performance Measures[8]

Performance Outcome	Measure	Metric		2017	2018	2019	2020	2021	Target
Customer Focus	Service Quality	New Residential/Small Business Services Connected on Time		100.00%	99.00%	99.67%	98.74%	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		95.00%	95.00%	90.86%	87.51%	89.99%	65.00%
	Customer Satisfaction	First Contact Resolution		A+	A+	A+	A+	A+	N/A
		Billing Accuracy		100.00%	100.00%	99.92%	99.96%	99.93%	98.00%
		Customer Satisfaction Survey Results		A	A	A	A	A	N/A
Operation Effectiveness	Safety	Level of Public Awareness		83.00%	83.00%	83.00%	84.00%	84.00%	N/A
		Level of Compliance with Ontario Regulation 22/04		C	C	C	C	C	C
		Serious Electrical Incident Index	0	0	0	0	0	0	0
			0.000	0.00	0.000	0.000	0.000	0.000	0.000
	System Reliability	Avg. Number of Hours that Power to a Customer is Interrupted		1.85	2.12	1.41	0.75	1.28	1.77
		Avg. Number of Times that Power to a Customer is Interrupted		2.94	2.61	2.25	1.85	1.96	2.49
	AM	Distribution System Plan Implementation Progress		106.13	101.14	100.00	95.60	97.41	N/A
	Cost Control	Efficiency Assessment		3	3	3	3	3	N/A
		Total Cost per Customer		$652	$678	$675	$641	$651	N/A
		Total Cost per Km of Line		$29,252	$30,585	$30,199	$28,793	$29,384	N/A
Public Policy Responsiveness	Connection of REG	REG Connection Impact Assessments Completed on Time		-	-	100.00%	-	-	N/A
		New Micro-embedded Generation Facilities Connected on Time		100.00%	100.00%	100.00%	-	100.00%	90.00%
Financial Performance	Financial Ratios	Liquidity: Current Ratio (current assets/current liabilities)		1.82	1.70	1.81	2.03	1.73	N/A
		Leverage: Total Debt (short-term and long-term) to Equity Ratio		0.84	0.78	0.76	0.79	0.74	N/A
		Profitability: Regulatory Return on Equity - Deemed		8.84%	8.84%	8.85%	8.85%	8.85%	N/A
		Profitability: Regulatory Return on Equity - Achieved		3.01%	8.11%	9.71%	7.98%	7.82%	N/A

[8] https://www.oeb.ca/documents/scorecard/2021/Scorecard%20-%20Synergy%20North%20Corporation.pdf

From the table above it is evident that SNC has met or exceeded target performance expectations for every measure over the historical period. SNC is committed to continuing this trend by applying leading aspects of asset management planning and diligent management of its cost control measures.

5.2.3.2 Service Quality and Reliability

The following subsections detail SNC's service quality and reliability performance over the historical period 2017 through to 2022.

5.2.3.2.1 Service Quality

Table 5.2-3 summarizes SNC's performance as it relates to Service Quality Requirements (SQR). SNC monitors its service quality and reports on the same in accordance with Chapter 7 of the OEB's DSC.

Table 5.2-3 Historical Service Quality Metrics SNC

Metric	2017*	2018*	2019	2020	2021	2022	Target
Low Voltage Connections	100.00%	99.14%	99.67%	98.74%	100.00%	100.00%	>90%
High Voltage Connections	100.00%	100.00%	100.00%	94.44%	100.00%	100.00%	>90%
Telephone Accessibility	94.81%	94.79%	90.86%	87.51%	89.99%	90.53%	>65%
Appointments Met	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	>90%
Written Responses to Enquiries	100.00%	96.37%	98.62%	97.36%	96.52%	99.88%	>80%
Emergency Urban Response	93.33%	90.91%	100.00%	98.84%	100.00%	100.00%	>80%
Emergency Rural Response	96.00%	90.48%	100.00%	100.00%	100.00%	100.00%	>80%
Telephone Call Abandon Rate	0.24%	0.24%	0.42%	0.48%	0.19%	0.34%	<10%
Appointment Scheduling	96.16%	93.38%	99.21%	88.51%	94.51%	92.84%	>90%
Rescheduling Missed Appointments	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100%
Reconnection Performance Standard	100.00%	100.00%	100.00%	97.56%	100.00%	100.00%	>85%

*2017/2018 Data for TBHEDI

Table 5.2-4 Historical Service Quality Metrics KHECL

Metric	2017	2018	Target
Low Voltage Connections	100.00%	100.00%	>90%
High Voltage Connections	n/a	n/a	>90%
Telephone Accessibility	99.98%	97.00%	>65%
Appointments Met	99.48%	100.00%	>90%
Written Responses to Enquiries	100.00%	100.00%	>80%
Emergency Urban Response	100.00%	100.00%	>80%
Emergency Rural Response	n/a	n/a	>80%
Telephone Call Abandon Rate	0.02%	3.00%	<10%
Appointment Scheduling	99.72%	100.00%	>90%
Rescheduling Missed Appointments	100.00%	100.00%	100%
Reconnection Performance Standard	100.00%	100.00%	>85%

SNC works to provide its customers with excellent service as is evident from its historical performance. For each metric over the historical period, SNC was able to meet the targeted performance level, except for Appointments Scheduling in 2020 (highlighted in Table 5.2-3). This was due to Locates being provided in 5 days less than 90% of the time in 2020. SNC made a strategic decision to forgo providing in-person locates during the month of March/April of 2020 during the provincially mandated lockdown due to COVID-19. Service was restored mid-May, but the implication was that a landslide of locate requests submitted in May resulted in the utility being unable to manage to a 90% in 5-day service metric.

5.2.3.2.2 Reliability Performance

SNC's reliability of supply is measured using the internationally accepted indices of System Average Interruption Index (SAIDI) and System Average Frequency Index (SAIFI) as defined within the OEB's Electricity Reporting & Record-Keeping Requirements[9]. SAIDI represents the length of outage customers experience in the year on average, expressed as hours per customer as shown in Equation 1, and is calculated by dividing the total customer hours of sustained interruptions over a given year by the average number of customers served during that time. SAIFI represents the number of outages customers experience in the year on average, expressed as the number of interruptions per customer as shown in Equation 2. It is calculated by dividing the total number of sustained interruptions over a given year by the average number of customers served during that time. An interruption is considered sustained if it lasts for a minute or more.

[9] "Electricity Reporting and Record Keeping Requirements", Section 2.1.4.2, p. 9, Ontario Energy Board, March 31, 2020. URL: https://www.oeb.ca/sites/default/files/RRR-Electricity-20200331.pdf

$$SAIDI = \frac{Total\ customer\ hours\ of\ sustained\ interruptions}{Average\ number\ of\ customers\ served} \quad \text{Equation 1}$$

$$SAIFI = \frac{Total\ customer\ interruptions}{Average\ number\ of\ customers\ served} \quad \text{Equation 2}$$

To further meet the reporting requirements, SNC also considers the impacts of other defined parameters such as Loss of Supply (LOS) and Major Event Days (MED) to calculate adjusted values of the reliability indices. LOS is defined as an interruption that is caused due to a problem and/or failure of assets owned and/or operated by another party, and/or in the bulk electricity supply system. Similarly, MED is defined as an event that is beyond the control of the LDC and is unforeseeable, unpredictable, and unavoidable. MEDs are calculated using the IEEE[10] standard methodology.

5.2.3.2.3 Outage details

SNC's 2017 to 2022 reliability indices are shown in the following figures and found in Appendix 2-G. The figures demonstrate improvement for both SAIDI and SAIFI following the merger of TBHEDI and KHECL. Since merging, SNC has been able to meet its target annually and the investments proposed in DSP have been chosen to support this trend. On average, SNC customers experience two outages per annum and are without power for one hour.

Figure 5.2-10 and Figure 5.2-12 below illustrates a significant decrease in SAIDI and SAIFI for the years 2017 through to 2020 which is largely due to a decrease in adverse weather conditions. Customers did experience a modest increase in outage duration in 2021 and 2022 mainly driven by scheduled outages. The need to test and renew underground infrastructure in backyard easements and the degree of difficulty associated with executing these programs led to the rise in outage times. SNC expects similar levels of scheduled outages during this filing to account for ongoing underground programming. SNC understands the impact of disruptions on customers and carefully considers how to best execute its plans while minimizing outage times. Where work practices allow, SNC will avoid interruptions, however in some cases a disruption of service is unavoidable due to the nature of the work (e.g., live-front pad mount transformer replacements). In these cases, SNC provides customers with advanced noticed of the date and duration of the outage.

[10] IEEE STD 1366-2012 - Guide for Electric Power Distribution Reliability Indices

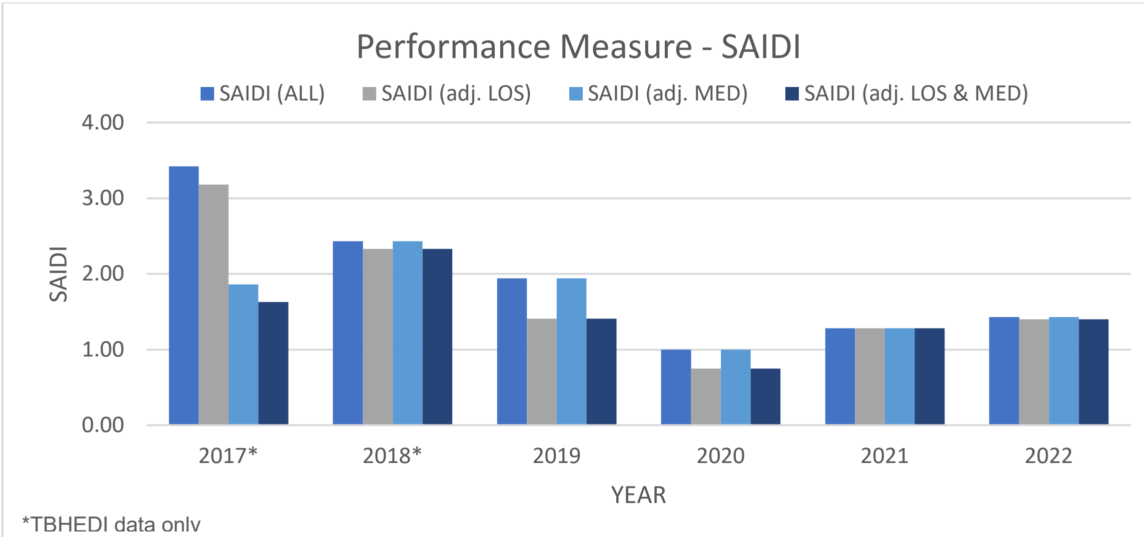


Figure 5.2-10 Historical Performance – SAIDI

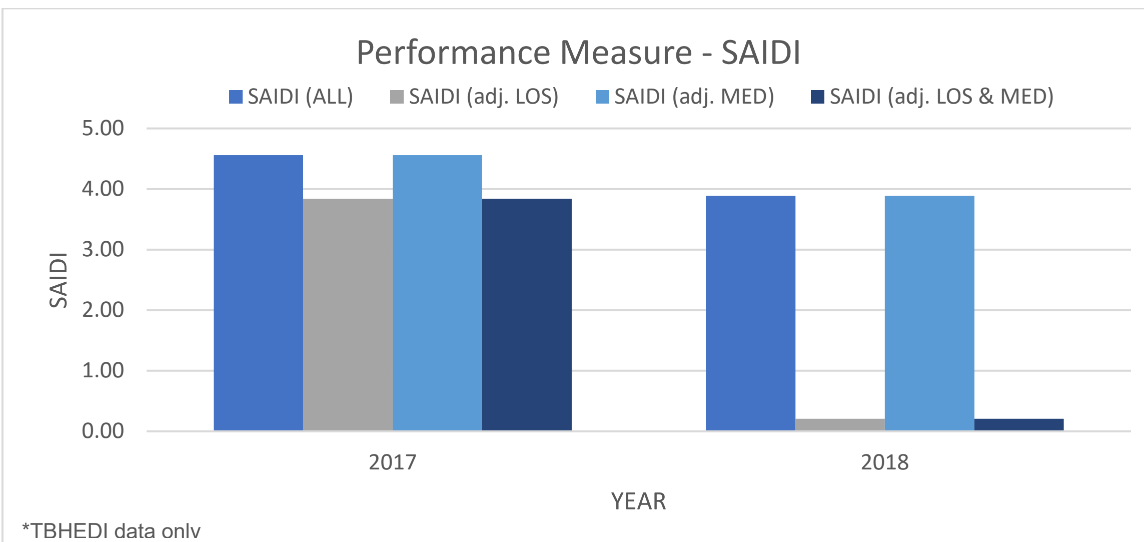


Figure 5.2-11 Historical Performance KHECL- SAIDI

In Figure 5.2-11 above, outages in Kenora in 2018 were largely attributed to loss of supply. HONI and SNC are addressing this by installing a new switch at the Rabbit Lake station to provide a redundant feed to supply SNC's substation.

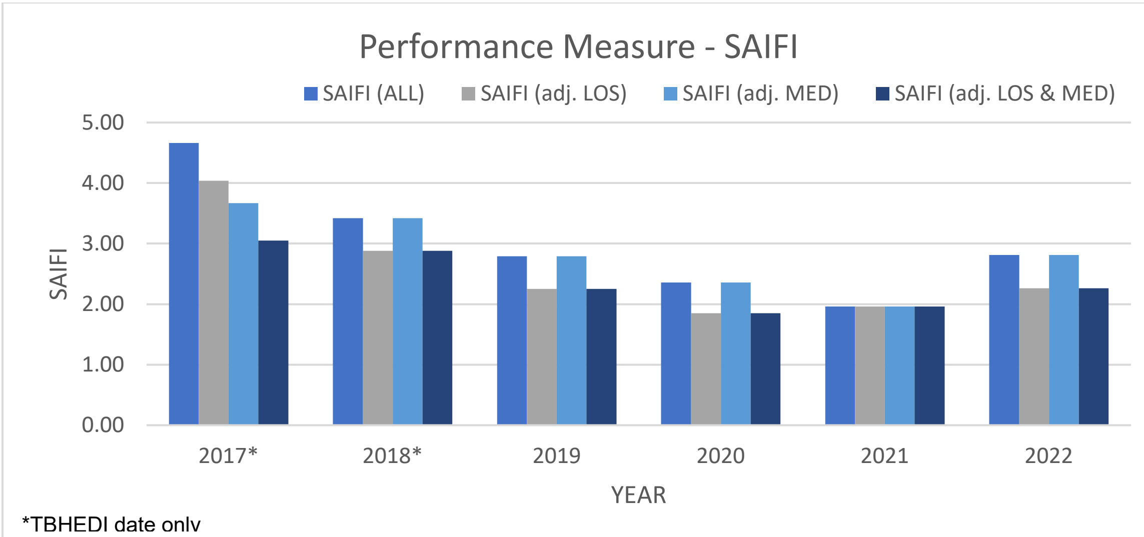


Figure 5.2-12 Historical Performance – SAIFI

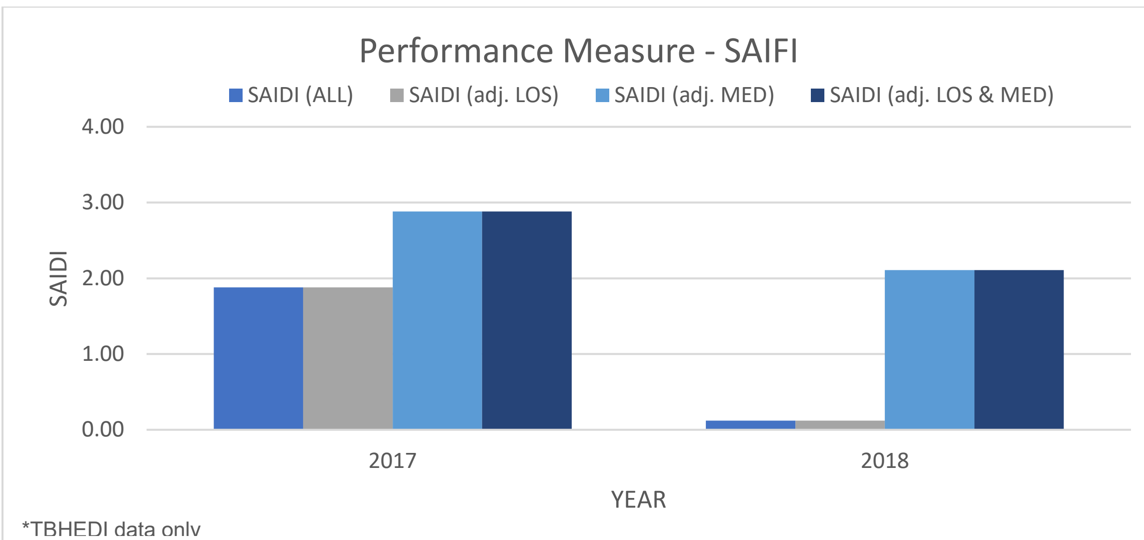


Figure 5.2-13 Historical Performance KHECL- SAIFI

5.2.3.2.4 Summary of Major Event Days

SNC experienced one major event day in 2017 that falls within the historical period. During this period Adverse Weather contributed to most of the interruption. The following table summarizes the impact of the major events in terms of number of interruptions, number of customer interruptions and number of customer hours of interruptions.

Table 5.2-5 Major Events Summary

Major Event Details	2017	2018	2019	2020	2021	2022
Number of Interruptions						
0 - Unknown / Other	-	-	-	-	-	-
1 - Scheduled Outage	-	-	-	-	-	-
2 - Loss of Supply	-	-	-	-	-	-
3 - Tree Contacts	2	-	-	-	-	-
4 - Lightning	-	-	-	-	-	-
5 - Defective Equipment	-	-	-	-	-	-
6 - Adverse Weather	59	-	-	-	-	-
7 - Adverse Environment	-	-	-	-	-	-
8 - Human Element	-	-	-	-	-	-
9 - Foreign Interference	-	-	-	-	-	-
Number of Customer Interruptions						
0 - Unknown / Other	-	-	-	-	-	-
1 - Scheduled Outage	-	-	-	-	-	-
2 - Loss of Supply	-	-	-	-	-	-
3 - Tree Contacts	113	-	-	-	-	-
4 - Lightning	-	-	-	-	-	-
5 - Defective Equipment	-	-	-	-	-	-
6 - Adverse Weather	50,067	-	-	-	-	-
7 - Adverse Environment	-	-	-	-	-	-
8 - Human Element	-	-	-	-	-	-
9 - Foreign Interference	-	-	-	-	-	-
Number of Customer Hours of Interruptions						
0 - Unknown / Other	-	-	-	-	-	-
1 - Scheduled Outage	-	-	-	-	-	-
2 - Loss of Supply	-	-	-	-	-	-
3 - Tree Contacts	1,455	-	-	-	-	-
4 - Lightning	-	-	-	-	-	-
5 - Defective Equipment	-	-	-	-	-	-
6 - Adverse Weather	77,503	-	-	-	-	-
7 - Adverse Environment	-	-	-	-	-	-
8 - Human Element	-	-	-	-	-	-
9 - Foreign Interference	-	-	-	-	-	-

Table 5.2-6 Major Event Details

Date	Customers Interrupted	Description
05-Dec-2017	50,180	Windstorm causing resonant conductor galloping

5.2.3.2.5 Customer Interruptions

The following figure represents the summation of outages at SNC over the historical period. The top three causes of outages are Scheduled Outages, Foreign Interference, and Defective Equipment.

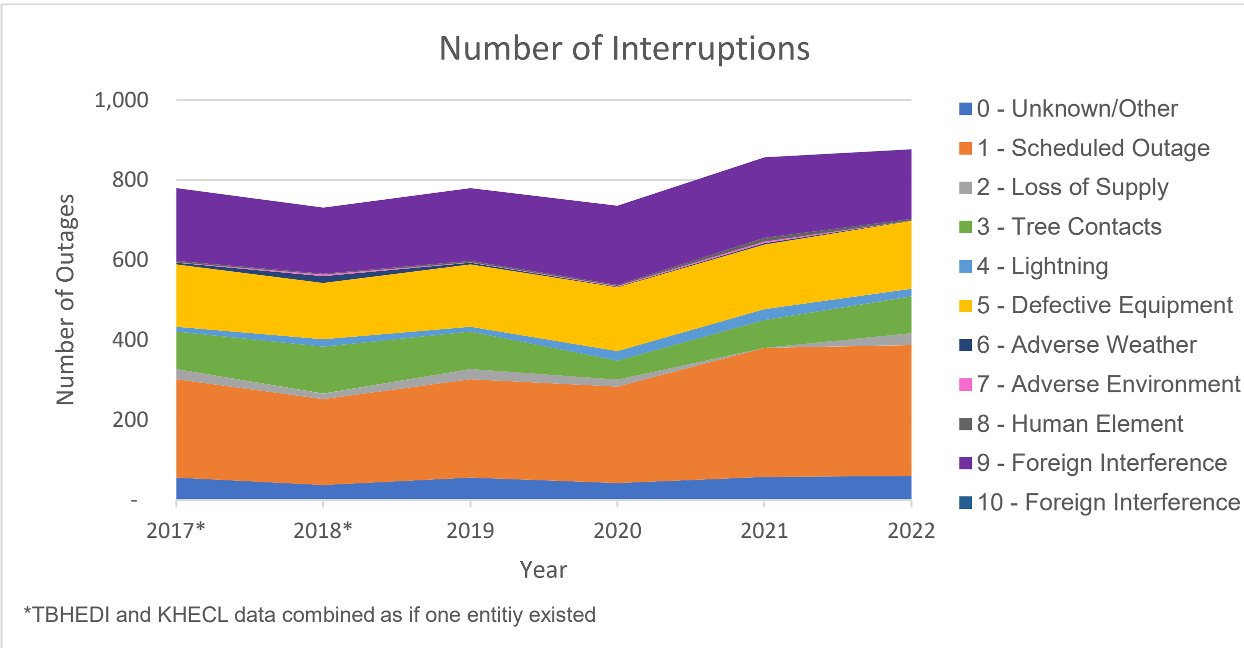
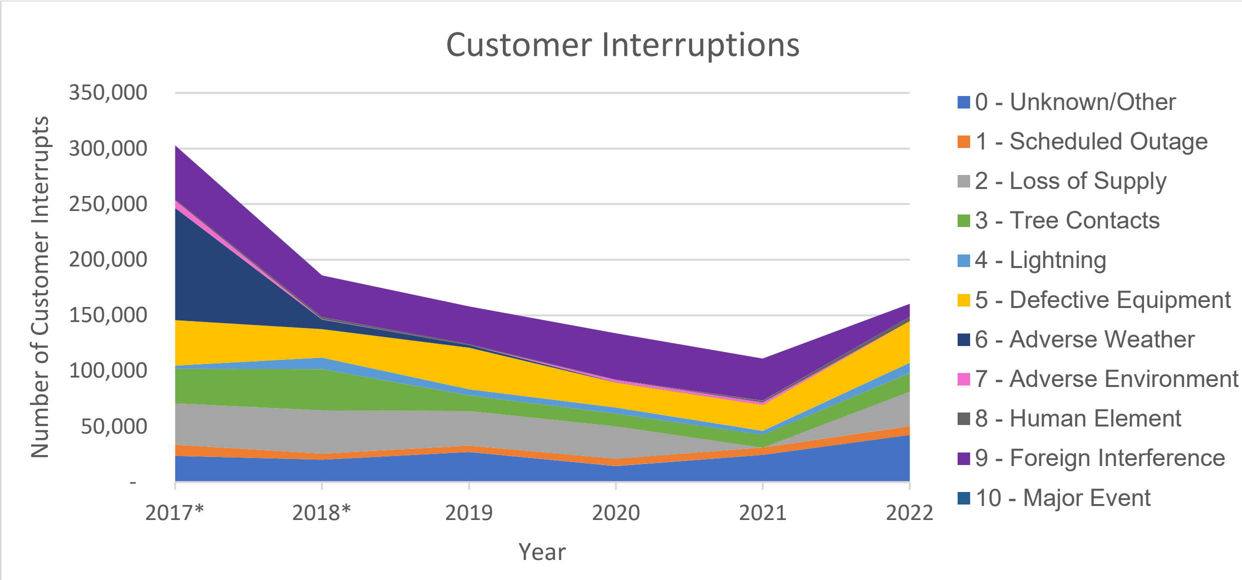


Figure 5.2-14 Total Number of Outages Annually

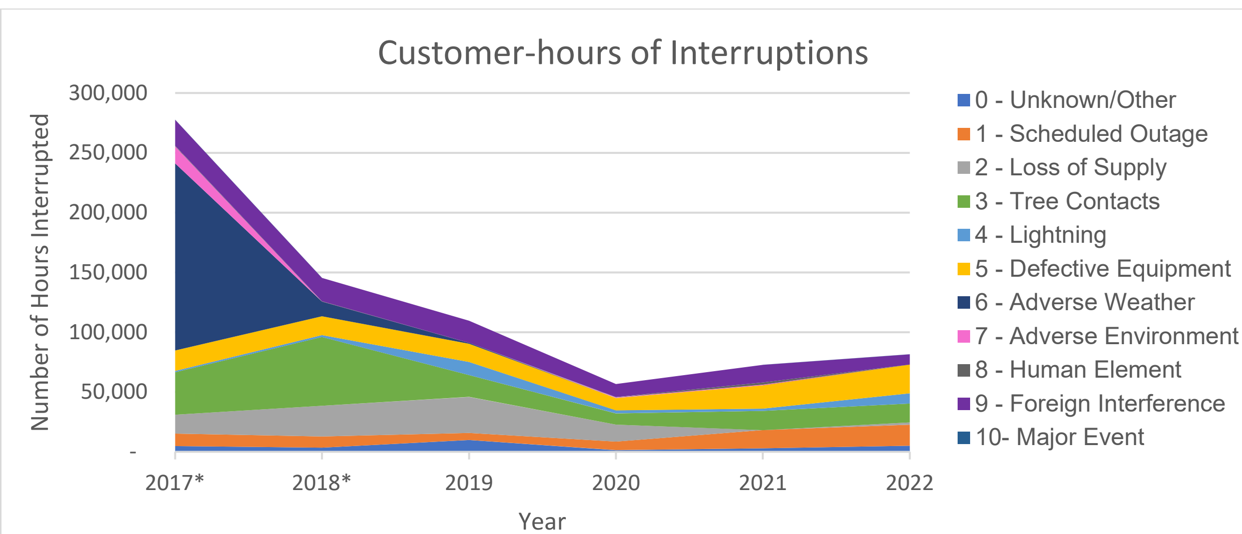
The following figure represents the summation of outages experienced by SNC's customers over the historical period. The top three causes of Customer Interruptions (CI) are Foreign Interference, Defective Equipment, and Loss of Supply.



*TBHEDI and KHECL data combined as if one entitiy existed

Figure 5.2-15 Total Number of Customer Interrupted Annually

The following figure represents the summation of hours SNC’s customers were without power over the historical period. The top three causes of Customer-Hours of Interruptions (CHI) are Adverse Weather, Tree Contacts, and Loss of Supply.



*TBHEDI and KHECL data combined as if one entitiy existed

Figure 5.2-16 Total Number of Customer Hours Interrupted Annually

In analyzing Figures 5.2-4 to 5.2-6 it's clear to see that while the quantity of interruptions customers experience fluctuates very little year after year, the impact to customers for both CI and CHI has significantly decreased over the historical period.

It's important to note that the correlation between system maintenance activities and electricity reliability statistics is not absolute as reliability can be influenced by factors such as weather events, changes in demand, and external factors beyond the utility's control. Nonetheless, SNC believes there is a strong relationship between targeted vegetation management and system renewal efforts and the subsequent decrease in CI and CHI. Within the forecast period of this DSP, SNC will continue to use outage data to gauge the effectiveness of its programs and remains committed to controlling the number of outages and meeting its established reliability targets via the following programs:

- Voltage conversion program to replace end-of-life 4kV distribution assets.
- Decommissioning of end-of-life 4kV station assets.
- Proactive vegetation management program.
- Targeted grid modernization activities.
- Renewal and rejuvenation of direct buried cables.
- Inspection and maintenance of distribution assets to mitigate potential problems.

5.2.3.2.6 Distributor Specific Reliability Targets

SNC uses the fixed performance target set out in the Scorecard for SAIDI and SAIFI based on its historical average performance, excluding LOS and Major Events.

5.2.3.2.7 Summary of Effects on the DSP

Service Quality

SNC has currently met or exceeded all the OEB defined metrics for monitoring its service quality (as reflected in Table 5.2-3 and

Table 5.2-4). For this reason, these metrics are not directly influencing capital expenditures during this planning cycle. SNC is committed to supplying electricity in a fair and dependable manner to its customers and expects to achieve similar results through the forecast period.

Customer Satisfaction

Customers have consistently stated that reliability of supply while stabilizing costs is at top of mind (see section 5.2.2.1). SNC was able to achieve reductions in the frequency and duration of outages customers experienced over the historical period, while maintaining consistent performance in terms of const control.

Feedback has indicated that while customers dislike rate increases, they also understand that increased investment is necessary to maintain assets and improve functionality. Figure 5.2-8 and Figure 5.2-9 illustrate that customers feel that the level of investment is appropriate and are confident that SNC is directing investment appropriately.

Safety

SNC has currently met or exceeded all the OEB defined metrics for monitoring the safety of its employees and the public as shown in Table 5.2-2. SNC's top priority is to ppromote, work and live safety achieving positive health and safety outcomes for employees and the public. Projects and programs which pose a safety risk have been prioritized in a manner that will allow SNC to achieve comparable results over the forecast period.

<u>System Reliability</u>

In SNC's previous filing[11] nearly one quarter of all outages could be attributed to Defective Equipment. As noted in Figure 5.2-17 below, this number had dropped to 13%. This is due to SNC's commitment to continuously monitoring reliability metrics and noting underperforming assets and/or feeders. Continued renewal investments focused in these problematic areas will allow the utility to maintain its reliability targets.

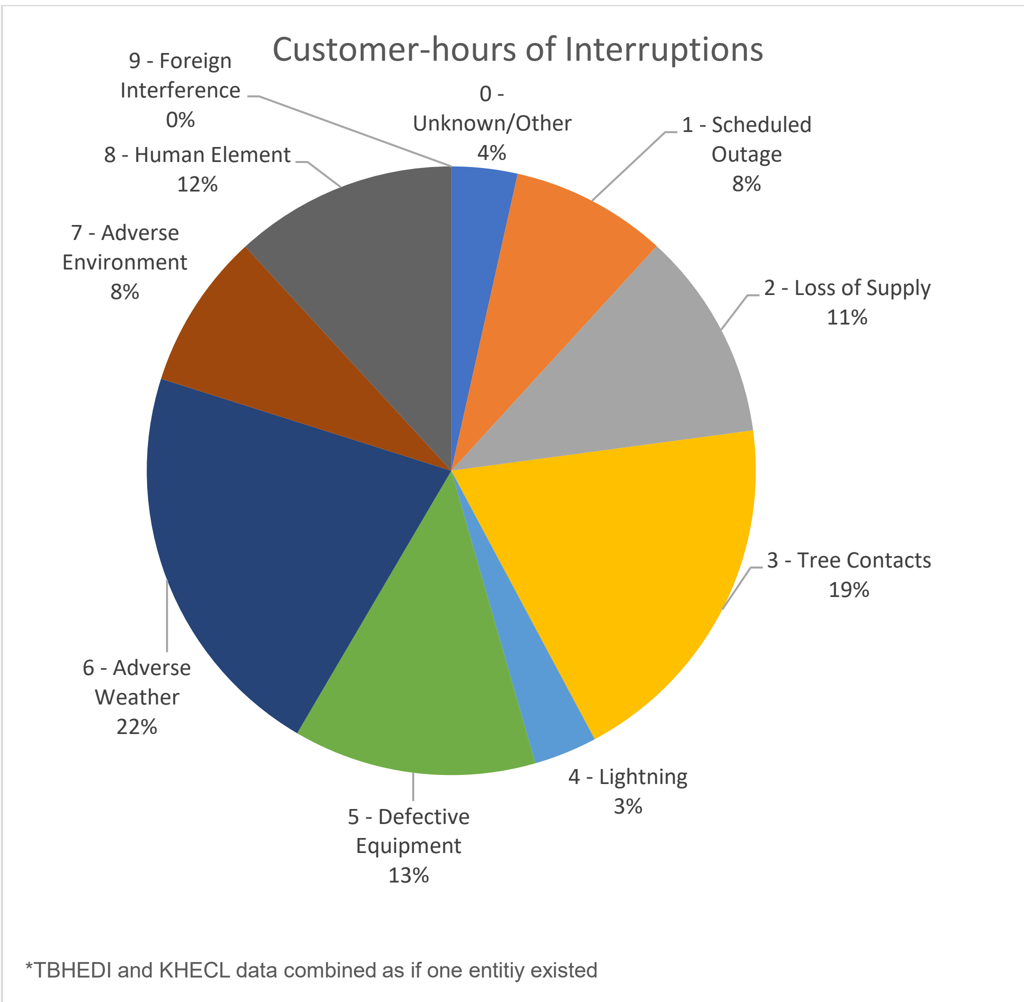


Figure 5.2-17 Outage Causes by Duration 2017-2022

[11] *2017 Cost of Service Application*, EB-2016-0105 – Thunder Bay Hydro Electricity Distribution Inc.

Additionally, System Service investments have been focused in high impact areas and have allowed operators to quickly identify, isolate, and restore power with the assistance of grid modernizing software and devices. These high impact areas are assessed based on criticality (those impacting large quantities of customers and/or extended outage periods), restoration times and system redundancy. This process will allow SNC to continue to define project areas and equipment to implement in the system.

SNC customers have experienced an average annual improvement in SAIDI (all causes) of 12%, and average improvement in SAIFI (all causes) of 6% over the historical period.

<u>Asset Management</u>

SNC uses the following asset management metric to monitor the progress of the DSP annually:

Financial performance measured as plan vs. actual expenditures (in percent)

a) Over Expenditure >100%
b) Under Expenditure <100%

Exclusive of System Access expenditures, SNC was able to achieve a cumulative total implementation of 97.41% of the total planned investments for the 5-year period 2017-2021 for which the previous DSP covered. SNC plans to continue to execute its programs with a high degree of control to achieve similar results for the forecast period.

SNC committed to improving in its data collection efforts to close the gaps identified as part of its last filing, and in so doing has increased the integrity of the asset condition analysis. SNC accomplished this for a significant portion of its major assets, in particular those assets identified for renewal in this DSP (see 5.3.1.2 for detailed explanations). SNC intends to continue its data collection efforts to better understand the current state of its assets and make informed investment decisions that benefit its customers.

<u>Cost Control</u>

In the previous planning cycle proposed investments to improve operation efficiency included implementation of operations technology and SCADA. SNC was able to complete several upgrades to its SCADA system and successfully implement an Outage Management System (OMS). This has significantly improved visibility into grid operations allowing for efficient response to outages. SNC plans to continue investing in this grid modernizing technology and devices in anticipation of further improvements in efficiencies.

<u>Public Policy Responsiveness</u>

Based on historical results SNC is not anticipating these metrics to directly influence operational imperatives. However, SNC will continue to support programs aimed at improving customers' ability to connect DER and increased EV adoption.

In the previous filing a reduction in REG connections was anticipated for the forecast period. These reductions were realized and had a minimal impact on capital expenditure.

<u>Financial Ratios</u>

SNC has currently met or exceeded all the defined metrics for financial ratios. As is evident from Table 5.2-2 the financial metrics remained stable over the historical period and are partly influenced by the steady application of capital that was planned in the previous filing. As SNC is committed to the pursuit of being better in everything we do we expect to continue to achieve similar results by closely monitoring the progress of the investments proposed in this DSP.

5.3 Asset Management Process

5.3.1 Planning Process

5.3.1.1 Overview of Planning Process

SNC constructs and maintains a safe, environmentally responsible, sustainable, and economical distribution system that reliably delivers electricity to our customers. This statement forms the basis of our asset management process and influences all planning decisions.

The asset management process facilitates the planning, operation, maintenance, and retirement of assets. The process incorporates facets of leading asset management practices; aligns long-term asset management strategies with corporate goals; continuously reports on targets and compares their intended results and incorporates regular reviews designed to seek improvements to the process.

All asset management initiatives implemented by SNC are designed to fulfill the intentions of the asset management strategy and strategic corporate goals. To this end SNC has adopted the following Asset Management Objectives.

- Health and Safety – SNC is obligated to ensure that the way it executes its initiatives positively impacts the health and safety of the general public, customers and SNC's employees.

- Environment – SNC seeks to minimize impact to the environment through consideration of the environmental risks in the project area, the potential contaminants released during asset failure and the consequences of climate change on our infrastructure.

- Regulatory/Legal Obligations – SNC seeks to prioritize projects based on the successful completion of regulatory and/or legal obligations.

- Customer Preference – SNC is committed to engaging customers and incorporating feedback into its plans.

- Asset Performance – SNC seeks to prioritize project selection based on assets that are at or beyond their useful life as determined through SNC's Asset Condition Assessment (ACA) process.

- Operational Efficiency – SNC seeks to maximize factors that positively affect financial performance through consideration of long-term operating and maintenance practices, equipment types, materials, human resources, and the analysis of future requirements of the system.

- System Reliability – SNC is committed to providing a consistent level of service to its customers by identifying and successfully completing projects in high impact areas.

The asset management objectives listed above are listed in order of importance and are used to inform the project selection and prioritization process found in Section 5.4.2.1 (the detailed scoring methods for determining the degree to which a project satisfies these objectives can be found here). The asset management objectives are closely related to SNC's corporate goals and strategic initiatives (see Table 5.3-1 and Section 5.3.1.3 below). Because of this relationship SNC can consistently identify and prioritize assets for renewal or refurbishment and uses this to inform the Capital Expenditure (CAPEX) Plan. The prioritization process was developed and verified in collaboration with METSCO and the resulting report can be found in Appendix K.

Table 5.3-1 Asset Management Objectives & Corporate Values

AM Objective	Corporate Values
Health & Safety	**Health & Safety Culture, Human Resources**
Environment	**Environment & Sustainability**
Regulatory/Legal Obligations	**Relationships**
Customer Preference	**Customer Service Focus**
Asset Performance	**Effective Asset Management**
Operational Efficiency	**Sound Financial Framework**
System Reliability	**Supply Electricity & Related Services**

The long-term corporate values are the defining characteristics that the organization seeks to maximize in its day-to-day operations. The goals and strategies defined at this level and the relationship to the asset management objectives are used to assess the degree to which projects adhere to the guiding principles of the organization.

Health & Safety

SNC is committed to creating and maintaining a corporate culture where Health and Safety are the utility's top priority. The ultimate objective of health and safety efforts is the pursuit of zero workplace incidents through the implementation and continued support of the utility's safety programs. In support of this goal, SNC continually focuses on incident performance trends and ensuring safe work practice and procedure documents are current.

Human Resources

Long term success requires SNC to continue offering a fulfilling, fair and challenging work environment to allow us to attract, develop, engage, and retain high quality staff. SNC regularly seeks to engage its employees through meetings and other communications that outline the relevant utility developments. Formal feedback from employees is sought both through bi-annual engagement surveys that serve to inform on existing programs; as well through the design and selection phase of projects to ensure that knowledge gained from past projects is integrated early on in an attempt to reduce costs and ensure the highest levels of safety are maintained.

Environment & Sustainability

SNC has a diverse asset population that has the potential for harm to the environment. For this reason and through the inspection and design process, SNC seeks to minimize the impact that its assets have on the environment where and when it is appropriate to do so. SNC also actively seeks out ways to manage its waste streams to reduce their effect on the environment.

Relationships

SNC has an ongoing commitment to the relationships it has established with its employees, customers, local municipalities and provincial regulators and ministries. Through regular dialog with these stakeholders, SNC can stay at the forefront of challenges facing the utility. SNC is further able to stay informed of developments, constraints, and changing requirements in the industry. This knowledge is an important factor in the development and implementation of an effective distribution system plan, and it informs on project selection and timing, ensuring SNC executes projects which provide the greatest benefit to the ratepayer.

Customer Service Focus

At its core, SNC exists to provide safe, reliable electricity to its customers. Meeting this obligation requires an understanding of our customers' needs and expectations and a commitment to delivering a high level of service. SNC continuously monitors its performance in the form of OEB metrics targeted towards providing timely service and effective communication to our customers.

Effective Asset Management

To ensure the long-term performance of the utility, a well-developed, long-term approach to infrastructure investment and maintenance is critical. In support of this goal and in support of this DSP, SNC maintains a rolling capital expenditure and asset replacement plan that reflects the utility's commitment to optimized, long-term fiscal sustainment and infrastructure renewal.

Sound Financial Framework

SNC is dedicated to effectively and efficiently managing all the resources required by the utility. It is important to the long-term success of the utility that specific strategies be employed to ensure we can maintain capital expenditure levels and operating and maintenance costs.

Supply Electricity & Related Services

SNC is committed to providing a highly reliable electricity supply to its customers as is evidenced in section 5.2.3.2. We regularly analyze our reliability statistics to determine opportunities for improvement and use this data to assess the extent to which certain projects will impact reliability and how best to effectively implement these opportunities.

5.3.1.2 Summary of changes to the Asset Management Process (since last DSP)

SNC has undertaken several initiatives since its last filing to enhance its asset management processes.

5.3.1.2.1 Pole Testing

In 2019, SNC began a program to systematically test the remaining strength at the ground line of its wood pole population. This was performed in conjunction with the inspection cycles as outlined in the Distribution System Code (DSC) Appendix C. The results provide quantitative data on the condition of the poles within the system and informs the ACA with objective information. The data collected improved the quality of the ACA and closed the data gaps identified in the Kinectrics report[12]. Additionally, the quantitative nature of the testing allows SNC to make informed decisions on the volume and timing of replacements in an effort to achieve the minimum level of intervention required to maintain the system. SNC began by testing 1200 poles in 2019 and has continued to do so on an annual basis since that time. To date, SNC has tested approximately 4800 poles.

5.3.1.2.2 Asset Removal Data

Also in 2019, SNC began to collect data on the driver for replacement for its major asset categories including but not limited to, poles, switches, cables, and transformers. The intent of the results was again to inform the ACA with objective information regarding the age at which assets fail. The data collected can be compared against the statistical models developed in the ACA to improve the quality of the analysis. This was identified as an area for improvement following the ACA in 2015. SNC will continue to collect this information and use it to inform statistical rates-of-failure models during this investment cycle.

5.3.1.2.3 Cable Testing

SNC began a program in 2020 to begin non-destructive cable testing in several areas throughout Thunder Bay. The areas mainly focused on direct buried cables installed in residential backyards; as well, downtown underground cores in Thunder Bay. The intent of the testing was to inform future cable rejuvenation efforts (see 5.3.1.2.5) in these areas. The

[12] Thunder Bay Hydro 2015 Asset Condition Assessment

program initially started with testing 100 cables and since then targets 200 cable segments annually. To date, 546 segments have been tested (approximately 52km).

5.3.1.2.4 Integration of ACA data with geospatial asset data.

SNC has been integrating the results of the ACA with the geospatial asset data since 2018. This process has improved the qualitative assessment of projects by aggregating the health and failure rate data of several different assets into a visual health assessment tool (see Appendix H – Overhead Renewal).

5.3.1.2.5 Cable Rejuvenation

SNC undertook a pilot project in 2021 to determine the viability of cable rejuvenation for primary direct buried cables installed in residential neighbourhoods. The proprietary process of cable rejuvenation effectively restores the electrical properties of the cable, by injecting technical fluid into the cable which both removes moisture and impurities, then cures to re-establish the dielectric strength of the cable. All this is performed while the cable is de-energized, but effectively undisturbed otherwise.

The original installed location of these cables poses a significant challenge to traditional replacement, given that space in existing easements has been consumed over time, and obstacles such as fences, and sheds can be found throughout these areas. In partnership with Novinium, SNC was able to successfully rejuvenate 2300 meters of cable for approximately one third the cost of directionally boring in and installing new cable and duct (see Appendix H – Material Investment Report - Underground Cable for more information). SNC intends to pursue this option in the future where the technology and cable construction allow.

5.3.1.2.6 System Resilience

SNC is aware of climate change impacts that could affect infrastructure in its service territory. Although there has been only one major storm in its service territory in the historical period (as classified by the OEB reliability metrics) North American cities are already facing more frequent and severe “climate hazards and extreme events[13]” which have and will continue to contribute to infrastructure damage.

To ensure system resilience, SNC has implemented several practices across divisions. The first being the incorporation of the new overhead standards for pole class and guying which align with the latest climate adaptation version of the CSA (Canadian Standards Association) Overhead Standard. This standard required SNC to order and install a higher class of poles in 2021 while replacing aging infrastructure to storm harden those assets should a major event occur.

Another key aspect of ensuring resilience is through the addition of automated reclosing devices. These devices have been programmed to work with other devices in the field to

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[13] IPCC, 2022: Climate Change 2022: *Impacts, Adaptation and Vulnerability* – Fact Sheet – North America

automatically restore power when possible (self-healing) and to isolate pockets of load to minimize the impacts of an outage to customers.

Vegetation Management has been perhaps the largest system resilience initiative that Synergy North has undertaken in the last historical 7-year period. While Synergy North was aware that there were increasing levels of customer calls due to vegetation growing into the overhead lines, the ability to fully quantify this did not take place until 2021. At this time SNC decided to partner with the City of Thunder Bay and KBM Forestry to purchase lidar data and have it analyzed for proximity to overhead lines. The data results demanded a re-evaluation of SNC vegetation management program. Over 3000 spans of overhead line posed an immediate safety risk and over 4500 more spans were not meeting legislated requirements. Due to the potential risk that vegetation in proximity to overhead lines could have on customer safety, and the potential for ignition of vegetation causing forest fires, it was deemed a top priority for SNC. SNC had been in a drought year in 2021 and a fire ban had been in place throughout the service territory and beyond. That summer over 51,000 hectares[14] of forest burned in northwestern Ontario, causing air quality and evacuations. SNC worked with known metrics for vegetation management as well as its internal registered professional forester to develop a plan to meet legislated requirements within 7 years.

In reviewing the London Economics study prepared for the OEB on resilience Synergy North has implemented 5 of the 9 identified resilience event agnostic physical improvements, 3 of the 7 physical improvements to address specific weather events, and 4 of the 8 event agnostic policy/practice improvements.

The 5 event-agnostic physical improvements that SNC has implemented through its Grid Modernization, 4kV Conversion, Overhead Renewal and OM&A programs are as follows:

1) automated components to improve problem detection as well as data collection;
2) self-healing grid components ;
3) replacing aging infrastructure;
4) energy efficiency; and
5) vegetation management.

The 3 physical improvements that SNC has implemented through its 4kV Conversion, Overhead Renewal include:

1) reinforcing poles;
2) installing guy wires; and
3) install hardened pole-and-line designs and configurations.

The 4 event-agnostic policy/practice improvements that SNC has implemented through its operations activities:

1) participating in shared inventory/mutual assistance programs;

[14] "Northwestern Ontario dealing with surge in forest fires as hot, dry weather settles into region" Nick Westoll, GlobalNews, Posted July 9, 2021

2) developing business continuity and emergency action plans;
3) regular testing of backup generators; and
4) identifying critical infrastructure.

Event-agnostic physical improvements	Physical improvements to address specific weather events	Event-agnostic policy/practice improvements
• **Automated components** (smart meters, intelligent switching) to improve **problem detection** as well as **data collection** during an outage • **Protect key communication systems** used during a disaster • **Self-healing grid** components • **Microgrids** for critical facilities • **Replace aging infrastructure** • **Mobile substation equipment** • **DERs** to reduce load during a crisis • **Energy efficiency** to maintain livable conditions for longer periods • **Vegetation management**	• **Undergrounding** distribution lines • **Reinforce** poles • Install **guy wires** (i.e., tensioned cables to add stability to free-standing structures) • Install **hardened** pole-and-line designs and configurations • **Coat lines** to prevent ice buildup • **Elevate substations** • Use **advanced weather-prediction models**	• Develop **response and communications protocols** • Participate in **shared inventory/ mutual assistance programs** • Develop business continuity and **emergency action plans** • Create **demand response programs** • **Regular testing** of back-up generators • Utilize **drones** for damage inspections • **Regular security briefings** on emerging threats • Identify **critical infrastructure** and key resources

Source: Lawrence Berkeley National Laboratory. Utility Investments in Resilience of Electricity Systems, April 2019.

Figure 5.3-1 Excerpt from London Economics Study for OEB

5.3.1.3 Process

SNC employs a strategic and systematic approach to operating, maintaining, upgrading, and expanding physical assets effectively throughout their lifecycle. By focusing on business and engineering practices for resource allocation and utilization, with the objective of better decision making based on quality information and well-defined objectives, SNC can assess the current state of its distribution assets and identify current and future needs.

The investments proposed in this DSP are founded on a thorough understanding of the current state of the distribution system. These investments are evaluated and prioritized through the planning process that results in proposed near-term capital and maintenance programs. Investments are reviewed at the enterprise and customer levels through the engagement process and alternative solutions proposed. Finally, the investments are acquired and/or built through the execution phase. This process, as shown in Figure 5.3-2, is cyclical in nature allowing for feedback from every phase to inform the next.

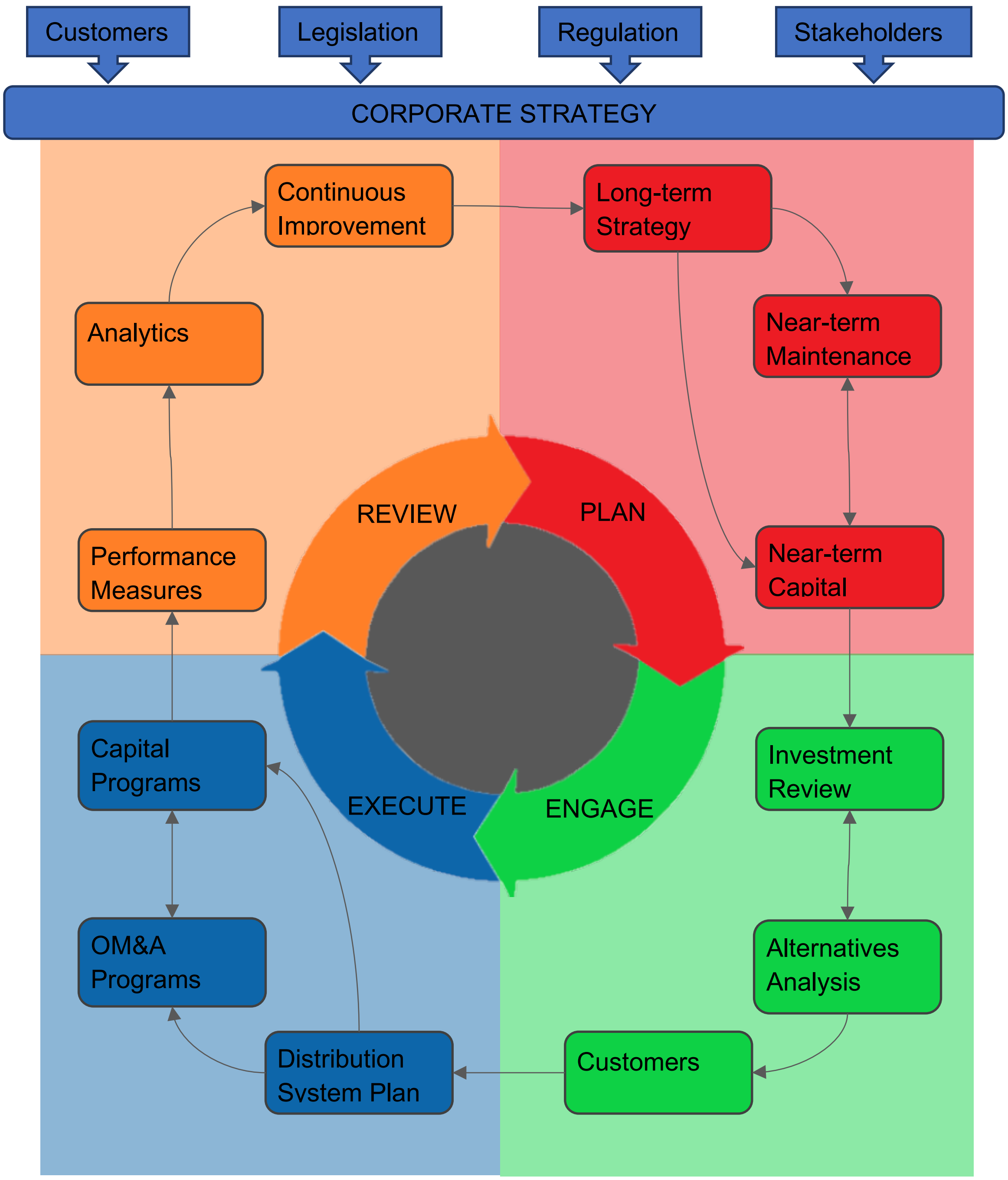


Figure 5.3-2 Asset Management Process

REVIEW PHASE

SNC establishes the current state of the distribution system in this phase by assessing performance measures and analyzing data. During this phase, the actual and anticipated needs of the customer, assets and system at large are evaluated. SNC gathers data across all repositories within the utility to support this process. This includes various enterprise systems, third-party reports, inspection records and data analysis methods. This process is further described below. The information collected during this process varies in its frequency, formality and type of information collected (e.g., surveys, discussions, unsolicited feedback, etc.).

Customer Needs

SNC regularly and proactively connects with customers with a variety of approaches, including formal surveys, on-going engagement activities and customer connection requests.

Following SNC's previous filing, a Local Advisory Council (LAC) was established to represent the voice of SNC's customers. The LAC has been able to offer input on customer needs and expectations to help shape SNC's plans by providing feedback on system planning, strategy and policies that directly impact customers.

In 2022 and 2023 feedback from customer engagement activities directly informed the investment plan. SNC conducted a comprehensive customer engagement planning survey that provided valuable input for the development of scenarios including investment envelopes and preferred outcomes. Approximately 70% of distribution customers prioritized reasonable rates and reliable service and supported maintaining the current level of investment. Additionally, most customers support; a) an increase in spending for vegetation management to meet standards, b) a proactive approach to replacing infrastructure, and c) technology investments that reduce costs and improve their experience managing their electricity usage. Refer to Section 5.2.2.1 for further details.

Additionally, SNC monitors its Service Quality Indicator performance (as mandated by the OEB) as insights may serve as an indicator of underlying issues with SNC's systems or equipment.

New service connections, relocations, and developments are developed as a direct response to customer needs and drive System Access investment.

Asset Needs

Asset condition is the primary measure when considering asset needs within the distribution system. SNC regularly assesses and considers the condition, criticality, and failure rates of specific asset groups to provide long-term insight into its asset portfolio. The age demographics of specific asset groups assist in the assessment of asset condition, but it is not the primary driver for any specific investments. Information on the assessment of major distribution assets is provided in Section 5.3.2.1.5.

The output of the assessment process yields a levelized renewal target (i.e., assets flagged-for-action) for each of the major asset categories identified the above section. The quantity of assets identified as flagged-for-action is the statistical minimum level of intervention required to maintain the asset base. The ACA is an essential driver for SNC decisions on maintenance levels, maintenance requirements, and decisions regarding the selection and scope of capital investments. Ultimately, the objective of this assessment is to monitor the physical indicators of asset degradation or malfunction and determine the appropriate level of intervention (e.g., maintain or replace) to ensure the distribution system continues to operate effectively and economically.

Asset needs directly inform the development of System Renewal investment (voltage conversion investments are underpinned by station replacement deferral, and reductions in system losses). A substantial portion of the System Renewal category will fund the replacement of assets that do not meet the criteria to remain in service across all major distribution asset categories including distribution stations, wood pole replacements, underground refurbishments, and distribution transformer replacements.

System Needs

System needs investments consider reliability studies which focus on maintaining or improving power quality and reliability, regional planning requirements, capacity constraints, and the ability to connect distributed energy resources.

System reliability is assessed using outage data collected by control room operators and is compiled into quarterly statistic reports. The data is aggregated by outage code and is analyzed by the asset management and engineering team to determine trends in poor performing feeders.

System loading is captured using AMI and SCADA data logging capabilities. SNC staff analyze the data which serves as predictive input as to the extent of asset deterioration and identifies areas of potential capacity constraints where upgrade projects may be required in the future. SNC also collaborated with Elenchus in developing a comprehensive load forecast for its service territories. The econometric approach leverages historical system loading data and third-party forecasts of statistically significant load predictors (heating degree days, COVID impacts) to develop an overall load prediction. This model is tested for fitness against historical data (see Figure 5.3-3) and establishes the potential range of load growth that SNC can expect to materialize in the near term.

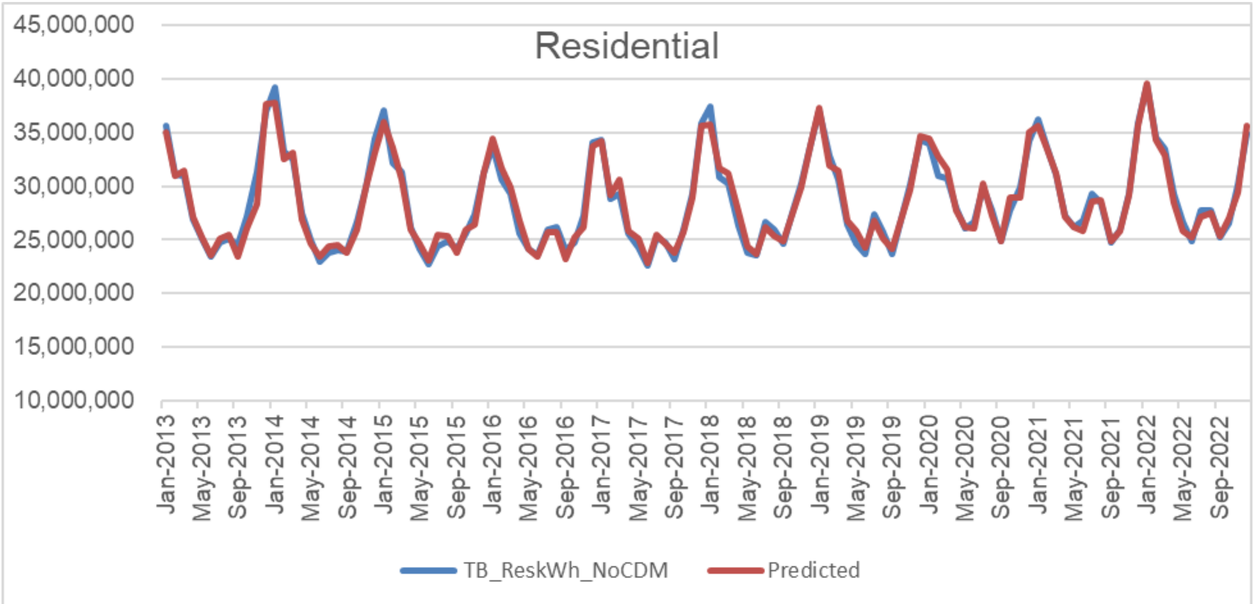


Figure 5.3-3 Load Forecast Model Predicted vs. Actual

Additionally, SNC worked in conjunction with IESO during the IRRP planning process to utilize the IESO 2020 Annual Planning Outlook for the adoption of electric vehicles. SNC correlated the data provided in the outlook to its service territories to determine the adoption of EV's within a 20-year timeframe. This was incorporated into a 'high electrification' load forecast within the 2022 Northwest IRRP. This information is detailed in Appendix B. In the first quarter of 2023 when SNC continued to work with HONI to produce the Regional Infrastructure Plan, the guidance from the November 2, 2022 "Load Forecast Guideline for Ontario" was considered and incorporated. SNC validated its previous load forecast and ensured that EV adoption aligned with Section 3.5.1 Electric Vehicles from the IESO 2022 Annual Planning Outlook. No modifications to the load forecast were necessary due to the updated planning outlook.

Key investments in this category include improvements to the existing system, which account for a small portion of the overall expected capital expenditure over the forecast period. The forecast consists of installing automated reclosing devices and distributed automation modules to allow SNC to take the initial steps, moving towards becoming a fully integrated network orchestrator (FINO) or a total Distribution System Operator (DSO). These investments are in direct response to technological advancements and form the basis of System Service.

Operational Needs

Environmental impact monitoring is one of the major AM objectives for SNC. Given this, and to ensure ongoing compliance with the relevant legislation and regulations, SNC diligently follows all required environmental reporting and remediation guidelines and identifies trends with equipment performance for evaluation during the planning process.

SNC refers to policies, inspection results, and expert judgement to identify operational needs as it relates to the condition of assets including buildings, fleet, rolling stock, tools and equipment.

These assets are monitored closely by operations staff utilizing maintenance and operating records as well as lifecycle costs to target replacement or refurbishment.

IT infrastructure assessments occur periodically to evaluate the state of vendor support and functional capability of the utility's hardware and software systems relative to evolving user needs and regulatory requirements. Expenditures related to information systems are largely driven by policy and cyber-security legislative requirements. Operational needs directly inform the development of General Plant investment and is largely driven by fleet replacements.

The insights gathered during this phase inform the basis of action for a variety of asset types and assist in determining the breadth and scope of intervention (e.g., replace, refurbish, maintain). The process incorporates facets of leading asset management practices, trends, and benchmarking to evaluate SNC's performance against peer utilities.

PLANNING PHASE

The preceding stage in the AM process creates a comprehensive set of inputs defining the current state of SNC's system and considers natural and accelerated asset degradation and external drivers for expansion. Following the review phase where customer, asset and system needs are identified, SNC focuses on converting these inputs into potential investment candidates utilizing various AM analysis tools and processes combined with important sources of input such as alignment with organizational strategy.

While SNC does not conduct formal economic lifecycle analyses for its assets the general application of investment planning techniques is utilized. This assessment applies broadly to System Renewal and General Plant investments where, based on available data, SNC can determine the following:

- Which assets, and how many are statistically likely to require intervention within the planning window based on their health;
- Whether the potential impact of running to failure will have a greater effect on service levels than proactive replacement;
- Whether poor performance of an asset or assets warrants early intervention prior to end of service life (e.g., worst feeder);
- Manufacturer and/or regulator recommend/expect replacement or refurbishment (e.g., smart meter reseal programs);
- Whether assets and/or equipment is deemed no longer safe to remain in service or parts are unavailable to ensure ongoing performance;
- Whether anticipated growth creates opportunities for harmony between programs and reduces overall costs; and
- Consideration of future capacity requirements of assets (e.g., service wires and transformers). Several programs (4kV Conversions, Overhead Renewal, Underground Cable Renewal, and all new Residential and General Service connections) have actively been reviewed and practices have been updated to include secondary service wire and

transformer sizing in consideration of increased loading due to fuel switching and the adoption of electric vehicles.

The output of this analysis determines the scope of assets warranting some potential intervention over the planning period. SNC recognizes that the amount of available capital each year is unlikely to be sufficient to address all the identified needs proactively. Additionally, assets with comparatively lower anticipated impact of failure (e.g., minimal customer interference, quick restoration times, ease of replacement) may mean proactive replacement is economically detrimental due to diverting resources away from more critical infrastructure.

To address these potential constraints SNC examines the potential investment candidates based on their relative importance. In doing so several elements are considered as applicable to different asset types such as: health and safety (e.g., is the area overhead or underground); impact to the environment (e.g., Prescence of large oil filled equipment in poor health); operational efficiency (e.g., removal of legacy equipment); and reliability (e.g., potential to impact many customers). In this way, SNC can consider addressing the investments that pose the highest criticality first with work in these programs proceeding as soon as practicable.

In the process of creating the capital expenditure programs and developing individual project scopes, SNC attempts to align the timing of its investments as closely as possible to the moment the need arises.

For System Access projects driven by customer requests, customers are required to meet several financial and technical milestones to indicate their readiness to proceed with a project. Once this occurs, SNC staff can engage in the process of proceeding with formalized planning and execution of the work. This allows SNC to manage the financial and resource related (schedule) risk of putting assets in service earlier, than is optimal. As previously noted, SNC regularly engages with third party requestors to gain an understanding of the scope and timing of their planned construction activities to reduce the volatility associated with these programs.

When planning System Service projects that are intended to improve the capabilities of the system SNC reviews several options that may reduce or defer the investment need. When deploying automated reclosing devices, the utility examines the viability of interim or permanent alternatives, such as load transfers, to reduce the impact of outages without the need for additional expenditure.

System Renewal investments are typically planned so that asset replacement volumes remain consistent year over year. The annual volume for this program is established through the asset condition assessment. To further enhance this assessment SNC is taking steps towards an advanced risk-based planning approach using failure rates, criticality, and composite health. The benefit of this approach will be the ability to estimate the risk avoidance and health improvement cost on a per project basis.

For General Plant investments, the planning is largely based on the operating conditions required and threshold-based inspections. In cases where an inspection has determined an asset is in an adequate state to remain in service, replacement or refurbishment can be delayed. Additionally, an investment may require reprioritization should evidence emerge (e.g., catastrophic failure) that projects other than those originally planned require intervention in the near term.

SNC leverages the data collected during the review phase to form the basis for evaluating and prioritizing investments and in doing so establishes the DSP. Proposed investments are assessed in terms of their relative importance, condition, and alignment to objectives. These systems are reviewed to ensure they continue to align with risks across the organization.

SNC assesses the relative rank of each potential investment across several categories– Health and Safety, Environmental Impact, Customer Preference, Asset Performance, System Reliability, and Financial/Operational Impact.

The above categories are tied directly to the asset management objectives and feature a concise definition which permits a consistent application and assessment for each investment candidate. The assessment considers the risks associated with proceeding or deferring the investment, cost-effective alternatives to replacements as well as other innovative technologies where applicable.

Table 5.3-2 Prioritization Criteria

Criteria	Description	Weight (A)
Health & Safety	Risk of safety incidents sustained by SNC's staff, contractor, or general public, living, and working in the vicinity of the utility's equipment.	41.1
Environmental Impact	Risk of unplanned and uncontrolled release of a hazardous substance (e.g., PCB Spills) or the consequences of climate change, vegetation contact, flooding.	22.9
Regulatory/Legal Compliance	Assesses the degree to which project, service, or product is compliant with regulations and legal obligations.	12.3
Customer Preference	Preferred impact of project, service, or product to customer requirements.	8.4
Asset Performance	Project, service, or product replaces substandard equipment or otherwise improves the operations and maintenance practices on the system thereby addressing asset health concerns, premature failures, etc.	6.3
Operational Efficiency	Project, service, or product that otherwise improves or avoids the following: • Reduces operating expenses; • Avoids future capital costs; • Coordinates with other programs; or • Decreases liability or increases without action.	4.7
System Reliability	Electrical service continuity: translating it into customer interruption statistics and determining customer base affected.	4.2

The above method of ranking investments only applies to discretionary programs. Investments that are non-discretionary in nature (those in the System Access category) are given top priority and are planned and implemented based on the in-service requirements of the requestor or legislation. This process is further described in section 5.4.2.

ENGAGEMENT PHASE

Following the ranking assessment, the candidate investments are reviewed by internal stakeholders from across the organization to discuss the scoring of investments and ensure that the system has been applied consistently.

During this phase, the ranking is reviewed in conjunction with the organization goals to determine if there is a particular asset or group of assets that may be influencing the overall ranking of the investment candidate. The outcome may be to reduce the scope of a given investment to address a given asset or group of assets, thereby increasing the performance of the proposed dollars in that program.

Enterprise engagement is undertaken to support execution decisions. This ensures that the plan is reviewed and updated by lines and operations staff. It considers resource and material availability, cost estimates, and validates that scopes and schedules are prudent and reasonable.

Customers are at the top of mind in all corporate strategy decisions. These influence the utility's asset management decisions because there is a line-of-sight between them. Customer feedback received through a variety of mechanisms is reflected in these decisions and is an important part of the asset management process.

The initial customer engagement survey associated with this DSP attempted to convey the nature of the investment plan and gain an understanding as to what was important to customers. Additionally, SNC sought specific feedback on emerging technology such as electric vehicles and distributed energy resources. The insights gained through this activity provide value to the AM process in a variety of ways. These could include:

- Measuring the customers' perspective on levels of service with respect to reliability and service quality;
- Investigating customers' attitudes and intentions towards electric vehicle adoption and the impact it may have on SNC's investment priorities;
- Exploring customers' preferences on proactive and reactive replacement strategies that could impact reliability;
- Receiving feedback on levels of support for specific rate increases resulting from anticipated programs.

In the second customer engagement survey associated with this DSP SNC sought to gauge customers' understanding of the cost drivers associated with the proposed rate changes because of SNC's investment plan and their overall acceptance of the investment plan as presented. These cost drivers included:

- SNC's commercial funding methodology and resulting debt repayment plan to the shareholder;
- Proactive replacement strategy and resulting balanced capital expenditure plan;
- Cost allocation and resulting impact by customer class;
- The impact of inflation on commodities; and
- Impacts due to meeting regulatory requirements such as the Green Button Initiative.

Additionally, engagement meetings are scheduled for each planned capital project area and incorporate customer feedback prior to the execution phase. If customers are unable to attend the meeting it is recorded and can be viewed at another convenient time. Further information on the customer engagement activities can be found in section 5.2.2.1.

EXECUTION PHASE

The Distribution System Plan (DSP) is intended to communicate the five-year CAPEX plan and its subsequent impact to operating and maintenance plans (OM&A); as well, communicate SNC's coordination activities with third parties, the Asset Management process (presented in this section) which forms the basis for the CAPEX plan. Additionally, the DSP demonstrates SNC's performance since its last filing via variance analysis, which outlines SNC's actual spending in the previous five-year period as compared to planned investment during the same period. The performance measures presented in this DSP were created to allow SNC to communicate the overall effectiveness of the CAPEX and OM&A investments over the planning period.

The five-year Capital Program contains discrete projects within the test year and forms most of the CAPEX plan. The program and underlying projects are to be executed during the planning period. Further details on SNC's capital program planned for this DSP can be found in Section 5.4.1.

OM&A programs consist of in-field inspection and testing of assets across the distribution system. Asset inspection and testing cycles vary by asset type. The method of inspection and testing depends on the complexity of the asset being inspected. Further details on SNC's current OM&A programs can be found in Section 5.3.3.2.

Depending on the nature of the work, SNC relies on internal and external resources to complete its detailed design and construction activities, with the majority undertaken by internal staff. The focus at this phase is on saftey, accuracy, efficiency and compliance with internal and external policies and regulations. Most activities follow a standard workflow; however the efficiency and accuracy are tied directly to the outputs of the precedeing stages of the asset management process.

The final element of the process is aimed at qualitative and quantitative feedback in the form of lessons learned and financial metrics. This is a crucial stage as it informs future planning efforts and forms the basis of evaluation of past successes and oversights. At this stage SNC attempts to reconcile planning and design cost estimates with final project costs to improve the estimating framework; compare reactive repalcments with forecast amounts; and a review of assumptions underpinning System Access investment and the amount of which materialized.

The coordinated and consistent methods of this process leverage best practices while providing safe and reliable system performance and accommodating economic growth.

5.3.1.4 Data

SNC uses several repositories to assess the status of its distribution system and determine its capital and operational investments. These include condition assessments, engagement activities, and inspection results all of which inform the AM process and are linked to the OEB performance outcomes. Key components are explained below.

i. Asset Register

The asset register is made up of data from various databases and is generally available through SNC's GIS interface. The data comprises all the information that allows each asset to be uniquely identified such as serial number, nameplate data, and SNC's assigned identifiers. It also contains data regarding the physical characteristics such as age and configuration of the asset as well as installation and removal data and location. The register is routinely updated as assets are installed, removed, or refurbished as requirements dictate.

ii. Customer Engagement Results

SNC conducts customer engagement sessions to gather feedback on its services and to ensure that customers' opinions are considered during the development of long-term plans. Both formal and informal engagement activities have taken place over the last several years. More information on SNC's activities can be found in Section 5.2.2.1.

iii. Asset Condition Reporting

An ACA study was originally completed by Kinectrics in 2015. Since then, the data has been updated and maintained by SNC staff to determine the current health of SNC's distribution system assets, as well as an understanding of the Data Availability Index (DAI) and where data gaps exist. The report describes the methodology used to analyze the major assets within the distribution system. The resulting information provides a levelized asset replacement schedule which helps to inform the renewal portion of the capital expenditure plan. An excerpt from the report is included in Appendix I. In some cases, the DAI has trended downward from the 2015 ACA to current. SNC has worked diligently to address the largest and most significant data gaps identified in the past ACA. However, collecting this quantitative data and incorporating it into the ACA immediately decreases the DAI of those assets for which the data was collected (this is due to a small portion of the population now having an extra condition parameter relative to the remaining population). SNC has taken a measured approach with regards to the difficulty and cost associated with collecting this data against the benefits associated with increased confidence in the assessment. SNC has significantly improved the assessment confidence in the asset classes that form the largest part of this DSP by reducing the data gaps from high to low.

iv. Technological Innovation

As part of its commitment to continuous improvement, SNC monitors the state of technological advancements made within the utility sector. System automation, electric vehicle uptake, battery storage and other non-wires alternatives are considered as part of SNC's planning process. Where it is financially responsible to do so these technologies may be incorporated into renewal and upgrade projects to meet the current and future needs of customers, improve operational effectiveness, as well, support the integration of renewables and smart grid technologies.

v. Historical Period Data on Customer Interruptions caused by Equipment Failure

SNC has a large repository of data relating to customer interruptions, including those caused by equipment failure. The outage data is considered during the risk assessment process and involves analyzing the frequency and duration of outages and the number of customers affected by a given project. The impacts to SAIDI and SAIFI are considered at this time when selecting and prioritizing projects. These factors are also considered early in the selection and design process where performance or reliability issues can be resolved.

vi. Reliability-Based 'worst performing feeder' information and analysis

SNC tracks feeder performance as a composite of all OEB defined outage categories; as well individually by OEB outage category and trends feeder performance overtime. By analyzing the data SNC can identify the poorest performing feeders annually, as well as feeders that have continually performed poorly. Feeder performance is further analyzed to determine how current programs will impact these statistics and consideration to this fact is given at the time of selecting and prioritizing projects.

vii. Financial Metrics

SNC utilizes financial metrics on a per unit basis for its major asset categories based on actual historical replacement to estimate future capital costs for projects of similar size and scope. These metrics are updated annually to ensure that the estimating process continues to be effective and is based on the best available data each year.

viii. Targets/Constraints

This dataset contains renewal targets as well as financial, schedule and resource constraints. The renewal targets are mainly driven from the results of the ACA and provide information on the levels of renewal required annually for each asset class. Financial constraints are driven from SNC's strategic corporate goals and direction from senior management and assist in guiding the overall financial envelope annually. Schedule constraints arise from the fact that SNC schedules specific activities during certain times of the year, as they are most effectively executed at these times. Resource constraints consider internal personnel availability as well as contractor and material availability.

ix. External Drivers

External influences often impact SNC's decision making process when optimizing plans for the system. These can include:

- Environmental – aspects include renewable resources, weather, and climate change policies.

- Social – broad changes in customers' needs and preferences.
- Economic – economic changes, either growth or decline within SNC's service territory as well as shifts in business operations and residential housing.
- Regulatory/Legal – changes in requirements from the OEB, health and safety, labour laws, consumer protection and design standards.

SNC is committed to maintaining its awareness of these external drives when developing its plans.

5.3.2 Overview of Assets Managed

5.3.2.1 Description of the Service Area

5.3.2.1.1 Overview of the Service Area

SNC's service territory, previously shown in Figure 5.2-2 and Figure 5.2-3 includes the Cities of Thunder Bay and Kenora, as well as the Fort William First Nation reserve.

SNC's service territory in Thunder Bay encompasses an area of approximately 387 square kilometers. The service area is made up of approximately 70% rural and 30% urban (by customer density). Kenora serves an area of approximately 24 square kilometers and includes servicing customers on two islands on Lake of the Woods which are only accessible by boat or ice road. Both service territories are serviced mainly overhead resulting in a significant number of overhead assets per customer. Also, the geology in both areas consist of areas of bedrock surrounded by areas of silt, sand, and gravel; interspersed with areas of swamp. This geology can present installation challenges for both overhead and underground infrastructure.

Temperature/Extreme Weather

The climate in the Thunder Bay area is typical of a mid-latitude inland location with a Great Lake Moderating influence. The moderating effect of Lake Superior results in cooler summer temperatures and warmer winter temperatures for an area along the lakeshore extending inland. The large rural area previously described provides greater exposure to significant weather events such as high winds and heavy ice/snowstorms. The impacts of weather-related events on reliability have been described in detail in Section 5.2.3.2.2.

The climate in the Kenora area is typical of a mid-latitude inland location. Unlike the Thunder Bay area, there is no moderating effect of Lake Superior. Compared to Thunder Bay, average temperatures in Kenora tend to be colder in the winter and warmer in the summer. Kenora also experiences exposure to significant weather events such as high winds and heavy ice/snowstorms. The impacts of weather-related events on reliability have been described in detail in Section 5.2.3.2.2.

Economic Growth

A load forecast was completed in 2021 and reevaluated in January 2023, as a part of the IRRP process and through the process provided SNC with insight into the economic trends and variables affecting growth in its distribution system. The economic factors that were determined to influence growth in the service area are listed below:

- Commodity Prices (Timber, Grain, and Metals).
- Unemployment rates.
- Consumer Price Index (CPI).
- Inflation.

By reviewing these factors and their predictors over the forecast period, SNC expects economic growth to be gradual (Inflation of 0.5% in Thunder Bay and 1.25% in Kenora) over the forecast period. This prediction of slow economic growth is an input into the System Access category investment planning, and projects in this category are expected to remain relatively steady over the 2024-2028 forecast periods.

5.3.2.1.2 Customers Served

In 2022, SNC served 56,000 distribution customers across its service territory. The Thunder Bay service area includes urban and rural settings on the shore of Lake Superior. The Kenora service area includes urban as well as service to nearby islands on Lake of the Woods.

Table 5.3-3 below illustrates the changes in SNC's customer base over the historical period which includes customers divided into generic rate classes of residential, general service less than 50kW (GS<50), general service 50kW to 999kW (GS,50-999) and general service greater than or equal to 1000kW (GS>1000).

Table 5.3-3: SNC's 2017-2022 actual customer base

Year	Residential	GS<50 kW	GS,50-4999 kW	GS≥5000kW	Total
2022	50,974	5,452	480	0	56,906
2021	50,961	5,491	493	0	56,945
2020	50,903	5,451	533	0	56,887
2019	50,731	5,440	529	0	56,700
2018*	50,567	5,412	536	0	56,515
2017*	50,457	5,418	550	0	56,425

*Data for TBHEDI and KHECL have been combined as if a single entity existed.

5.3.2.1.3 System Demand and Efficiency

Table 5.3-4 shows the annual peak demand in kilowatts for SNC's distribution system.

Table 5.3-4: SNC's Peak demand 2017-2021

Year	Winter Peak (kW)	Summer Peak (kW)	Average Peak (kW)
2021	167,439	157,028	144,332
2020	163,651	152,810	140,845
2019	180,436	145,528	147,504
2018*	184,533	153,623	135,250
2017*	172,966	153,825	131,804

*Data for TBHEDI and KHECL have been combined as if a single entity existed.

SNC experiences its peak demand during the winter months. The data includes the net effect of embedded loads and generation. Variability in seasonal peaks is attributed to the loading impacts associated with the number of heating degree days.

Table 5.3-5 indicates the efficiency of the kilowatt-hours purchased by SNC. Losses remain in line with, or slightly below the provincial average annually. SNC anticipates a positive impact on losses as more of its system is converted from operating at 4kV to 25kV.

Table 5.3-5: Efficiency of kWh purchased by SNC 2017-2021

Year	Total kWh Purchased	Total kWh Delivered	Total Distribution Losses (kWh)	Losses as % of Purchased	Provincial Avg. as % [1]
2022	1,006,265,643	971,079,301	35,186,342	3.5%	-
2021	977,156,852	943,385,680	33,771,172	3.5%	-
2020	981,125,355	944,798,644	36,326,711	3.7%	4.0%
2019	1,018,293,942	977,890,898	40,403,044	4.0%	3.8%
2018[2]	1,027,796,515	992,998,487	34,798,028	3.4%	4.1%
2017[2]	1,014,412,596	982,184,499	32,228,097	3.2%	3.8%

[1] OEB metrics revised for 2021, only includes Total Metered Consumption
[2] Data for TBHEDI and KHECL have been combined as if a single entity existed.
Provincial data from OEB Yearbooks[15]

5.3.2.1.4 System Configuration & Utilization

In Thunder Bay, SNC's customers are serviced through three HONI owned and operated transformer stations:

- Port Arthur TS (P2);
- Birch TS (P17); and
- Fort William TS (P17)

These supply points distribute 25kV throughout the city. SNC further owns and operates four (4) 12kV municipal substations, and at the time of writing this DSP seven (7) 4kV municipal

[15] https://www.oeb.ca/ontarios-energy-sector/performance-assessment/natural-gas-and-electricity-utility-yearbooks

substations. The 12kV substations supply most of the rural distribution through the service territory and are generally configured in radial format with some capability to interconnect feeders. The 4kV network was, in general, meshed, however is becoming less so over time as conversion to 25kV continues.

In Kenora, SNC's customers are serviced through one municipal transformer station, KMTS. Three transformers at this station supply service to the entire City of Kenora at 12kV. The following tables further describe the circuit length and station utilization.

Table 5.3-6 Substation Ratings

<table>
<tr><th>STATION #</th><th>STATION NAME</th><th>TX ID</th><th>WINTER LTR RATING (MVA)</th><th>2022 PEAK DEMAND</th><th>PERCENT UTILIZATION</th></tr>
<tr><td rowspan="2">STN #2</td><td rowspan="2">PATS</td><td>2T1</td><td rowspan="2">61</td><td rowspan="2">28.1</td><td rowspan="2">46%</td></tr>
<tr><td>2T2</td></tr>
<tr><td rowspan="3">STN #17</td><td rowspan="3">BRTS</td><td>17T3</td><td rowspan="3">111</td><td rowspan="3">62.5</td><td rowspan="3">56%</td></tr>
<tr><td>17T2</td></tr>
<tr><td>17T4</td></tr>
<tr><td rowspan="2">STN #10</td><td rowspan="2">FWTS</td><td>10T5</td><td rowspan="2">109</td><td rowspan="2">73.4</td><td rowspan="2">67%</td></tr>
<tr><td>10T6</td></tr>
<tr><td rowspan="3">Kenora</td><td rowspan="3">KMTS</td><td>T1</td><td rowspan="3">24</td><td rowspan="3">18.9</td><td rowspan="3">79%</td></tr>
<tr><td>T2</td></tr>
<tr><td>T4</td></tr>
</table>

The following figures represent the forecasted peak electrical demand for SNC's service territory based on which the regional demand forecasts and planning have been completed. Figures Figure 5.3-4 to Figure 5.3-6 represent the load forecasts for SNC's Thunder Bay service area. While each station is projected to experience a modest increase in load in the future, asset utilization is not a material investment driver for SNC through the forecast period of 2024-2028 for these stations.

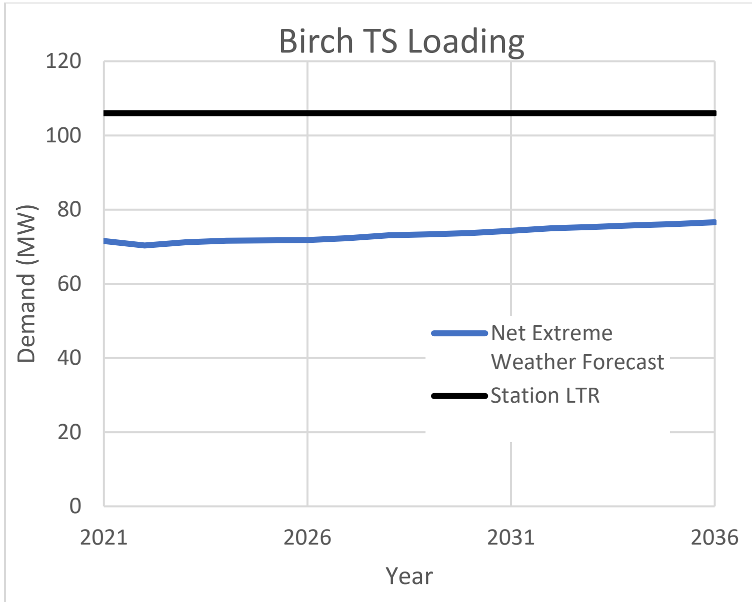


Figure 5.3-4 Birch TS Load Forecast

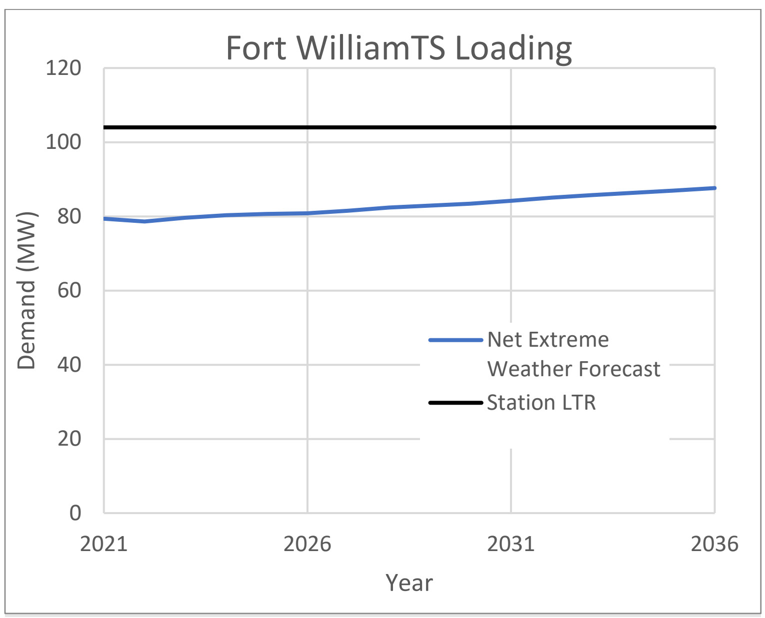


Figure 5.3-5 Fort William TS Load Forecast

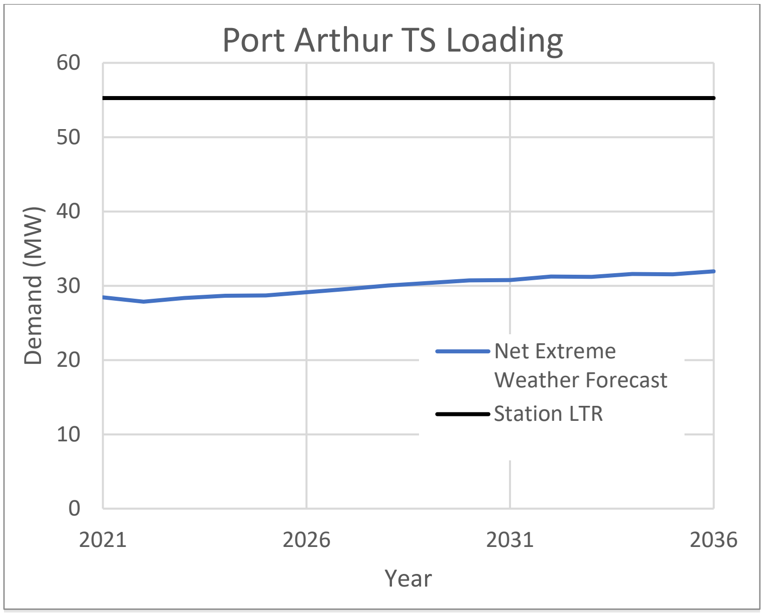


Figure 5.3-6 Port Arthur TS Load Forecast

Through the analysis performed as part of the Northwest IRRP, the IESO and SNC forecast for Kenora MTS is projected to reach capacity around 2030, as depicted in Figure 5.3-7 below.

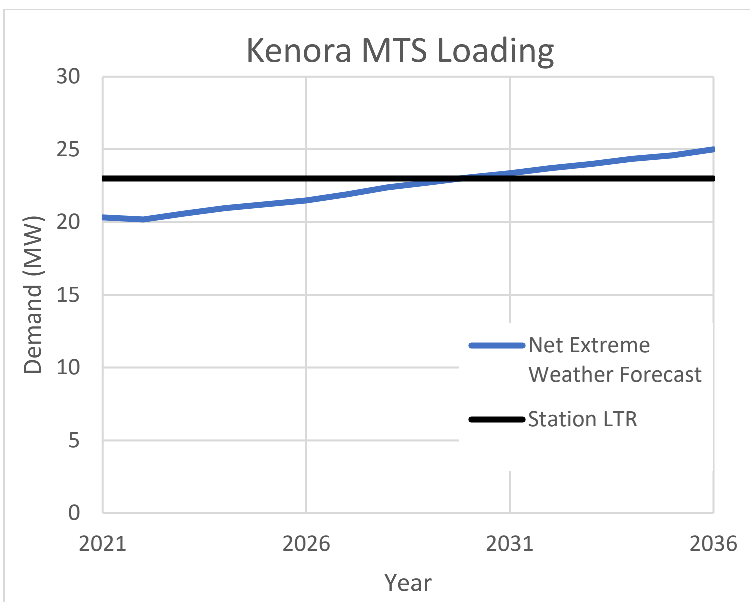


Figure 5.3-7 Kenora MTS Load Forecast

SNC does not intend to engage in any material investments in this DSP to mitigate this challenge. However, in anticipation of KMTS reaching its thermal capacity, SNC has retained the services of Power Advisory Group to provide options for managing this peak demand. Power Advisory was tasked with investigating investment solutions with emphasis on non-wires alternatives (NWAs). Their analysis has indicated that energy storage deployment opportunities may be more cost-effective than traditional wires investments.

The results of the study indicate that grid scale and behind-the-meter (BTM), energy storage solutions would allow for access to many different services reducing the cost of reliable service to Kenora; further, the project could be developed in stages to reduce cost and align with the load growth as compared to a traditional wires investment (e.g., new substation). Furthermore, BTM energy storage offers enhanced reliability for radially supplied customers that would otherwise not have effective options to improve their reliability, particularly for momentary outages. SNC is not seeking ACM funding for this constraint in this cost-of-service application. This is due to the uncertainty of the load growth, as well as the lack of complete information on the cost and timing to fully support a request for funding for the expected solution. SNC will continue to monitor the situation, as there is the possibility that load growth will arise unexpectedly and SNC will determine the appropriate regulatory tool for funding.

SNC, in conjunction with Power Advisory, has developed a roadmap to ensure that it remains well positioned to address the challenge with sufficient time for deployment and with the most cost-effective solution for its customers. The timeline is shown in Figure 5.3-8 below.

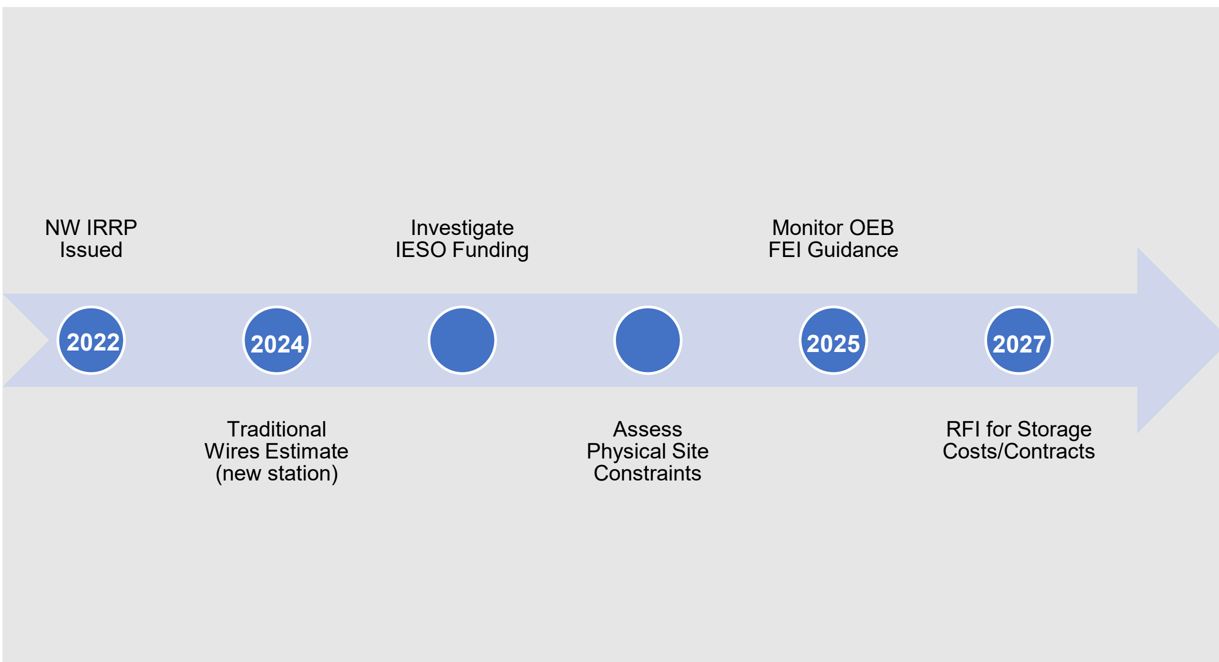


Figure 5.3-8 KMTS Energy Storage Deployment Timeline

5.3.2.1.5 Asset Condition and Demographics

The following table summarizes the approximate number of major distribution assets within SNC's service territory. Information regarding the condition of SNC's assets is presented in Figure 5.3-9 as a graphical overview. Both sources of information are current as of March 30, 2023.

Table 5.3-7 Major Distribution Assets (as of March 30, 2023)

Asset Description	Quantity (units[1])
Power Transformers	20
Circuit Breakers	58
Wood Poles	22362
Pad Mount Transformers	2490
Pole Mounted Transformers	4900
Vault Transformers	280
Overhead Switches	990
Underground Switches	88
Reclosers	65
Metering	57,074
Overhead Primary Conductor	998 cct-km
Overhead Secondary Cable	1169 cct-km
Underground Primary Cable	277 cct-km
Underground Secondary Cable	519 cct-km

[1] Unless otherwise noted, cct-km is the total length of conductor irrespective of configuration (I.e., Single phase or three phase) and will be less than total conductor length.

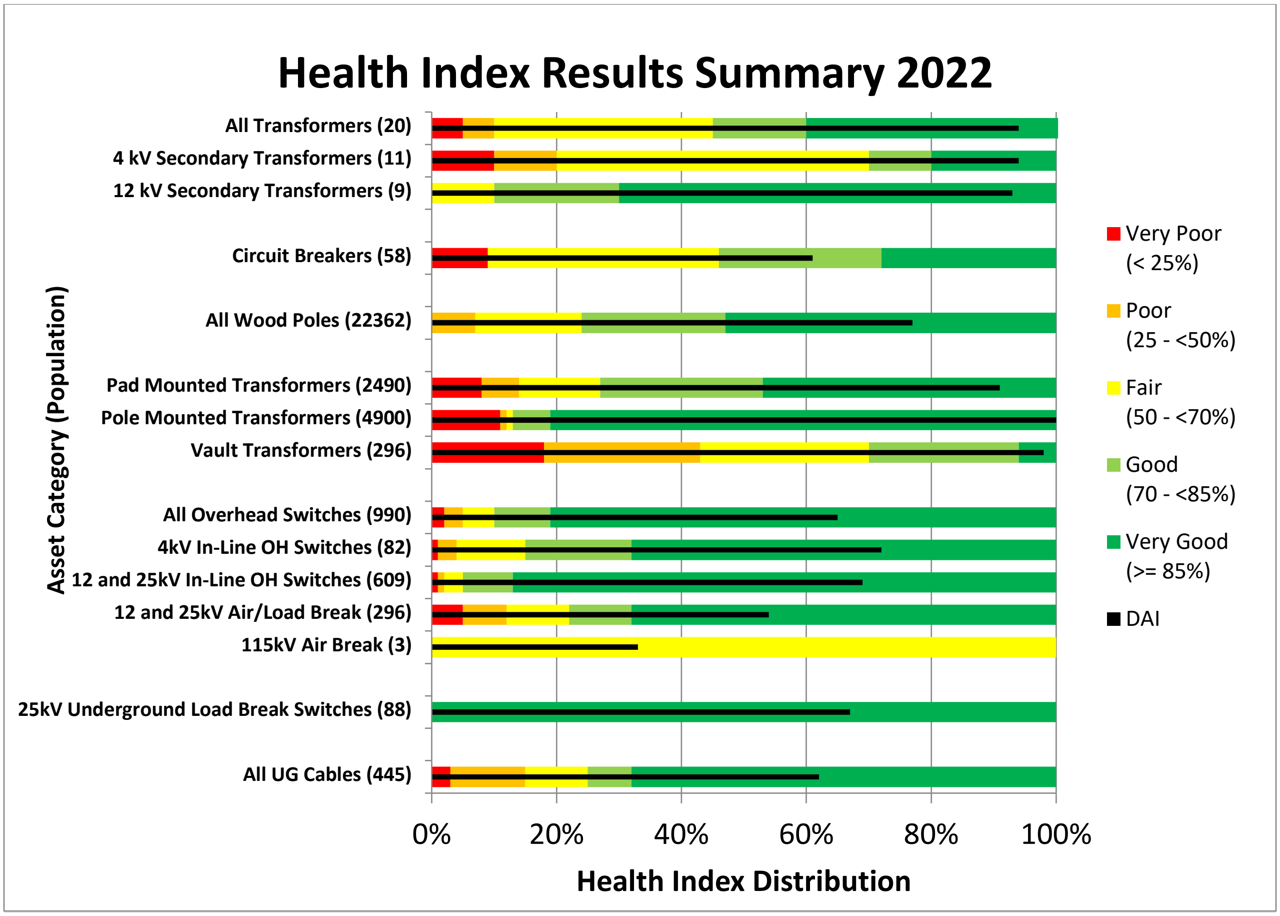


Figure 5.3-9 Health Index Summary

The Health Index (HI) is a direct output of the Asset Condition Assessment (ACA). ACA is the process by which the condition of an asset is determined based on known characteristics of the asset as well as the condition data that has been collected during inspection. SNC performs the detailed analysis of its assets. The methodology consists of creating a health index for each asset whereby condition scores are assigned to weighted categories unique to each asset class. Failure rates are then applied to each asset based on expert knowledge and industry averages. The result of this is a quantitative distribution for each asset category based on the 'health' of the individual assets in the category. The graphical representation of this, a stacked horizontal bar chart, allows for the easy identification of assets that are in poor health as a percentage of the population.

Health Index (HI) is a composite quantitative measure of an asset's condition based on available condition data (testing, inspections, utilization, expert opinion, age, etc.). The purpose of HI is to identify a subset of assets within the total population which require action. There are fundamentally 2 groups of assets:

1. Reactively replaced, i.e., run to failure with only replacement available as an action. For these assets the objective of the condition assessment was to predict what percentage of the population SNC needs to worry about over the next several years. For reactively replaced assets it is assumed that the consequence of failure is the same for each unit

and specific units are not identified for action, rather percentage of the total population. The probability of failure is related to the HI and used in conjunction with the demographics to estimate the number of units that are expected to fail each year. The probability curve was generated using typical and extreme lives of assets in each category to estimate the number of units (rather than specific units) that are expected to fail. Even “young” assets with low probability of failure contribute to the overall estimate since even some of the recently installed assets may fail while not all the “old” assets will.

2. Proactively replaced assets are usually replaced/refurbished/repaired before they fail based on the on their overall risk, which is a combination of probability of failure and consequence of failure, estimated using criticality. This is done for specific units, and they are marked for action once a threshold risk score or probability of failure levels is exceeded.

An overview of the strategy that SNC employs within each category is listed in Table 5.3-8 below.

Table 5.3-8 SNC Asset Operating Strategy

ASSET CATEGORY	OPERATING STRATEGY
Power Transformers	Proactive Maintenance
Circuit Breakers	Proactive Maintenance
Wood Poles	Reactive Maintenance
Pad Mounted Transformers	Reactive Maintenance
Pole Mounted Transformers	Reactive Maintenance
Vault Transformers	Reactive Maintenance
Overhead Switches	Reactive Maintenance
Underground Switches	Reactive Maintenance
Underground Primary	Reactive Maintenance
Reclosers	Reactive Maintenance
Metering	Reactive Maintenance
Overhead Primary Conductor	Reactive Maintenance
Overhead Secondary Cable	Reactive Maintenance
Underground Secondary Cable	Reactive Maintenance

5.3.2.2 Asset Information

5.3.2.2.1 Power Transformers

SNC’s 4kV and 12kV networks rely on power transformers to stepdown from 25kV primary to the secondary voltage noted. These assets are located throughout SNC’s distribution territory. It can be noted that from Table 5.3-9 these assets are well beyond the TUL of 45 years, as identified in the Report [16]provided by Kinectrics to the OEB for this asset class. Historically, SNC's replacement strategy has focused, and will continue to focus, on decommissioning heavily aged substation assets in conjunction with heavily aged wood pole assets connected to the aforementioned substations; as in general there is a strong correlation in condition. The implementation of this strategy has been to convert the 4kV network to 25kV through the wood pole renewal plan resulting in a decommissioning schedule whereby all 4kV power transformers would be removed from service over a 20-year period. This long-term strategy was initiated by the utility in 2008 and SNC continues to employ this strategy to the extent that it will continue to convert the 4kV network to 25kV and decommission its substations as a result. The rate at which this occurs will see all stations converted by the end of this DSP.

The decommissioning of these stations and subsequent project areas have been prioritized based on several factors including: interconnectivity of the station; condition of the substation; and condition of the assets connected to the station. A significant influencing factor in the project selection and prioritization was the interconnectivity of a particular 4kV station with other 4kV stations. This factor would allow SNC to maintain the network mesh of heavily interconnected substations for as long as possible for several reasons:

- Redundancy – preventing any one station from becoming islanded or disconnected from other stations thereby increasing the impact of failure;
- Reliability – maintaining the network mesh allows for load to be more readily transferred to other feeders during an outage event; and
- Operability – capability to isolate and transfer load during maintenance operation with minimal customer interruption.

The above considerations regarding interconnectivity along with the age of the infrastructure previously defined how SNC prioritized its overhead renewal projects.

Additionally, SNC intends to maintain all its 12kV power transformers as SNC's strategy has been to keep this subnetwork in-service long-term.

[16] "Asset Depreciation Study for the Ontario Energy Board", conducted by Kinectrics, July 8, 2010.

Table 5.3-9 Power Transformer Health

ID	Location	MVA	Pri. Voltage (kV)	Sec. Voltage (kV)	Age	HI Category	Flagged for Action Year
16T1	STN#16	4	23	4	69	Very Poor	0
21T1	STN 21	4	23	4	67	Poor	2
5T1	STN 5 DONALD	4	22	4	65	Poor	5
16T2	STN#16	4	23	4	64	Fair	5
21T2	STN 21	4	23	4	64	Fair	5
4T1	STN #4 VICKER	4	22	4	64	Fair	6
18T1	BALSALM	6.667	23	12	63	Fair	6
14T1	STN#14 ALGOMA	4	23	4	64	Fair	7
11T1	STN 11 HIGH ST	5	23	4	63	Fair	7
5T2	STN 5 DONALD	4	22	4	60	Good	10
12T1	STN#12 CAMELOT	6.667	24	4	54	Very Good	15
12T2	STN#12 CAMELOT	6.667	24	4	54	Very Good	15
36T1W	STN #36	2	22	12	55	Good	20+ years
36T1R	STN #36	2	22	12	55	Good	20+ years
36T1B	STN 36	2	22	12	55	Good	20+ years
KT4	KENORA MTS	9	115	12.5	13	Very Good	20+ years
23T1	STN#23	6.667	24.94	12	51	Very Good	20+ years
KT1	KENORA MTS	10	115	12.47	15	Very Good	20+ years
KT2	KENORA MTS	9	115	12.5	14	Very Good	20+ years
19T1	STN 19	6.667	24.94	12	43	Very Good	20+ years

Further review of Table 5.3-9 indicates that SNC's 4kV power transformers are in general, fair to poor health. In the case of the 12kV secondary transformers, which will remain in service, are in very good health. The Kinectrics study performed in 2016 that extended the serviceable life of power transformers has proven to align with SNC's observations from the field to date. Heat is one the main elements that contribute to insulation degradation in transformers. Overloading of transformers and high utilization during peak ambient temperatures contribute to increased heating within transformers, which in turn leads to insulation and dielectric breakdown.

Oil tests provide insight into whether these events have occurred in the past and are a consideration in the health of transformers. SNC's oil test results indicate that over time, the rate of degradation of the 4kV power transformers has slowed. The results of the oil tests are likely a consequence of the fact that the transformers are lightly loaded (due to the conversion process systematically removing load), and peak loading occurs in the winter months. These factors have likely contributed to the findings in the ACA for this asset category.

However, SNC has experienced unexpected failures of these units where internal arcing required the transformers to be immediately removed from service, repaired, and closely monitored to ensure that the failure was corrected. The costs associated with this activity go directly to OM&A.

SNC has attempted to align its 4kV renewal program with the flagged for action year identified in Table 5.3-9 allowing each transformer to remain in service as long as possible, with the intent of decommissioning all 4kV stations by the end of this DSP. This is contingent upon several factors including the condition of the connected assets, as well as the interconnectivity of the stations.

5.3.2.2.2 Circuit Breakers

SNC currently only employs circuit breakers within its 4kV substations. In general, the age and condition of these units are like that of the stations in which they are deployed. This is evident from Table 5.3-10 below. These assets are inspected and maintained to ensure that they remain in service while the corresponding station is in service; otherwise, they are removed from service at the time of station decommissioning.

Table 5.3-10 Power Circuit Breakers

ID	Station	Location	Type	Manufacturer	Age	HI Category	Flagged for Action Year
34912	14	Algoma St.	OCB	General Electric	67	Very Poor	1
34913	14	Algoma St.	OCB	General Electric	67	Very Poor	1
34914	14	Algoma St.	OCB	General Electric	67	Very Poor	1
34915	14	Algoma St.	OCB	General Electric	67	Very Poor	1
34916	14	Algoma St.	OCB	General Electric	67	Very Poor	1
2-0444-1	4	Vickers	ACB	Allis Chalmers	64	Fair	20+ years
2-0444-2	4	Vickers	ACB	Allis Chalmers	64	Fair	20+ years
2-0444-3	4	Vickers	ACB	Allis Chalmers	64	Fair	20+ years
2-0444-4	14	Algoma St.	OCB	General Electric	74	Fair	0
38923	14	Algoma St.	OCB	General Electric	74	Fair	0
38924	14	Algoma St.	OCB	General Electric	74	Fair	0
38925	14	Algoma St.	OCB	General Electric	74	Fair	0
38926	14	Algoma St.	OCB	General Electric	74	Fair	0
38927	4	Vickers	ACB	Allis Chalmers	69	Fair	17
52775	4	Vickers	ACB	Allis Chalmers	69	Fair	17
52776	4	Vickers	ACB	Allis Chalmers	69	Fair	17
52777	4	Vickers	ACB	Allis Chalmers	69	Fair	17
52781	16	MacDonnell	OCB	General Electric	69	Fair	17
201097	16	MacDonnell	OCB	General Electric	69	Fair	17
201131	16	MacDonnell	OCB	General Electric	69	Fair	17
201133	16	MacDonnell	OCB	General Electric	69	Fair	17
231986	16	MacDonnell	OCB	General Electric	69	Fair	17
231987	16	MacDonnell	OCB	General Electric	69	Fair	17
52778	16	MacDonnell	OCB	General Electric	69	Fair	17
52782	16	MacDonnell	OCB	General Electric	69	Fair	17
52784	16	MacDonnell	OCB	General Electric	69	Fair	17
52785	21	Windemere	OCB	English Electric	67	Fair	20+ years
51854	21	Windemere	OCB	English Electric	67	Good	20+ years

ID	Station	Location	Type	Manufacturer	Age	HI Category	Flagged for Action Year
51853	21	Windemere	OCB	English Electric	67	Good	20+ years
51855	21	Windemere	OCB	English Electric	67	Good	20+ years
51856	21	Windemere	OCB	English Electric	67	Good	20+ years
51857	21	Windemere	OCB	General Electric	67	Good	20+ years
55979	21	Windemere	OCB	General Electric	67	Good	20+ years
55980	21	Windemere	OCB	General Electric	67	Good	20+ years
55981	21	Windemere	OCB	General Electric	67	Good	20+ years
55982	5	Donald	OCB	General Electric	65	Good	20+ years
55983	5	Donald	OCB	General Electric	65	Good	20+ years
52774	5	Donald	OCB	General Electric	65	Good	20+ years
52779	5	Donald	OCB	General Electric	65	Good	20+ years
52780	5	Donald	OCB	General Electric	65	Good	20+ years
52783	5	Donald	OCB	General Electric	65	Good	20+ years
52786	5	Donald	OCB	General Electric	65	Good	20+ years
55560	5	Donald	OCB	General Electric	65	Very Good	20+ years
55565	5	Donald	OCB	General Electric	65	Very Good	20+ years
55561	5	Donald	OCB	General Electric	65	Very Good	20+ years
55563	18	Balsam St.	OCB	General Electric	64	Very Good	20+ years
55570	18	Balsam St.	OCB	General Electric	64	Very Good	20+ years
55559	18	Balsam St.	OCB	General Electric	64	Very Good	20+ years
55562	18	Balsam St.	OCB	General Electric	64	Very Good	20+ years
55564	18	Balsam St.	OCB	General Electric	64	Very Good	20+ years
55566	12	Camelot St.	ACB	General Electric	61	Very Good	20+ years
55567	12	Camelot St.	ACB	General Electric	61	Very Good	20+ years
55569	12	Camelot St.	ACB	General Electric	61	Very Good	20+ years
1742876	12	Camelot St.	ACB	General Electric	61	Very Good	20+ years
1742877	12	Camelot St.	ACB	General Electric	61	Very Good	20+ years
1742875	12	Camelot St.	ACB	General Electric	61	Very Good	20+ years
1742878	12	Camelot St.	ACB	General Electric	61	Very Good	20+ years
1742879	12	Camelot St.	ACB	General Electric	61	Very Good	20+ years

Both circuit breakers and station transformers are highly critical assets and as such, are assessed on an individual basis and a corresponding condition is assigned to each unit. This methodology is typically employed for assets which are proactively maintained or those that are costly to replace on a per unit basis.

It can be noted in Table 5.3-10 that that ACA has identified several assets which are flagged for action outside of the current planning window of this DSP. The intent is to maintain the breakers to ensure that they remain in service until such time as the corresponding station is decommissioned, rather than attempt to replace these with new units, which would require a capital investment from SNC.

The remainder of the assets to follow are operated on a run-to-fail basis (see Table 5.3-8 for a summary of operating strategies). These types of assets are assessed as a population. As a result, a condition is assigned to a percentage of the population and more specifically a quantity of assets is flagged for each category. Together these two approaches support an effective and balanced renewal program in this DSP.

5.3.2.2.3 Wood Poles

The results of the latest ACA for SNC's wood pole population are shown in Figure 5.3-10 and Figure 5.3-11 below. The condition is based on several factors both characteristic and extrinsic to the asset which are documented through SNC's inspection process. The figures indicate that approximately 75% of the wood pole population is in Good to Very Good condition. The sample size used to determine the health index equates to 100% of the population.

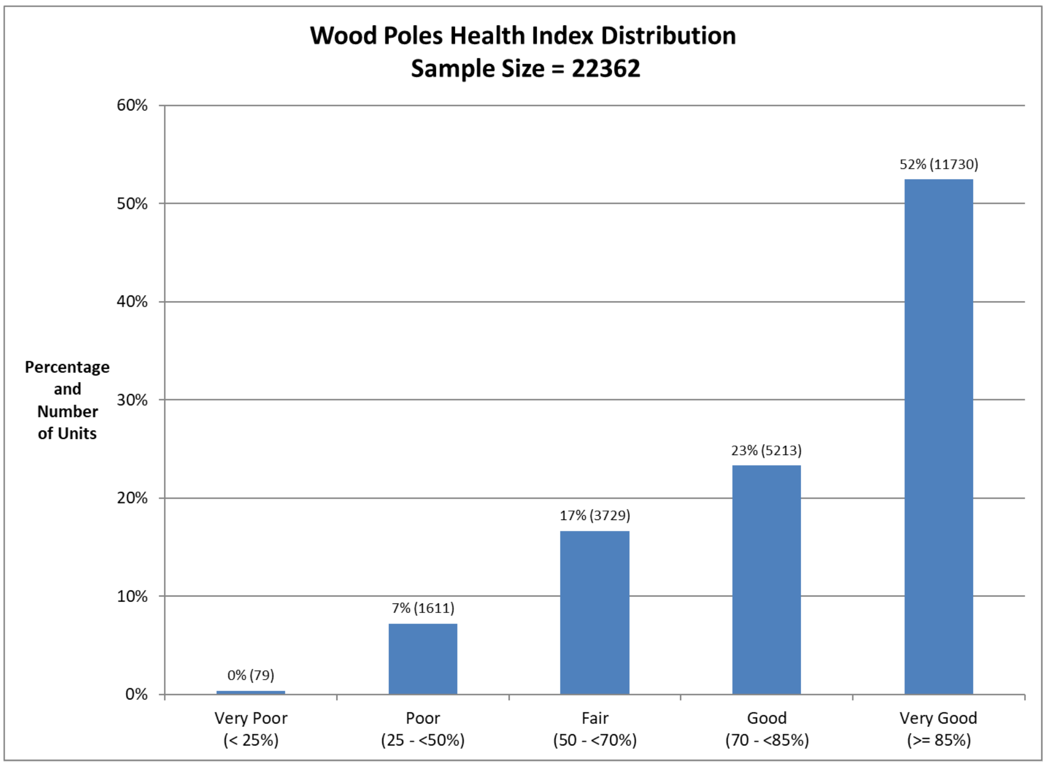


Figure 5.3-10 Wood Pole Health

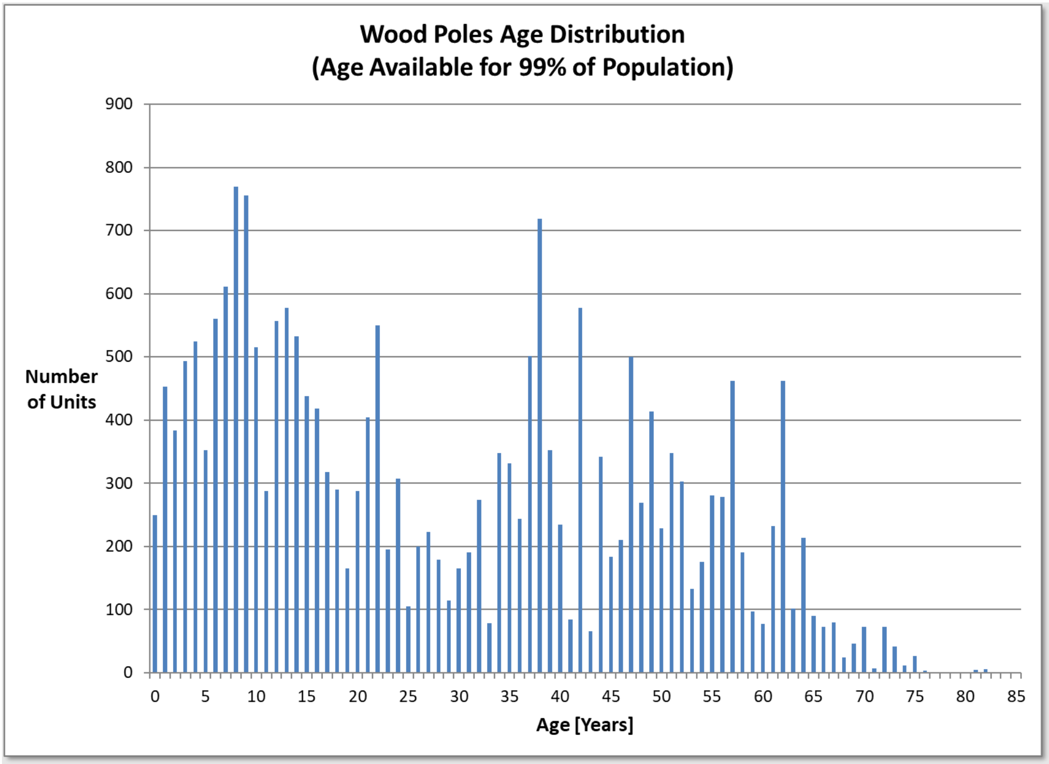


Figure 5.3-11 Wood Pole Age Distribution

5.3.2.2.4 Pad Mounted Transformers

Pad mount transformers and pad mount equipment in general are largely impacted by external factors that lead to expedited degradation such as salt and moisture at the ground level. This information is tracked via the inspection process and is an important factor in determining the health of the assets in this category. The sample size used to determine the health index equates to 100% of the population.

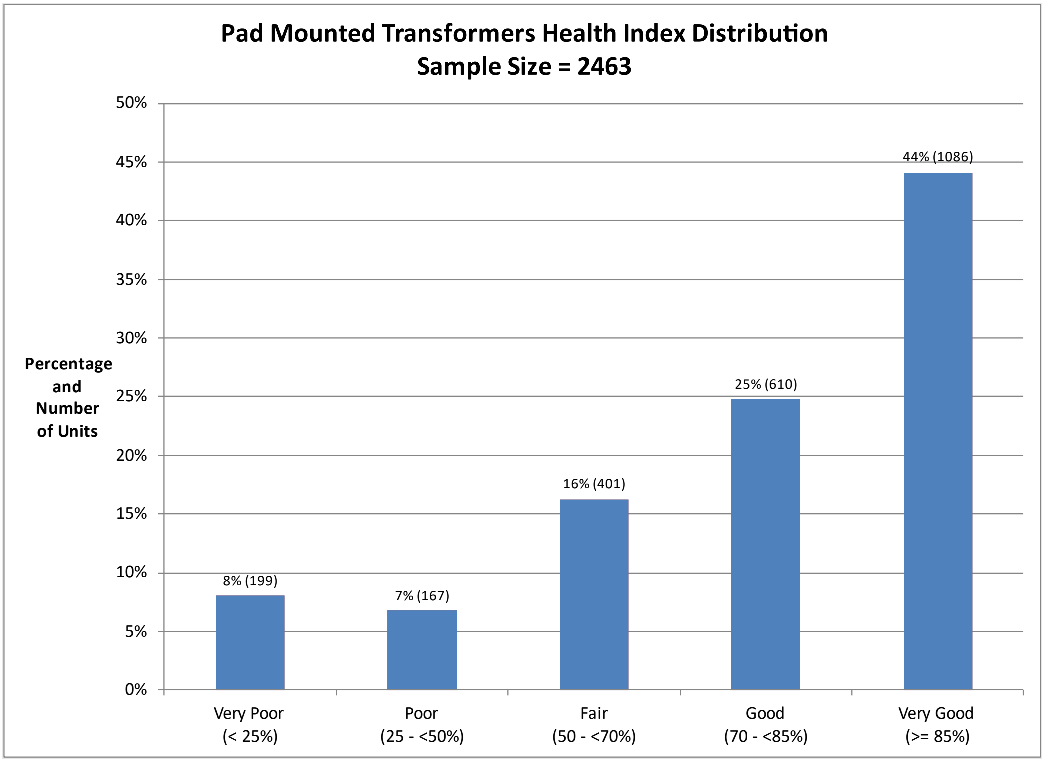


Figure 5.3-12 Pad Mounted Transformer Health

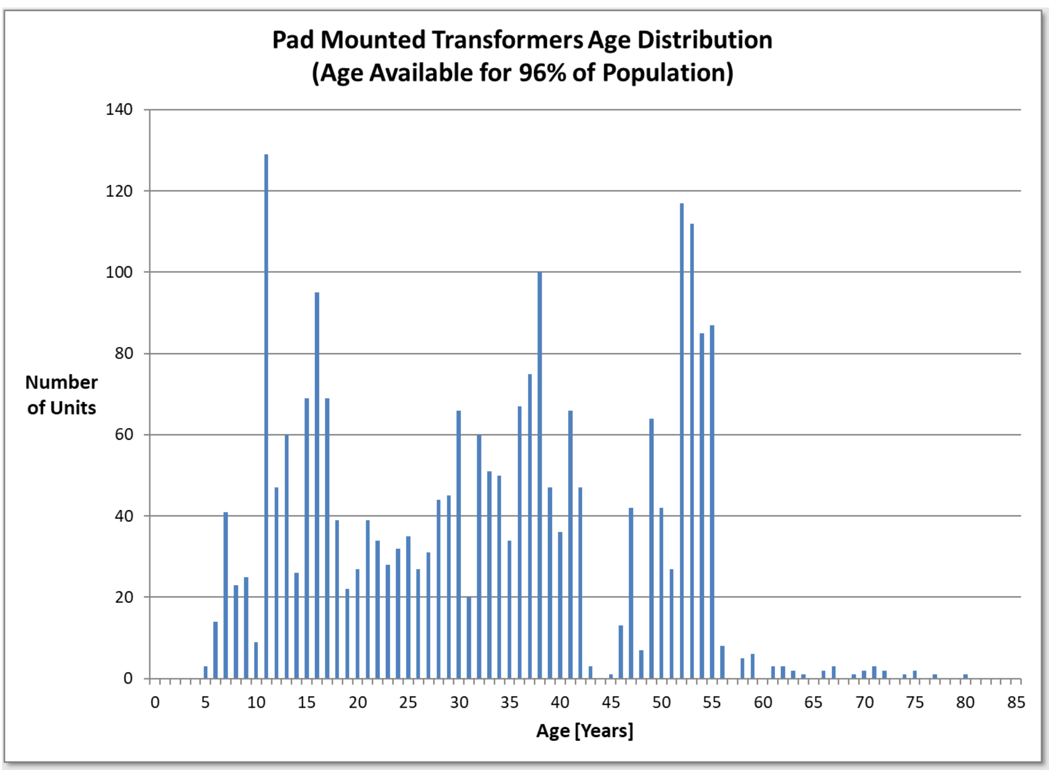


Figure 5.3-13 Pad Mounted Transformer Age Distribution

a

5.3.2.2.5 Pole Mounted Transformers

Pole mount transformers are minimally impacted by external factors and as a result most of the population are in very good health for a wide variety of ages as indicated in Figure 5.3-14 and Figure 5.3-15 below. Most of these units are managed through the conversion process and through attrition. The sample size used to determine the health index equates to 100% of the population.

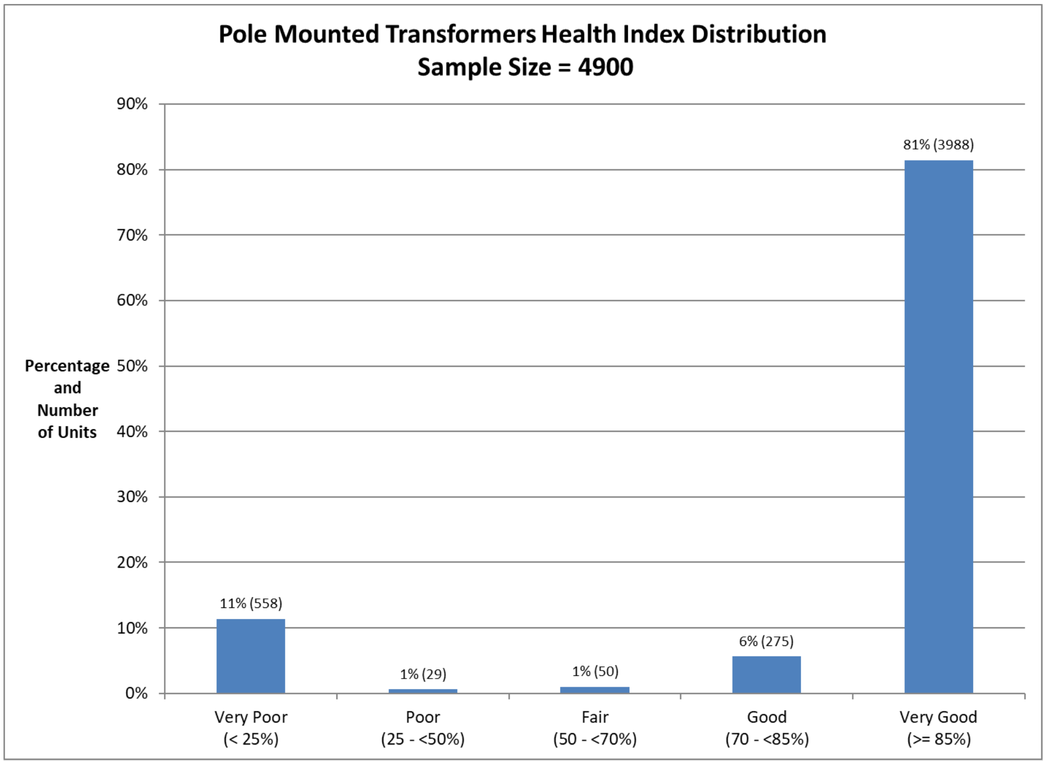


Figure 5.3-14 Pole Mounted Transformers Health

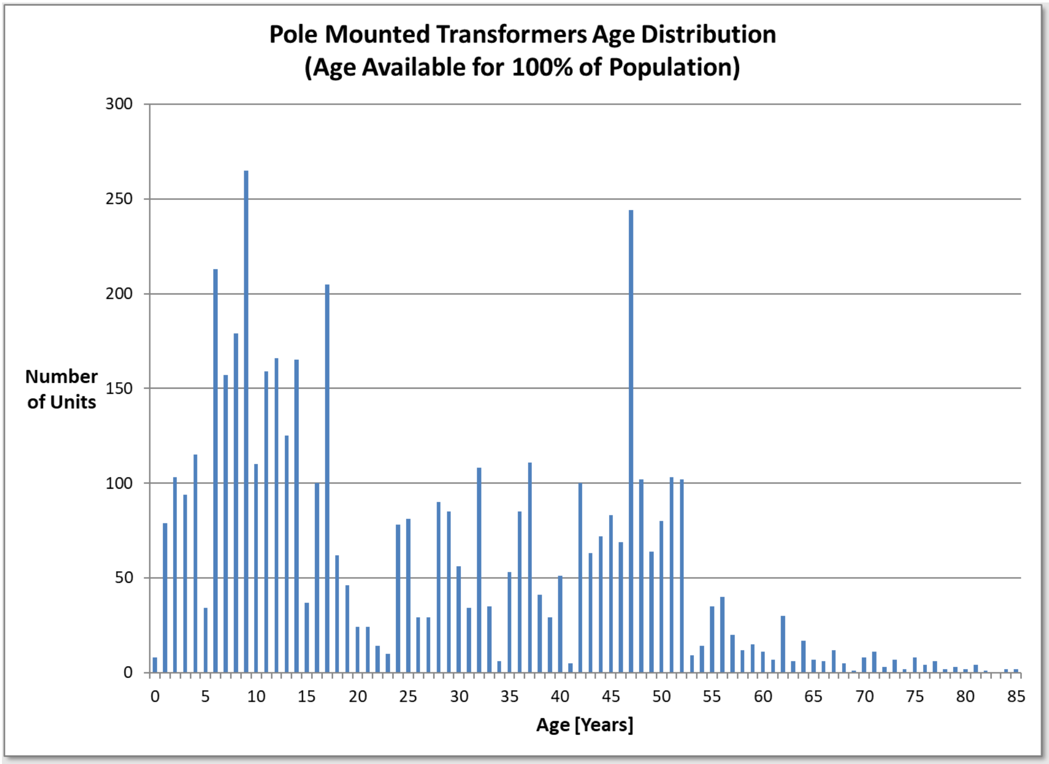


Figure 5.3-15 Pole Mounted Transformers Age Distribution

5.3.2.2.6 Vault Transformers

Vaults represent a relatively small asset group. However, they generally service commercial customers and subsequently their health can be of greater concern. The condition of these units is monitored closely through the inspection process and is an important factor in the overall health of the units. It can be noted from Figure 5.3-16 and Figure 5.3-17 below that older units represent a large majority of the population. The sample size used to determine the health index equates to 100% of the population.

Due to the nature of their installation (difficult access, business and commercial customers require replacements off hours, longer replacement duration), the replacement of vault transformers must be carefully considered. With nearly 70% of these units in fair to very poor condition SNC is moving towards a proactive replacement schedule for these assets.

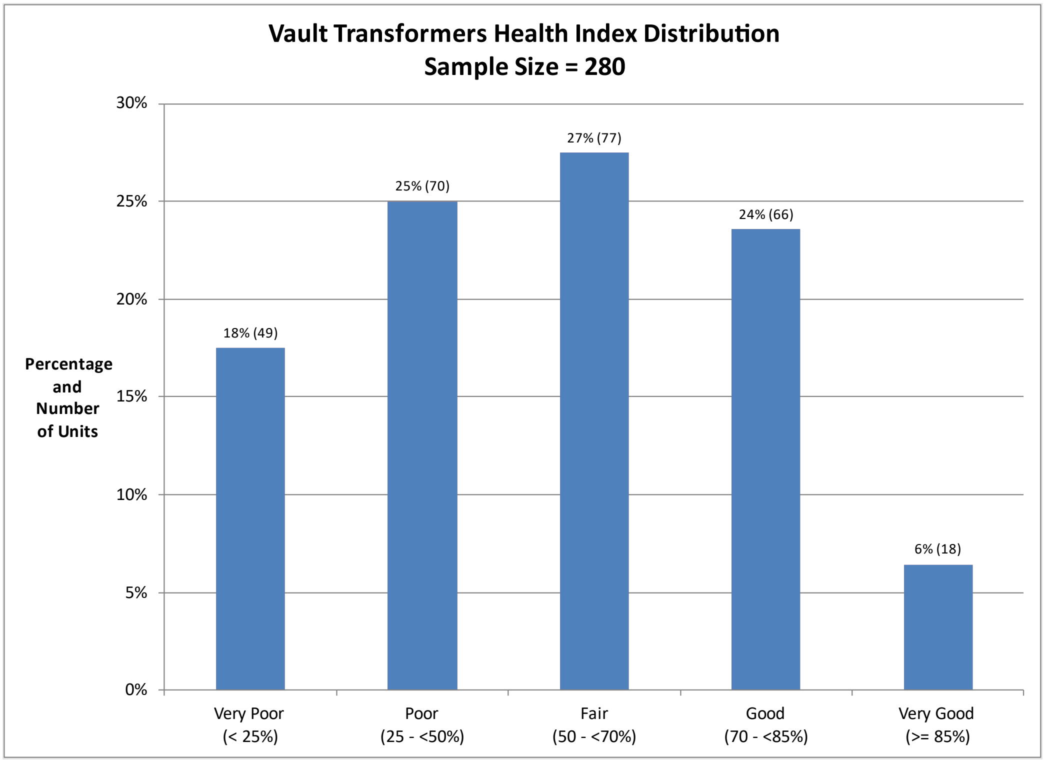


Figure 5.3-16 Vault Transformer Health

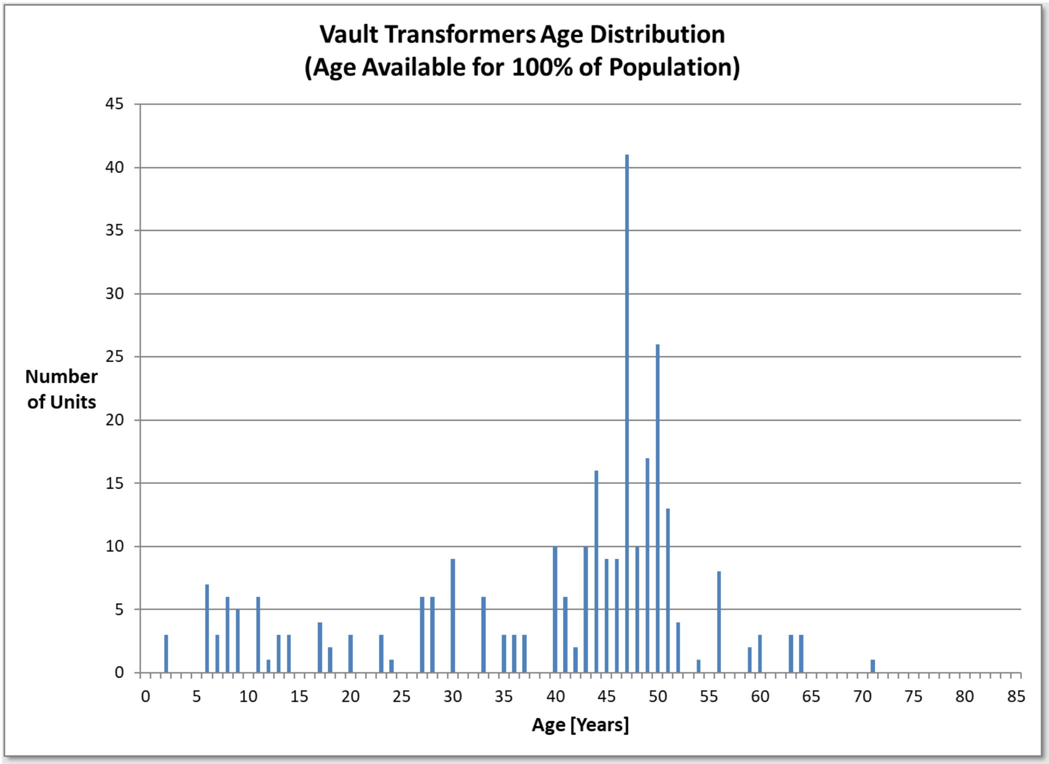


Figure 5.3-17 Vault Transformer Age Distribution

5.3.2.2.7 Overhead Switches

Overhead and Underground switch health is monitored through the inspection process where each switch is inspected once every three years to align with the requirements of the distribution system code. This helps to ensure that SNC can quickly and effectively isolate and restore power to its customers to minimize outage times and provide a safe working environment for its employees. The sample size used to determine the health index equates to 85% of the population and is based on the inspection data for the population which is the main consideration in the health of these assets.

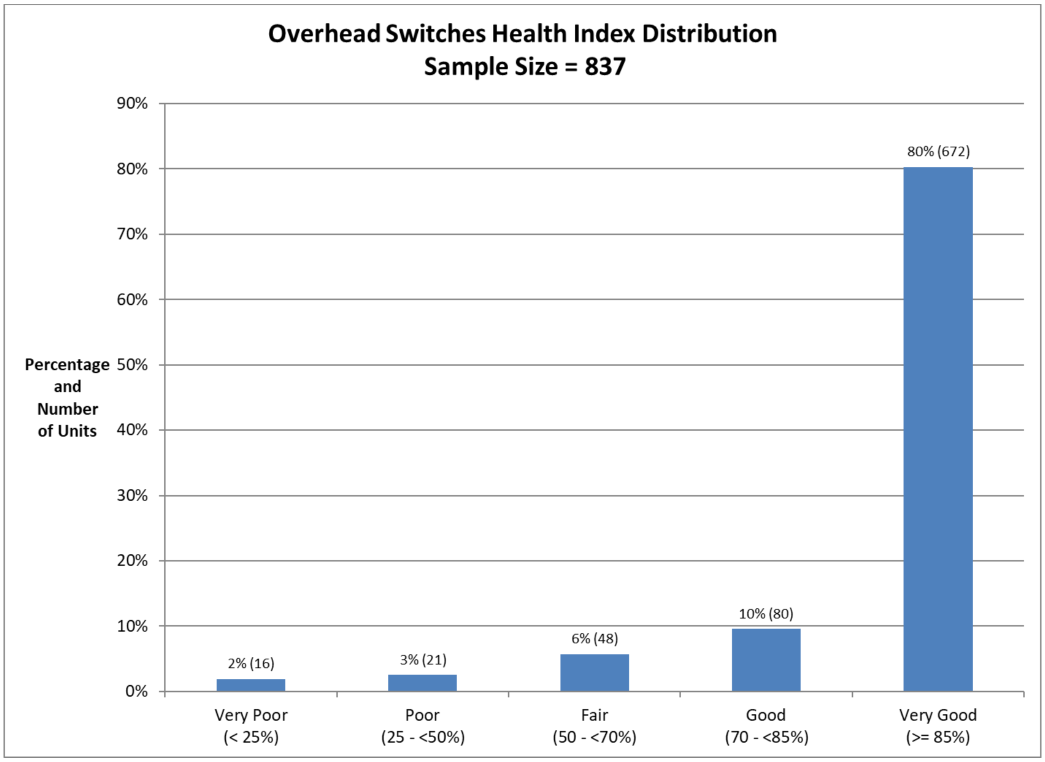


Figure 5.3-18 Overhead Switch Health

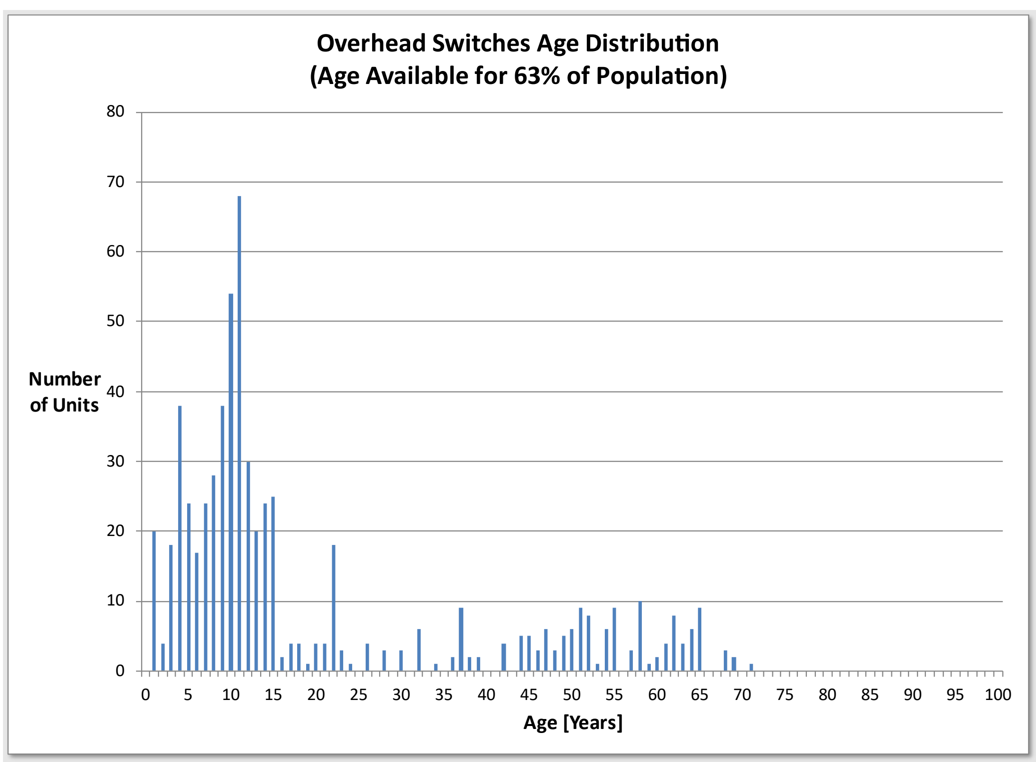


Figure 5.3-19 Overhead Switch Age Distribution

5.3.2.2.8 Underground Switches

The sample size used to determine the health index equates to 90% of the population and is based on the inspection data for the population which is the main consideration in the health of these assets.

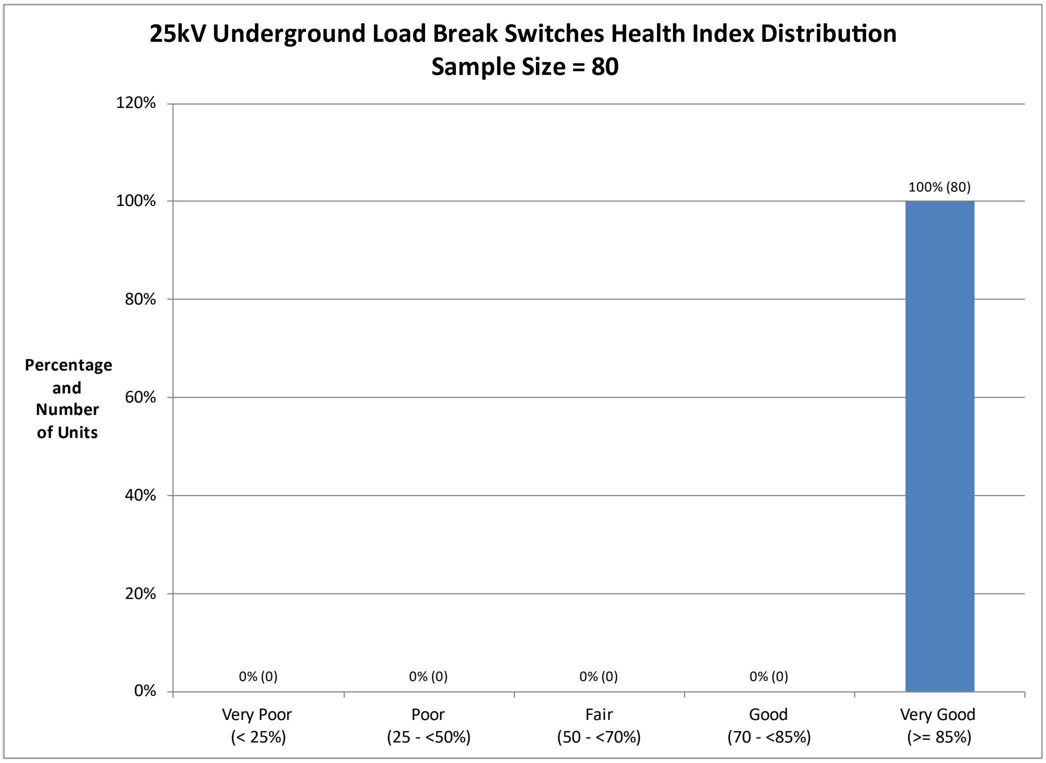


Figure 5.3-20 Underground Switch Health

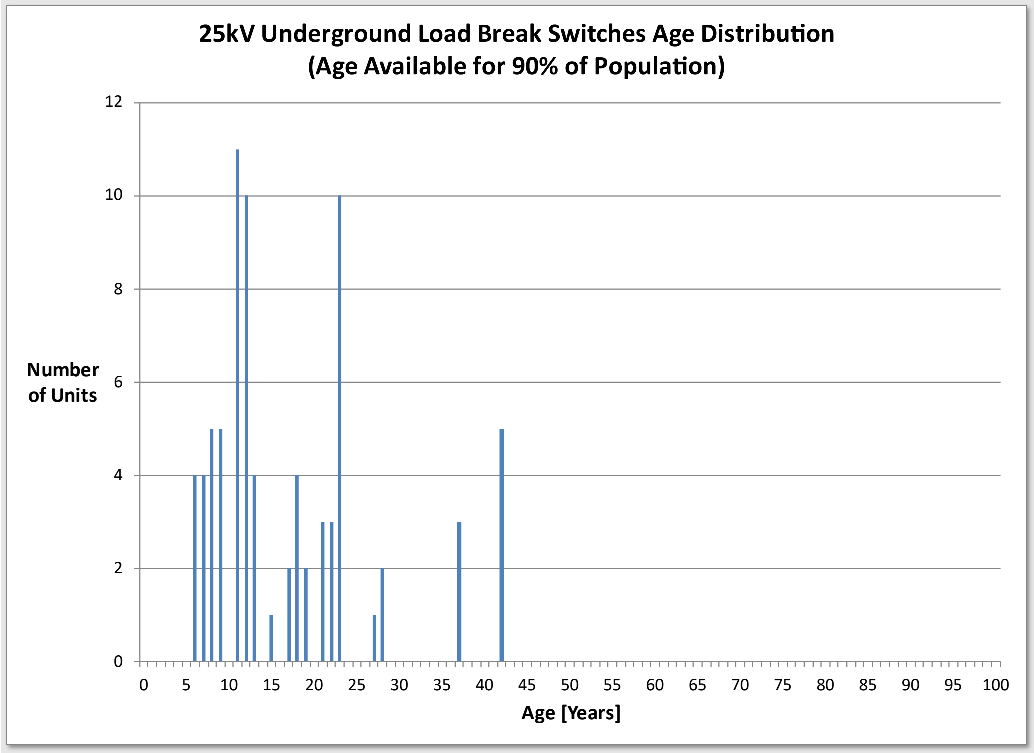


Figure 5.3-21 Underground Switch Age Distribution

5.3.2.2.9 Underground Cables

SNC has a large backlog of underground cable to address through rejuvenation or replacement. As it is comparatively expensive to replace and difficult to observe the degradation of the health of underground infrastructure as opposed to overhead, thus the implementation of a renewal strategy has been delayed. The results of this delay have become apparent through the findings within the ACA and noting that there is a spike of assets (36 conductor km) that are 47 years of age, indicate that this asset class requires attention. SNC is in the process of performing quantitative testing on direct buried cables in its subdivisions, as well as critical cables elsewhere to enable cost effective planning on how to address this backlog. As discussed in section 5.3.1.2.5, SNC is investigating the merits of cable rejuvenation as it is approximately one third the cost of traditional replacement. The sample size used to determine the health index equates to 91% of the population and is based on the known age data for the population and non-destructive testing data.

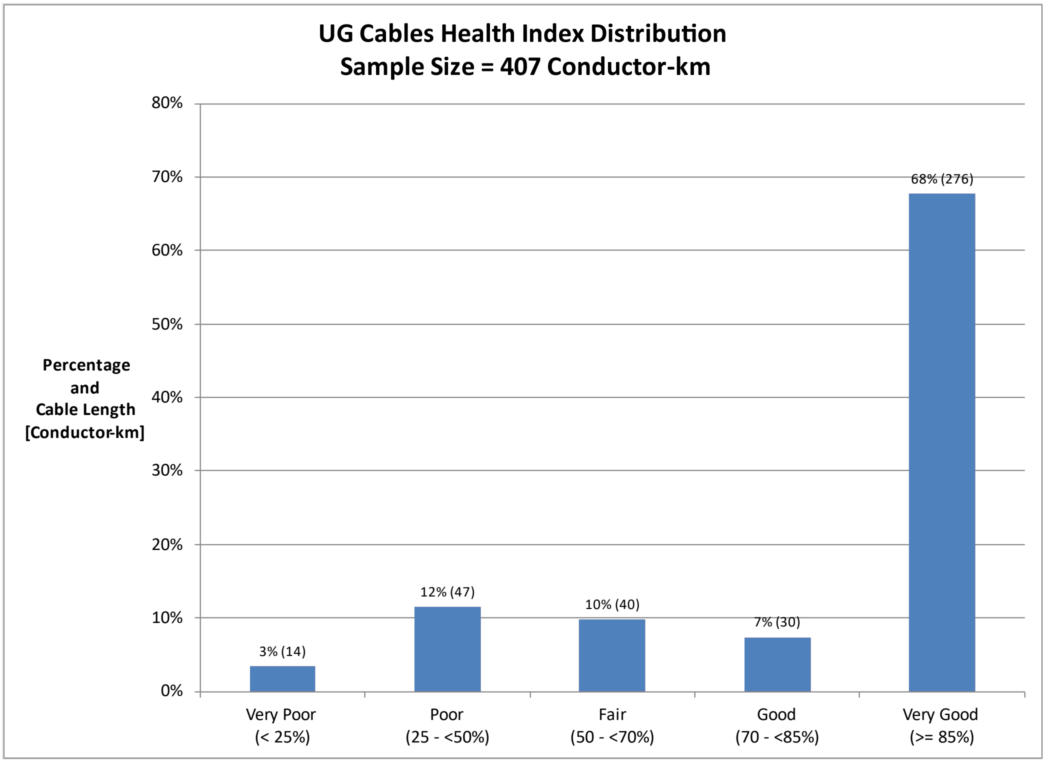


Figure 5.3-22 Underground Cable Health

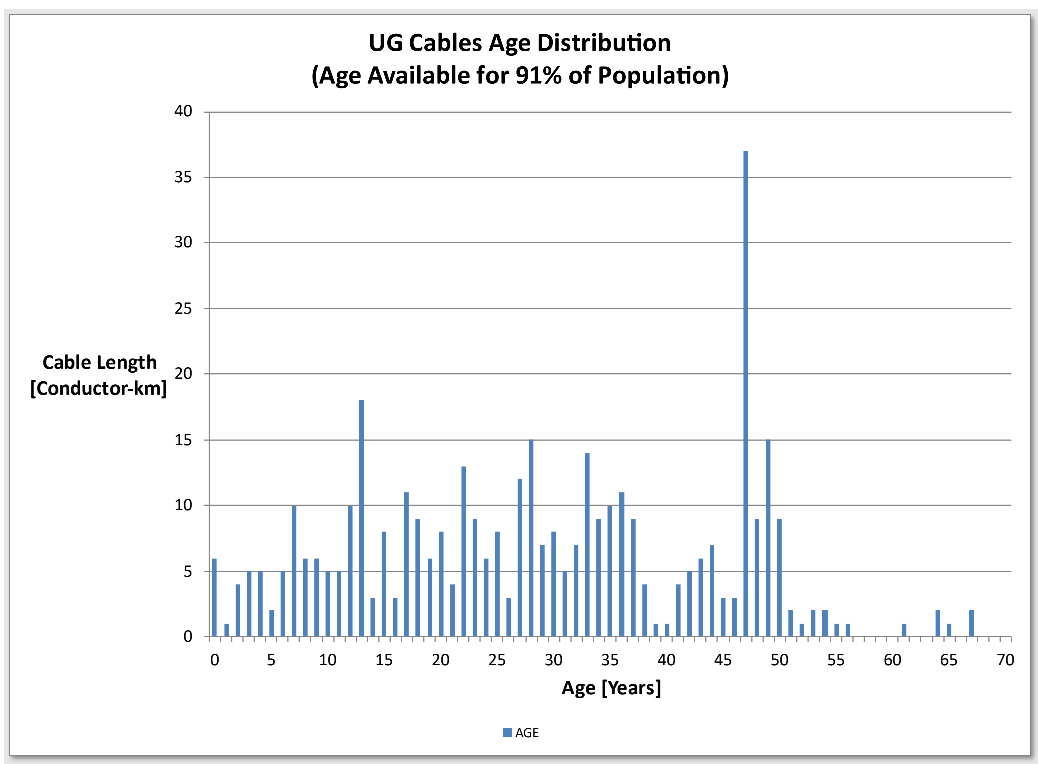


Figure 5.3-23 Underground Cable Age Distribution

5.3.2.2.10 Meters

SNC owns approximately 57,074 electronic smart meters, which were originally installed in 2009. These meters, manufactured by Elster, expired in 2019 and SNC undertook a comprehensive sampling campaign to extend their seal life. As per Measurement Canada requirements a meter with an expired seal cannot be left in service for revenue / billing purposes. SNC has developed a Smart Meter Sampling Plan (Appendix F) which detail all the activities necessary to establish a smart meter pre-sampling and final compliance sampling program which aligns with the requirements detailed within Measurement Canada's (MC) Statistical Method Specification (S-S-06). SNC anticipates another re-seal campaign to occur for 46,584 of these meters in 2027. This is to allow the utility to extend their smart meter's in-service life and ultimately maximize the return on investment (ROI).

5.3.2.2.11 Fleet/Rolling Stock

As of May 1, 2023, SNC has 67 mobile units and 24 trailered / towed items within its fleet. There are 27 light vehicles (supervisor, crew, departmental, underground and stations vehicles), 22 line trucks (RBDs, single / double buckets) and 5 pieces of load/haul/dump (LHD) equipment, 1 fork-lift and 1 easement machine and 1 work boat. The trailered / towed fleet items include pole trailers, equipment floats, stringing machines, pullers / tensioners, cable reel trailers, dump trailers, portable compressor, and an emergency power supply trailer. For additional details, see Appendix E.

5.3.2.3 Transmission and High Voltage Assets

SNC owns the following high voltage assets:

- 115/12.47kV Transmission Station KMTS (Kenora)

These assets have been deemed as distribution assets and SNC does not intend to change their status to transmission assets.

5.3.2.4 Host & Embedded Distributors

SNC is not a host or embedded distributor. SNC receives electricity from HONI at the transmission level. There are no embedded distributors served by SNC's distribution system.

5.3.3 Asset Lifecycle Optimization Policies and Practices

SNC uses a wholistic approach to managing assets throughout their lifecycle. SNC places emphasis on balancing performance, cost and risk when determining the optimal trade-off between refurbishment and replacement. See section 5.3.1.2 for a summary of changes to the asset management processes since the last filing.

5.3.3.1 Asset Replacement and Refurbishment Policy

5.3.3.1.1 Asset Replacement vs. Asset Renewal Strategy

SNC attempts to balance the customer's need for reliability and the capital expenditure costs associated with maintaining or improving that reliability. This is done by considering the relative scale and importance of assets or systems and selecting the most appropriate asset management approach to achieve the overall organizational objectives. Alternatives of proceeding or not proceeding with a given approach are given careful consideration. See the alternatives analysis in Appendix H for more information.

Additionally, SNC also considers the future requirements of the asset when selecting the appropriate asset management approach. For example, in the case of transformer replacements, SNC will analyze historical loading data in conjunction with future demand forecasts regarding EV loading and home heating requirements. This data will inform transformer replacement sizing.

For most of SNC's overhead distribution assets, replacement is the only viable option. Assets such as distribution transformers, conductor, insulators, lighting arrestors and poles represent a low initial capital investment and have few renewable components. SNC has explored and implemented several restorative techniques for these infrastructure types in the past but has not found a widely accepted maintenance practice that will cost effectively extend the life of these assets, nor reduce the instance of premature failure. As a result, these assets continue to be replaced rather than refurbished. SNC continues to explore and implement new techniques when deemed appropriate.

Assets targeted for refurbishment are generally high value assets or those required for system protection, the majority of which are in stations and fleet. Assets such as power transformers, circuit breakers, light-duty and heavy-duty vehicles are inspected and maintained on a regular basis to ensure they are in proper working order. Several of these assets pose a significant capital investment and have many renewable components; the replacement of which can ensure the asset continues to remain in service as long as possible. Recently, SNC piloted a project of cable rejuvenation to determine its viability. This process was discussed in Section 5.3.1.2.5.

In some instances, functional obsolescence requires the replacement of assets. Distribution assets that no longer meet the demands of the system due to loading, short circuit levels or other specific criteria are generally targeted for replacement.

Several assets in SNC's distribution system are either no longer supported by manufacturers and/or the manufacturers no longer exist. Assets where equipment suppliers no longer stock renewable components for these assets and/or where SNC has depleted any remaining collected renewable components are often targeted for replacement. One example of this includes overhead air-break switches.

5.3.3.2 Description of Maintenance and Inspection Practices

SNC's Operations and Maintenance (O&M) programs are designed to follow the guidelines set out in the OEB's Appendix C of the DSC for inspection and maintenance of all key distribution system assets. The results of these inspections are a key component of the asset condition assessment and are critical to the prioritization of O&M as well as capital spending. The output provides a levelized list of assets targeted for action. This action can be refurbishment or replacement and is contingent upon the asset renewal strategy described below.

SNC employs a reactive based maintenance (RM) strategy for most of its assets outside of stations. This is often defined as breakdown maintenance and is unscheduled and immediate remediation of a failed asset. As previously indicated, most of the assets managed in this manner cannot be cost effectively maintained in a way that reduces their instance of failure. SNC is open to any new techniques and research that becomes available but does not anticipate any changes to this practice will occur over the forecast period.

Preventative maintenance (PM) is employed for some station assets that SNC owns and operates. This PM strategy is the time-based or operations-based maintenance at a particular interval to attempt to curb untimely failures. The extent and frequency to which PM is performed is based on the type of asset, industry best practice, manufacturer specifications and impact of previously mentioned untimely failures. One example of assets targeted for PM is medium voltage circuit breakers. See Table 5.3-8 for SNC's asset operating strategy for its major assets.

SNC regularly monitors the condition of its large value assets using industry best practice methods. These assets, aside from regular visual inspection, do not lend themselves well to routine PM as they lack routinely renewable components. These assets typically represent large capital investments and high customer impact such as station transformers. The results of these analyses are utilized to predict the future condition of these assets and determine if there is an imminent risk of failure. This condition-based maintenance (CBM) approach allows for a cost effective, proactive response to mitigate the risk of failure.

For detailed information on SNC's maintenance and inspection programs refer to Appendix C.

5.3.3.2.1 Maintenance Planning Assumptions

SNC plans its maintenance and inspection activities on an annual basis. Budgets for these functions are developed utilizing historical costs for repair as well as labour hours required to perform inspections.

It is assumed that exclusive of inflation, historical repair costs will be consistent with future repair costs for each asset category. The budget envelopes may be adjusted annually based on the quantity of assets assumed to require service based on health of the population and results of the inspection process.

Inspection costs are based on historical hours required to complete the asset inspections. SNC has divided its service territory into three inspection zones that contain approximately comparable quantities of assets for inspection in each zone annually. In this way SNC can predict what the typical inspection costs will be annually.

Municipal substation inspections occur monthly. As substations are removed from service over the forecast period, the labour associated with inspections is expected to be reallocated to other activities (such as increased maintenance levels at other stations to ensure they maintain their operability).

5.3.3.3 Routine and Preventative Inspection and Maintenance Programs

The following O&M programs are conducted annually to assess the condition of our assets, to perform routine maintenance and assist in identifying end-of-life assets to ensure the system continues to operate safely and reliably.

5.3.3.3.1 Municipal Substation Inspection and Maintenance

SNC currently owns and operates 11 municipal substations within its service territory. Testing and maintenance of transformers and associated substation equipment is aligned with the Distribution System Code (DSC) and occurs monthly, as well, some station equipment is inspected and or tested annually or semi-annually. Defects noted during inspection are either corrected immediately during the inspection phase or scheduled for corrective action, depending on the complexity of the repair. A summary of station inspection points is provided below.

Table 5.3-11 Substation Inspection and Maintenance

	Inspection Activity	Potential Findings/Inspection Points	Frequency
Power Transformers	Visual and/or Infrared Inspection	Tank and Gasket Integrity	Monthly
		Sampling valve seals	
		Oil Level	
		Oil conservator condition	
		External tank condition	
		Fan & pump condition	
		Bushing external condition and termination integrity	
		Surge arrester condition	
		Tap changer Position	
		Condition of pressure relief devices	
	Oil Screen & Moisture Content Testing	Soluble contaminants and oxidation products - sludging characteristics of the transformer	Annual
		Moisture content which may lead to degraded dielectric strength	
	Dissolved Gas Analysis	Gases formed during periods of fault or overload	Annual
	Furanic Compound Testing	Dissolved compounds indicative of cellulose breakdown/decomposition caused by sustained periods of overheating	Annual
Circuit Breakers	Visual/Operational Inspection	Drawout Assembly Function	Annual
		Arcing Contacts Integrity	
		Main Contacts Integrity	
		Insulator Hygiene	
		Tank Condition	

		Internal Mechanisms	
		Pallet Switch Condition	
		Oil Condition	
		Closing Mechanism Condition	
		Trip Mechanism Condition	
		Arc Chutes	
		Closing Relay	
		Motor Operator Function	
		Heaters	
		Trip Free Operation	
		Anti-Pump Operation	
	Electrical Testing	Hi-Pot Medium Voltage Terminations	Annual
		Hi-Pot Low Voltage Terminations	
		Main Contacts Resistance Testing	
Batteries	Standard Testing	Check Cell Float Voltage	Quarterly
		Check Battery Terminal Voltage	
	Performance Testing	Capacity Testing	Quinquennial
		Service Testing	
Fencing	Visual Inspection	Unauthorized access around perimeter	Annual
		Gaps in access	
		Mesh Condition	
		Barbed Wire Condition	
		Grounding & Bonding Condition	
		Objects in Proximity to the Fence	
Risk Assessments	Visual Inspection	OCB's	Annual
		Transformers	
		Switchgear	
		Structures	
		Fencing	
		Buildings	
		Relays	
		Control Equipment, Ancillaries, Battery Banks Etc.	

5.3.3.3.2 Pad mount Transformer and Switch Inspection and Maintenance

The inspection of these units coincides with the requirements set forth in the DSC in so far as they are inspected over a three-year cycle. Through the inspection process SNC assesses the current condition, through visual inspection, of the asset and the surrounding area, noting the integrity of the unit as well as any potential safety hazards. During this inspection, if defects are noted they are processed in several ways:

- defects that pose a safety hazard to personnel or the public (e.g., access to the cable chamber) are scheduled for immediate remediation;
- defects that appear to impact the integrity of the asset (e.g., significant rusting) are scheduled for a detailed inspection; and
- defects that may affect the operability of the asset or are minor in nature (e.g., vegetation in front of the door) are scheduled for remediation and are prioritized based on available resources to complete the work.

If a transformer is found to be in such poor condition or deemed unrepairable by trained inspectors, it will be replaced proactively to avoid reactive replacement in the near term.

5.3.3.3.3 Vault Transformer Inspection and Maintenance

The inspection of these units coincides with the requirements set forth in the DSC in so far as they are inspected over a three-year cycle. Vault transformers are contained within customer owned infrastructure and during the inspection process SNC inspects items related to its assets as well as those items related to the condition of the customer owned assets. This includes ensuring: the vault is secure and inaccessible to the public; lighting is working appropriately; the civil infrastructure is in good condition; ventilation functions normally; and the appropriate signage is in place. Along with this SNC inspects its transformer and connections and notes any defects that require maintenance. Due to the nature of the installation being out of the elements and in a controlled environment, vault transformers typically enjoy a long life. However due to the cost and complexity of removing and replacing these units upon failure, consideration is given to converting these installations to pad mounted infrastructure.

Where defects to customer owned infrastructure are identified, SNC notifies the customer as to the nature of the defect and seeks a timeline for remediation.

5.3.3.3.4 Pole Mounted Transformers Inspection and Maintenance

The inspection of these units coincides with the requirements set forth in the DSC in so far as they are inspected over a three-year cycle. The inspection process checks for leaks and general tank condition; condition of the bushings; and oil discoloration which indicates flashover. Pole mount transformers have relatively few failures as a population and as such require little in the way of regular maintenance to ensure these units reach their typical useful lives. However, if a transformer is found to be in such poor condition by trained inspectors, it will be replaced proactively to avoid reactive replacement in the near term.

5.3.3.3.5 Distribution Pole Inspection and Testing

The inspection of these assets coincides with the requirements set forth in the DSC in so far as they are inspected over a three-year cycle. SNC conducts a visual inspection of all the poles it owns within its service territory. The inspection considers overall pole condition and condition of pole attachments. Poles that have been identified, through visual inspection, as being in poor condition are further inspected in detail. Through non-destructive testing (Polux 5) inspectors attempt to ascertain the extent to which the asset has deteriorated at the ground-line. Poles identified as being a hazard or in imminent risk of failure are replaced immediately; other poles are prioritized based on their health as part of the asset management and capital planning process.

5.3.3.3.6 Overhead Switch Inspection and Maintenance

The inspection of these assets coincides with the requirements set forth in the DSC in so far as they are inspected over a three-year cycle. The intention is to ensure that every switch is at least visually inspected every three years. Visual inspection of the in-line, air-break, load-break, and recloser population is captured under this initiative. Switch maintenance activities are conducted in parallel with switch inspection activities. Where the inspection determines that maintenance of the switch is required, the inspection crew may conduct the maintenance immediately and note this on the inspection form. Where the crew is unable to immediately perform the maintenance, a deficiency is noted on the inspection form. The completed detailed inspection form is submitted for prioritization based on available resources and details of the annual inspection are then logged into the inspection database. In every case, switches targeted for renewal are vetted against their necessity in the system, if deemed appropriate, may be decommissioned as opposed to replaced.

5.3.3.3.7 Vegetation Management

Thunder Bay Service Territory

Historically, in Thunder Bay, SNC faced challenges in addressing significant vegetation overgrowth to return vegetation management to sustainable levels. While ongoing maintenance occurred, much of the vegetation was managed in a reactionary manner, responding to customer concerns as they arose. Between 2018 and 2021 SNC had seen a rise in reactionary spending due to the increase in customer driven requests. For example, in 2021, Synergy North budgeted $531,000 in OM&A sub-contractor costs for vegetation management but spent $784,000 due to customer driven calls to mitigate vegetation hazards.

In late 2021, SNC took a decisive step to managing vegetation along its power lines. Through a strategic partnership with the City of Thunder Bay, SNC was able to collect and analyze aerial lidar data for its Thunder Bay service area. The results of this analysis objectively indicate that most of the overhead distribution system was at risk due to vegetation in proximity.

Based on the extent of the problem SNC developed four key objectives to effectively manage the risk to the system. They are:

1. Eliminate Immediate Hazard – remove any vegetation within 1m of the overhead primary lines, to eliminate burning hazards.
2. Create a Vegetation Register – create and maintain an up-to-date tree inventory and assessment tool to gain a better understanding of tree growth rates and future needs to proactively manage encroachments.
3. Meet Industry Standards – demonstrate the levels of work, resources and budget that are required to meet the minimum industry standard of a 3m corridor for overhead primary wires.
4. Establish an Optimal Cycle – determine the levels of work, resource and budget that are required to maintain our levels of service, continue to operate in a safe and efficient state and reach an optimal cycle of vegetation management.

To achieve these objectives SNC has taken a phased approach to minimize the impact on customers.

Phase 1 – Hazard Elimination and Data Collection

Between 2022 and 2023 SNC plans to eliminate all vegetation within 1m of the overhead primary conductor and remove this immediate hazard. Concurrent to this activity SNC will refine its inventory and assessment tools of vegetation within the powerline corridor. This requires inventorying trees (including information such as height, diameter, health, species etc.), as well as define the likelihood and consequence of failure. This information will help model lifecycle behaviors and develop efficient vegetation control cycles.

Phase 2 – Meeting Industry Standards

Over the course of this phase, which is anticipated to last five years, SNC plans to continue to eliminate hazards, moving to meet the industry standards/regulatory requirements of up to 3m on primary lines.

Phase 3 – Optimal Cycle Moving Forward

SNC plans to utilize data and information gathered during the previous phases to develop detailed asset management plans specific to vegetation management. This will allow SNC to make informed decisions about our vegetation management practices balancing risk, cost, and performance in line with our other corporate policies, strategies, and objectives.

SNC analyzed three spending scenarios to determine the above course of action:

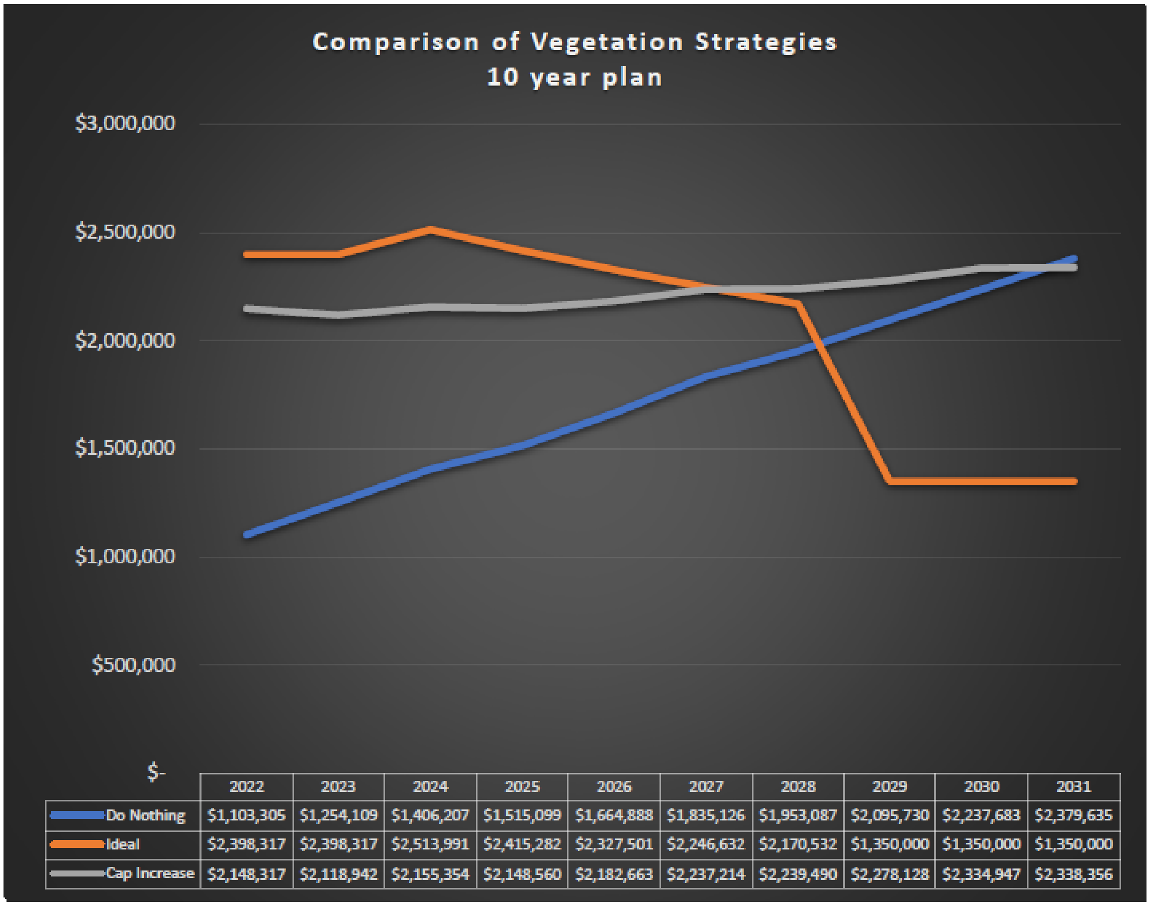
1) Do Nothing – continue to spend reactively over the next 10 years;

2) Increase spending to an annual cap – attempt to reach optimal cycle while minimizing rate impacts; and

3) Ideal program – increase spending to achieve an optimal cycle by the end of our DSP.

Table 5.3-12 10 Year Vegetation Management Projections

Scenario 1 – Continue Reactive Program	Scenario 2 – Increase budget with a cap of 1.1 million	Scenario 3 – Ideal Program
$ 17.85 million	$ 16.19 million	$ 17.84 million



	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Do Nothing	$1,103,305	$1,254,109	$1,406,207	$1,515,099	$1,664,888	$1,835,126	$1,953,087	$2,095,730	$2,237,683	$2,379,635
Ideal	$2,398,317	$2,398,317	$2,513,991	$2,415,282	$2,327,501	$2,246,632	$2,170,532	$1,350,000	$1,350,000	$1,350,000
Cap Increase	$2,148,317	$2,118,942	$2,155,354	$2,148,560	$2,182,663	$2,237,214	$2,239,490	$2,278,128	$2,334,947	$2,338,356

Figure 5.3-24 Vegetation Management Strategy Comparison

To compare the three scenarios against each other, the above chart was produced to indicate the total spend over the 10-year period, with the Ideal Scenario already having completed one iteration of the "Optimal Cycle" of the entire distribution system, while the Spending Cap program is still in the "Meeting Standards" phase due to the growth of vegetation.

The Do-Nothing program is similar in total spend to the Ideal program, but it continues to only manage customer-reported immediate hazards and leaves the utility in a high-risk position.

Based on the above, SNC's decision was to move forward with the Ideal vegetation management plan, and to achieve an optimal cycle following the completion of this DSP.

SNC made significant progress on this program in 2022 and is on track to complete Phase 1 of the plan to manage all vegetation within 1m proximity of the overhead line by the end of 2023.

One of the lessons learned during project initiation was that there were data gaps in the Lidar data set. It was discovered that the vegetation point cloud data was classified well, but there was a small issue in the overhead wires. Some of the wires were not fully captured. In these instances, SNC could not determine the distance to wire and discovered more vegetation within 1m proximity than originally thought. Phase 1 of the vegetation management plan included data collection to refine its inventory and assessment tools of vegetation within the powerline corridor. These data gaps have been closed to ensure accurate future lifecycle behavior and efficient vegetation control cycles. Refer to the Vegetation Management Plan in Exhibit 4 for further details.

Kenora Service Territory

In 2019, Kenora Hydro and Thunder Bay Hydro merged to become SNC. Up to this point, Vegetation Management activities in Kenora had been performed by internal PLT's. The work involved responding to customer concerns, storm activity and some maintenance activities, with no formal vegetation management program.

Since then, Kenora's service territory has been divided into 4 quadrants, with each zone being approximately equivalent in size (see Figure 5.3-25). Vegetation management activities took place in Zone 1 following the merger in 2019. Subsequently in 2020, operations continued in Zone 3. Coney Island's (Zone 4) vegetation was managed in 2021. This area is boat access only and requires crews and equipment to obtain the necessary transportation to perform work on site.

Vegetation management within Zone 2 is ongoing at the time of writing but is intended to be complete by the end of 2023.

All zones are being managed to meet the CSA Standard of 3m on overhead primary lines. Due to the scale of the work contractors were employed to complete these activities.

The cost to perform large scale vegetation management in Kenora is higher (relative to Thunder Bay) due to the requirements of mobilizing forestry crews from Thunder Bay to the Kenora area, as well as the mobilization costs to perform work on remote work locations such as Coney Island. However, Kenora's vegetation management activities have improved in cost-effectiveness due to the managed nature of activities post-merger. SNC is also investigating working with contractors local to the Kenora district to improve efficiency.

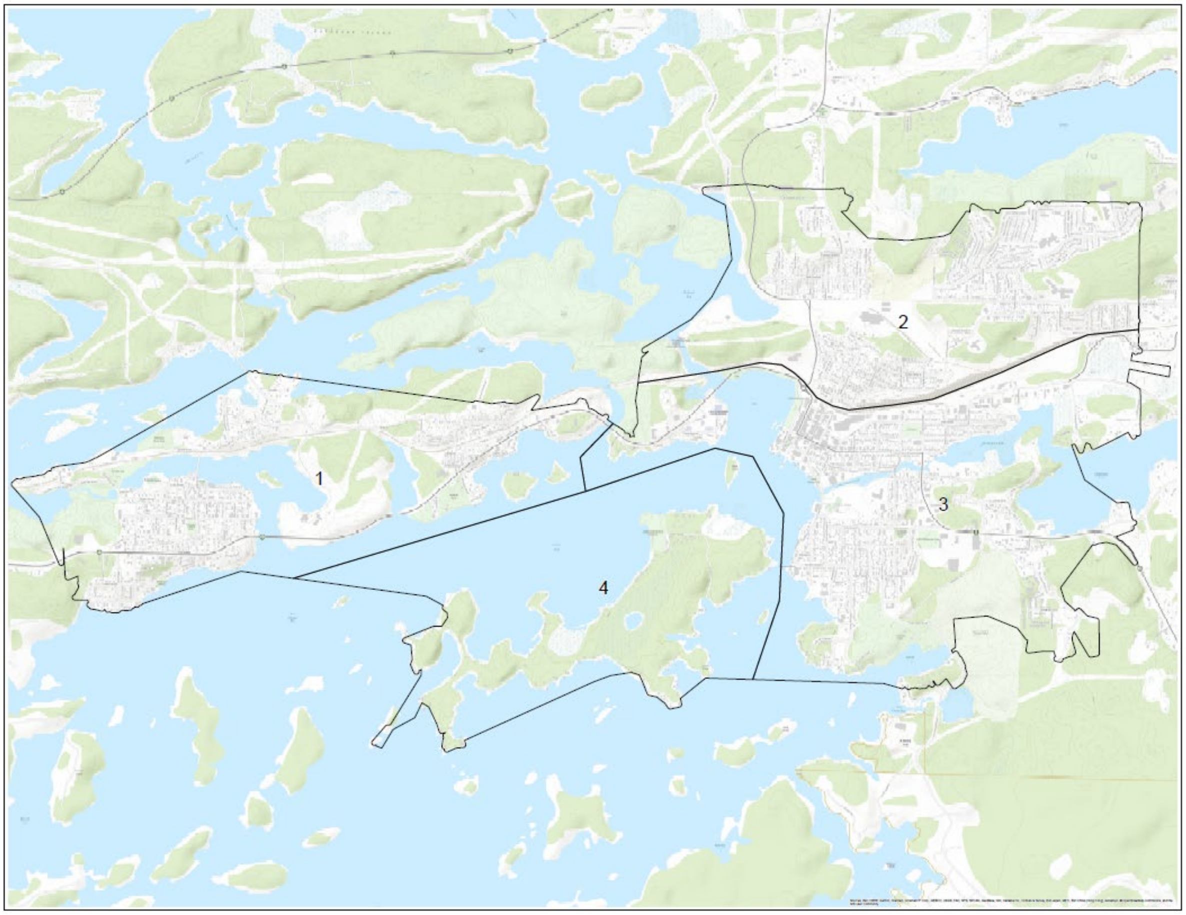


Figure 5.3-25 Kenora Vegetation Management Zones

5.3.3.3.8 Reactive Maintenance

Reactive maintenance occurs in many forms, at many different times and across all asset categories. It can occur during regular business hours or after hours; and can be completed by an overhead or underground crew. These events can include responding to trouble calls, repairing unexpected deficiencies and equipment failures; failures which cannot be accounted for or corrected by any other means.

As an example; a crew may respond to a customer outage caused by a tree on the line which in turn caused a line fuse to operate; and they may later respond to an outage as result of a faulted underground cable; if the cable can be isolated, and depending on the health of the cable may be replaced at a later date, or it may be spliced to extend its in service life and return service immediately.

Depending on the condition of the unit being repaired it may be considered for accelerated replacement based on its health and likelihood to continue deteriorating despite remedial efforts. This would be planned in conjunction with existing planned projects and available resources.

5.3.3.4 Processes to Forecast, Prioritize & Optimize Renewal Spending

5.3.3.4.1 System Renewal Optimization and Budget Alignment

SNC's system renewal program is driven from the outcome of the ACA which provides a levelized plan for assets in poor condition. System renewal efforts focus on assets requiring renewal in voltage conversion areas. The program considers the relative condition of the substations, the condition of the assets associated with each substation, and the targeted replacement level for each asset. A large portfolio of project areas requiring renewal is defined and is generally grouped by feeder.

SNC has developed financial metrics for each asset category on a per unit basis based on previous experience executing projects. These metrics are used to estimate the potential costs associated with specific project areas. A baseline budget is then developed based on completing the projects which have been prioritized based on the asset's optimal replacement times in conjunction with other constraints. If the estimated costs do not align with budget constraints, then alternatives are considered to achieve the targeted spending level. This iterative process continues until an optimized plan is achieved for the planning horizon. This process is illustrated below.

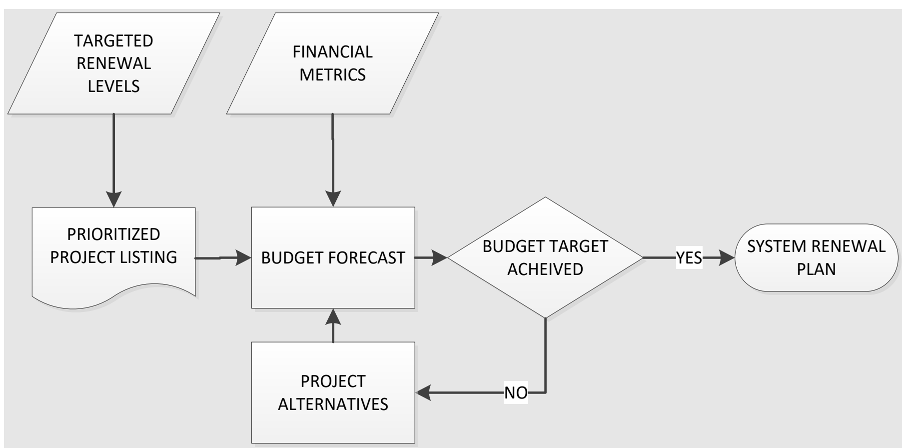


Figure 5.3-26 Iterative Budget Forecast Process

5.3.3.4.2 Targeted Renewal Levels

The targeted renewal levels are a direct output of the ACA process as detailed in Section 5.3.1.

Prioritized Listing

SNC creates a prioritized listing to achieve the desired renewal levels utilizing the data from the ACA based on individual risk assessments and value for each project. Risk is assessed for each project using probability of asset failure combined with impact of failure (as it relates to safety, reliability, operating efficiency etc.). As previously stated, the projects are generally grouped by feeder as the assets are commonly of similar condition.

SNC considers the risks of each project carefully, as well as the cost to mitigate those risks. Through this process, projects that mitigate the highest levels of risk have been prioritized for execution during this DSP. Other considerations during this process are the relative condition of the SNC's substations, the condition of the assets associated with each substation and those defined in Section 5.3.2. The prioritization process is further discussed in detail in Section 5.3.1.3.

Financial Metrics

SNC maintains a repository of information regarding its previously completed projects. Metrics for these projects are tracked to assist in future budgeting efforts. Data is tracked in the form of dollars as well as labour hours on a per unit basis to estimate projects costs based on the scope defined in the project listing.

5.3.3.4.3 Forecasting

A baseline budget forecast is developed based on previous execution of projects where assets are replaced at their optimal replacement time. This baseline budget is then compared against a targeted expenditure level. If the target levels are achieved the baseline forecast becomes the final system renewal plan. If the target expenditure level is not achieved, then SNC seeks out alternatives. Alternatives may include but are not limited to delaying projects when it is prudent and safe to do so; revising the scope of a project to defer costs; and splitting the project into stages to reduce the amount of work required in any given year.

As previously mentioned, SNC's projects are typically grouped by feeder which can encompass a large quantity of assets. SNC will delay small renewal projects or reactive capital replacements in these areas, to the extent possible, where doing so will pose no safety or environmental hazard. This strategy relates to the economy of scale. It is much more effective to bear the fixed costs of renewal across a large quantity of assets as opposed to a small amount thereby reducing the overall per unit cost of the project.

SNC continuously revises and improves its financial metrics as data from completed projects becomes available. This process has allowed SNC to effectively estimate projects reducing the overall variance between budgeted and actual. Effective estimating and variance reduction also has the positive effect of allowing SNC to plan more work for the same amount of budget.

5.3.3.4.4 Impact of System Renewal on O&M

SNC will delay O&M spending in areas that align with system renewal efforts, to the extent possible, where doing so will pose no safety or environmental hazard. This strategy is of particular importance in areas of voltage conversion. The O&M costs associated with maintaining substation assets are approximately $28,500 /year / station. The outcome of the conversion process is to decommission the substations, resulting in elimination of maintenance associated with that station. SNC maintains an annual listing of substations targeted for decommissioning. This strategy focuses on attempting to reduce or defer spending on those substations which are being decommissioned first while ensuring the substations that will be online the longest are being appropriately attended to.

SNC also considers the impact on operational efficiencies when implementing system renewal efforts. Considerations include improving remote operability, ease of access, ease of work and implementing solutions that are both cost effective and reduce restoration times. These considerations ensure that SNC provides the best value to its customers. An example of this scenario may be to relocate end-of-life assets that are constructed in a right-of-way to a street front location.

5.3.4 System Capability Assessment for REG and DER

Currently SNC has 24MW of REG connected to its distribution system.

In general, SNC is well situated to support a range of REG and DER initiatives as there are currently no restricted feeders. Together, with past initiatives, current system capacity and planned system service investments (see section 5.4.1.3.3), SNC expects to be able to support future REG and/or DER connections. Capacity information by feeder is available through SCN's website[17].

At the time of filing there are no embedded distributors in SNC's system and therefore would not contribute to any REG constraints. Further details regarding REG investments are included in Appendix A.

5.3.5 CDM Activities to Address System Needs

CDM activities are aimed at reducing electricity consumption to manage system costs, reduce peak demand and improve affordability for customers. CDM initiatives implemented by SNC over the historical period have resulted in some decline in peak demand, however it has not been substantial enough to avoid major infrastructure renewal investments.

While the latest CDM Framework [18] has reduced the role of LDC's like SNC in the delivery of CDM, the OEB guidelines[19] provide a path for the deployment of CDM to meet distribution system needs and manage delivery costs for SNC's customers. The OEB expanded definition of CDM activities to include any activity that manages energy consumption or provides energy savings expands the opportunities for SNC to incorporate new CDM service offerings to its customers. SNC believes CDM will be integral to the planning process for both temporary solutions (e.g., to manage load growth while infrastructure is being developed) and permanent solutions (e.g., shift demand to eliminate overloads).

With the broadened CDM definition provided in the guideline SNC expects non-distributor owned, behind-the-meter (BTM) resources will expand the growing capabilities of customers to support the distribution system and offer flexible demand services. SNC will closely monitor the

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[17] https://synergynorth.ca/embedded-generation/capacity-of-stations-and-feeders/

[18] 2021-2024 Conservation and Demand Management Framework Program Plan, IESO

[19] Conservation and Demand Management Guidelines for Electricity Distributors, EB-2021-0106

outcome of IESO initiatives to integrate distributed energy resources (DER) into the market and how best LDC's can participate.

As discussed in Section 5.3.2.1.4, SNC will begin pursuing energy storage options as an alternative to a traditional wires investment as KMTS nears its thermal capacity limit through to the end of this DSP. In Thunder Bay, SNC is well positioned to capitalize on future opportunities as it has ample capacity. While this means there are no constraints that will immediately offset traditional investments, CDM activities will allow SNC to maintain its current utilization at its stations.

Furthermore, page 65 of the Northwest IRRP Report states that the IESO will consider Kenora MTS as a potential focus area for the Local Initiatives Program under the 2021-2024 Conservation and Demand Management Framework. The IESO will collaborate with SNC in 2023 as further details for the next round of the Local Initiatives Program become available. In addition to the energy efficiency measures that may result from the IESO's Local Initiative Program, Synergy North may also use the Ontario Energy Board's Conservation and Demand Management Guidelines to leverage distribution rates for non-wires alternatives.

Beyond this, SNC will monitor the availability of new CDM programs and activities to offer to our customers.

5.4 Capital Expenditure Plan

This section details SNC's five-year capital expenditure plan within the DSP planning period from 2024 through to 2028. This plan was developed as a direct output of the asset management process described in Section 5.2.3.2.7.

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

Section 5.4.1.3 – Capital Expenditure Forecast: This section provides an analysis of the expenditures during the DSP's forecast period and encompasses the accounting treatment including construction work in progress.

Section 5.4.1.4 – Capital Expenditure Analysis: This section provides an analysis of the expenditures during the DSP's forecast period vs. the historical period.

5.4.1 Capital Expenditure Summary

The capital expenditure plan summary provides an overview of the capital expenditure plan over a 12-year period (7 historical, 5 forecast). The investments are allocated to one of the four categories based on the primary driver for the investment. Capital investments over the DSP planning period from 2024 to 2028 have been categorized to align with the four DSP investment categories.

The overview of OEB approved amounts from SNC's previous filing can be found in Table 5.4-1 and the forecast amounts broken down by category are provided in Table 5.4-2. Further details can be found in Appendix 2-AA and 2-AB.

During the DSP period from 2017-2022 SNC experienced unprecedented disruptions in its operating environment and these inhibited SNC's ability to deliver the entirety of its planned capital expenditures. The major disruptions are listed in chronological order below:

- Contributed capital received increased from 47% to 73% due to the types of recoverable projects experienced in the region. This greatly impacted actual vs estimated contributions
- Vehicle and material deliveries extended beyond a 12-month timeframe when historically they were received within the year of purchase.
- Kenora merger
  - Unavailable planning data for system access projects 2019-2020
  - Fibre to the home project encompassing the entire Kenora distribution service territory in a 2-year period from 2019-2020
- COVID-19 Pandemic
  - Uncertainty of customers' ability to pay bills which resulted in delays in capital work 2020.
  - Reduced availability of subcontractor resources 2021

  - Material cost increases and delivery interruptions 2021-2023 (See Section 5.4.1.4.2 System Renewal and 5.4.1.4.4 General Plant for specific increases)

Table 5.4-1 Historical Capital Expenditure and System O&M

Category	2017[1]			2018[1]			2019			2020			2021			2022			2023		
	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.[3]	Var.
	$'000		%	$'000		%	$'000		%	$'000		%	$'000		%	$'000		%	$'000		%
System Acces																					
Gross Capital	2,814	1,942	(31%)	2,575	1,688	(34%)	2,728	4,370	60%	2,667	3,299	24%	2,506	3,383	35%	2,483	4,066	64%	1,985	2,795	41%
Contributed Capital	(1,326)	(1,017)	(23%)	(1,207)	(1,243)	3%	(1,212)	(2,517)	108%	(1,218)	(2,923)	140%	(1,248)	(2,742)	120%	(1,510)	(3,415)	126%	(1,422)	(2,449)	72%
Net Capital	1,488	926	**(38%)**	1,368	445	**(67%)**	1,516	1,853	**22%**	1,449	376	**(74%)**	1,258	641	**(49%)**	972	651	**(33%)**	563	346	**(39%)**
System Renewal																					
Gross Capital	8,257	8,748	**6%**	9,264	9,403	2%	9,293	8,636	**(7%)**	9,990	8,674	**(13%)**	10,272	10,205	(1%)	10,478	11,451	**9%**	11,985	12,029	0%
System Service																					
Gross Capital	60	151	152%	300	289	(4%)	338	432	28%	280	87	**(69%)**	300	242	(19%)	247	142	(43%)	277	277	0%
General Plant																					
Gross Capital	1,304	929	**(29%)**	1,676	1,093	**(35%)**	1,256	1,073	**(15%)**	901	863	(4%)	969	1,273	**31%**	1,667	1,529	(8%)	1,174	1,140	(3%)
Totals																					
Gross Capital	12,435	11,770	(5%)	13,815	12,473	(10%)	13,615	14,510	7%	13,838	12,924	(7%)	14,047	15,104	8%	14,875	17,188	16%	15,420	16,241	5%
Contributed Capital	(1,326)	(1,017)	(23%)	(1,207)	(1,243)	3%	(1,212)	(2,517)	108%	(1,218)	(2,923)	140%	(1,248)	(2,742)	120%	(1,510)	(3,415)	126%	(1,422)	(2,449)	72%
Net Capital	11,109	10,754	(3%)	12,608	11,230	(11%)	12,403	11,993	(3%)	12,620	10,001	(21%)	12,799	12,362	(3%)	13,364	13,773	3%	13,999	13,792	(1%)
System O&M[2]	8,252	8,785	6%	8,823	9,155	4%	8,993	8,881	(1%)	9,244	8,317	(10%)	9,505	8,387	(12%)	10,542	11,359	8%	11,253	11,253	0%

Notes:
[1] TBHEDI and KHECL combined as if one entity existed.
[2] For detailed explanations of System O&M expenditures see section 4.3 – OM&A Program Delivery with Variance Analysis in Exhibit 4.
[3] Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year): 2023 Projections include 6 months of actual data.
Only Variances that meet the materiality threshold of $178k are highlighted in red will be explained in further detail in Section 5.4.1.1

Table 5.4-2 Forecast Capital Expenditure and System O&M

Category	Test Year	Forecast Period			
	2024	2025	2026	2027	2028
	$'000	$'000	$'000	$'000	$'000
System Acces					
Gross Capital	2,092	4,323	2,796	2,455	2,329
Contributed Capital	(1,534)	(3,437)	(1,865)	(1,596)	(1,628)
Net Capital	557	886	931	859	701
System Renewal					
Gross Capital	12,714	12,383	12,068	12,151	12,691
System Service					
Gross Capital	323	330	336	343	350
General Plant					
Gross Capital	1,282	1,480	1,473	1,617	1,701
Totals					
Gross Capital	16,411	18,516	16,674	16,566	17,071
Net Capital	14,877	15,079	14,809	14,969	15,442
System O&M	11,779	12,014	12,255	12,500	12,750

5.4.1.1 Summary of Changes to Capital Programs

Table 5.4-3 Summary of Changes to Capital Programs

Capital Program	Important Changes
Capital Recoverable	General decline in joint-use driven work due to completion of FTTH project by Tbaytel resulting in decreased expenditures. Notable exception is in 2025 with AHSIP program implementation. See Appendix H: Material Investment Report – Capital Recoverable for more details.
Services Residential	No Significant Changes
Services General	No Significant Changes
Subdivisions	No Significant Changes
Meters	No Significant Changes
4kV Conversions	Program has been paced to allow for conversions to be completed by the end of this DSP. See Appendix H: Material Investment Report – Voltage Conversions for further details.
Overhead Renewal	No Significant Changes
Line Safety Reports	No Significant Changes

Information Systems	No Significant Changes
Small Pole Replacements	No Significant Changes
Transformers/Switch/Switchgear	No Significant Changes
Fleet	Fleet complement targeted for reduction and harmonization due to completion of 4kV Conversion program. See Appendix H: Material Investment Report – Fleet for further information.
Underground Renewal	Data derived from DC depolarization testing program allows for better understanding of cable condition. Cable rejuvenation, where viable, is now being utilized in place of traditional replacement resulting in decreased expenditures for equivalent renewal. See Appendix H: Material Investment Report – Underground Renewal for more details.
Grid Modernization	No Significant Changes

5.4.1.2 Variances Over Historical Period

Reviewing historical variances provides invaluable feedback to the estimating process for SNC. This process is integrated into the planning process and informs future planning and promotes continuous improvement during the asset management process described Section 5.3.1.3.

The quantity of system access projects is based on historical averages and through discussion with stakeholders throughout SNC's service territory. The budgets developed from this process are again based on historical spending together with anticipated increases in resource and material costs. Most of these projects are submitted to SNC on an as needed basis, as a result they are tracked on a reactionary basis to balance the total annual budget against other discretionary investments (i.e., SNC may defer or advance system renewal investments to remain within the proposed budget annually).

In the previous DSP filed by Thunder Bay Hydro, the planning process for system access consulted with commercial customers, municipal governments, and third party attachers. The feedback received was informal and through verbal channels of communication on projects in the 2017-2021 period. The asset management process and forecasting for capital investments was not at a mature level and the City of Thunder Bay was unable to provide a formal document regarding timelines and scopes of project. Similarly, communication received from the telecommunication parties was that an increased investment was forecast in make-ready work, but that this would occur in conjunction with the renewal efforts by Thunder Bay Hydro. Therefore, historical averages of investment and the historical average of contributed capital was expected to be largely from relocation and customer driven projects, which were calculated at an approximate 47% contribution.

Similarly, Kenora Hydro did not have any formal documentation from municipal governments, commercial customers or third party attachers. In 2019, when Kenora Hydro and Thunder Bay

Hydro merged to become Synergy North, the telecommunication company submitted a plan to complete a fibre to the home project for the entire service territory in the next 2 years.

Due to these two factors, there were large variances in the system access category where the gross amount of work that was experienced was much higher than anticipated and the contribution was as high as 73% versus the anticipated 47% that was planned. This resulted in a decrease in the net capital, despite the increase in overall work completed by the utility.

For this planning period, SNC has made improvements to its engagement of customers and calculated contributions. The engagement was much more rigorous and as a result, SNC received formal responses from both the local telecommunication companies and the City of Thunder Bay for the 2024–2027-time frame, with specific project scopes and timelines. See section 5.2.2 for the details regarding the coordinated planning with third parties.

Discretionary investments are planned and budgeted based on a thorough understanding of the scope of the investment, preliminary design work and historical resource requirements (which are rigorously tracked and updated annually). Once detailed designs are available for a given investment, a detailed estimate and schedule is created. During the execution phase, the actual progression of the project is tracked against the plan on a bi-weekly basis to ensure costs are managed effectively.

Variances that meet the materiality threshold of $178,000 are explained in the following sections, first by category then by year as applicable.

5.4.1.2.1 System Access Net Variances

2017 – 38% ($563k) Under Budget

In 2017, customer driven work such as new residential and commercial services as well as expansions was down from anticipated levels. 240 new services were expected, with only 168 installed, which resulted in a negative variance of $646k. Additionally, a proposed residential subdivision and a City of Thunder Bay relocation project were both deferred resulting in a negative variance of $164k and $230k respectively. Counteracting the negative variance was a positive variance of $410k due to Joint Use Attachment projects bringing fibre to the home in Thunder Bay

2018 – 67% ($923k) Under Budget

In 2018, residential and commercial services were again down from anticipated levels of 240 with only 146 installed. This resulted in a negative variance of $734k. Growth in the region slowed and expansions for subdivisions and for new customers also experienced a negative variance of $323k.

2019 – 22% ($337k) Over Budget

System access spending in 2019 was higher than anticipated due to an externally driven project that was unknown to SNC at the time of budgeting. The project was the City of Kenora's Chipman Road reconstruction project. Due to the merger in 2019, the scope of work was not known until the year of construction and existing substandard installation conditions required a significant amount of re-work to meet SNC's current installations standards. While there was an increase in capital spending required, this project had the added benefit of infrastructure renewal and some of the renewal was recoverable from the requestor through the applicable cost sharing agreement.

2020 –74% ($1,073k) Under Budget

The system access gross spending was higher than anticipated due to the significant application of fibre to the home projects by telecommunication companies which targeted completing the entire City of Kenora by the end of 2020. These plans were not shared with Thunder Bay Hydro or Kenora Hydro in the last Cost of Service period to properly forecast the amount of work or spending that was required. The forecasted plan in the system access categories expected contributed capital to be largely from relocation and customer driven projects, which were calculated at an approximate 47% contribution. However, due to the customer driven nature of this work, it was prioritized over system renewal work and contributions of 100% resulted in the net spend in this program being greatly under budget.

2021 –49% ($617k) Under Budget

System Access spending continued to have a gross spend which was higher than anticipated due to work in the distribution region which was not shared with Thunder Bay Hydro or Kenora Hydro prior to the last DSP submission. Railway Ave rebuilds in the City of Kenora as well as the continued fibre to the home projects in both the City of Thunder Bay and Kenora. However, due to the nature of these projects, the telecommunications company, and the City of Kenora contributed 98% versus the anticipated 47% of contributed capital which resulted in the net spend in this program being under budget.

2022 – 33% ($322k) Under Budget

In 2022, the City of Thunder Bay required the relocation of poles along a major roadway to accommodate a walking trail. This project had a high degree of difficulty as it required significant vegetation management and land clearing to create a road to install the poles. Due to the project difficulty the project cost resulted in an increase to the gross spending, however, as this was a relocation due to road infrastructure, the City of Thunder Bay contributed 50% of labour and trucking. In addition, SNC had an increase in general service connections to a gross spend of $804k, of which 98% was contributed capital, resulting in a variance under budget.

2023 – 39% ($217k) Under Budget

In 2023, SNC received a project from the MTO to relocate overhead wires to underground to accommodate storm sewer and future interchanges. This project was unexpected, and the scope and notice were provided to SNC after the budget was set for 2023. In addition, Phase 3 of Railway Ave was approved by City Council late 2022 (again after the budget was set) and will be completed by the end of 2023. These two projects combined make up $992k worth of work for SNC. Due to the nature of these projects the capital contribution is expected to be $880k. With the general services expected to be $200k higher than planned and contributions for that work at 98% the net value of system access work is $217 less than SNC planned.

5.4.1.2.2 System Renewal Net Variances

2017 – 6% ($491k) Over Budget

Thunder Bay Hydro received its cost-of-service decision September 21st, 2017, and was unable to reduce the proposed capital budget in that year by $1.0 million before the end of the year. However, the one area where management was able to defer costs and projects that were not already underway was in system renewal. A large portion of the McDougall-Court 4kV conversion project was deferred into 2018 which reduced the spend but still resulted in Thunder Bay Hydro going $491k over budget in system renewal in 2017.

2019 – 7% ($657k) Under Budget

SNC planned to perform $320 of system renewal work in Kenora, however the staff in Kenora were unavailable, due to being allocated to the make-ready work for the fibre to the home projects in this region. These customer driven projects are prioritized over system renewal work and included pole replacements and significant anchor installations under System Access. The make-ready work also included significant OM&A adjustments to the overhead lines such as installing guy guards and completing ground connections to the SNC system. Because of the resources shifting to system access work, SNC was unable to complete its scheduled system renewal projects, and this resulted in a variance of $657k under budget.

2020 – 13% ($1,316k) Under Budget

Due to the uncertainty of the impacts of COVID-19 pandemic during 2020, SNC took decisive steps to defer a portion of its capital budget. The projects that were deferred posed an increased risk of transmission due to the nature of the work (i.e., staff were required to work near one another) but could be safely deferred without putting the system at significant risk.

2022- 9% ($973k) Over Budget

With the major impacts of COVID-19 on SNC and available subcontractor workforce behind the utility, SNC embarked on completing work that it had deferred due to Make-ready-work for fibre connections and the COVID-19 pandemic. The projects that had been deferred and began construction were the Central Ave 17M1/3 rebuild as well as the College-Tupper projects.

5.4.1.2.3 System Service Net Variances

2020 – 69% ($193k) Under Budget

Due to the uncertainty of the impacts of COVID-19 pandemic during 2020, SNC took decisive steps to defer a portion of its capital budget. The grid modernization projects in System Service could be safely deferred without putting the distribution grid at significant risk.

5.4.1.2.4 General Plant Net Variances

2017 – 29% ($375k) Under Budget

Prior to the merger of Kenora Hydro and Thunder Bay Hydro, Kenora was approved for a 2017 Board Approved Proxy of $150,000 in rolling stock and $155,000 in building improvements. These expenditures were not realized in 2017 as the building improvements were made in 2011 and 2012 and the single bucket truck in rolling stock was purchased in 2011.

2018 – 35% (584k) Under Budget

Computer equipment was budgeted in the DSP to cost $307,200 and $114,127 was spent due to the deferral of the IBM iSeries server replacements to 2019.

Like the 2017 General Plant variance explanation, $316,000 was budgeted in Kenora as a 2017 Board Approved Proxy for rolling stock and building improvements and only $20,000 was spent on tools.

2019 – 15% ($183k) Under Budget

Lead times between the order and receipt of rolling stock began to extend beyond a 12-month budget period. Due to this extension of lead times, SNC was invoiced for the chassis rather than the entire double bucket in 2019 with the vehicle delivery taking place in late 2020.

2021 – 31% ($304k) Over Budget

Due to the rolling stock availability, lead times and inflationary increases in pricing, the final invoices for rolling stock from 2020 were received at a higher cost in 2021. (2 single buckets)

In addition, spending in computer equipment increased to meet cyber security requirements such as the IBM Disaster Recovery software and upgrades of CISCO switches and IBM servers which were necessary and unpredicted when the DSP plan was drafted in 2016.

5.4.1.3 Forecast Expenditures

In total SNC plans to spend approximately $85M over the next five-year period. These investment decisions are based upon the AM and capital expenditure planning process which encompasses detailed project/program evaluations, and customer preferences.

The following table and figure illustrate the forecast period capital expenditures from 2024 through to 2028.

Table 5.4-4 Forecast Gross Expenditures 2024-2028

Category	Test Year	Forecast Period				Total $'000	Percent of Total
	2024	2025	2026	2027	2028		
	$'000	$'000	$'000	$'000	$'000		
System Access	2,092	4,323	2,796	2,455	2,329	13,995	16%
System Renewal	12,714	12,383	12,068	12,151	12,691	62,007	73%
System Service	323	330	336	343	350	1,682	2%
General Plant	1,282	1,480	1,473	1,617	1,701	7,553	9%
Gross Capital	16,411	18,516	16,674	16,566	17,071	85,238	100%

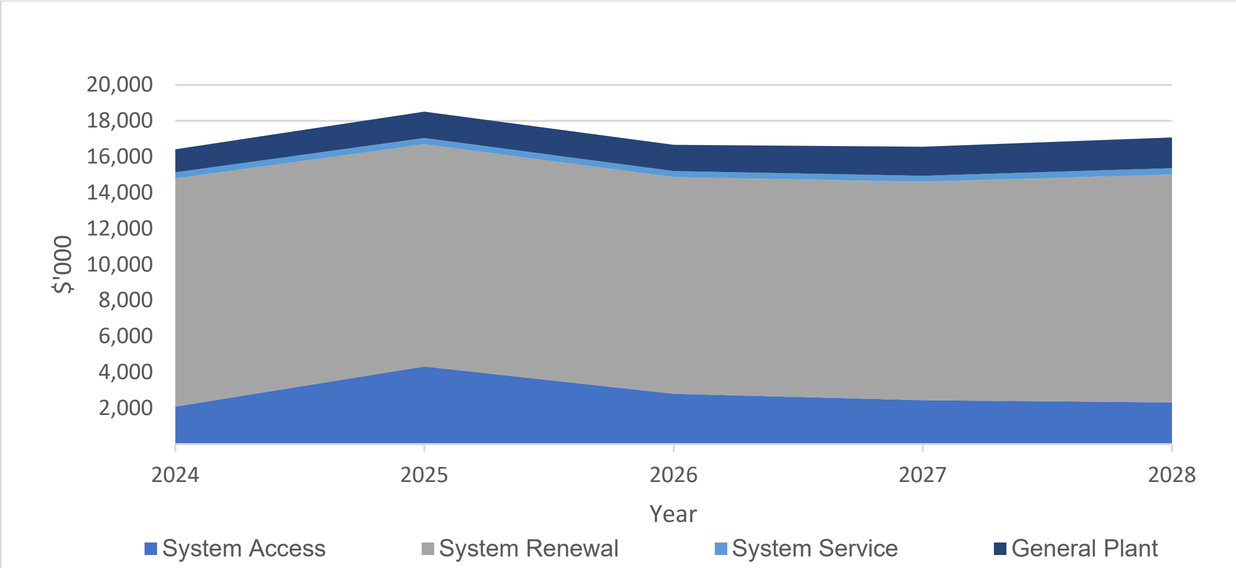

Figure 5.4-1 Forecast Gross Expenditures Trend 2024-2028

5.4.1.3.1 System Access

Proposed expenditures in this category are entirely driven by customer requests and/or mandated service obligations. The timing of these expenditures is driven by the needs of the requestor or legislation and is considered mandatory. The forecast investments for this category are captured in the following table and figure.

Table 5.4-5 Forecast Gross System Access Expenditure

System Access	Test Year	Forecast Period				Total $'000	Percent of Total
	2024	2025	2026	2027	2028		
	$'000	$'000	$'000	$'000	$'000		
Recoverable	434	2,232	349	356	364	3,736	27%
Expansions	55	57	58	59	60	289	2%
Services - Residential	447	456	465	474	484	2,325	17%
Services - General	652	765	780	796	812	3,804	27%
Subdivisions	141	144	147	150	153	735	5%
Relocations	93	394	716	98	100	1,402	10%
Meters	270	275	281	522	357	1,705	12%
Gross Capital	2,092	4,323	2,796	2,455	2,329	13,995	100%

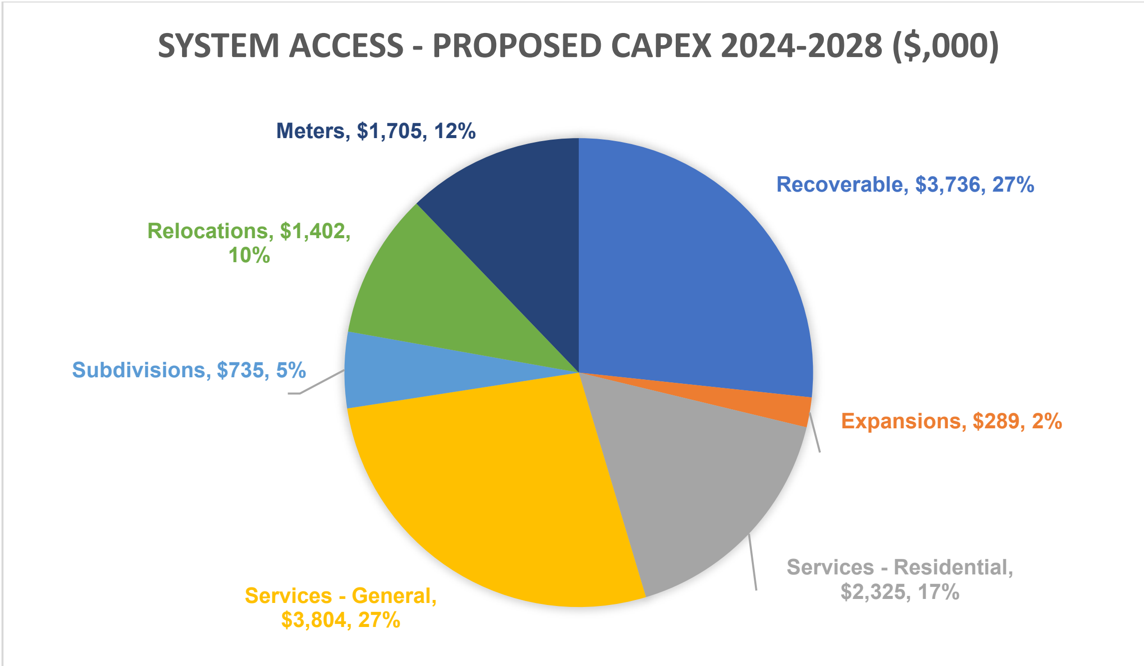

Figure 5.4-2 Forecast Gross System Access Expenditure Ratio

System access investments represent 16% of SNC's overall proposed capital expenditure over the forecast period. The estimated level of expenditure is based on historic spending levels and information gathered from stakeholders throughout the service territory about specific planned projects at the time of preparation of this DSP.

The largest portion in this category (44%) involves fulfilling customer requests regarding new and upgraded Services (residential and general services combined). Since there is little growth projected in SNC's service territory over the forecast period, service connections are anticipated to remain constant with costs rising in accordance with inflation.

At 27% Recoverable work represents the second largest driver within this category. Recoverable work consists of modifications to existing customer connections and make-ready work for third parties. Most of this work stems from asset replacements driven through the joint-use process and is expected to stabilize over the forecast period with costs rising with inflation.

At 12% the Meters project captures all the costs of meter replacements for failed meters as well as other meter replacements dictated by Measurement Canada. This also includes costs to acquire meters for the sampling program and the MIST (Metering Inside Settling Timeframe) program. The observed increase in 2027 is driven by the requirement to complete a meter sampling campaign and seal-life extension program for large test groups in that year. SNC has made the strategic decision to continue to perform sample testing and compliance to extend the life of the meters in service. This strategy allows SNC to keep its investments focused on the 4kV conversion process and assets which are in poor condition and allows for a levelized metering program investment. Re-evaluations will be done on new metering technology to determine when it is necessary and appropriate to invest in replacing existing infrastructure. See Appendix F for further details.

The remaining expenditures are split amongst Relocations (10%), Subdivisions (5%) and Expansions (2%). Relocations projects involve overhead and/or underground line relocations to accommodate road widening projects and are based on consultations with the Cities of Thunder Bay and Kenora. Subdivision and Expansion projects involve the resource requirements to facilitate customer connections driven by property development. Similarly, these projects are expected to remain stable over the forecast period, but costs will rise in accordance with inflation.

5.4.1.3.2 System Renewal

Investments in system renewal involve the replacement or refurbishment of system assets to ensure SNC can continue to supply its customers with electricity. The proposed investments are a direct result of the asset management process outlined in Section 5.3.1.3. The ACA is a key component of this process, the results of which drive our targeted asset renewals levels for SNC's major asset categories and thus structure the system renewal program.

The forecast investments for this category are captured in the following table and figure.

Table 5.4-6 Forecast Gross System Renewal Expenditure

System Renewal	Test Year	Forecast Period				Total $'000	Percent of Total
	2024	2025	2026	2027	2028		
	$'000	$'000	$'000	$'000	$'000		
4kV Conversions	7,954	8,351	6,903	4,401	-	27,610	45%
Overhead Renewal	1,557	764	975	2,498	7,334	13,127	21%
Underground Renewal	646	659	1,529	2,538	2,589	7,959	13%
Small Pole Replacement	767	782	798	814	830	3,992	6%
Safety Reports	859	876	894	911	930	4,469	7%
Transformers/Switches	932	951	970	989	1,009	4,850	8%
Gross Capital	12,714	12,383	12,068	12,151	12,691	62,007	100%

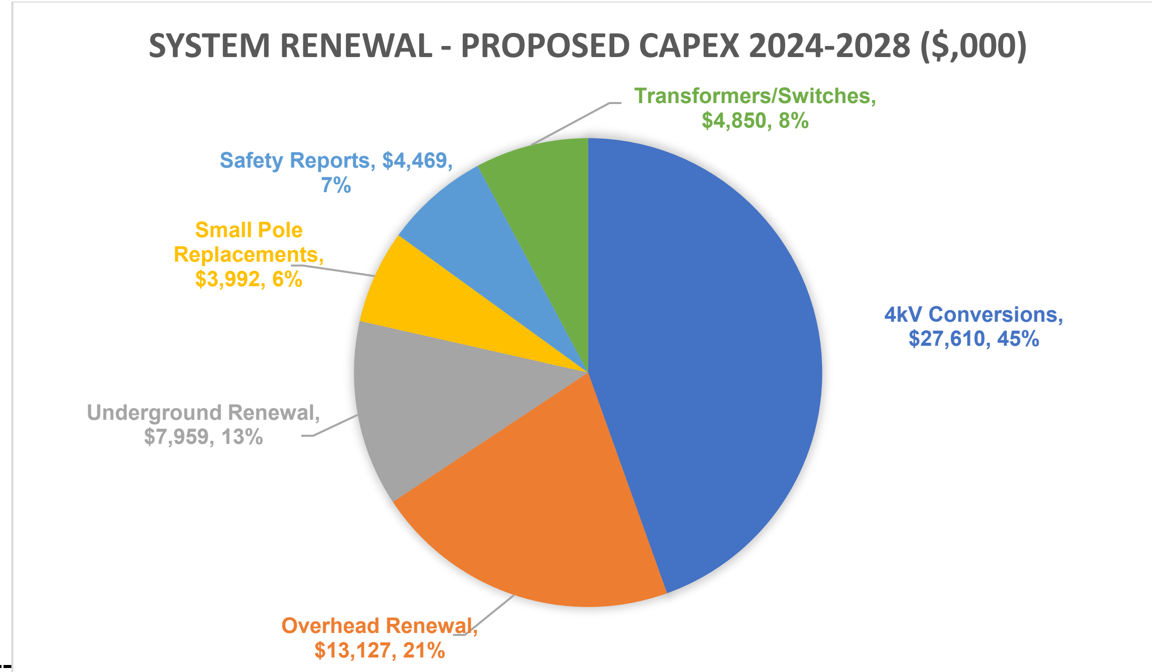

Figure 5.4-3 Forecast Gross System Renewal Expenditure Ratio

System renewal investments represent the largest portion (73%) of SNC's overall proposed capital expenditures over the forecast period. For detailed information on these programs refer to Appendix H.

The largest portion in this category (45%) of the proposed expenditure is 4kV Conversions. This program involves the proactive renewal of assets operating at 4kV and converting the operating voltage to 25kV during this process. This program is driven from the need to both renew overhead assets in these areas and decommission the 4kV substations that supply them. In doing so SNC can avoid the substantial capital cost associated with rebuilding the station. The conversion program is anticipated to be complete near the end of 2027 as indicated in Table 5.4-6.

At 21% Overhead Renewal represents the second largest driver within this category. This program involves the proactive renewal of overhead assets operating at 12/25kV. This program targets areas outside the planned 4kV conversions where asset condition drives preemptive replacement.

At 13% the Underground Renewal project captures all the costs associated with the renewal of underground assets. Major projects include underground direct buried cable rejuvenation together with live front transformer replacement and replacement of underground cable with high failure rates.

The remaining expenditures are split amongst Safety Reports (7%), Transformers/Switches (8%) and Small Pole Replacements (6%). These renewal efforts are driven mainly from emergency replacements of assets (Safety Reports), or through a need for replacement identified during routine inspection programs.

The proposed level of investment required over the forecast period was determined using SNC's asset management process, described in detail in Section 5.2.3.2.7. SNC has taken a wholistic view of its system and all its major asset categories (e.g., poles, transformers, switches, and underground cables) have undergone multiple inspections cycles. During the inspection process, SNC has been diligent in closing gaps identified in its previous filing and through this process has been able to effectively quantify the investment needed to support the distribution system.

The observed changes in investment level in the Voltage Conversion and Overhead renewal programs are due to the completion of the 4kV conversions in 2027. SNC expects to shift focus to increase renewal of its underground infrastructure to align with the decrease in 4kV conversion spending in this category that has been deferred in the past. All other programs are expected to remain stable over the forecast period, with costs increasing with inflation.

5.4.1.3.3 System Service

System service investment represent modifications to SNC's distribution system to ensure the system continues to meet operation objectives (reliability, system efficiency, power quality etc.) simultaneously addressing future customer electricity service requirement.

The forecast investments for this category are captured int the following table and figure.

Table 5.4-7 Forecast Gross System Service Expenditure

System Service	Test Year	Forecast Period				Total $'000	Percent of Total
	2024	2025	2026	2027	2028		
	$'000	$'000	$'000	$'000	$'000		
Grid Modernization	323	330	336	343	350	1,682	100%
Gross Capital	323	330	336	343	350	1,682	100%

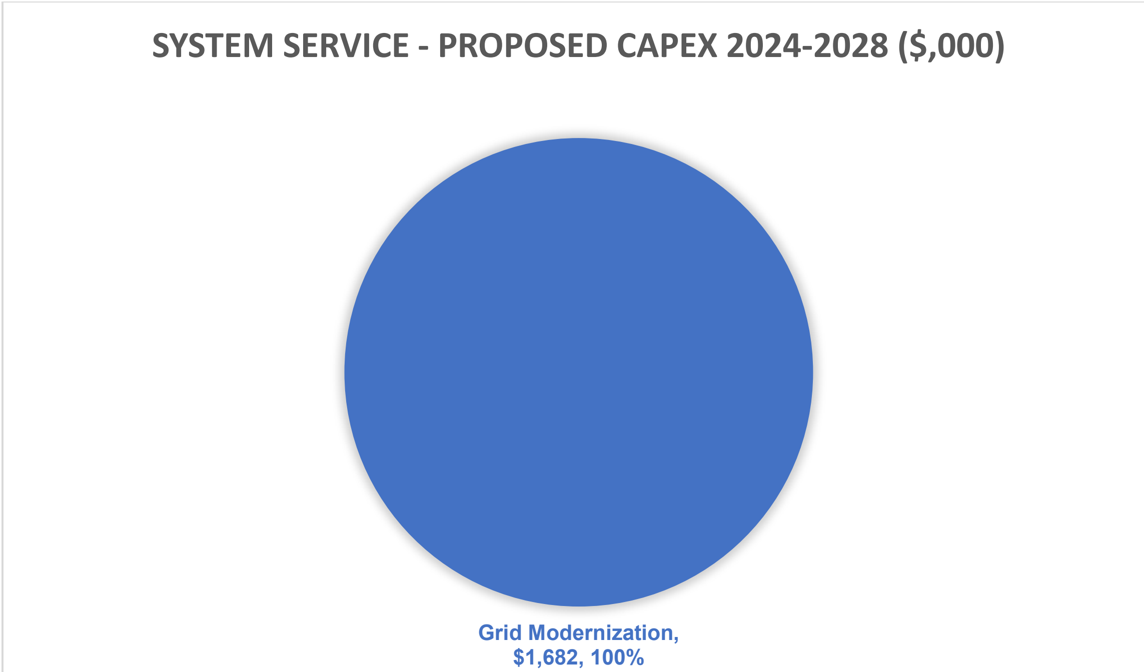

Figure 5.4-4 Forecast Gross System Renewal Expenditure Ratio

System service investments represent the smallest portion (2%) of SNC's overall proposed capital expenditures over the forecast period.

SNC's grid modernization investments include improvements in automated switching, distributed automation, and outage management systems. By incorporating these systems into the grid SNC will be able to detect and address emerging problems on the system before the affect service; as well as provide enhanced visibility into the system for operations staff and customers.

Through this category of investment SNC is taking the initial steps to becoming a FINO (see Appendix D for more information). As the DER and electric vehicle (EV) landscape evolves, allowing customers to take advantage of behind-the-meter resources will be key to achieving their reliability and affordability needs. It is through these types of modernization initiatives that SNC plans to strategically upgrade the distribution system to enable, and control loads and DERs.

5.4.1.3.4 General Plant

General plant investments are required to support SNC's day-to-day business and operations activities but are not part of the distribution system. This can include modifications, replacements, or additions to SNC's land, buildings, tools, equipment, rolling stock, electronic devices, and software.

The forecast investments for this category are captured int the following table and figure.

Table 5.4-8 Forecast Gross System Service Expenditure

General Plant	Test Year 2024 $'000	Forecast Period 2025 $'000	2026 $'000	2027 $'000	2028 $'000	Total $'000	Percent of Total
Fleet	600	715	715	800	850	3,680	49%
Building Improvements	155	158	162	165	168	808	11%
Information Systems	305	380	366	416	443	1,909	25%
Office Equipment	51	52	53	54	55	265	3%
Tools	171	175	178	182	185	891	12%
Gross Capital	1,282	1,480	1,473	1,617	1,701	7,553	100%

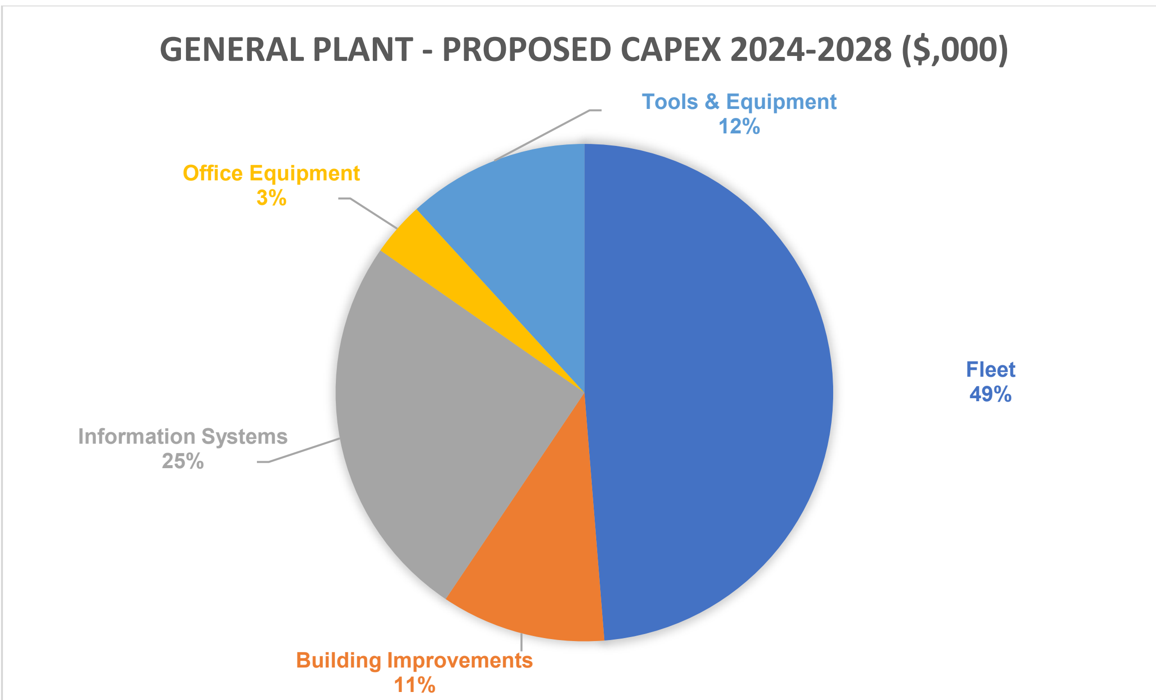

Figure 5.4-5 Forecast Gross System Renewal Expenditure Ratio

General plant investments represent 9% of SNC's overall proposed capital expenditure over the forecast period. The largest expenditure in this category (49%), Fleet involves planned replacement of rolling stock. To better understand the future needs of customers, as well as reduce carbon emissions, SNC has proposed to purchase a light-duty electric vehicle to replace one of its end-of-life fleet assets. Through this, SNC hopes to gain a better understanding of how electric vehicles fit into the current work environment and operational needs.

The proposed investment in this category accounts for the replacement of vehicles at end-of-life. Several factors assist in determining whether a vehicle requires replacement and prior to proceeding with a purchase SNC reviews the future requirements based on department needs and forecast workload. While the proposed investment includes replacement of several vehicles, the current fleet plan also includes fleet harmonization. This will be achieved by reducing the fleet complement to better align with future needs as voltage conversion comes to an end. For further information see Appendix H: Material Justification Reports – Fleet and Appendix E.

Information Systems represents the second largest investment in this category at 25% contains expenses primarily driven through the need to replace end-of-life electronic assets and a requirement to enhance the cyber-security of the utility. Given the constantly evolving nature of IT technology and cybersecurity threats, equipment replacement and technology upgrades are required on an annual basis. The capital forecast includes not only routine replacements but also the introduction of new initiatives and technologies to support the goals of the organization. The overall focus reflected in the capital expenditure is on ensuring the security and integrity of the data and infrastructure while also enhancing business efficiencies and automation. For further information on SNC's strategy regarding technological change and cyber security see Appendix G.

The final two categories are below materiality and consist of Tools and Equipment at 15% and Building Improvements at 11%. These categories contain expenses related to acquiring and replacing the specialized tools and equipment that are required to support SNC's daily activities and ensure the safety of its personnel. Examples of Tools and Equipment planned spend includes GPS capable locates equipment, surveying equipment, desks, chairs, etc. Building Improvements are expenses related to the renewal and upkeep of SNC's main facilities, both of which are critical to SNC's 24/7 operations. Ongoing investments such as roofing, and HVAC replacements proposed over the forecast period ensure the safe and reliable continuation of SNC's operations.

5.4.1.3.5 Investment Lifecycle >One Year

For capital projects spanning multiple years, costs remain in construction work-in-progress (WIP) until such time as the project is in service. Capitalization of assets then occurs upon completion.

Most of SNC's 4kV conversions and overhead renewal projects follow this cycle, often with poles being installed each year and then the overhead portion (framing, stringing, energizing) occurring the following year. In each case, costs remain in WIP annually and are capitalized once in service.

5.4.1.4 Comparison of Forecast and Historical Expenditures

5.4.1.4.1 System Access

The difficulty in predicting customer connection requests annually, combined with other external factors often leads to year-over-year variability in spending levels, this becomes evident when reviewing Figure 5.4-6. SNC is forecasting a change of approximately 1% between the bridge year and test year expenditures in system access . The proposed difference is mainly attributable to the consistent third-party attachment activity.

The local telecommunications provider has undergone an extensive fiber-to-the-home (FTTH) campaign in both the Thunder Bay and Kenora distribution territories, ultimately completing it in

2022. However, SNC anticipates a ramp up of work in 2025 due to AHSIP projects corresponding to approximately $1.9M. A return to pre-2017 levels in 2026 is anticipated, with slight increases in spending annually to account for inflation. The planned number of attachments has been formally communicated to SNC by all telecommunication attachers and has been incorporated into the forecast with the appropriate contributed capital associated with the make-ready work. Due to the formal receipt of plans and the discussions with telecommunications providers, SNC is confident that the forecasted recoverable work due to joint use attachment has been accurately provided for this DSP period.

Increases in 2025 through to 2027 can be attributed to increased relocations required by road construction in partnership with the City of Thunder Bay and the MTO for the “Northwest Arterial” and HWY 11/17 interchange upgrades. The relocations for the interchanges are estimated to account for $300k in 2025 and $620k in 2026 of gross expenditures. 50% of labour and trucking is expected to be received as a capital contribution from the City of Thunder Bay. SNC acknowledges that much of the relocation work due to road construction will be contingent on funding approvals from the MTO, City council and provincial funding bodies. However, SNC has incorporated the formal plans provided by the City of Thunder Bay and has assumed in its investments that these projects will be approved. These projects are further described in the material justification reports found in Appendix H.

Historically, the variability in spending can be largely attributed to the FTTH projects within the City of Thunder Bay. Increases in spending can be primarily attributed to the make-ready work associated with this project. This investment had the added benefit of contributing to the renewal of infrastructure that was approaching end of life and did so with capital contributions in accordance with joint-use agreements, benefiting ratepayers. The decline in expenditures in 2023 corresponds to the completion of this project and a return to typical levels.

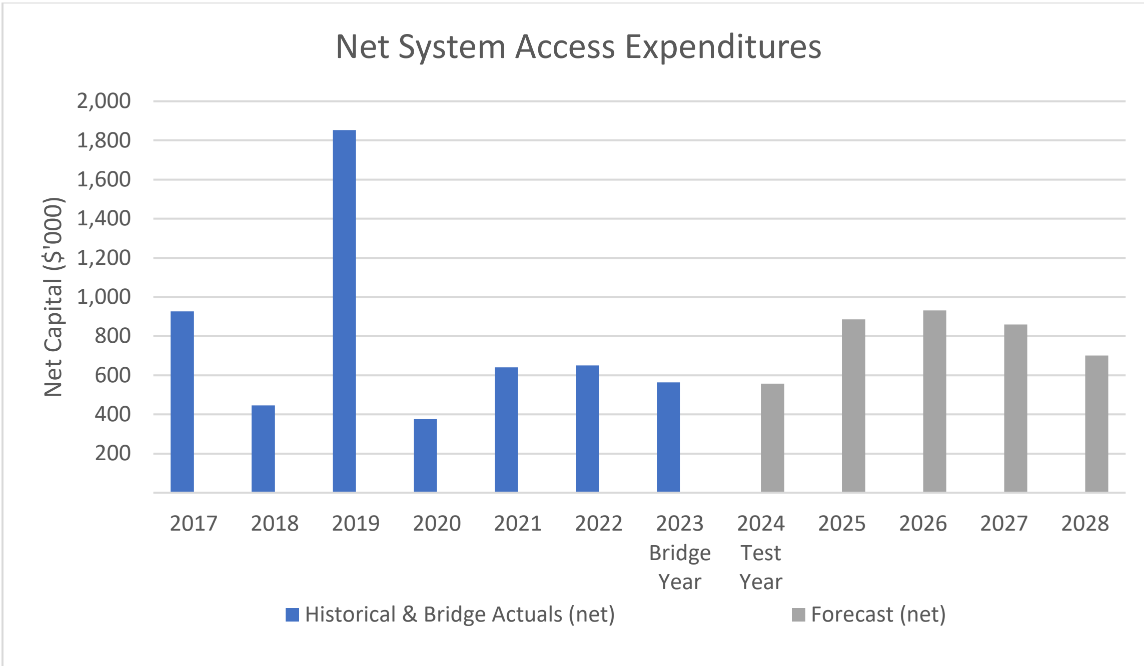

Figure 5.4-6 System Access Expenditure Comparison

5.4.1.4.2 System Renewal

As shown in Figure 5.4-7, SNC's forecast for the test year for system renewal is 6% higher than the historical bridge year. This is primarily the result of deferred asset renewal spending during COVID-19 and increased material and labour costs.

Global inflation has made an impact on the number of assets that SNC can renew for the same historical cost. For example;

- There has been a 31% increase in the price of diesel fuel and 20% increase in gasoline fuel costs from 2021 to 2022 significantly impacting the cost of deploying staff to perform renewal work;
- The cost for pad mount transformers has increased by an average of 75% on the most common units ordered by SNC from 2022 to 2023 due to the significant cost increase of core materials. This cost impacts the 4kV conversion projects, as each distribution transformer in a conversion area requires replacement;
- The price of wood poles has increased by 17% from 2022 to 2023 and again 95% in 2023 due to the supplier shortfalls and no longer being able meet SNC requirements; therefore, SNC has been forced to pay more with the only other supplier in Canada who meets the specifications; and
- Wire and cable costs, manufactured out of copper and aluminum have increased by an average of 60% from 2021 to 2022.

The above are examples of specific cost increases, but cost increases have been experienced across all materials and subcontracted services (such as hydro vac and powerline services) that SNC requires to complete system renewal projects. Despite these increases, and similar to past applications, SNC is projecting a consistent level of renewal spending over the forecast period with the goal of renewing those assets in the greatest need and deferring replacements where possible.

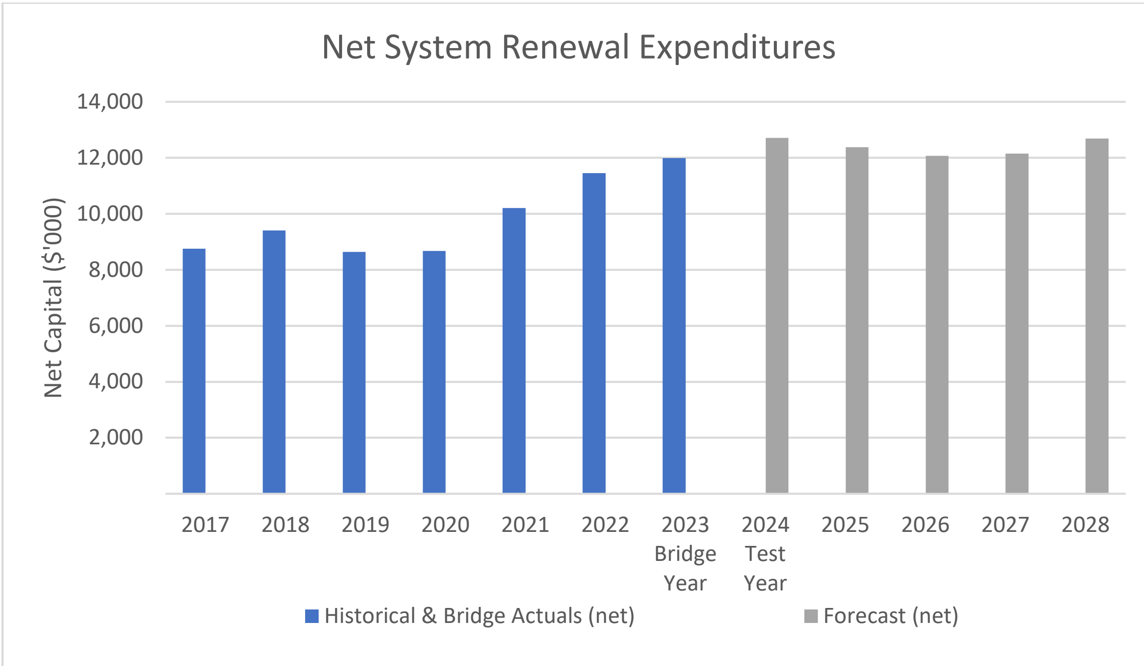

Figure 5.4-7 Net System Renewal Expenditure Comparison

5.4.1.4.3 System Service

As shown in Figure 5.4-8, SNC's test year forecast for system service is 17% higher than the historical bridge year. While a significant percentage, this amounts to an approximate $100,000 increase from an average of $225,000 historically to $325,000 forecast on an annual basis. This is primarily the result of adding automated switching to the system as part of SNC's grid modernization efforts. The material cost of an automated switch (recloser) has increased 20%, as has the price of fuel. Labour increases have also impacted on the cost of performing the installation work. Therefore, the forecast average increases are higher in part due to the cost of materials and labour to install the materials as well as an increase in the number of installations proposed. SNC is planning to install 4 automated switches in the distribution system on an annual basis, which is an increase from the average of 2 installed per year in the historical period. The increase shown in 2019 was due to the installation and payment of the Outage Management System.

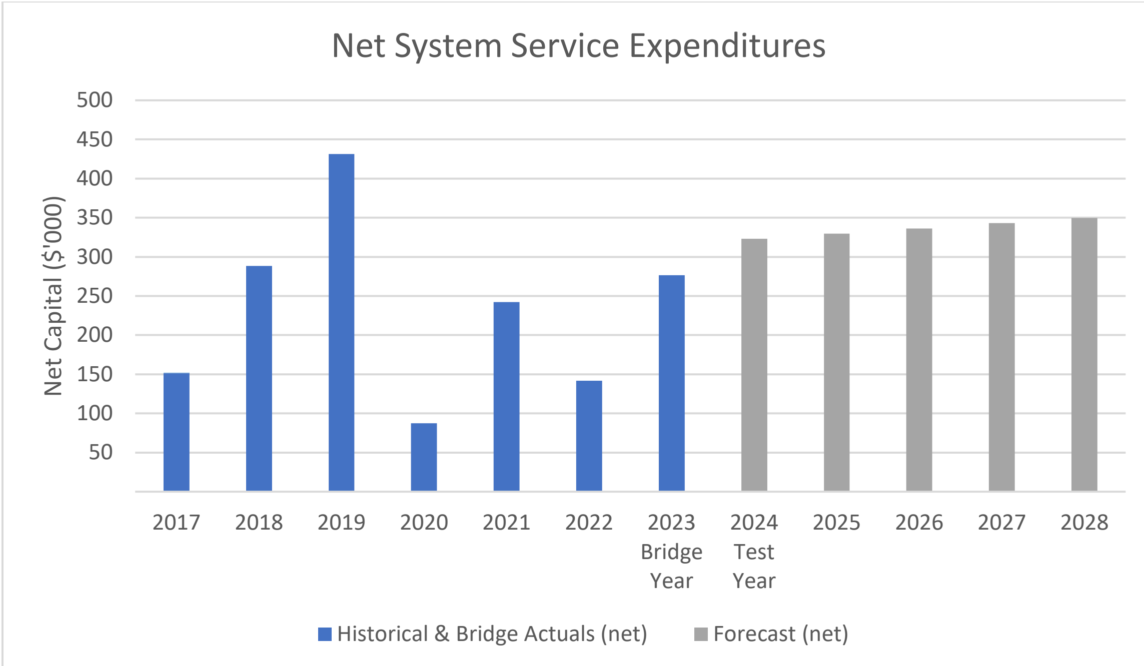

Figure 5.4-8 Net System Service Expenditure Comparison

5.4.1.4.4 General Plant

As shown in Figure 5.4-9, SNC's test year forecast for general plant is 19% higher than the historical bridge year. This is primarily the result of large increases in the cost of fleet related expenditures since the last cost of service filing in 2016. (Examples of increases to typical vehicles purchased by SNC are shown below and in Appendix H – Material Justifications – General Plant – Fleet).

- 63% increase on Light Duty trucks (Similar to a Ford F150) from 2018 to 2023
- 66% on Crew Cab trucks (Similar to a Ford F350)
- 55% on SUV's (Similar to a Ford Escape) from 2016 to 2023
- 61% on Single bucket trucks (Similar to Posi-Plus single axle cab Model 400-46) from 2016 to 2023

However, due to fleet harmonization and standardization SNC is projecting to avoid replacements of 16 vehicles during the forecast period, reducing its overall complement to 75 from 91. This results in a potential capital cost avoidance of nearly $2.8M in 2024 dollars.

The increase in 2022 was in part due to the need to purchase / upgrade disaster recovery software and the timing of receiving vehicles purchased in previous years. See Section 5.4.1.2.4- for further details.

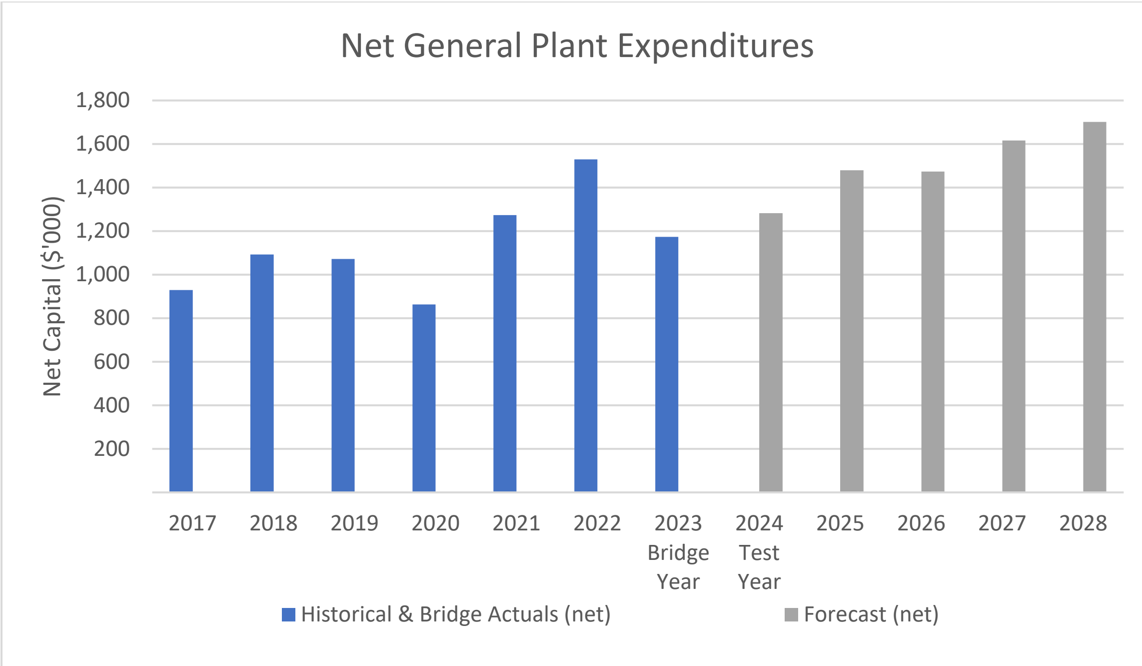

Figure 5.4-9 Net General Plant Expenditure Comparison

5.4.1.4.5 Overall

In reviewing the net overall expenditures, the increase over the forecast period as compared to the historical period appears notable. However, given the rising costs of goods and services required to complete work SNC is proposing a modest 6% increase from bridge year (2023) to test year (2024). Increases proposed over the entire forecast period amount to 2% on an annualized basis.

Figure 5.4-10 shows SNC's net average overall forecast as well as historical plus bridge year. The proposed increases are primarily the result of inflation and increased material costs over the forecast period.

Additionally, this reflects increases in net system access spending due the joint use attachments expected from AHSIP (Accelerated High-Speed Internet Program) projects which Bell will be implementing in 2025, as well as modest increases in system renewal, system service and general plant as required to upgrade and maintain SNC's distribution system, buildings, tools, and equipment.

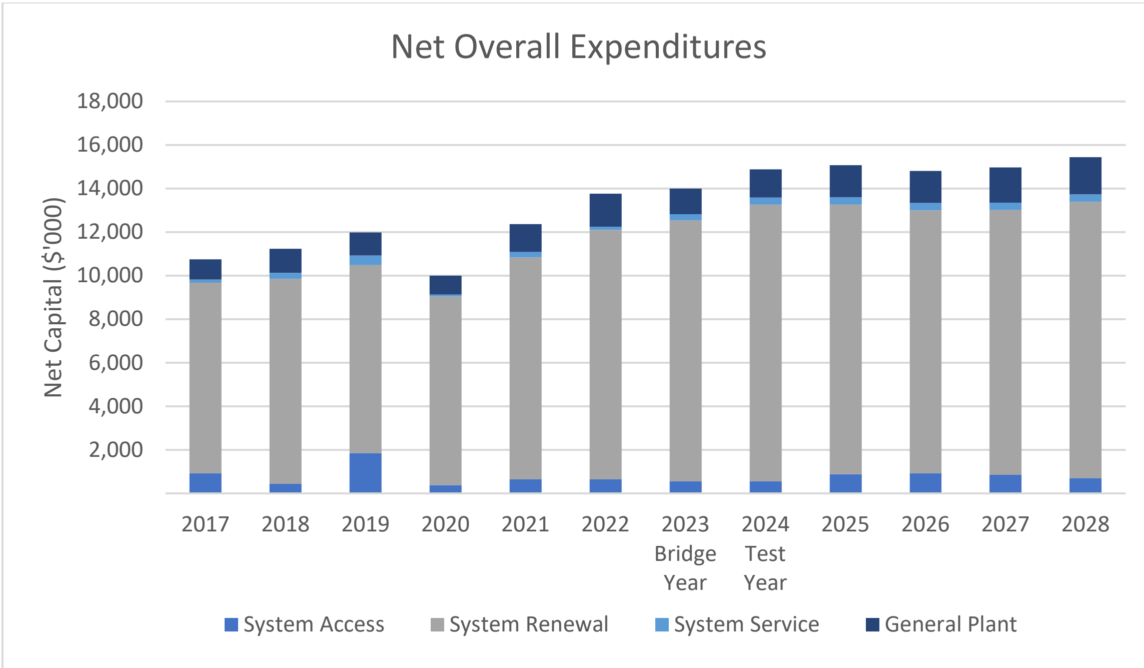

Figure 5.4-10 Net Overall Expenditure Comparison

The following figure shows the overall gross expenditure for reference.

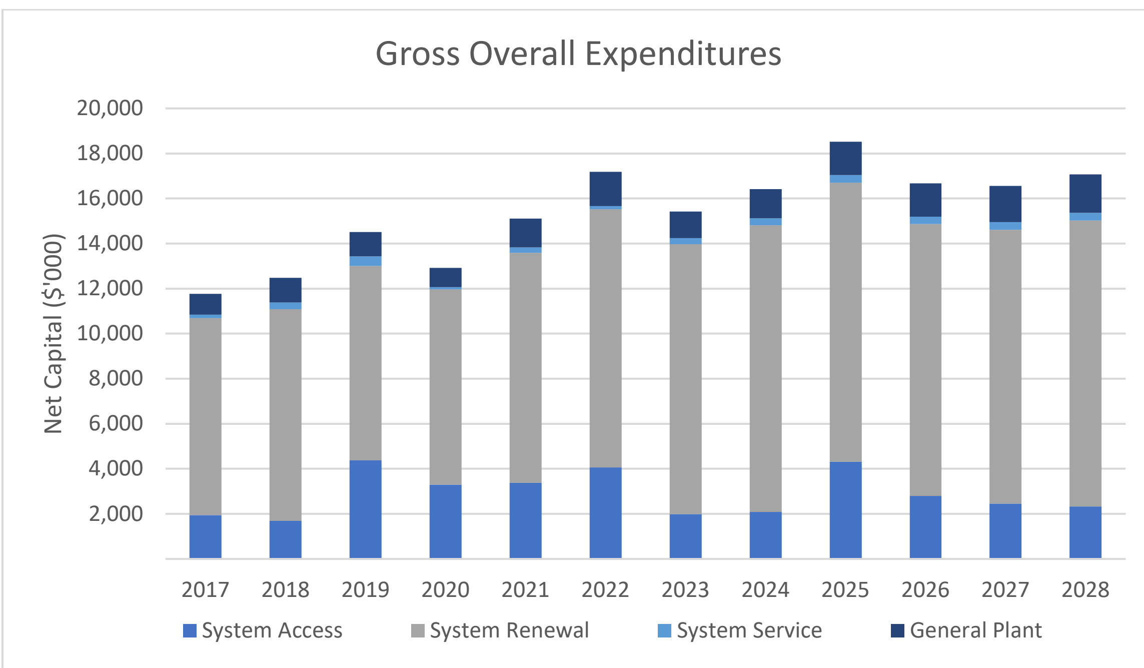

Figure 5.4-11 Gross Overall Expenditure Comparison

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

Table 5.4-9 summarizes the forecast system O&M spending over the forecast period.

Table 5.4-9 Forecast System O&M Expenditures

Category	Test Year	Forecast Period				Total $'000
	2024	2025	2026	2027	2028	
	$'000	$'000	$'000	$'000	$'000	
System O&M	11,779	12,014	12,255	12,500	12,750	61,298

SNC employs a strategy of deferring O&M spending in areas that align with system renewal efforts, to the extent possible, where doing so will pose no safety or environmental hazard. This strategy is of particular importance in areas of voltage conversion where the O&M costs associated with maintaining 4kV substations are carefully weighed against the eventual decommissioning of the station.

SNC also considers the impact on operational efficiencies when implementing system renewal efforts. Considerations include improving remote operability, ease of access, ease of work and implementing solutions that are both cost effective and reduce restoration times (e.g., relocate end-of-life assets out of a right-of-way). These considerations ensure that SNC provides the best value to its customers.

In general, capital investment over the forecast period is not expected to reduce system O&M costs but is expected to prevent them from outpacing inflationary increases. Efficiencies gained in some areas have, and will continue to, offset increased O&M needs in other areas (e.g., improved inspection and testing programs).

5.4.1.6 Non-Distribution Activities

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

5.4.2 Justifying Capital Expenditures

The following information provides an overview of SNC's capital expenditure planning process which includes details on planning objectives, planning criteria and assumptions used in the development of the capital expenditure plan. The asset management process is the foundation for the DSP and the capital expenditure plan which helps align each to SNC's overall corporate objectives. By following a strategic approach to the capital expenditure planning process SNC achieves efficiencies in work practices and productivity along with creating and maintaining a distribution system capable of meeting the needs of existing and figure customers. During the development of the capital expenditure plan, and number of objectives and planning processes are observed which ensures the plan aligns with the asset management objectives and therefor with the overall strategic goals of the corporation (see section 5.3.1.1). SNC's planning assumptions that have shaped the distribution system plan and capital expenditure plan include the following:

1. Provide the proper allocation of investments to meet Health and Safety obligations; ensuring the manner in which work is executed positively impacts the general public, customers and SNC staff.
2. Minimize impact to the environment through consideration of asset retirements and improve sustainability by considering the impacts to climate change.

3. Ensure proper allocation of investments to meet regulatory and customer obligation of system access projects (e.g., metering, system relocations, residential and general services connections).
4. Ensure adequate level of investment in the renewal of distribution system assets to maintain a safe and reliable system as determined through the continued ACAs.
5. Actively seek operation efficiencies that positively affect reliability and constraints on the system.
6. Review overall expenditures and determine impacts to financials and adjust spending as required.

The assumptions made during the planning process stem from input from various sources such as:

- Growth forecasts;
- Co-ordination with customers and third parties;
- Impact of regulatory initiatives;
- Asset condition forecasts; and
- Impact of CDM, REG, DER, and EV connections.

The degree to which each of these assumptions affects the overall capital plan varies along with the timing required to execute them. SNC strives for continuous improvement and as a result regularly audits and revises the above planning assumptions to ensure they accurately reflect reality. As part of the capital expenditure planning process, SNC has determined several assumptions need to be made in order to support in the development of the capital expenditure plan. Key assumptions include:

- The use of historical trends in categories related to system access to forecast capital expenditures;
- The validity of information from the City of Thunder Bay, City of Kenora and third parties with respect to future requirements of the distributions system to service new projects; and
- The use of historical growth, CDM, DER and EV adoption rates to assist in the forecasting future contributions to the demand of the distribution system.

SNC's asset management goal is to identify and prioritize assets for replacement in an optimal manner through the guiding principles of the Asset Management Objectives, in such a way as to both; minimize risks to SNC's vision and core values and maximize long term investment benefits. Each of the asset management objectives described in section 5.3.1.1 are considered by utilizing them as weighted criteria to assist in the selection and prioritization of projects in the capital expenditure planning process.

The core of SNC's planning processes are its corporate vision, values, and strategic initiatives. These principles shape the various inputs and outputs of all asset management and investment planning processes.

It is the goal of the utility to inspect, analyze, and plan all facets of the utility's operations in a holistic manner ensuring that all investments are optimized and coordinated to the fullest extent possible. Figure 5.4-12 below outlines the capital planning process with the various inputs and the output being the finalized capital plan.

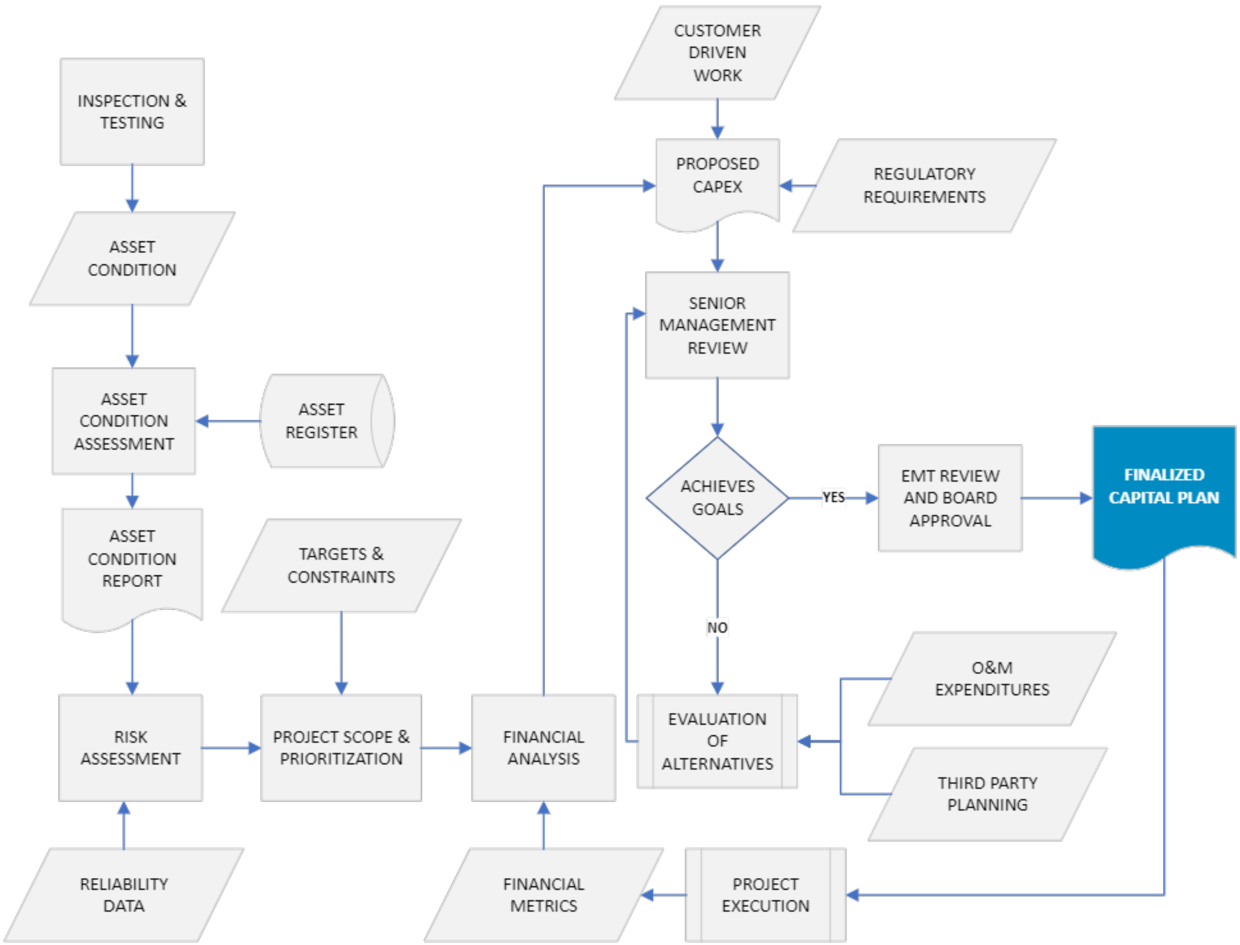

Figure 5.4-12 Capital Planning Process

The proposed capital investment plan is formed based on the analysis previously described in section 5.3.1.3 and Figure 5.3-2 and includes those investments required in order to be compliant with regulations and legislation. These required investments can include new connections, customer requests and relocations. While SNC generally employs alternatives analysis and cost reduction techniques, the timing of these types of investments generally leaves little discretion as to their execution and are integrated based on historical performance.

The proposed capital plan is reviewed by senior management for adherence to any corporate goals, regulated requirements, and overall financial fitness. Alternatives are considered at this stage that may impact the timing of certain projects. These considerations can include O&M alternatives and third-party projects. Once finalized, the capital expenditure plan is submitted to the Executive Management Team and Board for review and approval.

The final piece of SNC's capital planning process is related to its corporate goal of continuous improvement. This is achieved by providing feedback from executed projects in the form of lessons learned and financial metrics and utilizing this information to inform future planning processes.

SNC also keeps the following top of mind along the planning process path.

Customer Value

Customer-centric thinking is at the core of SNC's planning process because meeting customers' needs and expectations is a strategic part of SNC's asset management objectives. SNC connects with customers in a variety of ways, allowing them to stay informed on the process and progress. Assessing customer needs is a key input in the AM process and drives a key output, customer feedback provides invaluable information regarding the pacing of capital plans.

SNC uses a workflow for its planned (e.g., system renewal and service) and demand (e.g., system access) work programs. The process is designed to reduce the impact on work execution due to volatility in demand work. The workflow ensures that appropriate time is given for:

- customer engagement and feedback;
- notice of project and outage notifications to customers;
- coordination of activities with third parties;
- coordination of activities with other work;
- securing material and outside resources (when necessary); and
- scheduling work during optimal site conditions.

SNC maintains rigorous oversight over its program portfolio and improvements to the project delivery process have led to improved reporting and forecasting capabilities. Meetings are held regularly to review performance and adjust forecasts; this includes a review of system access and O&M trends to evaluate opportunities and risks. Detailed work performance reporting is provided on a bi-weekly basis and highlights information on schedule, cost, and scope.

SNC's resource strategy is designed to organize work safely and efficiently to deliver its capital programs at approved expenditure levels, while maintaining SNC's commitments to its customers. SNC uses a work-first approach to planning whereby internal resources are allocated to programs based on the program requirements. Additionally, overtime and contract resources may be used as required to manage work with conflicting priorities.

Fluctuations due to the seasonal nature of construction and variability in demand are addressed in a variety of ways. SNC remains flexible by developing and maintaining strategic relationships up and down the supply chain (e.g., temporary labour, pre-qualified contractors, and vendors), thereby ensuring that resources are always available to connect our customers.

SNC's system access programs are designed to ensure that needs driven by customer demand are being met. By considering how we can reduce costs (i.e., review overhead vs. underground options, ensuring transformers are sized appropriately) and mitigate potential risks (i.e., ensuring customers are aware of long delivery times on certain equipment) SNC is able to provide excellent value to its customers.

As the largest forecast expenditure, it is vital that SNC remain diligent in monitoring system renewal spending. This category has the objective of maintaining the safe and reliable supply of electricity to SNC's customers, while keeping retail rates from escalating beyond their affordability. To execute planned work efficiently, over the forecast period SNC has optimized the pacing of its investments based on the best available data from the asset management process and customer feedback; and will balance staffing levels in accordance with this planned level of work.

The proposed system service investments work in concert with system renewal investments to retain operational flexibility and improve system visibility to achieve customers' performance expectations with regards to reliability and power quality.

Technological Changes and Innovation

SNC has ongoing and proposed initiatives that address the issues surrounding grid modernization, distributed energy resources and climate change.

Outage Management System – SNC began its journey to implement an OMS during the historical period with the goal of providing a smart, self-healing grid that will proactively and autonomously engage with customers. This project requires the integration of several data sources (customer information systems, advance metering interface, geographic information systems, SCADA, outage tables and the Trouble Call System) to allow for full implementation of the objectives.

Voltage Conversion – SNC's long standing voltage conversion program is expected to be complete by the end of this filing period and is anticipated to benefit customers in several ways. The remaining circuits once transferred will allow for the connection of DER throughout the entire system, as the necessary protections to support their connection are installed. Elimination of multi-circuit lines reduces system complexity and serves to reduce the loading on poles making the system more resilient to severe weather conditions expected with climate change. Additionally, losses are expected to be reduced with the elimination of 160 km of 4kV overhead primary conductor combined with the decommissioning of seven 4kV substations which will have a net benefit on the environment.

SNC will continue to look for new and innovative ways to incorporate advanced technology in system design over the forecast period. Where the benefits outweigh the costs, these technologies may be incorporated during asset renewal to meet the current and future needs of the system and the customer to support and enable the integration of distributed energy resources.

Consideration of Traditional Planning Needs

Traditional planning needs including load growth, reliability, and asset condition are key inputs into SNC's AM process (Section 5.3.1).

At a system level, load growth is not anticipated to drive investment during the forecast period as there are no constraints that would prevent the connection of anticipated load or generation customers. However, as previously discussed in Section 5.3.2.1.4, SNC is anticipating some capacity constraints in its Kenora service territory (following the forecast period) for which traditional investments will be under consideration.

Reliability and asset condition are key inputs to the AM process and are used in identifying, selecting, and prioritizing system renewal investments. It is through the ACA and reliability studies that SNC can identify the portion of the system that has reached (or soon will) a point that requires renewal, and where in the system those assets pose the greatest risk to reliability and/or public safety. Asset quantities that are flagged for action directly influence the level of investment proposed over the forecast period and SNC has put forth renewal levels that will yield sustained investment levels as opposed to variable investment levels (i.e., to manage large demographics of assets in poor condition). Given that rate increases are of great concern to customers and that affordability is at the forefront of many customer engagements, SNC's challenge is finding an optimal balance between cost, risk, and performance.

In preparing this DSP, SNC has prioritized investments based on minimum levels of intervention to maintain current system performance across the entire asset base; thereby ensuring both a reliable supply and affordable rates for customers.

<u>Overall Capital Expenditures</u>

Net capital expenditure trends over the 2017 to 2028 period for each investment category along with the total investment envelope is shown in Figure 5.4-13.

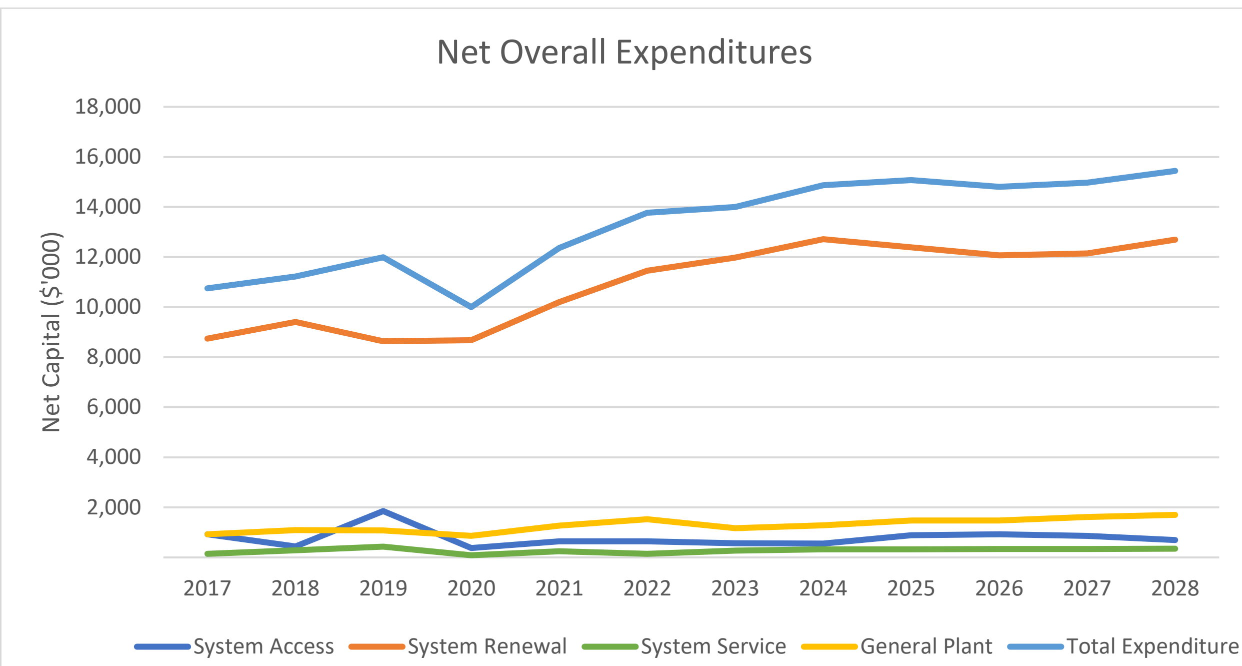

Figure 5.4-13 Overall Net Capital Expenditure Trend

The proposed level of capital expenditure over the forecast period is aimed at maintaining SNC's corporate goals of providing outstanding energy services in a safe, reliable, and trusted manner while simultaneously improving asset related performance to achieve the four performance outcomes established by the RRF.

The historical period for system access, system service and general plant shows a relatively stable trend. Variability can be found in system access due to the AHSIP in 2025 and is driven mainly by customer demand. This stable trend is expected to continue with increases in these categories adjusted to account for inflation.

It is apparent from Figure 5.4-13 that system renewal trend increases through the test year to 2025, then stabilizes through to the end of the forecast period. These increases are mainly due to market volatility and significant increases in material pricing.

It can be noted that while projected expenditures are increasing, SNC is proposing a similar level of work throughout the forecast period and that these increases closely align with the increasing trend in the cost of materials and labour.

5.4.2.1 Material Investments

SNC's materiality threshold has been established at $178,000 for this application. All capital programs proposed during the Test Year that exceed materiality are listed in Table 5.4-10.

Table 5.4-10 Proposed Capital Investments over Materiality - Test Year

Category	Project	Description	Rank	2024 Gross Expenditures ($'000)
System Access	A2402	Capital Recoverable	-	434
System Access	A2412	Services Residential	-	447
System Access	A2413	Services General	-	652
System Access	A2421	Meters	-	270
System Renewal	A2417	Line Safety Reports	1	859
System Renewal	Various	4kV Conversions	2	7,219
System Renewal	Various	Overhead Renewal	3	1,557
System Renewal	A2418	Transformers/Switch/Switchgear	4	932
System Renewal	A2416	Small Pole Replacements	5	767
System Renewal	Various	Underground Renewal	6	646
General Plant	Various	Fleet	7	600
General Plant	Various	Information Systems	8	305
System Service	A2235	Grid Modernization	9	323

The first four programs in the table fall in the system access category and meeting regulatory obligations is the primary driver. These programs form SNC's primary responsibility as a distributor which is to provide outstanding energy services to the communities we serve and are therefore not prioritized against discretionary programs. Six of the next ten projects belong to the system renewal category for which system reliability and public safety are the primary drivers. The two projects in the general plant category are primarily driven by business operation efficiency and non-system physical plant needs. Finally, system service for which the primary driver is improving system reliability and meeting current and future customer demands.

The following details the scoring methodology that SNC has developed in conjunction with METSCO (see Appendix K for more information). The final output is the prioritizing matrix shown in Table 5.4-19 which details the outcome of scoring for each of SNC's discretionary programs. For detailed justifications of the proposed material investments refer to Appendix H.

The prioritization process for the budget forecast consists of a two-element formula to score each program (n) in Equation 3. Part (A) consists of the weighted criterion from SNC's AM objectives. The asset management objectives are a set of goals that are reflective of SNC's corporate values which assist in making strategic decisions that align with the priorities and overarching corporate goals. Each objective is assigned its own weight (totaling to 100) based on its relative importance in achieving SNC's purpose using the analytical hierarchy process (AHP). The criteria and weights for the first element are shown in Table 5.4-11 below.

Equation 3

$$\text{Program Prioritization Score (C)} = \frac{\sum_{i=1}^{n}\left(A_i \times \frac{B_i}{20}\right)}{100}$$

Table 5.4-11 SNC's AM Objectives and Weighting

Criteria (n)	Description	Weight (A)
Health & Safety	Risk of safety incidents sustained by SNC's staff, contractor, or general public, living and working in the vicinity of the utility's equipment.	41.1%
Environmental Impact	Risk of unplanned and uncontrolled release of a hazardous substance (e.g., PCB Spills) or the consequences of climate change, vegetation contact, flooding.	22.9%
Regulatory/Legal Compliance	Assesses the degree to which project, service, or product is compliant with regulations and legal obligations.	12.3%
Customer Preference	Preferred impact of project, service, or product to customer requirements. • Affordability • Safety for employees and public • Reliability • Accommodating Renewable Energy • Support for EV	8.4%
Asset Performance	Project, service, or product replaces substandard equipment or otherwise improves the operations and maintenance practices on the system thereby addressing asset health concerns, premature failures, etc.	6.3%
Operational Efficiency	Project, service, or product that otherwise improves or avoids the following: • Reduces operating expenses; • Avoids future capital costs; • Coordinates with other programs; or • Decreases liability or increases without action.	4.7%
System Reliability	Electrical service continuity: translating it into customer interruption statistics and determining customer base affected.	4.2%

The second element of the formula, Part (B) is the impact score identified in the tables that follow. Each Criteria from Part (B) has a predefined scoring model which quantifies the impacts of non-execution. As it can be difficult to apply a singular scoring method to system and non-system investments, some scoring models contain a two-element impact score. For example, in the Asset Performance category, the scoring includes an element defined for distribution system assets (i.e., the identified program impacts substation reliability) and an element for non-system assets (i.e., the asset is operating outside of manufacturer support).

Table 5.4-12 Scoring Methodology for Health and Safety Impacts

Health and Safety	Scoring (B)	Prioritization Score (C)
Permanent disabling injury or fatality is almost certain (occur multiple times in 5yr)	20	41.1%
Serious injury requiring medical attention or serious security incident is very likely (occur more than once in 5yr)	15	30.8%
Moderate injury requiring first aid or moderate security incident likely (expected to occur in 5yr)	10	20.6%
Minor injury or security incident is likely (expected to occur in 5yr)	5	10.3%
No impact to health and safety	0	0.0%

Note:
Certain = occurring multiple times over planning period
Very Likely = occurring more than once over planning period
Likely = expected to happen over planning period

Table 5.4-13 Scoring Methodology for Environmental Impacts

Environmental Impact	Scoring (B)	Prioritization Score (C)
Addresses three (3) or more of SNC's identified environmental risks and provides risk mitigation to those risks	20	22.9%
Addresses two (2) or more of SNC's identified environmental risks and provides risk mitigation to those risks	15	17.2%
Addresses one (1) or more of SNC's identified environmental risks and provides risk mitigation to those risks	10	11.5%
Does not address any environmental risks or provide risk mitigation	0	0.0%

Note: Environmental Risks as follows
Risk of Flooding
Risk of Vegetation Contact
Risk of Oil Spills
Consequences of Climate Change
Controlling of Carbon Emissions

Table 5.4-14 Scoring Methodology for Regulatory/Legal Impacts

Regulatory/Legal Compliance	Scoring (B)	Prioritization Score (C)
Addresses a currently non-compliant issue to meet regulations or external standards for asset operations.	20	12.3%
Addresses an issue that with become noncompliant with regulations if no action is taken.	15	9.2%
Addresses a currently non-conformant issue with respect to best practices.	10	6.1%
Addresses an issue that may become nonconformant with best practices if no action is taken.	5	3.1%
No impact on regulatory compliance.	0	0.0%

Table 5.4-15 Scoring Methodology for Customer Preference Impacts

Customer Preference	Scoring (B)	Prioritization Score (C)
Delivers on all the top 3 priorities of customers (Affordability, Safety for Employees and the Public and Reliability)	20	8.4%
Delivers on two of the top 3 priorities of customers (Affordability, Safety for Employees and the Public and Reliability)	15	6.3%
Delivers on one of the top 3 priorities of customers (Affordability, Safety for Employees and the Public and Reliability)	10	4.2%
Delivers on one of the top 5 priorities of customers (Accommodating Renewable Connections and EV support)	5	2.1%
Does not deliver on any priorities of customers	0	0.0%

Refer to Exhibit 1.5 Customer Engagement, and Attachment 1-K COS Customer Engagement Surveys and Results for customer priorities.

Table 5.4-16 Scoring Methodology for Asset Performance Impacts

Asset Performance	Scoring (B)	Prioritization Score (C)
Asset deficiency impacting substation reliability or critical non-system assets operating outside manufacturer support	20	6.3%
>50% of assets in poor condition or non-system assets operating within extended manufacturer support	15	4.7%
>50% of assets in fair condition or non-system assets reaching end of manufacturer support	10	3.1%
Minor asset performance issue not impacting levels of service	5	1.6%
No impact asset performance or health	0	0.0%

Table 5.4-17 Scoring Methodology for Operational Efficiency Impacts

Operational Efficiency	Scoring (B)	Prioritization Score (C)
Aligns with 4	20	4.7%
Aligns with 3	15	3.5%
Aligns with 2	10	2.3%
Aligns with 1	5	1.2%
Aligns with none	0	0.0%

Note: The criteria for this category are as follows:
Program reduces Operating Expenses
Program avoids future Capital Costs
Program coordinates with Other Projects
Program decreases liability or increases with inaction.

Table 5.4-18 Scoring Methodology for System Reliability Impacts

System Reliability	Scoring (B)	Prioritization Score (C)
Sustained interruption of > 12.5 MW of distribution load (>2,500 residential customers)	20	4.2%
Sustained interruption of 4.5-12.5 MW of distribution load (900-2,500 residential customers)	15	3.2%
Sustained interruption of 1.5-4.5 MW of distribution load (300-900 residential customers)	10	2.1%
Sustained interruption of <1.5 MW of distribution load (100-300 residential customers)	5	1.1%
No impact on reliability of distribution.	0	0.0%

Table 5.4-19 Prioritizing Matrix for Test Year Programs over Materiality

Programs	Health and Safety	Environmental Impact	Regulatory/Legal Compliance	Customer Preference	Asset Performance	Operational Efficiency	System Reliability	Score	Category
Weight	41.1%	22.9%	12.3%	8.4%	6.3%	4.7%	4.2%		
Lines Safety Reports	Serious injury requiring medical attention or serious security incident is very likely (occur more than once in 5yr)	Addresses two (2) or more of SNC's identified environmental risks and provides risk mitigation to those risks	Addresses a currently non-conformant issue with respect to best practices.	Delivers on two of the top 3 priorities of customers (Affordability, Safety for Employees and the Public and Reliability)	>50% of assets in poor condition or non-system assets operating within extended manufacturer support	Aligns with 1	Sustained interruption of <1.5 MW of distribution load (100-300 residential customers)	67.5%	System Renewal
Voltage Conversions	Moderate injury requiring first aid or moderate security incident likely (expected to occur in 5yr)	Addresses three (3) or more of SNC's identified environmental risks and provides risk mitigation to those risks	Addresses an issue that may become nonconformant with best practices if no action is taken.	Delivers on two of the top 3 priorities of customers (Affordability, Safety for Employees and the Public and Reliability)	Asset deficiency impacting substation reliability or critical non-system assets operating outside manufacturer support	Aligns with 4	Sustained interruption of 4.5-12.5 MW of distribution load (900-2,500 residential customers)	67.0%	System Renewal
Overhead Renewal	Moderate injury requiring first aid or moderate security incident likely (expected to occur in 5yr)	Addresses two (2) or more of SNC's identified environmental risks and provides risk mitigation to those risks	No impact on regulatory compliance.	Delivers on all of the top 3 priorities of customers (Affordability, Safety for Employees and the Public and Reliability)	>50% of assets in poor condition or non-system assets operating within extended manufacturer support	Aligns with 1	Sustained interruption of <1.5 MW of distribution load (100-300 residential customers)	53.1%	System Renewal
Transformer/Switch/Switchgear Replacements	Moderate injury requiring first aid or moderate security incident likely (expected to occur in 5yr)	Addresses one (1) or more of SNC's identified environmental risks and provides risk mitigation to those risks	Addresses an issue that may become nonconformant with best practices if no action is taken.	Delivers on two of the top 3 priorities of customers (Affordability, Safety for Employees and the Public and Reliability)	>50% of assets in poor condition or non-system assets operating within extended manufacturer support	Aligns with 1	Sustained interruption of <1.5 MW of distribution load (100-300 residential customers)	48.4%	System Renewal
Small Pole Replacements	Moderate injury requiring first aid or moderate security incident likely (expected to occur in 5yr)	Addresses one (1) or more of SNC's identified environmental risks and provides risk mitigation to those risks	No impact on regulatory compliance.	Delivers on two of the top 3 priorities of customers (Affordability, Safety for Employees and the Public and Reliability)	>50% of assets in fair condition or non-system assets reaching end of manufacturer support	Aligns with 1	Sustained interruption of <1.5 MW of distribution load (100-300 residential customers)	43.7%	System Renewal
Underground Renewal	Minor injury or security incident is likely (expected to occur in 5yr)	Addresses two (2) or more of SNC's identified environmental risks and provides risk mitigation to those risks	No impact on regulatory compliance.	Delivers on two of the top 3 priorities of customers (Affordability, Safety for Employees and the Public and Reliability)	>50% of assets in poor condition or non-system assets operating within extended manufacturer support	Aligns with 2	Sustained interruption of <1.5 MW of distribution load (100-300 residential customers)	41.9%	System Renewal
Fleet/Rolling Stock	Moderate injury requiring first aid or moderate security incident likely (expected to occur in 5yr)	Addresses one (1) or more of SNC's identified environmental risks and provides risk mitigation to those risks	Addresses an issue that may become nonconformant with best practices if no action is taken.	Delivers on one of the top 5 priorities of customers (Accommodating Renewable Connections and EV support)	>50% of assets in fair condition or non-system assets reaching end of manufacturer support	Aligns with 1	No impact on reliability of distribution.	41.5%	General Plant
Information Systems	Moderate injury requiring first aid or moderate security incident likely (expected to occur in 5yr)	Does not address any environmental risks or provide risk mitigation	Addresses an issue that may become nonconformant with best practices if no action is taken.	Does not deliver on any priorities of customers	asset deficiency impacting substation reliability or critical non-system assets operating outside manufacturer support	Aligns with 1	No impact on reliability of distribution.	31.1%	General Plant
Grid Modernization	No impact to health and safety	Does not address any environmental risks or provide risk mitigation	No impact on regulatory compliance.	Delivers on one of the top 3 priorities of customers (Affordability, Safety for Employees and the Public and Reliability)	No impact asset performance or health	Aligns with none	Sustained interruption of > 12.5 MW of distribution load (>2,500 residential customers)	8.5%	System Service

APPENDIX A: IESO REG RESPONSE

Appendix A

SYNERGY NORTH

THE POWER OF THE NORTH

Renewable Energy Generation Plan 2023-2028

2023-01-27

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1. Executive Summary

Synergy North Corporation. (SNC) is a local electricity distributor serving approximately 50,000 customers in Thunder Bay, Ontario as well as approximately 5,000 customers in Kenora, Ontario. In accordance with the Ontario Energy Board's (OEB) filing Requirements for Electricity Transmission and Distribution Applications, chapter 5, Consolidated Distribution System Plan Filing Requirements, SNC has prepared the following Renewable Energy Generation (REG) Investment Plan. The REG Plan is based on current information and presents SNC's near-term and long-term plans that are intended to accommodate the connection of renewable generation facilities.

Given the current trends and available renewable generation contracts available to customers in the SNC service territory, we anticipate very minimal solar project connection requests. It is notable that in 2015 we connected 2 combined heat and power (CHP) projects with natural gas generators that generate in parallel with our distribution system. Although these generators are not considered renewable, they do compete for the same available generation capacities as renewable projects.

Overall SNC's distribution system has capacity to connect and accept moderate amounts of renewable generation. While a significant amount of local generation has connected to our system, the short circuit levels at the Hydro One transformer stations has also risen. Currently, of the three transformer stations in our service territory, two have short circuit levels exceeding 90% of the limits set by the transmission system code, and the third has short circuit levels is approaching the station equipment ratings, leaving very little, short circuit capacity for generation connections. Through the IRRP planning process, SNC is aware that Hydro One is addressing limiting hardware on the secondary side of Port Arthur TS, which will increase the short circuit capacity on this station and accommodate future renewable generation project connections.

Beyond short circuit limitations, SNC has encountered limitations related to the passive anti-islanding technique utilized by micro and small embedded generators. To date, these limits have been exceeded on only a few rural feeders, where minimum loads are much lower than their urban equivalent circuits. Although SNC has considered projects that would open some capacity on these feeders, a combination of issues; including wide acceptance of these solutions by other LDC's, research and development costs, and the limited amount of interest in generation projects that would benefit from this investment, has pushed interest in these types of renewable enabling projects to at least beyond the study period.

SNC does not expect any capital expenditures related to renewable energy generation in its Distribution System Plan. As well, no additional Operating, Maintenance and Administrative ("OM&A") costs related to renewable generation connections are anticipated, as SNC is capable of processing both micro embedded generation and other applications utilizing existing employees.

2. Overview of the SNC Distribution System

Initial interest in renewable generation development in the SNC service territory was high and since the introduction of the Feed-In-Tariff ("FIT") program by the former OPA in 2009, SNC has facilitated the connection of several projects. After the program was discontinued, there has been significantly less connections.

As of December 2022, SNC has a connected:

- 238 micro-DER projects
- 21 Small and Mid-Sized Renewable projects
- 24.3 MW total renewable nameplate capacity

The City of Thunder Bay is serviced from three, Hydro One owned transformer stations (TS); Birch TS, Fort William TS, and Port Arthur TS. These transformer stations supply SNC with a distribution level voltage of 25kV. The city of Kenora is serviced by a single SNC owned transformer station, Kenora MTS at a distribution voltage level of 12 kV.

The majority of SNC customers in Thunder Bay (84%) are served from distribution transformers fed directly from 25kV feeders, originating from one of three Hydro One transformer stations. The city's older urban districts (9% of customers) are served from distribution transformers fed from 4kV feeders originating from six SNC owned distribution sub-stations (DS's), which are in turn fed from 25kV circuits. The remaining 7% of customers, (generally rural), are serviced from distribution transformers fed by 12kV feeders, originating from four SNC owned DS's, also fed from 25kV circuits.

Of the SNC customers in Kenora, 100% are served by distribution transformers fed directly from 12kV feeders originating from the SNC owned transformer station in Kenora (KMTS).

The following table lists the ownership, voltage level and designation of each TS and DS which is directly connected to the SNC network.

Designation		Voltage Level	Ownership
P02	Port Arthur TS	25kV	Hydro One
P17	Birch TS	25kV	Hydro One
P10	Fort William TS	25kV	Hydro One
4	Vickers	4kV	SNC
5	Donald	4kV	SNC
11	High	4kV	SNC
12	Camelot	4kV	SNC
14	Algoma	4kV	SNC
21	Windemere	4kV	SNC
16	MacDonnell	4kV	SNC
18	Balsam	12kV	SNC
19	Broadway	12kV	SNC
23	Alice	12kV	SNC
36	Mapleward	12kV	SNC
1501	Kenora MTS	12kV	SNC

Table 1 - SNC System Transformer/Distribution Stations

2.1 Overview of the Capacity Assessment Process

Over the past 12 years, SNC has been committed to supporting the introduction of renewable generation into our distribution system. However, the distribution system was not designed to accommodate fully bidirectional flows, or the many sources associated with embedded generation and distributed resources. To ensure that SNC can operate a safe, efficient, and reliable distribution system, we must place limits on the amount of generation which is allowed on our system. When establishing the generation limits of our system, we consider the following: Available Short Circuit Capacity, Available Thermal Capacity and Anti-Islanding Requirements. These limits are evaluated independently for each station and circuit (feeder) within our system and are explained in detail below.

2.1.1 Available Short Circuit Capacity

All the equipment on our system must be rated for the level of electrical current that would be supplied during a short circuit condition. The addition of generation on our system increases the amount of electrical current that will flow during a short circuit condition. SNC therefore needs to constantly monitor the amount of available short circuit current and ensure that ratings are not exceeded. This is a safety concern in that, if equipment is exposed to currents which exceed their rating, they can fail violently.

2.1.2 Available Thermal Capacity

All the equipment on the SNC system must be rated for the level of electrical current that could be supplied during normal and contingency operation. The addition of exporting type generation on our system can increase the amount of electrical current that flows during normal operation. We therefore need to keep track of the maximum electrical current that could flow through our equipment in all situations. Operating equipment within its thermal limit is important to minimize line loss (maximize operating efficiency) and to minimize premature failure (maximize reliability and minimize operating cost) of SNC's assets.

2.1.3 Anti-Islanding Requirements

When generation operates in parallel with our distribution system, it introduces the possibility that when protection or switching operations isolate sections of our network, the generator(s) and load customers form a small island. When power is restored (which often happens within 0.5 – 2 seconds of interruption for re-close operations), the island may have drifted out of phase from the main system, resulting in a close operation which effectively creates a fault involving all the participants of the island. In this scenario, all the customers who participate in that island could have equipment and/or property damaged because of this operation, which is why SNC must avoid even the smallest possibility of this occurring.

Anti-islanding is achieved differently in micro and small generation installations, as compared to medium and large generator installations. For micro and small generation installations, it is achieved via two mechanisms. The first mechanism is a requirement for generation equipment to comply with CSA C22.3 No. 9 Interconnection of Distributed Energy Resources and Electricity Supply Systems or IEEE 1547-2018 Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces, which ensures equipment can sense voltage and frequency distortions, which are characteristics of a very short term (unstable) island. The second mechanism protects against medium-long term (slightly more stable) islands and is achieved by the utility ensuring that there is less generation on a given circuit than can support the minimum load of that circuit. The second mechanism is a requirement to ensure that the first mechanism works as designed.

For medium and large generation installations, where the amount of generation exceeds the minimum load of the circuit, the generator must implement a scheme called “transfer trip”. This type of protection scheme effectively forces the generation offline by means of a high-speed communication link, anytime a protection or switching event occurs, and blocks reclose operations until such time as the generator end is confirmed open. For these types of generators, it is not necessary to limit generation to less than minimum feeder loads. The trade-off, however, is the added cost of implementing a highly reliable high speed communication link to facilitate the transfer trip.

2.1.4 Hydro One TS available Capacity

Hydro One determines the generation capacity of the Port Arthur, Birch, and Fort William transformer stations separately from the SNC process. The available capacity for each station is publicly available at www.hydroone.com and is listed on the “Hydro One List of Station Capacity” (last updated November 1, 2022). Transformer station capacities are given as “Short Circuit Capacity” and “Thermal Capacity” and applied as a capacity pool to the entire station. The net station capacity is the gross capacity less the aggregation of the existing downstream generator’s short circuit and thermal contributions. Presently, capacity for the connection of renewable generation facilities to the SNC network is limited by the Hydro One TS capacities.

2.1.5 Northwest Region Capacity

Finally, both Synergy North’s service territories fall within the ‘Northwest’ region of the provincial transmission system (as defined by the Independent Electricity Service Operator). The construction of the East-West tie, which was placed in-service in March of 2022, has lifted the capacity constraints and added transfer capacity into the Northwest, reinforcing the 230 kV transmission path in the region. The Integrated Regional Resource Plan for the Northwest was released on January 13, 2023, and indicates that;

“With these reinforcement projects, the infrastructure in the Northwest will be adequate to support forecast growth except for some station capacity and local operational needs.”

2.2 Present Levels of Distributed Generation Connections

SNC has connected a significant number of micro, small and medium renewable projects to the distribution system along with providing connection to non-renewable generators. The following tables summarize the number of projects and their installed capacity of renewable and non-renewable connections.

Renewable Connections	**Pre 2016**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Micro Generation (<= 10kW)	221	3	5	2	0	0	5	2	238
Small Generation (<= 1 MW @ 25kV, <= 500KW @ 4kV)	14	0	0	0	3	0	0	0	17
Mid-Sized (>1MW @ 25kV, >500kW @ 4kV)	4	0	0	0	0	0	0	0	4
Large (> 10MW)	0	0	0	0	0	0	0	0	0
Total	239	3	5	2	3	0	5	2	259

Renewable Connected Load (kW)	**Pre 2016**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Micro Generation (<= 10kW)	1,946	24	39	18	0	0	30	16	2,073
Small Generation (<= 1 MW @ 25kV, <= 500KW @ 4kV)	1,803	0	0	0	686	0	0	0	2,489
Mid-Sized (>1MW @ 25kV, > 500kW @ 4kV)	19,700	0	0	0	0	0	0	0	19,700
Large (> 10MW)	0	0	0	0	0	0	0	0	0
Total	23,449	24	39	18	686	0	30	16	24,261

Table 2 – Existing Renewable Distributed Generation Connections

Non-Renewable Connections	**Pre 2016**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Micro Generation (<= 10kW)	0	0	0	0	0	0	0	0	0
Small Generation (<= 1 MW @ 25kV, <= 500KW @ 4kV)	0	0	0	0	0	0	0	0	0
Mid-Sized (>1MW @ 25kV, >500kW @ 4kV)	2	0	0	0	0	0	0	0	2
Large (> 10MW)	0	0	0	0	0	0	0	0	0
Total	2	0	0	0	0	0	0	0	2

Non-Renewable Connected Load (kW)	**Pre 2016**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Micro Generation (<= 10kW)	0	0	0	0	0	0	0	0	0
Small Generation (<= 1 MW	0	0	0	0	0	0	0	0	0

@ 25kV, <= 500KW @ 4kV)									
Mid-Sized (>1MW @ 25kV, > 500kW @ 4kV)	3,984	0	0	0	0	0	0	0	3,984
Large (> 10MW)	0	0	0	0	0	0	0	0	0
Total	3984	0	0	0	0	0	0	0	3984

Table 3 - Existing Non-Renewable Distributed Generation Connections

2.3 Present Capacity for the Connection of Distributed Generation

The following table provides the present capacity at a station level for the SNC 25kV distribution system to accommodate generation. Generation connections on 4kV and 12kV are reflected in their respective parent 25kV feeder capacity.

Hydro One Owned Transformer Station	SNC Feeder	Existing Renewable non-micro Connections (kW)	Existing micro-DER connections (kW)	Existing Non-renewable connections (kW)	DG In Progress (kW)	Net Station Capacity for Generator Connections *	
						Short Circuit Capacity (MVA)	Thermal Capacity (MW)
Port Arthur TS	02M1	-	-	-	-	8.4	31
	02M2	-	20	-	-		
	02M3	-	-	-	-		
	02M4	-	206	-	-		
	02M5	-	8	-	-		
Fort William TS	10M1	350	69	-	-	266.4	69.7
	10M2	-	-	-	-		
	10M3	600	84	-	-		
	10M4	100	55	-	-		
	10M5	8,900	-	-	-		
	10M6	-	176	-	-		
	10M7	-	37	-	-		
	10M8	7,175	103	-	-		
	10M9	75	69	-	-		
	10M10	3,368	26	-	-		
Birch TS	17M1	500	10	-	-	200.7	65.1
	17M2	578	76	-	-		
	17M3	-	63	2,000	-		
	17M4	-	63	-	-		
	17M5	100	68	-	-		
	17M6	100	79	-	-		
	17M7	119	-	-	-		
	17M8	-	30	1,984	6		
Kenora MTS	KFA	-	71	-	-	30.6	105.9
	KFB	-	21	-	1		
	KFC	-	-	-	-		
	KFD	-	56	-	-		
	KFE	-	20	-	-		
	KFF	225	12	-	-		

* Information obtained from Hydro One website November 2022

Table 4 - SNC Capacity to Accommodate Renewable Generation

2.4 Factors Limiting Full Utilization of Available Capacity

Currently, SNC has a gross feeder available capacity for embedded generation of approximately 40 MW of combined micro/small projects, or 470 MW of combined medium/large projects. When including short circuit and thermal limitations of Hydro One owned stations (per Hydro One, List of Station Capacity, November 1, 2022), the combined available embedded generation capacity for medium/large projects is further reduced to between 20 MW and 421 MW, depending on the type of generation; synchronous using the greatest short circuit capacity (assuming 25 times rated), versus inverter based using the least capacity.(assuming 1.2 times rated)

Starting in 2014, customers located on certain rural feeders that have requested micro/small generation connections have been rejected due to restrictions related to the anti-islanding requirements described in section 2.1.3. In particular, the load can be very small in rural areas, the amount of generation that can be supported is also minimal. However, using the average daily minimum load to define the thermal capacity has helped to allocate more capacity and allowed SNC to remove restrictions on some rural feeders.

The latest inverter standards require new technology including voltage and frequency control schemes which will allow further penetration of distributed energy resources. Using more advanced control schemes can alleviate some islanding concerns as well as providing system support during normal operating conditions.

3. 5 Year Distributed Generation Forecast

At present, it is difficult to predict the levels of renewable generation development. Since the cancellation of the FIT program, there has been a considerable decrease in renewable connections across the board. Given that no incentive programs for renewable generation are expected to come into effect, the number of new connections will remain low.

The connection of the East-West tie has reduced the capacity concerns at a regional level. Hence, there may be some additional interest in large generation connections. However, given that we do not have any applications in progress, thus, we cannot predict whether there will be any new connections.

The proposed work in the low voltage yard at PATS is expected to take place in 2025 which will increase the short circuit capacity available at the station. If the proposed hardware upgrades by HONI to PATS are not performed, further development of projects with nameplate ratings between 10kW and 500kW will continue to be limited while connecting to feeders originating from PATS.

Based on local interest and available short circuit capacity, we are not forecasting any additional mid-sized load displacement (non-renewable) generators within the next few years.

Renewable Connections	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**Total**
Micro Generation (<= 10kW)	5	5	5	5	5	5	30
Small Generation (<= 1 MW @ 25kV, <= 500KW @ 4kV)	0	0	0	0	0	0	0
Mid-Sized (>1MW @ 25kV, > 500kW @ 4kV)	0	0	0	0	0	0	0
Large (> 10MW)	0	0	0	0	0	0	0
Total	5	5	5	5	5	5	30

Renewable Connected Load (kW)	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**Total**
Micro Generation (<= 10kW)	30	30	30	30	30	30	180
Small Generation (<= 1 MW @ 25kV, <= 500KW @ 4kV)	0	0	0	0	0	0	0
Mid-Sized (>1MW @ 25kV, > 500kW @ 4kV)	0	0	0	0	0	0	0
Large (> 10MW)	0	0	0	0	0	0	0
Total	30	30	30	30	30	30	180

Table 5 – Forecast of Renewable Distributed Generation Connections

Non-Renewable Connections	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**Total**
Micro Generation (<= 10kW)	0	0	0	0	0	0	0
Small Generation (<= 1 MW @ 25kV, <= 500KW @ 4kV)	0	0	0	0	0	0	0
Mid-Sized (>1MW @ 25kV, > 500kW @ 4kV)	0	0	0	0	0	0	0
Large (> 10MW)	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0

Non-Renewable Connected Load (kW)	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**Total**
Micro Generation (<= 10kW)	0	0	0	0	0	0	0
Small Generation (<= 1 MW @ 25kV, <= 500KW @ 4kV)	0	0	0	0	0	0	0
Mid-Sized (>1MW @ 25kV, > 500kW @ 4kV)	0	0	0	0	0	0	0
Large (> 10MW)	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0

Table 6 – Forecast of Non-Renewable Distributed Generation Connections

4. Planning and Consultation

SNC has consulted with the IESO on numerous occasions and specifically during the current development of the Northwest Integrated Regional Resource Plan (IRRP). Although the focus of the meetings has been on load demand in the region, capacity limitations at the HONI transformer stations has also been discussed. Capacity limitations in the Northwest region have also been a topic of discussion during the working group meetings.

SNC has been in regular communication with several personnel at Hydro One throughout the development and connection phases of several renewable generation facilities in the past. These consultations have included collaboration in the 'Connection Impact Assessment' phase, coordination of technical and construction requirements with respect to facility upgrades and protection schemes, and partnership throughout the commissioning of the projects.

In 2011, SNC and Hydro One reached a consensus on tolerable fault levels which allowed for a significant increase in Fort William and Birch TS' ability to accommodate further renewable generation. The available capacities in section 2 are reflective of this change. Documentation supporting SNC's collaboration with Hydro One in these matters is available upon request. Although SNC has agreed that it can accept the increased short circuit levels on its system, should any one renewable generation project request to connect, increasing levels well beyond current limits, and causing the need to upgrade or add devices to accommodate these new levels, SNC would at that point request the upgrades be funded under a renewable enabling improvement project.

5. Investments to Facilitate Renewable Energy Generation

SNC has reviewed the need for capital and OM&A investments related to the connection of REG projects as it applies to the expansion of the distribution system and renewable enabling improvements. Based on this review and historic trends within our service territory, SNC does not expect any major REG investments for the period of 2023-2028. From an OM&A perspective, no additional OM&A expenses are anticipated as SNC is capable of processing both micro and larger DER applications using existing employees.

SNC shall continue to fully comply with its responsibility under the Distribution System Code as it relates to distribution expansion and renewable enabling improvements to the distribution system to support REG projects.

IESO response to Synergy North REG Investments Plan 2023 – 2028

As part of the OEB's Filing Requirements for Electricity Distribution Rate Applications, a distributor must submit a letter of comment from the Independent Electricty System Operator (IESO) on its Renewable Energy Generation (REG) Investments Plan, which is part of its Distribution System Plan. On January 27, 2023, Synergy North Corporation (SNC) sent its REG Investments Plan (Plan) to the IESO for comment. The IESO has reviewed SNC's Plan and reports that it contains no investments specific to connecting REG for the Plan period 2023 – 2028.

The IESO notes that SNC's service territory is within the Northwest region. The Northwest Integrated Regional Resource Plan (IRRP) was published by IESO in January 2023, indicating that Kenora MTS is expected to reach capacity in 2029. The IRRP recommended that SNC lead further Non Wires Alternatives (NWA) analysis and refinement as part of local planning. It was also recommended that SNC monitor load growth at Kenora MTS to determine when a firm commitment for additional capacity is required and implement NWAs if they remain feasible and cost-effective. Furthermore, the IESO will consider Kenora MTS as a potential focus area for the Local Initiatives Program under the 2021-2024 Conservation and Demand Management Framework. The IESO will also collaborate with Synergy North in 2023 as further details for the next round of the Local Initiatives Program becomes available.

On Page 14 of its Plan, under the heading Investments to Facilitate Renewable Energy Generation, SNC states that "SNC does not expect any major REG investments for the period of 2023-2028".

As SNC has determined it requires no system investments to connect REG over the 2023-2028 Plan period, the IESO submits that no comment letter from the IESO is required to address the bullets points in the OEB's Filing Requirements for Electricity Distribution Rate Applications – Chapter 5, Section 5.2.2 Coordinated Planning with Third Parties[1].

The IESO appreciates the opportunity provided to review the REG Investments Plan of SNC and looks forward to working together in further regional planning processes.

[1] OEB's Filing Requirements for Electricity Distribution Rate Applications - Chapter 5, Section 5.2.2, page 10: https://www.oeb.ca/sites/default/files/Chapter-5-DSP-Filing-Requirements-20200514.pdf

APPENDIX B: IESO NORTHWEST IRRP

Integrated Regional Resource Plan

Northwest Region
January 2023

Connecting Today.
Powering Tomorrow.

Disclaimer

This document and the information contained herein is provided for informational purposes only. The IESO has prepared this document based on information currently available to the IESO and reasonable assumptions associated therewith, including relating to electricity supply and demand. The information, statements and conclusions contained in this document are subject to risks, uncertainties and other factors that could cause actual results or circumstances to differ materially from the information, statements and assumptions contained herein. The IESO provides no guarantee, representation, or warranty, express or implied, with respect to any statement or information contained herein and disclaims any liability in connection therewith. Readers are cautioned not to place undue reliance on forward-looking information contained in this document, as actual results could differ materially from the plans, expectations, estimates, intentions and statements expressed herein. The IESO undertakes no obligation to revise or update any information contained in this document as a result of new information, future events or otherwise. In the event there is any conflict or inconsistency between this document and the IESO market rules, any IESO contract, any legislation or regulation, or any request for proposals or other procurement document, the terms in the market rules, or the subject contract, legislation, regulation, or procurement document, as applicable, govern.

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List of Acronyms

Acronym	Definition
APS	Achievable Potential Study
CDM	Conservation and Demand Management
DER	Distributed Energy Resource
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
LDC	Local Distribution Company
LTE	Long-term Emergency
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NWA	Non-wires Alternative
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
SCGT	Simple Cycle Gas Turbine
TS	Transformer Station
ULTC	Under-Load Tap Changer

This Integrated Regional Resource Plan (IRRP) was prepared by the Independent Electricity System Operator (IESO) pursuant to the terms of its Ontario Energy Board licence, EI-2013-0066.

This IRRP was prepared on behalf of the Technical Working Group (Working Group) of the Northwest region which included the following members:

Independent Electricity System Operator (IESO)

Hydro One Networks Inc. (Hydro One Transmission)

Hydro One Networks Inc. (Hydro One Distribution)

Atikokan Hydro Inc.

Fort Frances Power Corporation

Sioux Lookout Hydro Inc.

Synergy North

The Working Group assessed the reliability of electricity supply to customers in the Northwest Region over a 20-year period beginning in 2021; developed a plan that considers opportunities for regional coordination in anticipation of potential demand growth and varying supply conditions in the region; and developed an implementation plan for the recommended options while maintaining flexibility to accommodate changes in key conditions over time.

The Northwest Working Group members agree with the Integrated Regional Resource Plan (IRRP)'s recommendations and support the implementation of the plan, subject to obtaining necessary regulatory approvals and appropriate community consultations. The Northwest Working Group members do not commit to any capital expenditures and must still obtain all necessary regulatory and other approvals to implement recommended actions.

1. Introduction

This Integrated Regional Resource Plan (IRRP) addresses the electricity needs of the Northwest region over the next 20 years from 2021 to 2040. The Northwest region includes the area roughly bounded by Lake Superior to the south, the Marathon area to the east, and the Manitoba border to the west. It includes the districts of Kenora, Rainy River and Thunder Bay. A geographic map of the Northwest region is shown in Figure 1-1. Note that, for regional electricity planning purposes, the region is defined by electrical infrastructure rather than geography. The region encompasses the 230 kV circuits from the Manitoba interties in the west to Marathon TS in the east as well as the 115 kV sub-systems in between. A single line diagram of the electrical infrastructure in the region is shown in Figure 1-2.

Northwest regional electricity demand is winter peaking and, over the last five years, has grown on average by 1.1% per year. Electricity supply to the Northwest region is provided through the 230 kV East-West Tie circuits from Wawa TS, as well as from interconnections with Manitoba and Minnesota. Local generation in the region is predominantly hydroelectric and biomass-fueled.

The region's electricity is delivered by five local distribution companies (LDCs): Hydro One Networks Inc., Atikokan Hydro Inc., Fort Frances Power Corporation, Sioux Lookout Hydro Inc., and Synergy North. Hydro One Networks is also the lead transmitter in the region for regional planning purposes. Note that three transmitters own assets in the Northwest region: Hydro One Networks, Nextbridge Infrastructure, and Wataynikaneyap Power. As the lead transmitter, Hydro One Networks coordinates the involvement of other transmitters as necessary. This IRRP report was prepared by the Independent Electricity System Operator (IESO) on behalf of a Working Group composed of the aforementioned LDCs and Hydro One Networks.

Development of the Northwest IRRP was initiated in Jan 2021 following the publication of the Needs Assessment report in July 2020 by Hydro One and the Scoping Assessment Outcome Report in Jan 2021 by the IESO.[1] The Scoping Assessment identified needs that should be further assessed through an IRRP. The Working Group was then formed to gather data, identify near- to long-term needs in the region and develop the recommended actions included in this IRRP.

This report is organized as follows:

- A summary of the recommended plan for the region is provided in Section 2;
- The process and methodology used to develop the plan are discussed in Section 3;
- The context for electricity planning in the region and the study scope are discussed in Section 4;

[1] The Needs Assessment can found on Hydro One's Northwest Ontario regional planning website and the Scoping Assessment Outcome Report can be found on the IESO's Northwest regional planning engagement website.

- Demand forecast scenarios, distributed generation assumptions, and conservation and demand management are described in Section 5;
- Electricity needs in the region are presented in Section 6;
- Alternatives and recommendations for meeting needs are addressed in Section 7;
- An update on the Supply to the Ring of Fire study is provided in Section 8
- A summary of engagement to date and the next steps are provided in Section 9; and
- The conclusion is provided in Section 10

Figure 1-1 | Geographic Map of the Northwest Region

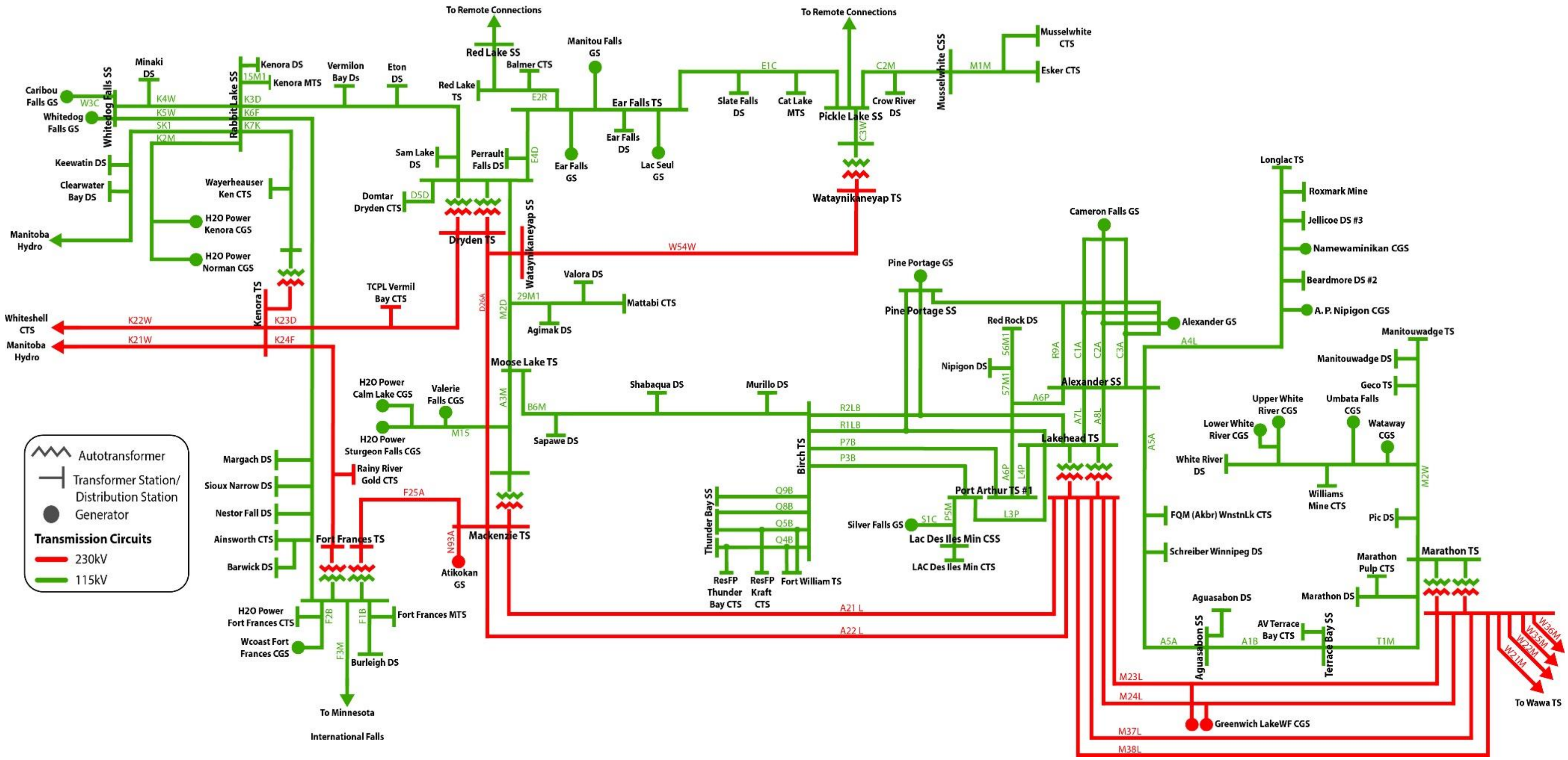

Figure 1-2 | Electricity Infrastructure in the Northwest Ontario Region

2. The Integrated Regional Resource Plan

This IRRP provides recommendations to address the electricity needs of the Northwest region over the next 20 years. The needs identified are based on the demand growth anticipated in the region and the capability of the existing transmission system as evaluated through the application of the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC) and reliability standards governed by the North American Electric Reliability Corporation (NERC) and the Northeast Power Coordinating Council (NPCC). The IRRP's recommendations are informed by an evaluation of options, representing alternative ways to meet the needs, that consider: reliability, cost, technical feasibility, maximizing the use of the existing electricity system (where economic and feasible), and feedback from stakeholders.

There are several recent or ongoing transmission reinforcement projects in the Northwest region including the:

- East-West Tie Reinforcement (new double circuit 230 kV line from Wawa TS to Marathon TS and from Marathon TS to Lakehead TS),
- Waasigan Transmission Line Project (Phase 1 being a new double circuit 230 kV line from Lakehead TS to Mackenzie TS and Phase 2 being a new single circuit 230 kV line from Mackenzie TS to Dryden TS), and
- Wataynikaneyap Transmission Project (new single circuit 230 kV line from Dinorwic Junction near Dryden to Wataynikaneyap TS near Pickle Lake as well as 115 kV remote connection circuits north of Pickle Lake and Red Lake).

Taken together, these projects reinforce many of the 230 kV transmission paths in the region. With these reinforcement projects, the infrastructure in the Northwest will be adequate to support forecast growth except for some station capacity and local operational needs. There are no new transmission projects recommended as a result of this Northwest planning initiative.

Northwest electricity demand growth is driven by the mining sector which tends to add large incremental blocks of load, often with short lead times. Therefore, this IRRP also studied several high growth sensitivities beyond forecast demand levels to test the robustness of the plan.

The plan below is organized into two sections: near-/medium-term recommendations and ongoing monitoring. Near-/medium-term recommendations include actions or further studies to be undertaken by Working Group member(s) by a specified date. These recommendations address needs with a high level of forecast certainty and requires firm commitments in this cycle of regional planning. Ongoing monitoring activities address long-term needs or potential needs flagged in high growth sensitivities that may emerge but are not yet certain based on the latest electricity demand forecast. This approach ensures that the IRRP provides clear guidance on investments needed in the near future while remaining flexible to consider new information such as electrification, energy efficiency, and industrial/mining development plans.

2.1 Near-/Medium-Term Recommendations

The near- and medium-term recommendations are summarized in Table 2-1 and further discussed below.

Table 2-1 | Summary of Near- and Medium-Term Recommendations

Need/Subsystem	Recommendation	Lead Responsibility	Required By
Kenora MTS Station Capacity	Non-wires alternatives (NWAs) can be cost effective depending on distribution system benefits; Kenora MTS will be a potential focus area for the IESO's Local Initiative Program and Synergy North will lead further non-wires analysis in local planning	Synergy North; IESO	2029
Crilly DS Station Capacity	NWAs not suitable; Hydro One Distribution will refine options for refurbishment or a new station in local planning	Hydro One Distribution	2027
Margach DS Station Capacity	NWAs not suitable; Hydro One Dx will install fan monitoring if growth materializes and monitor for additional growth that might necessitate a second transformer	Hydro One Distribution	2023
Fort Frances MTS Customer Reliability	Reconfiguration of Fort Frances TS to reduce supply interruptions to Fort Frances MTS during transmission system outages; Fort Frances Power and Hydro One Transmission will refine configuration in local planning	Fort Frances Power; Hydro One Transmission	As Soon as Practical
E1C Operation and High Voltage	With the new W54W circuit in-service, part of the Wataynikaneyap Transmission Project, E1C will be operated "normally open" and additional reactors will be installed at/near Pickle Lake SS to manage high voltages; Hydro One and IESO will collaborate in the Regional Infrastructure Plan to refine location of open point and reactor sizing	IESO Hydro One Transmission	As Soon as Practical

Note that all costs discussed below are planning-level estimates (-50% to +100%) provided for the purpose of comparing options. Material and labour costs have increased rapidly over the COVID-19 period and there is a high degree of uncertainty in future costs.

2.1.1 Kenora MTS Station Capacity

Kenora MTS is expected to reach capacity in 2029. There are no upstream supply constraints aside from the station capacity itself. The "wires" options range from installing an additional transformer at the existing station ($5M) to a new station across town ($30M) that would also incrementally improve reliability and provide distribution system benefits.[2] The wires options and distribution benefits are further discussed in Section 7.1.4.1. Based on the forecast hourly demand and associated energy-not-served profiles, three non-wires alternatives (NWAs) were identified including a 4 MW gas turbine facility, a 6-hour 4 MW battery, and a hybrid option of energy efficiency and demand response. The cost of these NWAs generally falls between the cost of expanding the existing station and a new station.[2] Therefore, the decision to pursue NWAs versus traditional wires options rests on distribution system benefits that can be realized by each option. NWA options analysis is further discussed in Section 7.1.4.2.

The technologies, regulatory framework, and protocols required to implement dispatchable NWAs to meet local capacity needs are still being tested. The IESO's York Region Non-Wires Alternative Demonstration Project[3] is currently exploring market-based approaches to secure energy and capacity services from distributed energy resources (DERs) for local needs. There is a window of opportunity between today and 2029 when the Kenora MTS capacity need arises to leverage learnings from the York Pilot and further refine NWAs for Kenora MTS.

Therefore, the IRRP recommends that Synergy North lead further NWA analysis and refinement as part of local planning. Synergy North should monitor load growth at Kenora MTS to determine when a firm commitment for additional capacity is required and implement NWAs if they remain feasible and cost-effective. Furthermore, the IESO will consider Kenora MTS as a potential focus area for the Local Initiatives Program[4] under the 2021-2024 Conservation and Demand Management Framework. The IESO will collaborate with Synergy North in 2023 as further details for the next round of the Local Initiatives Program becomes available.

2.1.2 Crilly DS Station Capacity

Crilly DS is expected to reach capacity in 2027. Crilly DS is a small (~2.2 MW) station supplied from a bus shared with Sturgeon Falls CGS, a small hydroelectric plant approximately 50 km west of Atikokan. This is a non-standard supply arrangement that results in annual outages to

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[2] The methodology for calculating cost estimates is set out in Section 7.1.1

[3] For more information on the pilot and latest developments, please see the York Region Non Wires Alternatives Demonstration Project engagement webpage.

[4] For more information on the Local Initiatives Program, please see the Save ON Energy Local Initiatives webpage and the 2021-2024 Conservation and Demand Management Framework webpage.

Crilly DS when the generator is undergoing maintenance. Diesel generation is currently used for backup power when Sturgeon Falls is on outage. Furthermore, station equipment is nearing end-of-life and space constraints limit in situ refurbishment options.

Non-wires alternatives are not suitable for Crilly DS due to the existing reliance on backup generation. Distributed energy resources cannot remove the reliance on backup power and provide reliability comparable with other standard supply arrangements. Furthermore, the pool of customers served at Crilly DS is too small to target demand-modifying solutions such as energy efficiency and demand response. The IRRP recommends that Hydro One Distribution conducts local planning, in coordination with the Regional Infrastructure Plan, to refine refurbishment/new station options identified in the IRRP with the goal of balancing reliability improvements and cost. Options considered thus far include:

- Refurbish Crilly DS at its current location (and continue to rely on backup power during outages),
- Rebuild Crilly DS at a different location as a 115/25 kV HVDS,
- Rebuild Crilly DS at a different location as a 230/25 kV HVDS, or
- Replace Crilly DS with a 115:25 kV padmount transformer (transformer enclosed in a grounded cabinet that can be accommodated outside the existing station fence).

Wires options for Crilly DS and the rationale for not pursuing non-wires alternatives are further discussed in Section 7.1.2. Hydro One Distribution should monitor load growth to determine when a firm commitment to refurbish/rebuild Crilly DS is required.

2.1.3 Margach Station Capacity

Margach DS is expected to reach capacity in 2023 due to a large existing industrial customer seeking to be resupplied at Margach DS from a nearby CTS. Margach DS is approximately 10 km east of Kenora. Non-wires alternatives are not capable of addressing this large near-term step increase in demand.

The IRRP recommends that Hydro One distribution install transformer fan monitoring which will increase the station capacity above forecast demand levels. If additional capacity needs arise, a second transformer at the station which currently acts as a spare can be brought into service but no recommendation beyond the fan monitoring is required today. Wires options for Margach DS and the rationale for not pursuing non-wires alternatives are further discussed in Section 7.1.3.

2.1.4 Fort Frances MTS Customer Reliability

Fort Frances MTS, a step-down transformer station that supplies LDC loads in Fort Frances, is supplied from the nearby Fort Frances TS. The two stations are located immediately across the street from each other. Fort Frances TS is configured in a manner that would result in Fort Frances MTS supply interruptions during certain transmission outages. Fort Frances MTS station equipment is also aging with both transformers and most breakers dating from the 1960s and 1970s. While the station equipment has not yet reached end-of-life, most equipment has reached or exceeded its typical useful life (as defined in the OEB's Asset Depreciation Study[5]) and will need to be replaced gradually over the next 10-15 years. While there is currently no firm station capacity need within the forecast horizon, several potential large customers have approached Fort Frances Power which could quickly use up the remaining station capacity. Furthermore, 115 kV breakers at Fort Frances TS are also approaching end of life around 2027 which presents an opportunity to reconfigure the station to minimize supply interruptions for Fort Frances MTS. Customer reliability, sustainment, and potential capacity needs are further discussed in Sections 6.2.2 and 0.

Fort Frances Power is developing a roadmap for Fort Frances MTS considering the replacement of aging assets, demand growth, and reliability improvements by reconfiguring supply from Fort Frances TS. Considering these needs simultaneously will ensure the most optimal and cost-effective outcome. Hydro One has proposed several Fort Frances TS reconfigurations that would incrementally improve customer reliability for Fort Frances TS and are further discussed in Section 7.2. The IRRP recommends that Fort Frances Power and Hydro One continue to collaborate and refine a configuration in local planning.

2.1.5 E1C Operation and High Voltage

With the new 230 kV Wataynikaneyap circuit W54W in-service, operating circuit E1C closed would result in a loop comprised of the E4D-E1C-W54W circuits. This arrangement would severely limit the transfer capability through E4D and W54W. The IRRP confirms that E1C should be operated normally open. This configuration is consistent with the 2015 North of Dryden IRRP.

With E1C operated normally open, high voltage arises due to line charging. Studies show that opening E1C closer to the Ear Falls TS end minimizes high voltage issues. Additionally, the IRRP recommends an additional reactor (approximately 10 MVar) at or near Pickle Lake SS.

E1C closed loop transfer limitations and E1C normally open high voltage issues are further discussed in Section 6.2.3. The IESO and Hydro One Transmission will collaborate in the Regional Infrastructure Plan to refine the location of the open point on E1C and the sizing of the reactor, considering asset conditions and costs.

[5] The OEB's Asset Depreciation Study can be found on the Ontario Energy Board's website.

2.2 Ongoing Monitoring

In addition to the needs addressed in the near- and medium-term plan above, there are several long-term or potential needs that may emerge over the forecast horizon. These needs will be monitored by the Working Group to determine when future planning studies should be triggered.

2.2.1 Station Capacity Needs Emerging in the Long-term

White Dog DS and Marathon DS are expected to reach capacity in 2032 and 2038 respectively. In both cases, current demand already exceeds 85% of the station capacity but forecast growth is modest over the forecast horizon. As with many stations across the Northwest, growth can materialize quickly if industrial development intensifies. Therefore, White Dog DS and Marathon DS should be monitored, and further planning activities should be triggered at least five years before anticipated capacity needs to enable consideration of non-wires alternatives. White Dog DS and Marathon DS station capacity needs are further discussed in Section 6.2.1.4 and 6.2.1.5.

2.2.2 Potential Growth in the Red Lake Area

The Red Lake area has significant mining activity and electricity demand is forecast to grow from 58 MW today to 70 MW by 2028. The W54W circuit recently completed as part of the Wataynikaneyap Transmission Project will help relieve constraints on the existing 115 kV circuits to Red Lake.

No capacity needs are anticipated based on the current demand forecast which was finalized by the end of 2021. However, the Working Group is aware of additional potential mining projects that are not captured in the current reference scenario demand forecast.[6] The timing and amount of load associated with these mines are not yet certain but, considering the typical size of new mining projects, remaining capacity in the Red Lake area can quickly be exhausted. Section 6.3.1 identifies the load meeting capability for the Red Lake area as well as constraints on the supply to Ear Falls and Dryden. Depending on the demand that materializes, bulk system enhancements beyond the scope of this IRRP (e.g., Waasigan Transmission Line Project Phase 2) may also be required.

The Working Group will monitor growth in the Red Lake area to determine when future planning activities should be triggered. The IESO will also continue to update the mining demand forecast, including mines in the Red Lake area, to inform ongoing bulk planning activities.

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[6] As described in Section 5.4, for the purpose of this IRRP, the mining sector demand forecast was finalized by the end of 2021. The Working Group is aware of additional future mining projects that were either brought to the awareness of the Working Group after 2021 or were not yet certain enough for inclusion in the demand forecast. The IESO is updating the mining sector demand forecast by end of Q1 2023 and will provide updates to the Working Group to inform the Regional Infrastructure Plan.

2.2.3 Potential Growth in the Fort Frances Area

Several large industrial customers have expressed interest in connecting in the Fort Frances area; these customers' potential loads are not included in the current demand forecast. While the incremental electricity demand associated with these customers (approximately totalling 100 MW) may be significant, no firm commitments have been made.

No supply capacity needs are anticipated based on the current demand forecast. Section 6.3.2 identifies the load meeting capability of the Fort Frances area. The Working Group will monitor growth in the Fort Frances area to determine when future planning activities should be triggered.

2.3 Coordination with ongoing Bulk Planning and Project Implementation Activities

In April 2022, as part of the IESO's obligation to recommend the specific scope and timing of the Waasigan Transmission Line Project, the IESO recommended a staged approach for construction with Phase 1 (a new line from Thunder Bay to Atikokan) being placed in-service as close to the end of 2025 as possible. The IESO will continue to monitor developments in the region, update the mining sector demand forecast and provide an update on the need for Phase 2 (a new line from Atikokan to Dryden) by Q2 2023.

The IESO is also conducting a Northern Ontario Voltage Study to identify reactive compensation needs across northern Ontario. There are several recently implemented or planned major transmission reinforcement projects in the north including the East-West Tie Reinforcement, Waasigan Transmission Line Project, Wataynikaneyap Transmission Project, and Northeast Bulk Plan recommendations.[7] These projects will impact the voltage characteristics across the northern bulk transmission system, including the Northwest region. The Northern Ontario Voltage Study is expected to be finalized in early 2023.

The Waasigan Transmission Line Project and Northern Ontario Voltage Study are further described in Section 4.2. The IESO will continue to update the Working Group regarding ongoing bulk planning and project implementation developments for consideration in the Regional Infrastructure Plan.

In addition to the plans above, the IESO is carrying out a Supply to the Ring of Fire study in parallel with this IRRP. The preliminary findings are discussed in Section 8. The Supply to the Ring of Fire Study will continue in 2023 and the IESO will update the working group on findings for consideration in future regional planning activities.

[7] The Need for Northeast Bulk System Reinforcements report can found on the Northeast Bulk Planning webpage.

3. Development of the Plan

3.1 Regional Planning Process

In Ontario, preparing to meet the electricity needs of customers at a regional level is achieved through regional planning. Regional planning assesses the interrelated needs of a region—defined by common electricity supply infrastructure—over the near, medium, and long term and results in a plan to ensure cost-effective and reliable electricity supply. A regional plan considers the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluates options for addressing needs and recommends actions.

The current regional planning process was formalized by the OEB in 2013 and is performed on a five-year planning cycle for each of the 21 defined planning regions in the province. The process is carried out by the IESO, in collaboration with the transmitters and LDCs in each planning region. The process consists of four main components:

1. A Needs Assessment, led by the transmitter, completes an initial screening of a region's electricity needs and determines if there are electricity needs requiring regional coordination;

2. A Scoping Assessment, led by the IESO, identifies the appropriate planning approach for the identified needs and the scope of any recommended planning activities;

3. An Integrated Regional Resource Plan (IRRP), led by the IESO, proposes recommendations to meet the identified needs requiring coordinated planning; and/or

4. A Regional Infrastructure Plan (RIP), led by the transmitter, provides further details on recommended wires solutions.

Further details on the regional planning process and the IESO's approach to regional planning can be found in Appendix A.

Regional planning is not the only type of electricity planning in Ontario. Other planning activities include bulk system planning, carried out by the IESO, and distribution system planning, carried out by LDCs. There are inherent overlaps in these three levels of electricity infrastructure planning.

The IESO completed a review of the regional planning process following the completion of the first cycle of regional planning for all 21 regions. The IESO's Regional Planning Process Review report is posted on the IESO's website. Implementation of Regional Planning Process Review recommendations by the IESO, Ontario Energy Board, and its Regional Planning Process Advisory Board are ongoing.

3.2 The Northwest Region and IRRP Development

The process to develop the Northwest IRRP was initiated in January 2021 following the publication of the Needs Assessment report in July 2020 by Hydro One and Scoping Assessment Outcome Report in January 2021 by the IESO. As per the 18-month timeline, triggered by the publication of the Scoping Assessment Outcome Report, the original publication date for the Northwest IRRP was scheduled for July 13, 2022.

In April 2022, the IESO wrote to the Ontario Energy Board (OEB) to provide notice that the IESO required an additional six months to complete the IRRP. The IRRP's original scope was expanded to include additional key developments in the Northwest region. The expanded scope enabled more extensive stakeholder engagement, consideration of additional growth sensitivities, and better alignment with ongoing bulk studies across the Northwest and Northeast regions. Based on the IESO's estimate of the additional time required to incorporate the expanded scope, the new expected posting date for the Northwest IRRP was extended to January 13, 2023.

4. Background and Study Scope

This is the second cycle of regional planning for the Northwest region. In the first cycle of regional planning, the region was divided into four sub-regions, each with its own IRRP:

- Greenstone-Marathon (published June 2016)
- Thunder Bay (published December 2016)
- West of Thunder Bay (published July 2016)
- North of Dryden (published January 2015)

A summary of each of the above IRRPs can be found in the 2021 Scoping Assessment Outcome Report[8]. The Scoping Assessment for this planning cycle recommended a single IRRP covering the entire Northwest region. This report presents an integrated regional electricity plan for the next 20-year period from 2021-2040.

Note that two new transmission system projects, the East-West Tie ("EWT") reinforcement and the Wataynikaneyap Transmission Project ("Watay Project") came into service during the current IRRP study. They were both assumed to be in-service for the purpose of this IRRP's technical assessments. The EWT reinforcement adds four new 230 kV circuits: M37L and M38L from Lakehead TS to Marathon TS and W35M and W36M from Marathon TS to Wawa TS. The new EWT circuits were placed in service in March 2022. The Watay Project includes a new 230 kV circuit, W54W, between Watay 230/115 kV TS and Dinorwic Junction on circuit D26A, which runs between Dryden TS and Mackenzie TS. W54W was placed in service in August 2022. The Watay Project includes the connection of ten remote First Nation communities north of Pickle Lake (electrically supplied by Pickle Lake SS) and an additional seven remote First Nation communities north of Red Lake (electrically supplied by Red Lake SS). As of Q4 2022, work is still underway to connect Pickle Lake and Red Lake remote communities, but they were assumed to be in service for the purpose of this IRRP's technical assessments.

4.1 Study Scope

This IRRP identifies electricity needs in the Northwest Region and develops and recommends options to meet these needs. A list of transmission facilities included in the scope of this study can be found in Appendix C. The plan was prepared by the IESO on behalf of the Working Group. The plan includes consideration of forecast electricity demand growth, conservation, and demand management (CDM), distributed generation (DG), transmission and distribution system

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[8] The 2021 Scoping Assessment Outcome Report can be downloaded from the Northwest Regional Planning engagement webpage.

capability, relevant community plans, condition of transmission assets and developments on the bulk transmission system.

The Northwest IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast and establishing needs over this timeframe (as described in the following steps);
- Examining the load meeting capability (LMC) and reliability of the existing transmission system, considering facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices. Needs were established by applying ORTAC, NERC, and NPCC criteria;
- Assessing system needs by applying a contingency-based assessment and reliability performance standards for transmission supply in the IESO-controlled grid;
- Confirming identified end-of-life asset replacement needs and timing with LDCs and transmitters;
- Establishing alternatives to address system needs including, where feasible and applicable, generation, transmission and/or distribution, and other approaches such as non-wires alternatives including conservation and demand management;
- Engaging with the community on needs and possible alternatives;
- Evaluating alternatives to address near- and long-term needs; and
- Communicating findings, conclusions, and recommendations within a detailed plan.

For the Northwest IRRP, areas of interest with high growth potential beyond forecast demand levels were identified through stakeholder engagement. Additional high sensitivity studies were performed for these areas to test the robustness of the system to supply higher than forecast demand.

4.1.1 Scope of Regional Planning Regarding New Connections

The purpose of the IRRP is to identify and address reliability needs that require coordination between transmitters, distribution companies, and the IESO. In the Northwest region, growth is driven in large part by industrial customers, predominantly in the mining sector. A subset of these customers are not currently connected to the electricity grid but are pursuing grid connection in the near term. The IRRP used the best available information to accurately simulate the connection arrangement of future customers and projects. However, IRRP technical studies were focused on evaluating the overall adequacy of regional infrastructure to supply forecast demand rather than the capability to supply any specific new project. The IRRP did not study the local connection requirements of any individual project unless there was an opportunity to align with broader regional needs.[9]

4.2 Parallel Bulk Planning Activities

The Waasigan Transmission Line Project and the Northern Ontario Voltage study are proceeding in parallel with this IRRP and the upcoming Regional Infrastructure Plan. Findings and recommendations from these bulk planning activities will inform ongoing regional planning activities.

4.2.1 Waasigan Transmission Line Project

The Waasigan Transmission Line Project ("Waasigan Project"), formally the Northwest Bulk Line, was identified in the Government's 2013 and 2017 Long Term Energy Plans (the "LTEPs") as a priority project to:

- Increase electricity supply to the region west of Thunder Bay;
- Provide a means for new customers and growing loads to be served with clean and renewable sources that comprise Ontario's supply mix; and,
- Enhance the potential for development and connection of renewable energy facilities.

The LTEPs divided the Waasigan Project into three phases:

- Phase 1 - a line from Thunder Bay to Atikokan;
- Phase 2 - a line from Atikokan to Dryden; and,
- Phase 3 - a line from Dryden to the Manitoba border through Kenora.

Following the 2013 LTEP, the Ontario Government issued an Order in Council, also in 2013, that amended Hydro One's license to develop and seek approval for the Waasigan Project according to the scope and timing specified by the IESO.

In 2018, the IESO recommended that Hydro One commence development work (i.e., complete the Environmental Assessment) for Phase 1 and Phase 2 based on the timing of projected supply capacity needs and the risk of them materializing earlier. The IESO committed to ongoing monitoring to determine when construction of both Phase 1 and Phase 2 should begin and to confirm that they are the best course of action to meet the needs.

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[9] Potential customers seeking connection should note that participation in the IRRP does not replace connection processes, namely Customer Impact Assessments (CIA) or System Impact Assessments (SIA). Furthermore, the absence of regional reliability needs identified through the IRRP in a particular area does not guarantee that connection requests in that area will be approved in a CIA or SIA.

In 2022, the IESO updated the demand forecast for the region west of Thunder Bay with information from the IRRP demand forecast and feedback from stakeholders. The mining sector demand forecast drove the majority of the demand growth and is further discussed in Section 5.4. The updated demand forecast showed a need for Phase 1 starting in 2025 and a temporary need for Phase 2 in 2026 and 2027, but not thereafter as some existing mining projects reach end of life. Therefore, the IESO recommended a staged approached for construction where Hydro One would construct the Project to meet near-term system capacity needs, with Phase 1 being placed in service as close to the end of 2025 as possible. The IESO will continue to monitor developments in the Region and provide an update in Q2 2023 on the expected need date for Phase 2. This is a balanced approach to accommodate growth in a timely manner while managing ratepayer risks.

The IESO recognizes that a firm need for Phase 2 could materialize quickly given the potential for additional growth in the region. The IESO is currently in the process of updating the mining demand forecast to reflect additional information received over the past year since the last forecast iteration and to better capture future growth driven by electrification trends and government policy. The forecast update is expected to be completed in Q1 2023.

4.2.2 Northern Ontario Voltage Study

The IESO is conducting a Northern Ontario Voltage Study to identify reactive compensation needs across the bulk system in northern Ontario. The Northern Ontario Voltage Study is expected to be finalized in early 2023.

4.3 Supply to the Ring of Fire

The Ring of Fire is a remote area approximately 500 km north of Thunder Bay rich in critical minerals but without grid power supply. The decision to pursue transmission supply to the Ring of Fire ultimately lies with mining companies and remote communities as they are the direct beneficiaries, or with the provincial and federal governments, to advance broader policy objectives.

Transmission supply to the Ring of Fire was contemplated in the 2015 cycle of regional planning. With renewed interest in developing the Ring of Fire from both government and mining companies, the IESO is updating its Supply to the Ring of Fire study in parallel with this IRRP to help inform government policy and potential customers seeking connection. This study outlines opportunities for alignment, updated high-level transmission supply cost estimates, updated avoided diesel system costs from connecting remote communities, and greenhouse gas reductions as a result of supplying remote communities and potential mines from the electricity grid instead of local generation. The preliminary findings are discussed in Section 8.

The study scope and timing of this ongoing study will evolve with government policy direction. The IESO will share updates with the Working Group to inform upcoming regional planning activities such as the Regional Infrastructure Plan.

5. Electricity Demand Forecast

This section describes the development of the demand forecast for the Northwest Region that underpins this IRRP. The 20-year forecast has three components:

- **Distribution-connected**: The distribution-connected forecast reflects demand served on the distribution systems in the Northwest and is based on information submitted by local distribution companies.

- **Transmission-connected**: The transmission-connected forecast reflects demand served directly from the transmission system. This is typically comprised of large industrial customers that have their own transformation station. The transmission-connected forecast is informed by direct engagement with customers.

- **Mining Sector**: The mining sector forecast captures electricity demand from both existing grid-connected and known future mining projects that are not yet grid-connected. The mining sector forecast is informed by data from government, industry publications, and engagement individual project proponents. Note that electricity demand from existing mining projects is also reflected in the above transmission- and distribution-connected forecast components. When the mining sector component is layered on top of the distribution-connected and transmission-connected components, only the contribution of new mining projects is shown to avoid double counting

Each forecast component is described in detail below. Note that the forecasts in this section refer to the non-coincident peak demand forecast (i.e., the sum of each station's individual peak demand). Coincident forecasts (i.e., contribution of each station to the overall peak demand hour) for the subsystem in question are used for the purpose of identifying need dates and options analysis in Section 6 and 7. Coincident forecasts are found by applying a coincidence factor based on the contribution of each station to the subsystem's coincident peak over the past five years.

Additional details related to the development of the demand forecast are provided in Appendix B. Though the Northwest IRRP forecast was created prior to October 2022, the Ontario Energy Board has also since published a Load Forecast Guideline for regional planning, through the Regional Planning Process Advisory Group.[10]

[10] The Load Forecast Guideline can be found on the Ontario Energy Board's website.

5.1 Historical Demand

Figure 5-1 shows the net and gross historical demand over the last five years in the Northwest region. Distribution-connected customer historically make up approximately 55% of peak demand with the remainder made up of transmission-connected customers. Growth has been steady over the last five years, with an average annual demand growth rate of 1.1% and Northwest demand hovering just over 800 MW from 2018 through 2020. Northwestern Ontario is winter peaking, with the peak demand hour for each year typically occurring on winter evenings between 7 p.m. And 11 p.m.

Existing distributed generation resources historically contributed approximately 10-15 MW during peak demand conditions. This contribution was added back into the net demand forecast to arrive at the gross demand forecast. The 2020 gross demand was used as the starting point for the forecast unless station-level adjustments were necessary to account for anomalous demand conditions on a case-by-case basis.

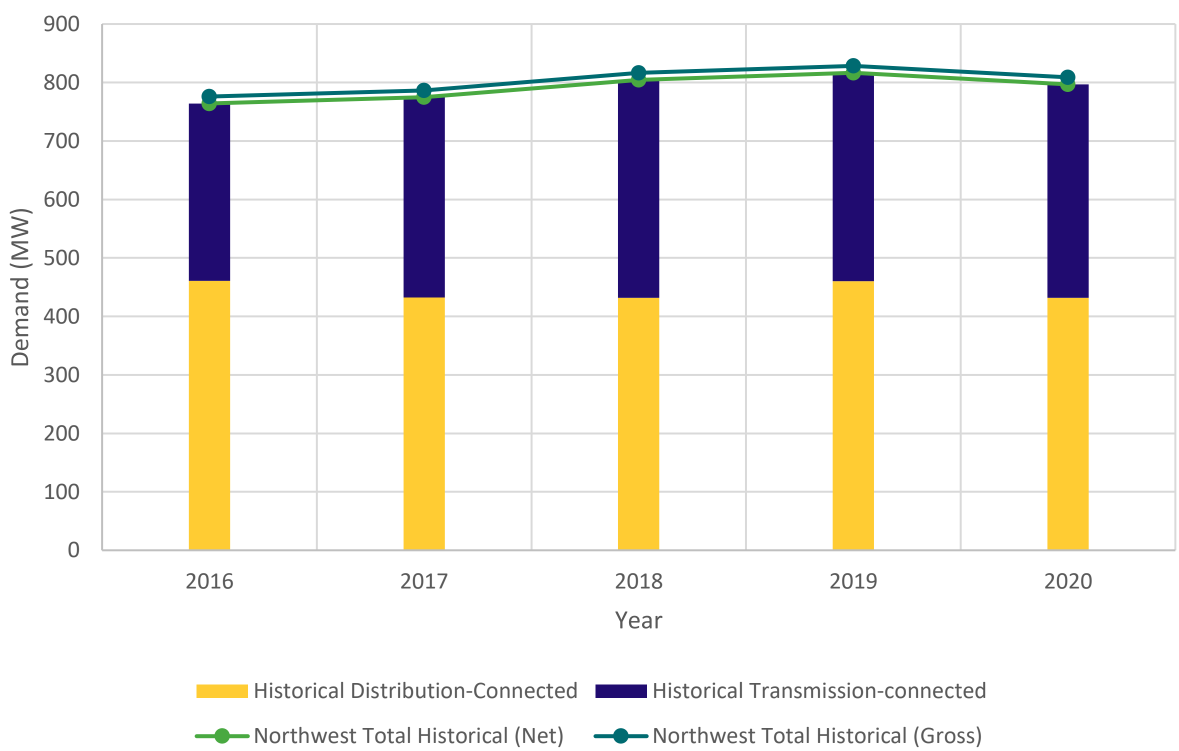

Figure 5-1 | 2016-2020 Historical Demand

5.2 Distribution-connected Forecast

The distribution-connected forecast component starts with a gross station-level demand forecast developed by local distribution companies for their service territory. The gross forecast was then modified to reflect the peak demand impacts of provincial conservation targets and distributed generation contracted through previous provincial programs such as FIT and microFIT[11] and adjusted to reflect extreme weather conditions to produce a reference scenario net forecast for planning assessments. Additional details related to the development of the distribution-connected demand forecast are provided in the sections below and in Appendix B.

5.2.1 Gross Local Distribution Company Forecast

Each participating local distribution company in the Northwest region prepared gross demand forecasts at the station level, or at the station bus level for multi-bus stations. These gross demand forecasts account for increases in demand from new or intensified development and known connection applications within their service territories.

Note that the regional planning process relies on distributors to consider municipal and regional official plans and translate development plans into electrical demand forecasts. Distributors have a better understanding of future local demand growth and drivers than the IESO, since they have the most direct involvement with their customers, connection applicants, and the municipalities they serve. More details on each distributor's demand forecast assumptions can be found in Appendix B.2 to B.6. Distributors are also expected to account for changes in consumer demand resulting from typical efficiency improvements and response to increasing electricity prices, i.e., "natural conservation", but not for the impact of future distributed generation or new conservation measures which are accounted for by the IESO, as discussed in Section 5.2.2 and 5.2.3 below.

The distribution-connected demand forecast compiled from distributors is adjusted to account for extreme weather conditions according to the methodology described in Appendix B.1. Figure 5-2 shows the total gross distribution-connected forecast for the Northwest region.

[11] More information about the Feed-in Tariff can be found on the IESO's website.

The distribution-connected demand forecast compiled from distributors is adjusted to account for extreme weather conditions according to the methodology described in Appendix B.1. Figure 5-2 shows the total gross distribution-connected forecast for the Northwest region.

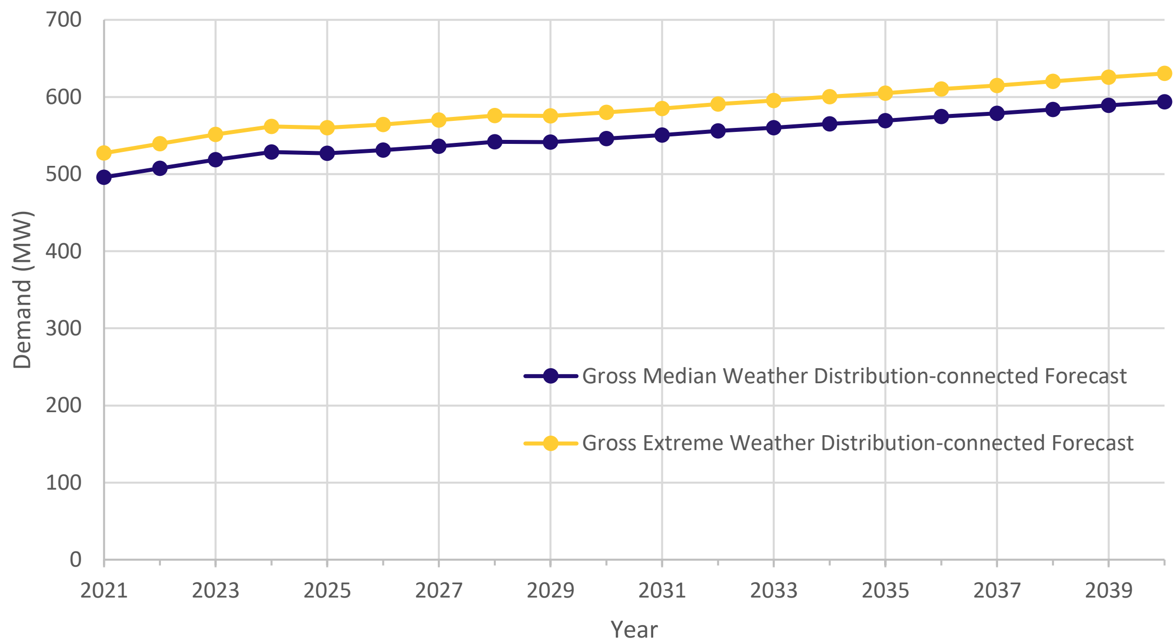

Figure 5-2 | Total Gross Median Weather Distribution-connected Forecast

5.2.2 Contribution of Conservation to the Forecast

CDM is a clean and cost-effective resource that helps meet Ontario's electricity needs and is an integral component of provincial and regional planning. Conservation is achieved through a mix of codes and standards amendments as well as program-related activities. These approaches complement each other to maximize conservation results.

The estimate of demand reduction due to codes and standards is based on expected improvement in the codes for new and renovated buildings and through regulation of minimum efficiency standards for equipment used by specified categories of consumers, i.e., residential, commercial, and industrial consumers.

The estimates of demand reduction due to new program-related activities account for Ontario programs, federal programs that result in electricity savings in Ontario, and forecast future energy efficiency programs. The 2021 – 2024 CDM Framework is the central piece in which the IESO delivers programs on a province-wide basis to enable Ontario's electricity consumers to improve the energy efficiency of their homes, businesses, institutions, and industrial facilities.

Figure 5-3 shows the estimated total yearly reduction to the demand forecast due to conservation (from codes, standards and CDM programs) for residential, commercial, and industrial market segments. Additional details on the conservation forecast methodology are provided in Appendix B.9.

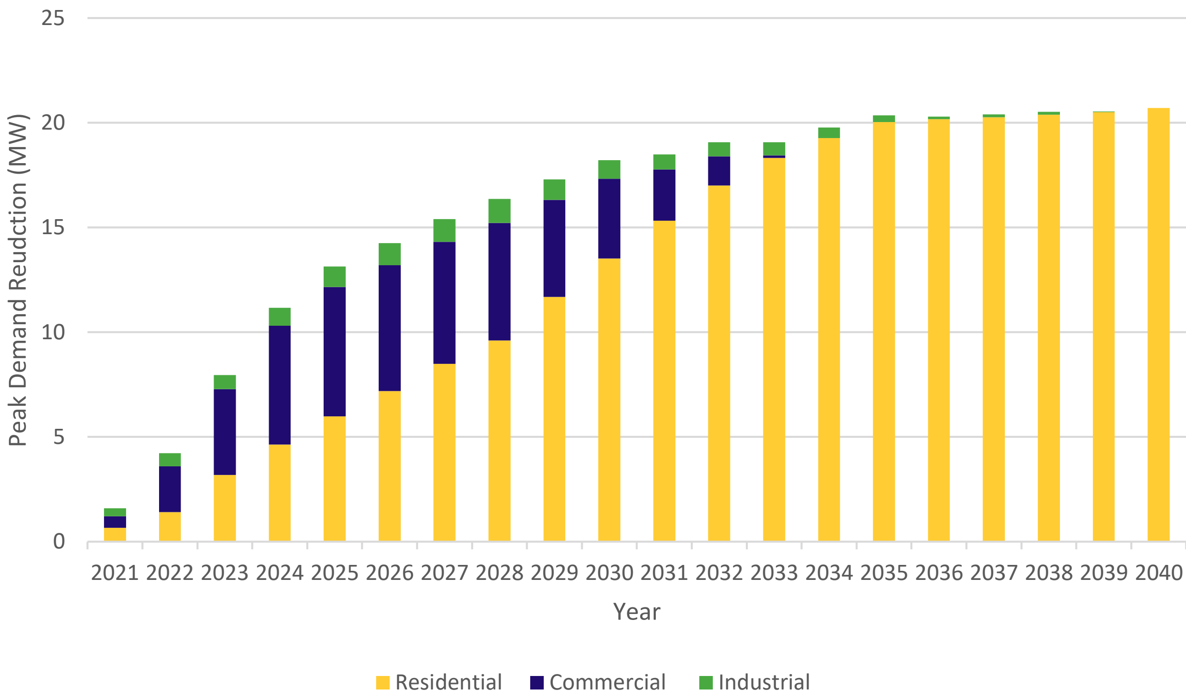

Figure 5-3 | Total Forecast Peak Demand Reduction (Codes, Standards, and CDM Programs)

5.2.3 Contribution of Distributed Generation to the Forecast

In addition to conservation resources, distributed generation in the Northwest region is also forecast to offset some peak demand requirements. The introduction of the Green Energy and Green Economy Act, 2009, and the associated development of Ontario's FIT Program, has increased the significance of distributed renewable generation which, while intermittent, contributes to meeting the province's electricity demands. The installed distributed generation capacity by fuel type and contribution factor assumptions can be found in Appendix B.10.

After reducing the demand forecast due to conservation as described above, the forecast is further reduced by the expected contribution from contracted distributed generation in the region (similar to the adjustment between net and gross historical demand described in Section 5.1 except with forward looking contracted distributed generation rather than existing distributed generation). Figure 5.5 shows the impact of distributed generation reducing the demand forecast. In the long term, the contribution of distributed generation is expected to diminish as these contracts expire. Note that any facilities without a contract with the IESO are not included in the distributed generation peak demand reduction forecast.

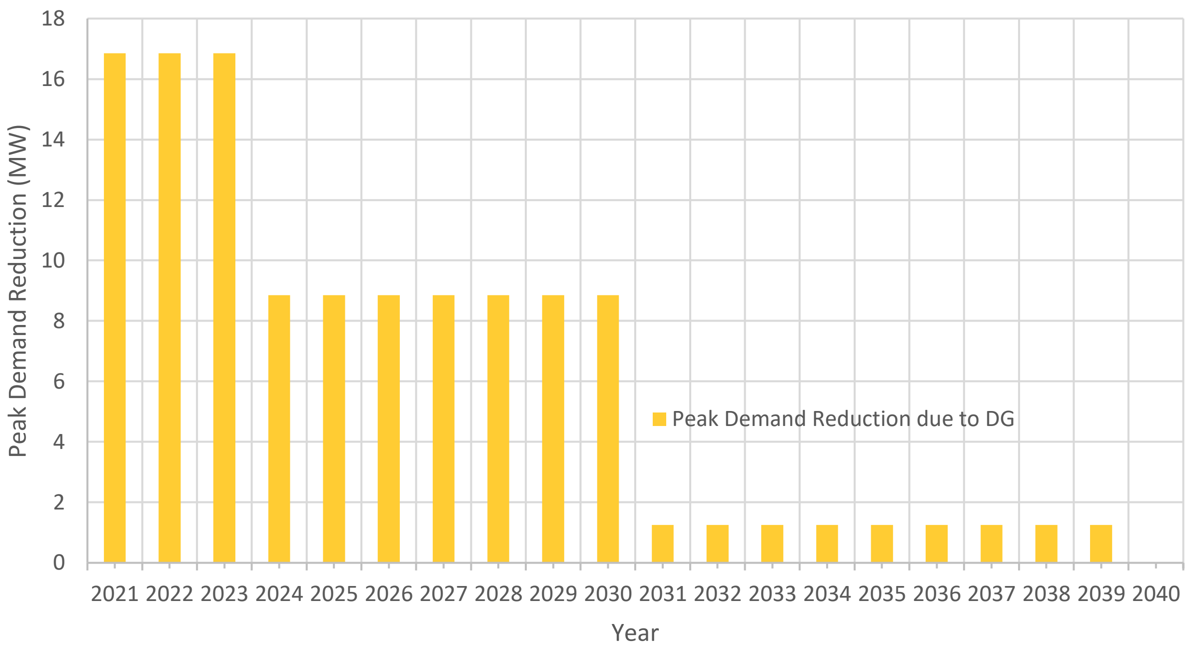

Figure 5-4 | Peak Demand Reduction to Demand Forecast due to Contracted Distributed Generation

5.3 Existing Transmission-connected Forecast

The Northwest region has fifteen customer transformer stations (CTS) that directly serve customers connected to the high-voltage transmission system. The IRRP relies on information from these customers to inform the transmission-connected forecast either directly through their account representative or through comments submitted through the IRRP engagement events. If, for a given station, no information about future demand changes is available, the default assumption is that demand at that station will remain the same as the average historical peak demand over the last five years. Figure 5-5 shows the total non-coincident transmission-connected customer demand forecast. The transmission-connected forecast is generally flat except for a few project expansions/retirements resulting in growth in 2026 and subsequent decline in 2028. Note that, unlike the distribution-connected forecast component, the transmission-connected component is not adjusted for extreme weather because industrial demand does not typically fluctuate with weather. Furthermore, while some customers have behind-the-meter generation facilities, they are not reflected in the forecast unless they are contracted with the IESO.

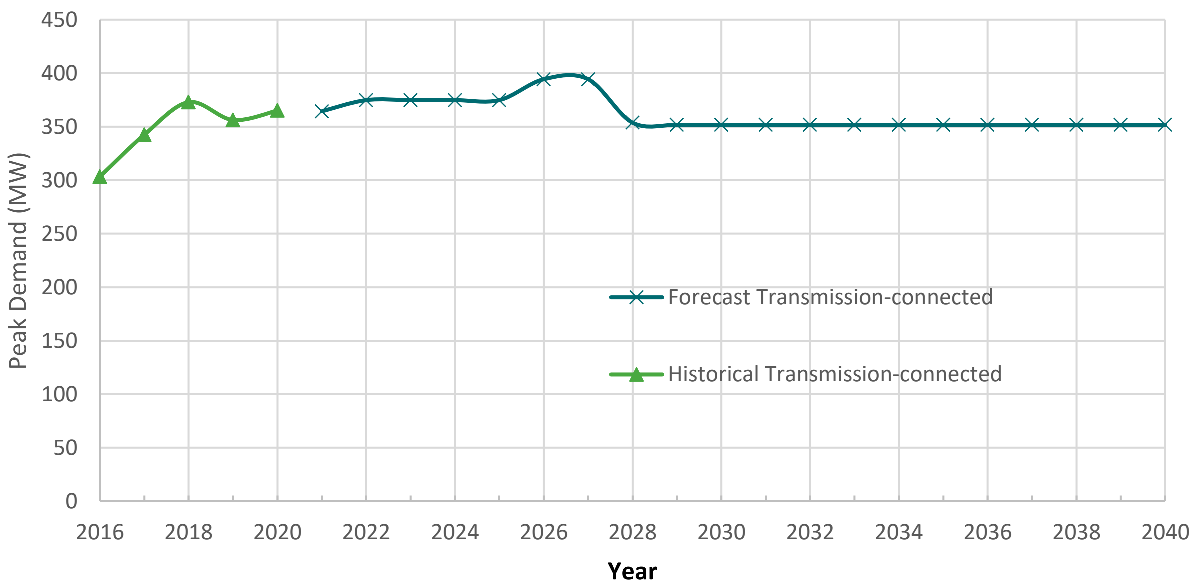

Figure 5-5 | Total Transmission-connected Demand Forecast

5.4 Mining Sector Forecast

In addition to the distribution- and transmission-connected forecasts, expansion of existing mines and new mining projects connecting to the grid are expected to make up the majority of the overall electricity demand growth in the Northwest region. As of Q4 2021, the IESO was aware of more than 20 potential future mining projects in the Northwest region at various stages of planning and development that had known electricity demand forecasts and projected in-service dates. The IESO is also aware of at least ~7-10 projects that are under consideration but have not yet progressed far enough to have an in-service date or electrical demand forecast. Note that information about future mining projects changes frequently. The IESO solicited public feedback on the mining demand forecast and associated list of known mining projects in May 2021. For this IRRP, the mining forecast was considered finalized by the end of 2021 to allow sufficient time for technical assessments that depended on forecast inputs. The mining projects incorporated in the IRRP mining forecast are listed in Appendix B.7.

The mining forecast is project-based and built from the bottom up based on known mining exploration or projects collected from proponents, industry publications, utility companies, and government. Each project is assigned one of four "likelihood" factors ranging from "most likely" to "least likely" that represents the probability of its electricity demand materializing to enable the creation of scenarios that represent different potential future outcomes.

Table 5-1 | Mining Forecast Scenario Descriptions

Scenario	Description
Low	- Conservative scenario including only existing mining projects and their extension/expansion/retirement plans - The full demand forecast for all existing mining projects is included
Reference	- Includes all demand in the low scenario plus the full undiscounted demand forecast from projects classified as "most likely" and "likely" - Aligned with 2021 Annual Planning Outlook[12] reference scenario
High	- Includes all known mining projects with each project's demand forecast discounted according to their likelihood classification: o "Most likely" project forecasts are not discounted o "Likely" project forecasts discounted to 80% of their full project demand o "Less likely" project forecasts discounted to 50% of their full project demand o "Least likely" project forecasts discounted to 20% of their full project demand - Aligned with 2021 Annual Planning Outlook high scenario

[12] The Annual Planning Outlook forecasts electricity demand, assesses the reliability of the electricity system, identifies capacity and energy needs, and explores the province's ability to meet them. The latest Annual Planning Outlook is available on the IESO's Planning and Forecasting webpage.

A project's likelihood is informed by factors such as the reliability of available data sources, development stage of the project, project timing, and permitting information. The IESO also incorporates input from the Ministry of Mines on the forecast and likelihood factors. The mining forecast scenarios are summarized in Table 5-1 above.

Figure 5-6 shows the low, reference, and high mining demand forecast scenarios. The total aggregate undiscounted (i.e., without consideration of likelihood factors) forecast demand from all known projects is also shown in a dashed line. Note that the total aggregate undiscounted forecast demand is not a realistic growth scenario since it is highly unlikely for all proposed mining projects to materialized. The undiscounted forecast is provided for transparency to illustrate the scale of potential demand growth considered in the low, reference, and high scenarios.

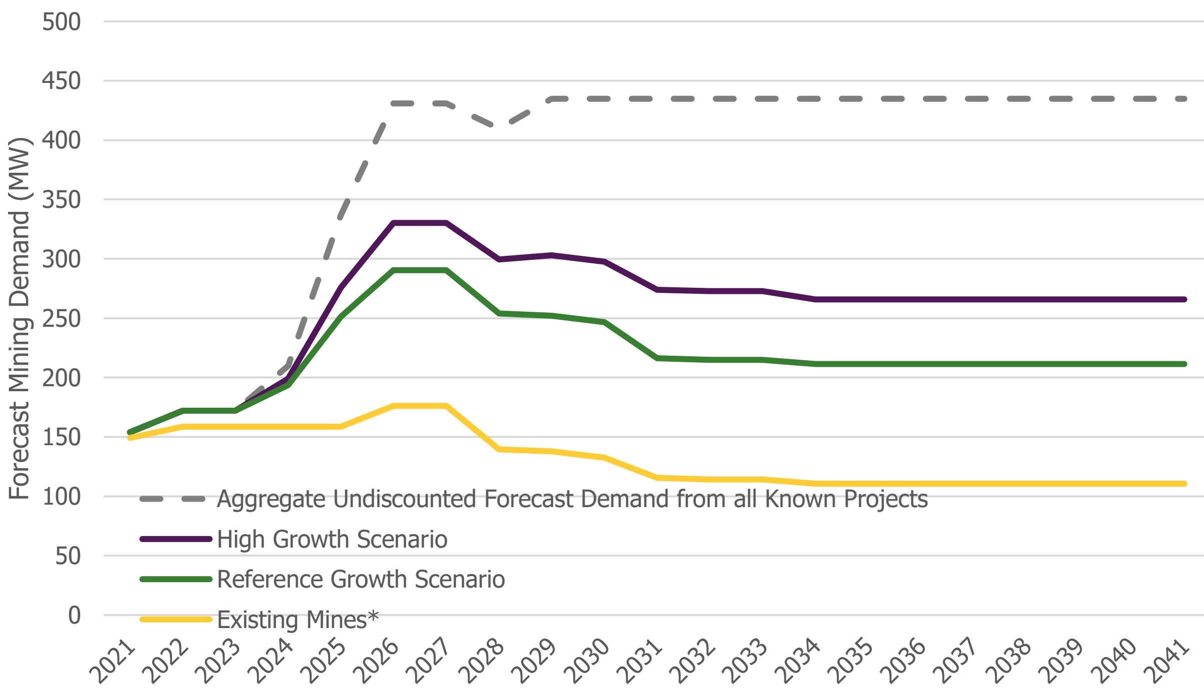

Figure 5-6 | Mining Demand Forecast

The mining sector already accounts for approximately 150 MW of demand today and is projected to grow to 290 MW by 2027 under the reference scenario. The low and high scenarios grow to 175 MW and 330 MW by 2027, respectively. Note that the IRRP does not provide disaggregated project-level forecast to preserve confidentiality.

Generally speaking, the existing mines (low) scenario informs local reliability needs that must be addressed even if no new mines materialize. The reference scenario informs the identification of needs that will likely arise and options to address those needs if/when mines materialize. Finally, the high scenario explores possible additional needs to test the robustness of the IRRP.

Note that in all scenarios, the mining forecast peaks in 2027 before declining for the remainder of the forecast horizon. This is a result of developing a project-based demand forecast as opposed to a top-line forecast for the mining sector as a whole. Information about existing and near-term projects are more readily available than information about long-term projects. Most known near- and mid-term new mining projects plan to come in-service by 2027. After 2027, demand begins to taper off as both existing and new mines reach the end of their planned operating life. The forecast scenarios do account for project extensions beyond their initial operating life but high uncertainty surrounding these extensions has meant that they were assigned low likelihood factors. In sum, the forecast performs well for predicting near- and medium-term mining growth but has less visibility of longer-term trends. Despite this shortcoming, a project-based demand forecast is more useful than a top-line forecast for the purpose of infrastructure planning. The project-based forecast provides relatively detailed information in the near- to mid-term when planning decisions must be made and provides critical geographic granularity necessary for transmission system studies.

5.5 Total Northwest Demand Forecast Scenarios

The total non-coincident Northwest demand forecast is shown in Figure 5-7 below. Note that when the mining forecast component is layered on top of the distribution-connected and transmission-connected components, only the contribution of new mining projects is shown to avoid double counting. The reference scenario Northwest demand grows to 1060 MW by 2027. The low and high scenarios growing to 945 MW and 1100 MW by 2027, respectively. Note that the discontinuity between historical and forecast demand from 2020 to 2021 is partly due to the extreme weather correction applied to the distribution-connected forecast.

The IRRP reference forecast is approximately 20% higher than the Annual Planning Outlook forecast for the Northwest zone. This difference is in part due to the non-coincidence of the IRRP's station-level forecast; the non-coincident forecast is typically 10-15% higher than the coincident forecast in the Northwest. The sum of regional planning forecasts is also generally higher than their bulk planning counterparts since regional forecasts capture potential growth at a greater granularity not all of which may materialize when aggregated at a larger geographic scale.

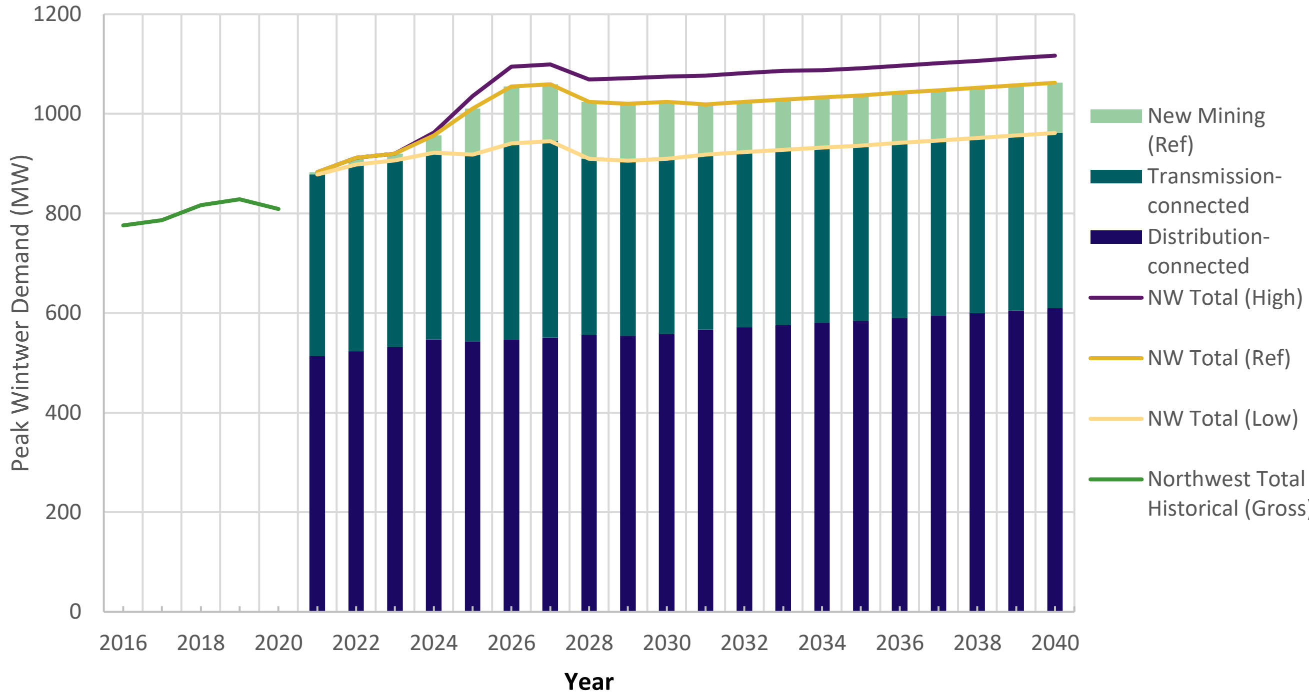

Figure 5-7 | Total Northwest Demand Forecast

5.6 Demand Profiling – Kenora MTS

In addition to the annual peak forecast, hourly load profiles (8,760 hours per year over the 20-year forecast horizon) for stations or groups of stations with identified needs can be developed to characterize their needs with finer granularity. This is typically undertaken to inform an analysis of potential non-wires alternatives.

For this IRRP, hourly demand profiles were developed for Kenora MTS where a firm station capacity need was identified for which non-wires alternatives are promising. The Kenora MTS hourly demand profiles can be found in Appendix D.2. There were no other needs identified in this IRRP which could be addressed by non-wires alternatives.

Hourly demand profiles are created by first training a multiple linear regression model with historical data and then repeatedly applying the model under different weather/calendar variable permutations to forecast a range of possible future hourly profiles. The profiles are then ranked based on their median energy values. The median profile is scaled to match the peak demand forecast in each year and used to size and simulate non-wires alternatives as described in Section 7.1. A more fulsome description of the demand profiling methodology can be found in Appendix D.1.

Note that this data is used to roughly inform the overall energy requirements that a non-wire alternative would need to meet for the purposes of evaluating alternatives; it cannot be used to deterministically specify the precise hourly energy requirements. Further, this data is only used to select suitable technology types and roughly estimate operating costs. Demand patterns can change significantly as consumer behaviour evolves, new industries emerge, and trends like electrification achieve greater adoption. The Working Group will continue to monitor these changes as part of the implementation of the plan.

6. Needs

This section summarizes the needs identified through the IRRP process. Taking into account committed transmission projects identified through bulk planning processes (i.e., the East West Tie expansion and the Waasigan transmission line), the Northwest region is generally adequate to support forecast electricity demand growth. The needs identified in the IRRP deal with localized supply to various pockets of demand in the Northwest as well as high-growth scenarios in areas identified as having strong future development potential.

This section is organized as follows:

- Section 6.1 summarizes the methodology for identifying needs,
- Section 6.2 describes firm station capacity and local operational needs (i.e., needs that would materialize under the reference forecast scenario), and
- Section 6.3 describes potential needs that may arise if higher than forecast growth materializes in select subsystems in the region.

Section 6.2.3 (E1C Operation and High Voltage Need), in addition to specifying the needs identified, will also discuss the recommended solutions since there are no "alternatives" that would normally be discussed in Section 7.

Note that bulk system needs are not in scope for the IRRP, which is focused on local reliability and ensuring that local/regional infrastructure can serve forecast demand. Nonetheless, this IRRP report flags any potential interactions between regional and bulk system needs.

6.1 Needs Assessment Methodology

Based on the reference demand forecast (extreme weather, net demand), system capability, transmitters' identified end-of-life asset replacement plans, and the application of ORTAC and NERC/NPCC standards, the Working Group identified electricity needs which generally fall into the following categories:

- **Station Capacity Needs** arise when the demand forecast exceeds the electricity system's ability to deliver power to the local distribution network through the regional step-down transformer stations at peak demand. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by station equipment. Station ratings are often determined based on the 10-day Limited Time Rating (LTR) of a station's smallest transformer under the assumption that the largest transformer is out of service.[13] A transformer station can also be limited when downstream or upstream equipment (e.g., breakers, disconnect switches, low-voltage bus, or high voltage circuits) is undersized relative to the transformer rating.

- **Supply Capacity Needs** describe the electricity system's ability to provide continuous supply to a local area at peak demand. This is limited by the Load Meeting Capability (LMC) of the transmission supply to an area. The LMC is determined by evaluating the maximum demand that can be supplied to an area accounting for limitations of the transmission elements (e.g., a transmission line, group of lines, or autotransformer) when subjected to contingencies and criteria prescribed by ORTAC and NERC/NPCC standards. LMC studies are conducted using power system simulation analysis. For the high growth sensitivities in Section 6.3, the LMCs for the subsystems in question are higher than the total forecast demand (both reference and high scenarios). Nonetheless, as these areas have been identified to have future development potential, the IRRP explores the existing limitations in these areas to identify the remaining LMC and inform future planning activities should higher growth materialize. Details regarding the power flow simulations, including the system topology and credible contingencies studied, can be found in Appendix C.

- **End-of-life Asset Refurbishment Needs** are identified by the transmitter with consideration to a variety of factors such as asset age, expected service life, risk associated with the failure of the asset, and its condition. Replacement needs identified in the near- and early mid-term timeframe would typically reflect condition-based information, while replacement needs identified in the medium to long term are often based on the equipment's expected service life. Note that IRRPs do not typically study and make recommendations for all end-of-life needs[14] where like-for-like replacements have been established to be appropriate in earlier phases of the regional planning process. Instead, the IRRP focuses on a subset of end-of-life needs where there are interactions with other regional needs and where there may be opportunities to reconfigure or right-size assets. Therefore, in the sections below, end-of-life needs are described in conjunction with other needs where relevant.

[13] Some stations in the Northwest only have a single transformer in which case the transformer's LTR is the limiting element.
[14] A list of transmission assets reaching end-of-life can be found in the Needs Assessment.

- **Load Security and Restoration Needs** describe the electricity system's ability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements are prescribed by Section 7 of ORTAC.

6.2 Needs Identified

Table 6-1 summarizes the firm needs identified in this IRRP and are further discussed in the sections below. Note that the White Dog DS and Marathon DS station capacity needs occur in the long-term and are not further discussed in Section 7 since no firm recommendations are needed at this time.

Table 6-1 | Summary of Needs

Need	Need Description	Need Date
Fort Frances MTS Customer Reliability	Frequent loss of supply due to transmission outages; end-of-life assets at both Fort Frances TS and Fort Frances MTS	Today
E1C Operation	Supply capacity limitations with E1C operated normally closed; high voltage issues with E1C operated normally open	Today
Margach DS	Station step-down transformer capacity	2023
Crilly DS	Station step-down transformer capacity	2027
Kenora MTS	Station step-down transformer capacity	2029
White Dog DS	Station step-down transformer capacity	2032
Marathon DS	Station step-down transformer capacity	2038

6.2.1 Station Capacity Needs

6.2.1.1 Margach DS

Margach DS is approximately 10 km east of Kenora. Margach DS has an LTR of 10.4 MW and historical demand has been stable at just under 10 MW. As shown in Figure 6-1, Margach DS is expected to reach capacity in 2023 due to a large existing industrial customer seeking to be resupplied at Margach DS from a nearby CTS.

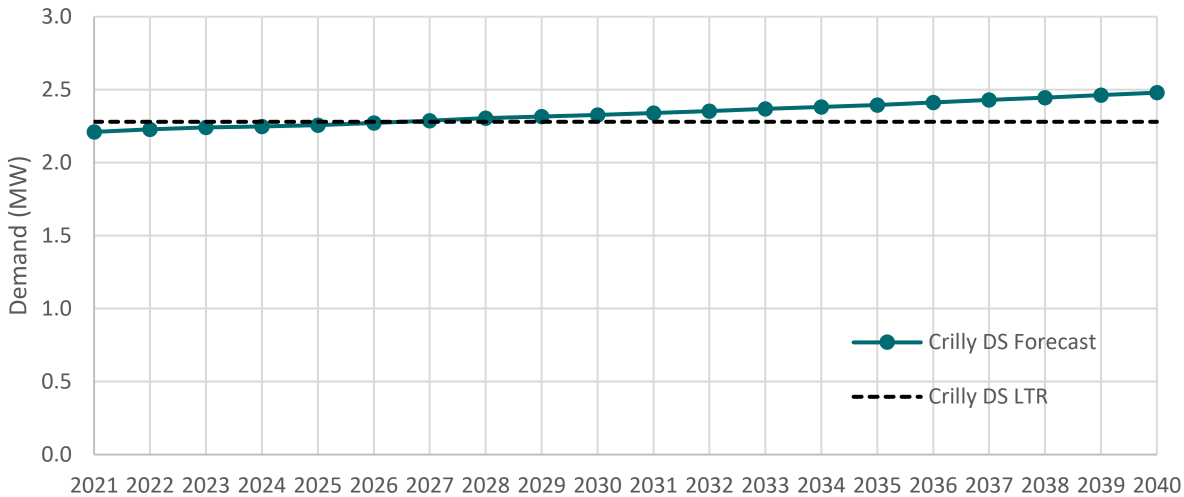

Figure 6-1 | Margach DS Forecast

6.2.1.2 Crilly DS

Crilly DS is a small (~2.2 MW LTR) station supplied from a bus shared with Sturgeon Falls CGS, a small hydroelectric plant approximately 50 km west of Atikokan. This is a non-standard supply arrangement that results in annual outages to Crilly DS when the generator is undergoing maintenance. Diesel generation is currently used for backup power when Sturgeon Falls is on outage. Furthermore, station equipment is nearing end-of-life and space constraints limit in situ refurbishment options.

Crilly DS is expected to reach capacity in 2027 due to incremental growth in the community as shown in Figure 6-2.

6.2.1.3 Kenora MTS

Kenora MTS serves the City of Kenora and has a LTR of 23.4 MW. Synergy North has received inquiries from potential customers seeking new connections, including a new 4 MW project, but no formal agreements have been finalized. While these projects have not been included in the forecast, a relatively high annual growth rate of 1.25% was applied to account for the high degree of development interest.

Figure 6-2 | Crilly DS Forecast

Kenora MTS is expected to reach capacity in 2029 as shown in Figure 6-3.

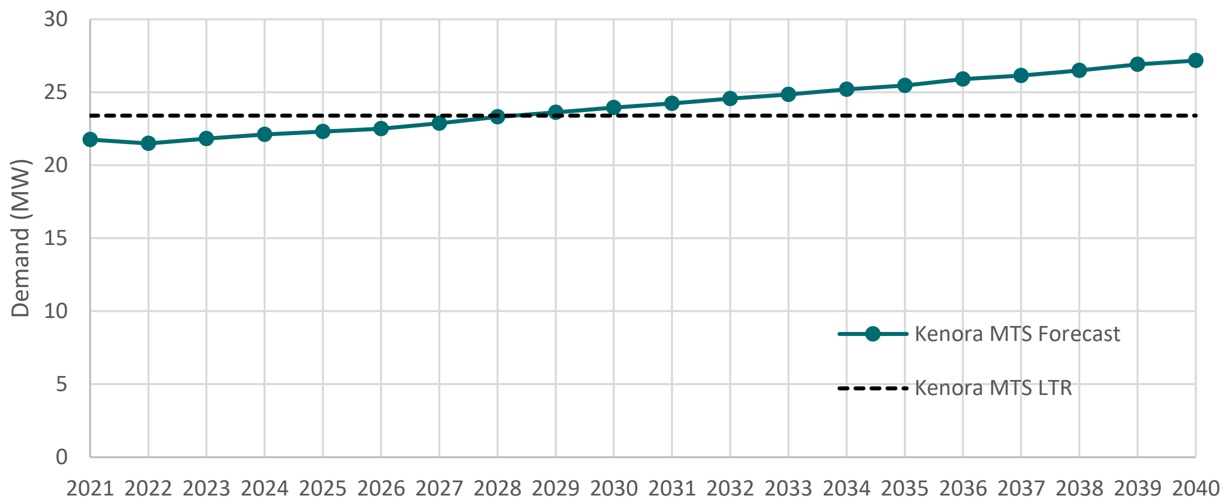

Figure 6-3 | Kenora MTS Forecast

6.2.1.4 White Dog DS

White Dog DS is located approximately 50 km northwest of Kenora and has a LTR of 2.9 MW. White Dog DS demand is expected to grow relatively quickly at an average rate of 1.3% annually due to growth in the community. White Dog DS is expected to reach capacity in 2032 as shown in Figure 6-4.

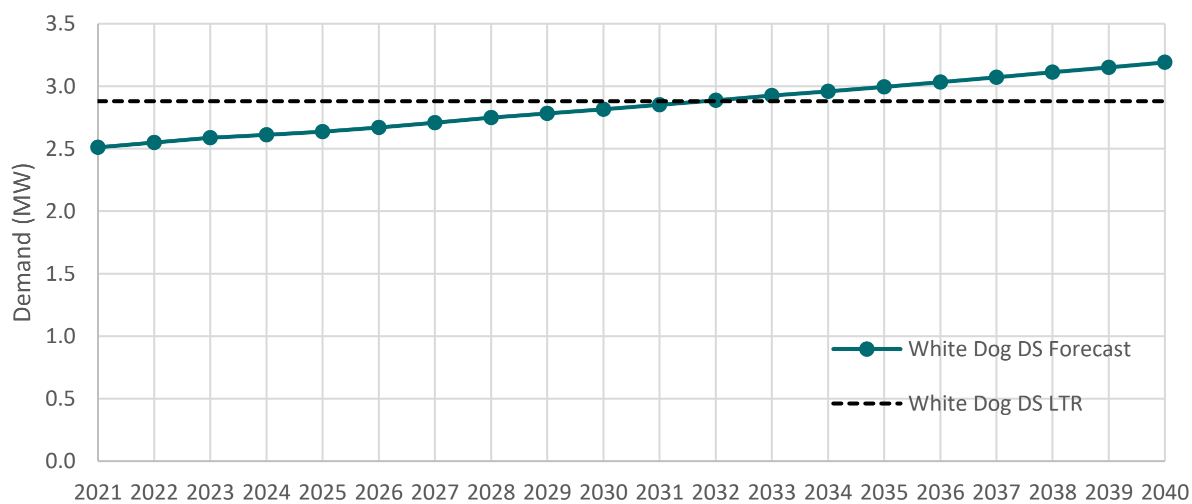

Figure 6-4 | White Dog DS Forecast

6.2.1.5 Marathon DS

Marathon DS serves the Town of Marathon and has a LTR of 10.4 MW. Growth is expected to be moderate and stable at an average annual growth rate of 0.9%. Marathon DS is expected to reach capacity in 2038 as shown in Figure 6-5.

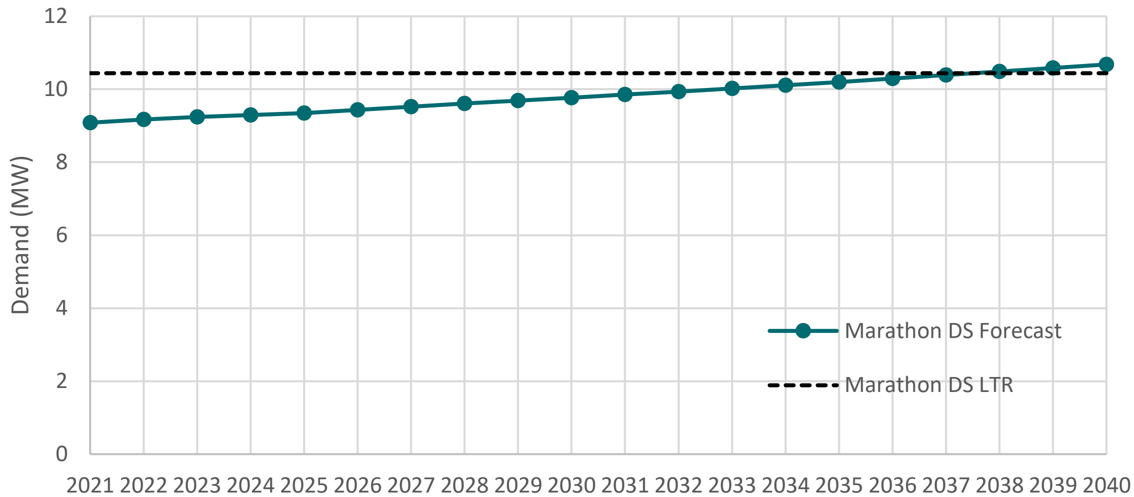

Figure 6-5 | Marathon DS Forecast

6.2.2 Fort Frances Customer Reliability Need

Fort Frances MTS, a step-down transformer station that supplies the Town of Fort Frances, is supplied via a single circuit 115 kV line, F1B, from the nearby Fort Frances TS. The two stations are located across the street from each other as shown in Figure 6-6. Fort Frances MTS experiences outages semi-annually to accommodate planned maintenance outages on F1B. Despite there being two step-down transformers at Fort Frances MTS, the single circuit supply configuration results in community-wide power outages since there is no redundant supply path to the station.

Historically, outage durations ranges from 4 to 8 hours and impact critical loads such as the regional hospital and local health clinics. Customers have raised concerns with interruptions to surgery schedules and vaccine spoilage due to the loss of refrigeration. Power outages also disrupt other commercial and residential customers. Customer surveys conducted by Fort Frances Power suggest that customers can tolerate short outages but are increasing sensitive to prolonged outages. Of the 10 causes of distribution system customer interruptions tracked by the Ontario Energy Board, loss of transmission supply accounts for 90% of Fort Frances Power’s customer interruptions over the last 10 years.

Note that this customer reliability issue does not violate ORTAC load security and restoration criteria due to the relatively low total demand served at Fort Frances MTS. Fort Frances MTS serves approximately 16 MW of load today and is expected to grow to 18 MW by the end of the forecast horizon.[15] Load security criteria limits the total amount of demand interrupted with any single element out of service to 150 MW. For loads under 150 MW, load restoration criteria only require that service is restored within 8 hours. Despite compliance with ORTAC criteria, the Fort Frances MTS supply configuration is still highly disruptive for customers and could potentially be improved with relatively low-cost solutions given the proximity to Fort Frances TS.

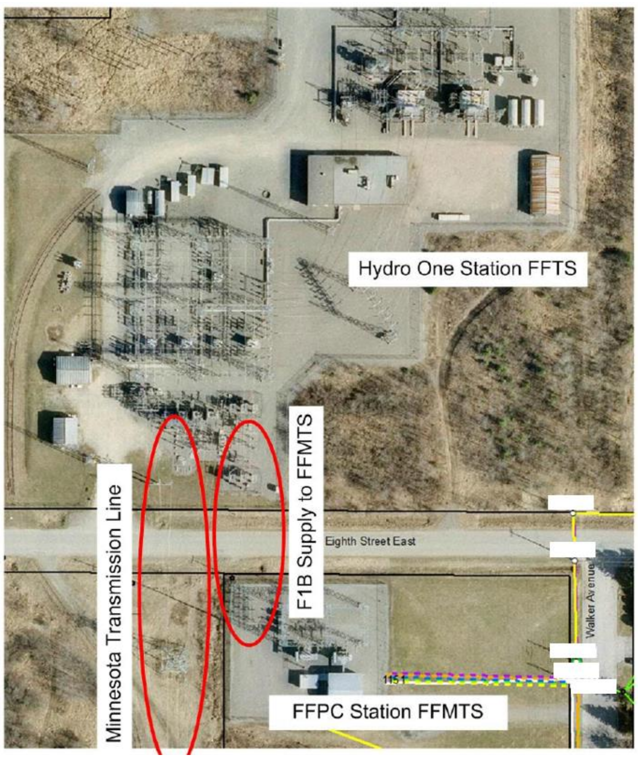

Figure 6-6 | Overhead view of Fort Frances TS (labeled as FFTS) and Fort Frances MTS (labeled as FFMTS)

[15] While there is currently no firm station capacity need within the forecast horizon, several potential large customers have approached Fort Frances Power that could quickly use up the remaining station capacity if they commit. This is further discussed in Section 6.3.2.

Fort Frances MTS station equipment is also aging with both transformers and most breakers dating from the 1960s and 1970s. The OEB's Asset Depreciation Study defines minimum, typical, and maximum useful life for a variety of electricity system assets. Apart from the main station breaker, which was replaced in 2019, all equipment at Fort Frances MTS is between its typical and maximum useful life. Furthermore, Fort Frances TS 115 kV breakers are also approaching end of life around 2027, which presents an opportunity to reconfigure the station to minimize supply interruptions for Fort Frances MTS.

6.2.3 E1C Operations and High Voltage Need

This section discusses the E1C operations with the new 230 kV Wataynikaneyap circuit, W54W, in service. W54W was first energized in Aug 2022. However, C3W, a short 30 m circuit between Wataynikaneyap TS and Pickle Lake SS, is still operated normally open. Therefore, W54W is not yet connected to the existing 115 kV circuits from Ear Falls TS to Pickle Lake SS and Musselwhite CSS (E1C, C2M, and M1M). C3W will be operated closed in the near future so that W54W can help support demand growth on C2M. This is consistent with the IESO's original recommended scope for the Wataynikaneyap Transmission Project in 2016.[16] For the purposes of this IRRP report, W54W being "in-service," refers to the final state with C3W closed. A single-line diagram of the area is shown in Figure 6-7.

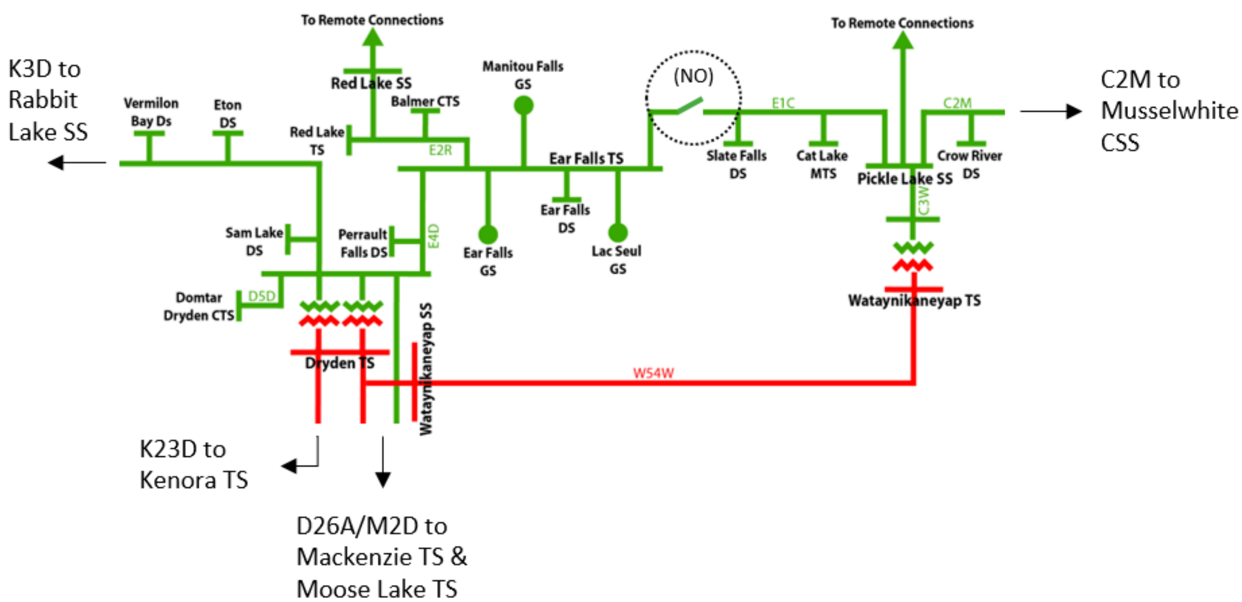

Figure 6-7 | Simplified Single Line Diagram of the Dryden and Pickle Lake Areas with Potential Normally Open Point

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[16] The IESO's 2016 Recommended Scope of the new Line to Pickle Lake and Support Scope for the Remotes Connection Project is available on the Ontario Energy Board's priority transmission projects webpage.

With W54W in-service and connected to E1C via C3W, operating circuit E1C normally closed would result in a loop comprised of the E4D-E1C-W54W circuits. This arrangement would severely limit the transfer capability through E4D and W54W as documented in the 2016 W54W System Impact Assessment (SIA) report.[17] When operating with the E4D-E1C-W54W loop closed, loads in the Ear Falls area will remain connected through E1C via the 230 kV path following the loss of E4D. Post-contingency voltage collapse limits the E4D+W54W flow to 57 MW which is insufficient for supplying existing demand in the Ear Falls, Red Lake, and Pickle Lake areas. The SIA notes that E1C must be opened pre-contingency as a mitigating control action when flow exceeds 57 MW and that this could occur multiple times per day at existing demand levels.

Furthermore, the SIA found that with the E4D-E1C-W54W loop closed, the Manitou Falls and Ear Falls hydro generators would remain connected to the grid following the loss of E4D, which causes transient instability when the post-contingency flow on the E1C exceeds 30 MW. To ensure that transient stability of the generators is maintained, pre-contingency generation levels would need to be reduced such that post-contingency flow on E1C does not exceed 30 MW. This reduction of transfer capability on E1C not only violates ORTAC Section 4.1, which limits reduction in transfer capability that results from a new connection, but would bottle hydro-electric generation that is otherwise available to provide capacity to the Northwest system. Therefore, the SIA recommended that the E4D-E1C-W54W loop should be opened pre-contingency to prevent pre-contingency generation reductions.

Due to these documented issues, this IRRP reaffirms that E1C should be operated normally open once W54W is in-service with C3W closed. This configuration resolves the violations described above and the resulting system is adequate to serve forecast demand in the Ear Falls, Red Lake, and Pickle Lake areas. This configuration is consistent with the recommended scope for W54W (which was referred to as the "Line to Pickle Lake") in the 2015 North of Dryden IRRP. Note that operating E1C normally open enables W54W to relieve E4D which allows W54W to serve the dual purposes of improving the load meeting capability of both the Pickle Lake and Ear Falls/Red Lake areas. This was an important consideration that contributed to the recommendation for W54W.

However, with E1C operated normally open, another problem emerges. High voltage violations (voltages exceeding 127 kV) occur post-contingency under light load conditions. High voltages occur on the line end open of E1C and either Pickle Lake SS or Ear Falls TS depending on where the open point on E1C is located. High voltage violations are less severe when opening E1C near Ear Falls TS compared to near Pickle Lake SS. When E1C is open near Ear Falls TS, the most critical contingency is the loss of one of the existing 20 MVar reactors at Wataynikaneyap TS. The high voltage violations can be addressed by installing an additional 10 MVar reactor at or near Pickle Lake SS. The post-contingency voltages at nearby stations with and without this

[17] The 2016 W54W System Impact Assessment report is available on the IESO's Application Status webpage by searching for SIA ID 2016-567.

additional 10 MVar reactor are shown in Table 6-2. The post-contingency voltages exceed 127 kV at the E1C open line end and Pickle Lake SS for the loss of the existing 20 MVar reactor at Wataynikaneyap TS. Post-contingency voltages are maintained below 127 kV with the additional 10 MVar reactor.

Table 6-2 | Post-contingency Voltages with and without Additional 10 MVar Reactor at Pickle Lake SS with E1C Normally Open at Ear Falls TS

Bus/ Station Name	Post-contingency voltage (kV)	Post-contingency voltage (kV) with additional 10 MVar Reactor at Pickle Lake SS
E1C LEO	**130.7**	123.3
Pickle Lake 115	**127.7**	120.6
Watay 115	126	120.1
Watay SS 230	238	235.5
Dinorwic 230	237.8	235.6
Mackenzie 230	244.8	244
Musselwhite 115	120	115.1

The IRRP recommends that the IESO and Hydro One collaborate in the Regional Infrastructure Plan refine the location of the E1C open point and associated reactive compensation devices required. The E1C open point can be fine-tuned to minimize high voltages. The open point on E1C should consider the location and condition of existing switches as well as their accessibility for restoration purposes should E1C be needed to partially restore loads following a W54W or D26A contingency.

Furthermore, the Regional Infrastructure Plan should consider the installation of a voltage-based automatic switching scheme for the reactors at Pickle Lake SS, Wataynikaneyap TS, and Dinorwic Jct similar to existing switching schemes at other stations across the Northwest region. Voltage-based automatic switching would improve the transmission system's operational flexibility, help manage high voltage conditions currently experienced across the Northwest and help reduce post-contingency high voltages to the acceptable continuous maximum voltage within 30 minutes. Potential interactions with the existing Northwest reactor switching scheme should be considered as this scheme is developed.

6.3 Potential Needs and High Sensitivities

No firm regional supply capacity needs were identified in the Northwest in either the reference or high forecast scenarios. However, most of the growth in the Northwest is driven by large mining and industrial development which can add large, incremental blocks of demand with minimal lead time that can quickly use up remaining supply capacity. Through engagement with development proponents and stakeholders, the Working Group identified two areas in the Northwest, the Dryden/Ear Falls/Red Lake area and the Fort Frances area, where there is particularly strong development interest and where the existing transmission system, although adequate for current forecast scenarios, may become constrained if all known proposed projects materialize.

For these two areas, the IRRP studied high growth sensitivities to quantify the load meeting capability and identify the limiting phenomena on the existing system. This was accomplished by adding hypothetical loads at existing stations/busses to simulate new developments and increasing the hypothetical load until a planning standards violation was observed.

As discussed in Section 4.1, the IRRP did not study local connection requirements of any individual project. The purpose of the high growth sensitivity studies is to quantify system limitations so that growth can be more effectively monitored between regional planning cycles and future planning activities can be initiated in a timely manner if growth materializes. Regardless of the availability of regional supply capacity identified in the IRRP, customers seeking connection may be subject to additional requirements and limitations specified in Customer Impact Assessments (CIA) or System Impact Assessments (SIA).

6.3.1 Dryden/Ear Falls/Red Lake Load Meeting Capability

The Dryden/Ear Falls/Red Lake area hosts significant mining activity today. It includes the 115 kV system supplied from the Dryden TS autotransformers, circuit K3D from Rabbit Lake SS, and M2D from Moose Lake TS. The recently completed 230 kV Wataynikaneyap Transmission Project line W54W will help relieve constraints on the 115 kV circuit E4D, once the recommendations in section 6.2.3 are implemented, and no incremental capacity needs are anticipated in this area based on the current demand forecast.[18]

The area's load meeting capability (LMC) is a function of three nested local constraints as shown in Figure 6-8:

(1) Supply to the Red Lake subsystem including: Red Lake TS, Balmer CTS, and Red Lake remote communities

[18] Consistent with the recommendation in Section 2.1.5 (E1C Operation and High Voltage) and the needs discussed in Section 6.2.3, the IRRP technical studies assumes that E1C will be operated normally open at Ear Falls TS.

(2) Supply to the Ear Falls subsystem including: Ear Falls DS, Perrault Falls DS, and the Red Lake subsystem described above

(3) Supply to the Dryden subsystem including: Sam Lake DS, Eton Ds, Vermilion Bay DS, Domtar Dryden CTS, and the Ear Falls subsystem described above

An implication of this "nesting" is that, depending on where new loads connect, they could contribute to one or more subsystem needs. For example, a load connecting close to Dryden would contribute to needs in the Dryden subsystem only, whereas a load connecting at Red Lake would contribute to potential needs in all three subsystems.

The supply capacity in these subsystems may be further constrained by bulk system limitations on the 230 kV supply to the area West of Thunder Bay. Bulk system limitations are outside the scope of regional planning and will be addressed by the Waasigan Transmission Line Project.

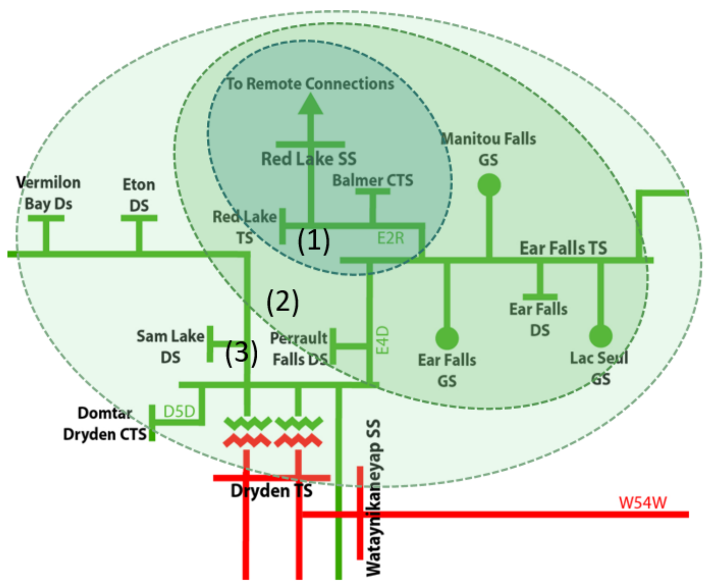

Figure 6-8 | Dryden/Ear Falls/Red Lake Nested Subsystems

Depending on which subsystem was being tested, the load meeting capabilities were derived by adding new hypothetical loads at Red Lake TS, Ear Falls TS, or the 115 kV bus at Dryden TS until a limiting phenomenon was encountered. The load meeting capabilities and the most limiting phenomenon or season for each subsystem is summarized in Table 6-3 and further described below. Note that, since the Northwest region is winter peaking, the IRRP forecast was developed for winter peak demand. However, since the Ear Falls and Red Lake subsystems can be thermally constrained, a summer peak forecast was also developed using the historical ratio between each station's summer and winter peaks.

Table 6-3 | Summary of Dryden/Ear Falls/Red Lake Load Meeting Capabilities

Subsystem	Load Meeting Capability	2032 Reference Peak Demand Forecast	2040 Reference Peak Demand Forecast
1. Red Lake	74 MW (summer thermal limitation)	61 MW summer peak	67 MW summer peak
2. Ear Falls	90 MW (summer thermal limitation)	67 MW summer peak	74 MW summer peak
3. Dryden	160 MW [19](summer/winter voltage decline)	129 MW winter peak	140 MW winter peak

6.3.1.1 Red Lake Subsystem

The Red Lake subsystem load meeting capability is limited in the summer by pre-contingency thermal overload of circuit E2R. The E2R continuous summer rating is 421 A which translates to a load meeting capability of approximately 74 MW.

The winter load meeting capability is higher than the summer capability. The winter load meeting capability is limited to 93 MW due to E2R pre-contingency thermal and voltage limitations. The winter E2R continuous winter rating is 528 A which translates to a load meeting capability of approximately 93 MW. 93 MW of load also causes pre-contingency voltage decline at Red Lake TS (i.e., voltages are under 113 kV). Note that the pre-contingency voltage limitation can be mitigated by installing appropriately sized voltage devices at the connection point of any new load. All load meeting capabilities described for the Red Lake and Dryden subsystems below assume that any new load will be accompanied by voltage devices to maintain adequate voltage performance at the point of connection.

Figure 6-9 below shows the Red Lake subsystem summer and winter peak demand forecast and associated load meeting capabilities.

The summer thermal limitation on E2R could be addressed by upgrading to higher rated conductors. There are several conductor options available with summer continuous ratings ranging from 590 A to 740 A.

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[19] This LMC is significant higher than the existing Dryden Area Inflow (DAI) limit in existing System Control Orders documentation. This difference is mainly due to topology changes (i.e. new W54W). The IRRP sensitivity study also assumes that new loads will connect with appropriate voltage control devices installed at the point of connection which alleviates previously documented low voltage issues.

Upgrading to 740 A conductors would result in a summer load meeting capability of approximately 130 MW. Note that upgrading to higher rated conductors would also necessitate replacing existing structures to increase their height so that the conductors can be operated at a higher temperature. Furthermore, Red Lake TS would need an alternative supply while work on E2R is carried out. Upgrading E2R would cost approximately $23M (real $2022 overnight capital cost) based on high-level per km refurbishment costs for typical 115 kV wood pole lines.[20] The cost difference between different conductor choices is relatively insignificant. Note this is a planning-level estimate (-50% to +100%); material and labour costs have increased rapidly over the COVID-19 period and there is a high degree of uncertainty in future costs.

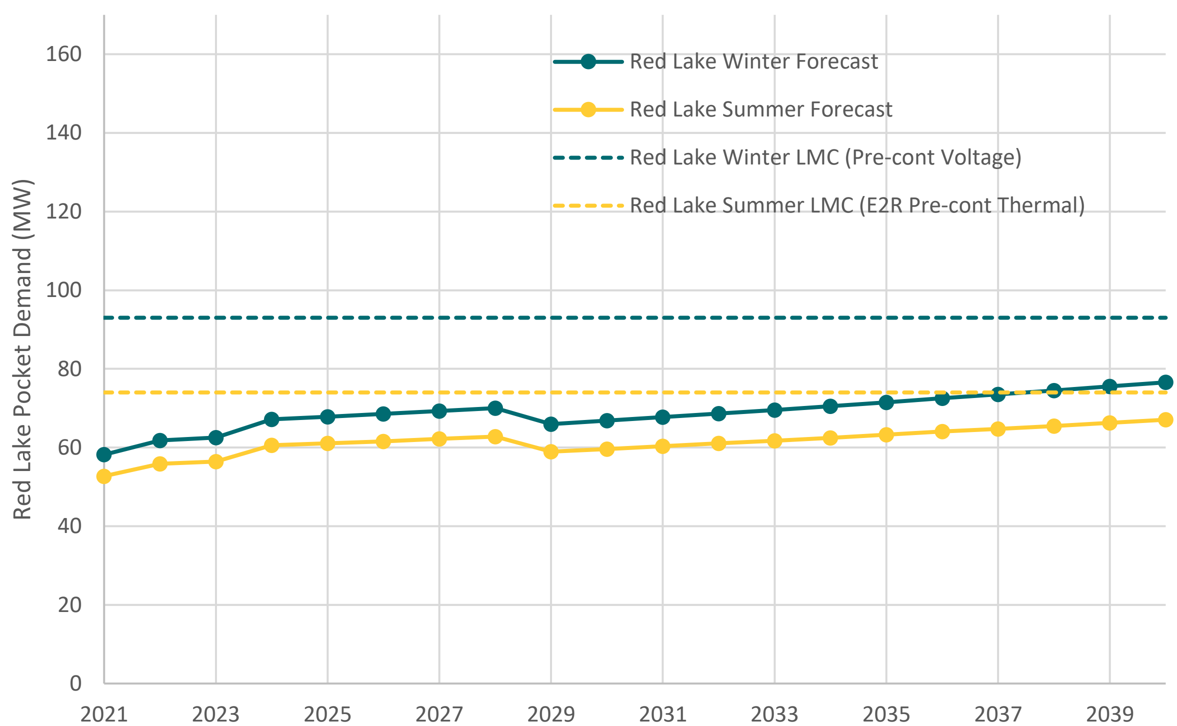

Figure 6-9 | Red Lake Subsystem Load Meeting Capabilities and Demand Forecast

E2R is approximately 75 years old. Hydro One anticipates that the average expected service life for the conductors is 90 years. The wood pole structures have a shorter expected service life at approximately 50 years. The end-of-life date for E2R will be based on actual asset conditions and no date has been determined for E2R as of 2022. If growth materializes, future planning

[20] The provided cost estimates do not include any associated upgrades that may be required to achieve the desired rating (e.g., raising poles, etc.) and should be viewed as high-level minimum costs.

studies should consider the cost of advancing E2R refurbishment as compared to alternatives such as local generation.

6.3.1.2 Ear Falls Subsystem

The Ear Falls subsystem load meeting capability is limited in the summer by E4D pre-contingency thermal overload. The E4D continuous summer rating is 410 A, which translates to approximately 72 MW. There is also a combined 18 MW of summer 98th percentile dependable hydro generation output from Ear Falls GS, Manitou Falls GS, and Lac Seul GS. Together the thermal capability and hydro generation results in a load meeting capability of approximately 90 MW.

Note that the winter load meeting capability is not expected to be limiting since it is significantly higher than the summer capability due to both the higher winter thermal rating of the circuit as well as higher dependable hydro generation output (approximately 64 MW of 98th percentile dependable hydro generation output).

Figure 6-10 below shows the Ear Falls subsystem summer demand forecast and load meeting capability.

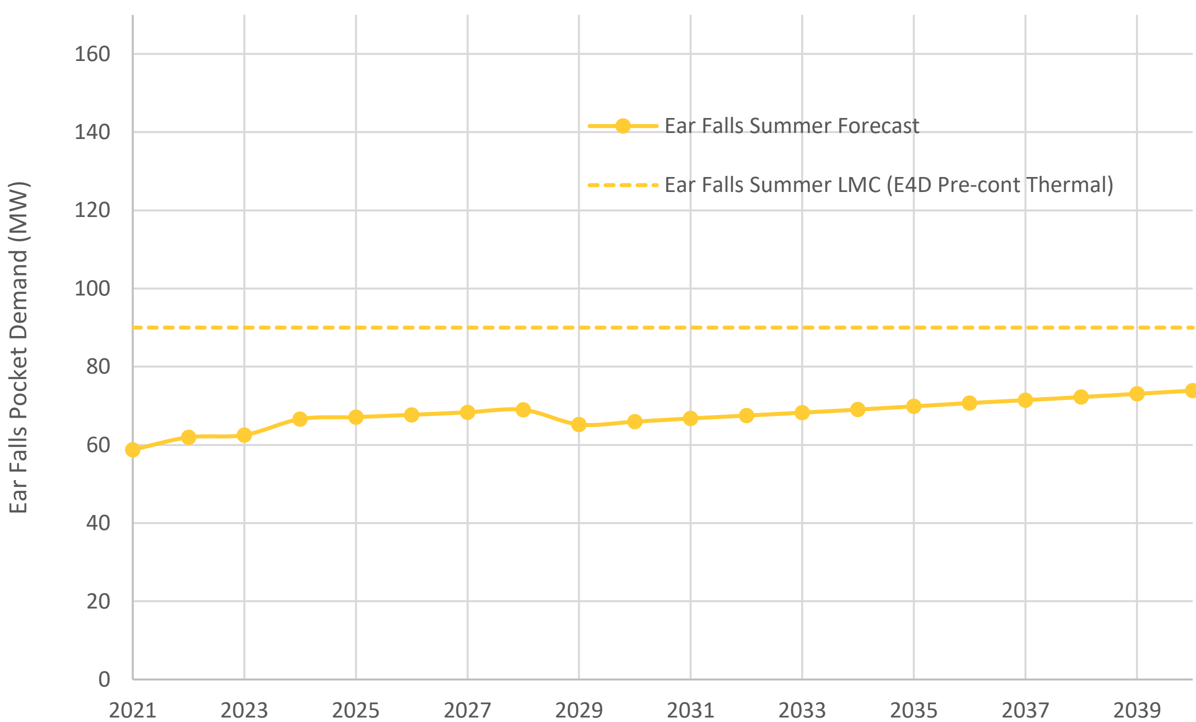

Figure 6-10 | Ear Falls Subsystem Load Meeting Capability and Demand Forecast

The summer load meeting capability for the Ear Falls subsystem can be increased to 130 MW by upgrading E4D with higher rated conductors (740 A summer continuous rating similar to conductors contemplated for E2R in the previous section). Upgrading E4D would cost approximately $35M (real $2022 overnight capital cost) based on high-level per km refurbishment costs for typical 115 kV wood pole lines.[21] Note this is a planning-level estimate (-50% to +100%); material and labour costs have increased rapidly over the COVID-19 period and there is a high degree of uncertainty in future costs. E4D is approximately the same age as E2R; future planning studies should also consider the cost of advancing E4D refurbishment as compared to alternatives such as local generation.

6.3.1.3 Dryden Subsystem

The Dryden subsystem load meeting capability is limited to 160 MW in both the summer and winter due to post-contingency voltage decline following the loss of D26A. When total demand in the Dryden subsystem exceeds 160 MW, the voltage decline at Dryden TS will exceed criteria (10% decline) as shown in Table 6-4. Note that for the purpose of deriving a conservative load meeting capability, a constant MVA load model was used as opposed to a voltage dependent load model.

Table 6-4 | Post-Contingency (D26A N-1) Voltage Change (160 MW Dryden Subsystem Total Demand)

Station	Pre-Cont Voltage	Post-Cont (Pre-ULTC) Voltage	Post-Cont (Post-ULTC) Voltage
Mackenzie TS	247 kV	242 kV	239 kV
Dryden TS	237 kV	216 kV	214 kV (10% decline)
Kenora TS	243 kV	229 kV	230 kV
Fort Frances TS	244 kV	229 kV	231 kV

Dryden TS post-contingency voltage decline will no longer be limiting once Phase 2 of the Waasigan Transmission Line Project is built since it will provide a redundant path from Mackenzie TS to Dryden TS parallel to D26A. Without Phase 2, the post-contingency voltage decline could be addressed by a dynamic voltage device at Dryden TS, but this was not further studied since the device requirements would depend on the connection arrangement and characteristics of future loads.

[21] The provided cost estimates do not include any associated upgrades that may be required to achieve the desired rating (e.g., raising poles, etc.) and should be viewed as high-level minimum costs.

Note that the D26A + K23D N-1-1 contingency results in more severe voltage decline but could be addressed by a load rejection scheme since special protection systems are permitted by ORTAC for outage conditions.

Figure 6-11 shows the Dryden subsystem summer and winter peak demand forecast and associated load meeting capabilities.

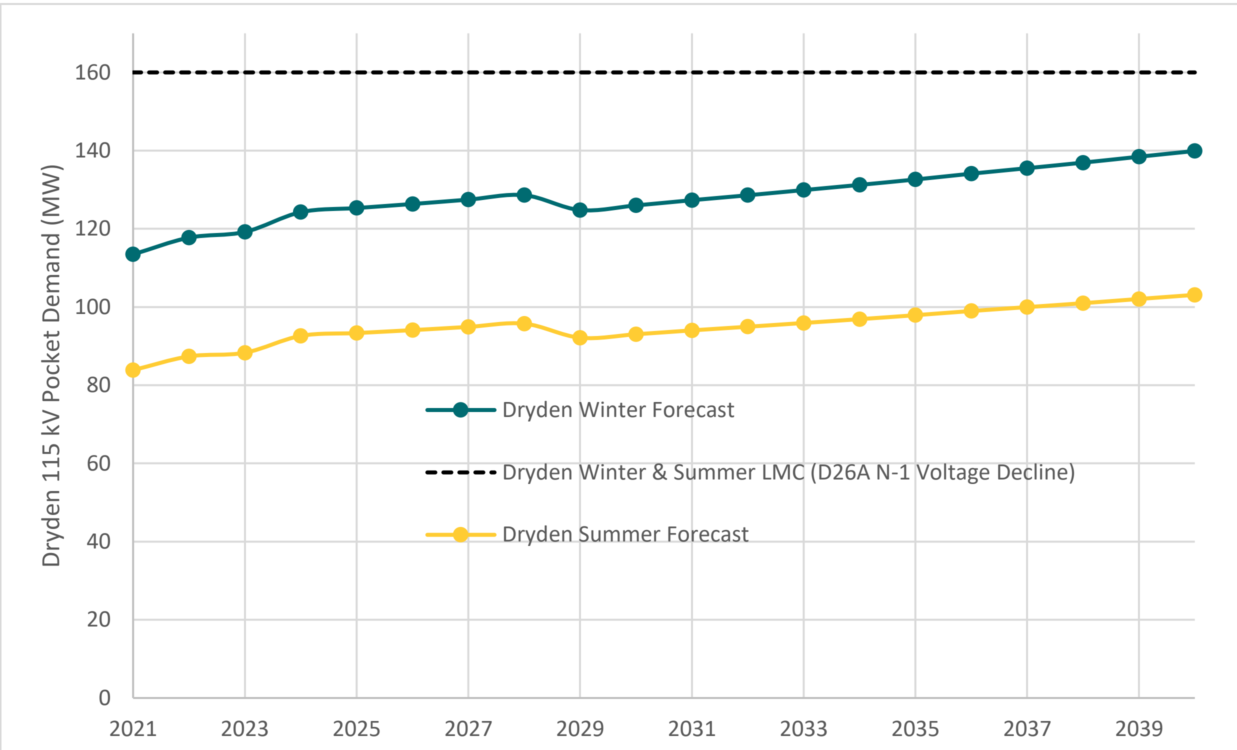

Figure 6-11 | Dryden Subsystem Load Meeting Capabilities and Demand Forecast

6.3.2 Fort Frances Load Meeting Capability

The Fort Frances area includes the 115 kV system supplied from the Fort Frances TS autotransformers and circuit K6F from Rabbit Lake SS as shown in Figure 6-13. For this high-growth sensitivity study, the Fort Frances area includes Fort Frances MTS, Burleigh DS, and a new hypothetical load connected directly to the 115 kV bus at Fort Frances TS. The stations connected to K6F do not materially impact the load meeting capability of the Fort Frances area.

Forecast demand in the Fort Frances area is relatively modest and is expected to grow from 21 MW today to 23 MW in 2040. However, the Working Group is aware of multiple inquiries from potential large new customers seeking connection in the Fort Frances area. Their combined load exceeds 100 MW but there is a high degree of uncertainty in whether their developments will proceed and where they may choose to connect to the grid. Some potential customers are also considering connection points in other parts of the province.

The Fort Frances load meeting capability is limited to 82 MW inclusive of approximately 3 MW of 98th percentile winter dependable hydro generation output from Fort Frances GS. This load meeting capability is the maximum total amount of load that can be served at Fort Frances MTS, Burleigh DS, and a new hypothetical load directly served on the Fort Frances TS 115 kV bus. It does not include load served on K6F. To achieve this load meeting capability, two new 25 MVar capacitor banks are assumed to be installed on the Fort Frances TS 115 kV bus to manage pre-contingency voltages. The load meeting capability is limited by post-contingency voltage decline on the Fort Frances TS 115 kV bus following the loss of F25A as shown in Table 6-5. The F25A contingency has a significant impact on 115 kV bus voltages because it removes one of the Fort Frances TS transformers (and the existing capacitor bank on its tertiary winding) by configuration. Note that for the purpose of deriving a conservative load meeting capability, a constant MVA load model was used as opposed to a voltage dependent load model.

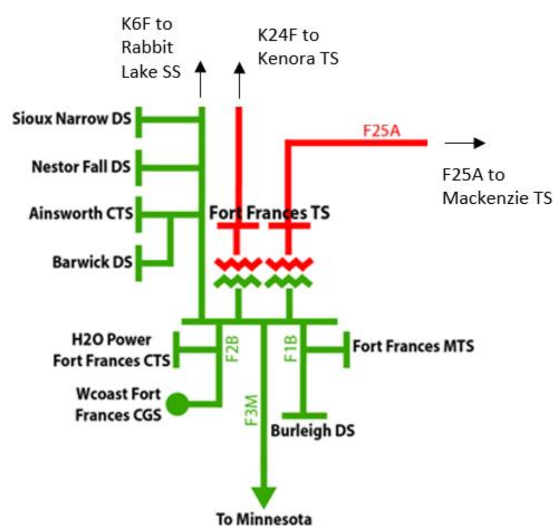

Figure 6-12 | Fort Frances Subsystem

Figure 6-13 below shows the Fort Frances subsystem winter peak demand forecast and associated load meeting capability.

Table 6-5 | Post-Contingency (F25A N-1) Voltage Change (82 MW Fort Frances Subsystem Total Demand)

Station/Bus	Pre-Cont Voltage	Post-Cont Pre-ULTC Voltage	Post-Cont Post-ULTC Voltage
Fort Frances TS (230 kV)	240 kV	234 kV	228 kV
Fort Frances TS (115 kV)	123 kV	110 kV (10% decline)	116 kV

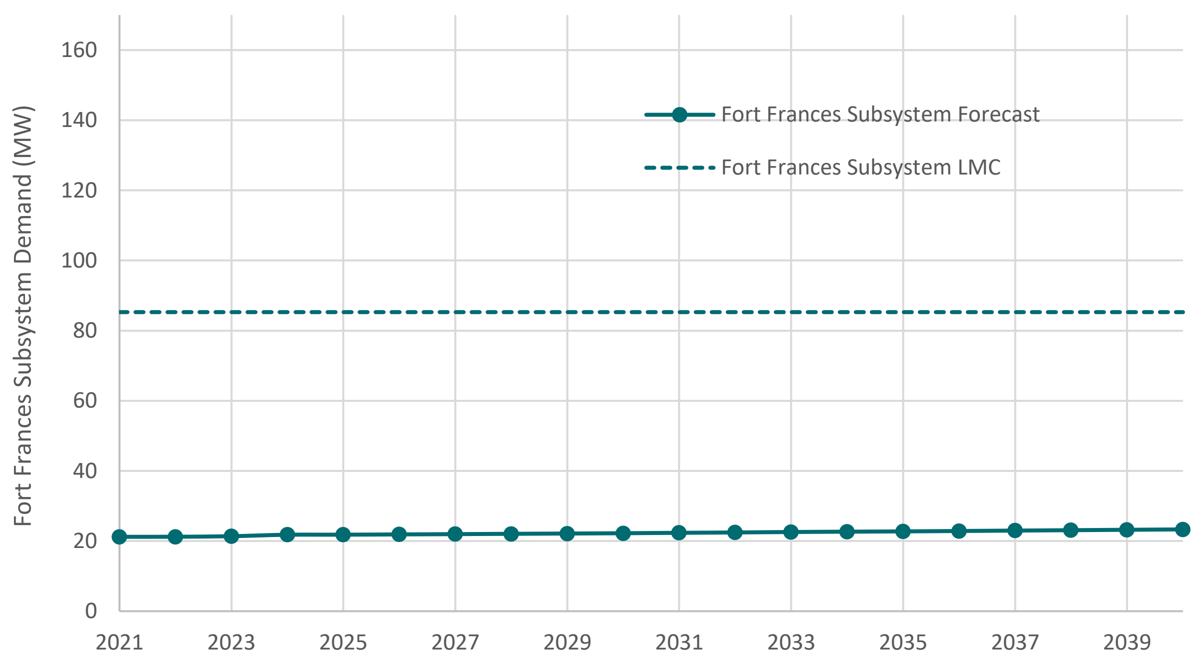

Figure 6-13 | Fort Frances Subsystem Load Meeting Capability and Demand Forecast

7. Options Considered and Recommendations

This section describes the options considered and recommendations to address the near- to medium-term needs identified in section 6. This section is organized as follows:

Section 7.1 describes the options considered for the Margach DS, Crilly DS, and Kenora MTS station capacity needs. This includes a discussion of how each station capacity need was screened for non-wires alternative suitability and, where there were promising non-wires opportunities, the options considered and financial analysis.

Section 7.2 explores configuration options to improve customer reliability at Fort Frances TS. These options will inform the Regional Infrastructure Plan where a final configuration will be chosen.

Note that the recommendation for the E1C operations and high voltage need can be found in Section 6.2.3 and will not be further discussed in this section.

7.1 Options and Recommendations for Station Capacity Needs

7.1.1 Methodology and Options Considered

There are two approaches for addressing station capacity needs:

- Build new infrastructure to increase station capacity. This is commonly referred to as a "wires" option and typically entails upsizing the existing station (e.g., replacing transformers with higher rated transformers or adding additional transformers) or building a new station to supply incremental demand growth. Wires options may also include modifications to or the addition of other power system equipment such as voltage regulation devices, switches, or breakers.

- Install or implement measures to reduce net peak demand to maintain loading within existing station capacity. This is commonly referred to as a "non-wires" alternative and can include options like energy storage, local distributed generation, demand response, conservation and demand management, or any combination of the above. Note that centrally delivered energy efficiency measures under the 2021-2024 Conservation and Demand Management framework are already included in the load forecast, as discussed in Section 5.2.2. Additional conservation and demand management can be considered as a non-wires alternative.

While wires options typically provide a step-change increase in capacity and are available in all hours, non-wires alternatives are more targeted and must account for the frequency and duration of the capacity need in addition to its magnitude. Therefore, identifying suitable technology types, sizing options, and simulating their discounted cash flows are significantly more complex for non-wires alternatives than wires options.

Non-wires alternatives are not suitable for all station capacity needs and there are often qualitative factors that rule out the use of non-wires alternatives. Before carrying out options analysis, a screening process is first applied to determine the suitability of non-wires alternatives for each need that considers the characteristics of the demand growth, the technical feasibility of non-wires alternatives to address the limiting phenomena, and any additional factors that would complicate or facilitate the implementation of non-wires alternatives. For stations where non-wires alternatives are suitable, the IRRP carries out options analysis as described below.

High-level cost estimates for wires options are usually provided by the transmitter. In contrast, cost estimates for generation and other non-wires alternatives are based on benchmark capital and operating cost characteristics for each resource type and size. Note that the error margin in cost estimates is significant at the planning stage (-50% to +100%); they are only intended to enable comparison between options during the IRRP. Material and labour costs have increased rapidly over the COVID-19 period and there is a high degree of uncertainty in future costs. Wires option costs can be reviewed in the Regional Infrastructure Plan before implementation work begins and the Working Group will revisit recommendations if cost estimates differ significantly. Actual non-wires alternative costs can also vary significantly from the benchmark estimates used in the IRRP depending on local market constraints at the time of implementation. The entity responsible for implementing the non-wires alternative (for station capacity needs, this will typically be the local distribution company) will only implement the alternative if it remains cost effective. Subsequent regional planning activities will be triggered if future costs differ significantly from those in the current IRRP.

For non-wires options, upfront capital and operating costs are compiled to calculate the levelized unit energy cost ($/MW-year). Similarly, an annual revenue requirement ($/year) is compiled for wires options. For each option, a discounted cash flow model is created which includes the levelized unit energy cost or annual revenue requirement as well as bulk system energy and capacity costs where applicable. Note that, in order to enable an apples-to-apples comparison, the discounted cash flow for the non-wires options includes a credit for the bulk system capacity value it provides. The discounted cash flow model for all options is compiled over the lifespan of the longest option considered (typically 70 years for wires options). The net present value (in 2021 CAD dollars) of these cash flows are the primary basis through which options are compared.

A list of the assumptions made in the economic analysis can be found in Appendix E.

7.1.2 Options and Recommendation for Crilly DS

Crilly DS is expected to reach capacity in 2027. Crilly DS is a small (LTR of ~2.2 MW) station supplied from a bus shared with Sturgeon Falls CGS, a small hydroelectric plant approximately 50 km west of Atikokan. This is a non-standard supply arrangement that results in annual outages to Crilly DS when the generator is undergoing maintenance. Diesel generation is currently used for backup power whenever Sturgeon Falls is on outage. Furthermore, the existing station equipment will reach end-of-life over the next ~10 years and space constraints limit in situ refurbishment options.

Non-wires alternatives are not suitable for Crilly DS due to three factors. First, non-wires alternatives will not be able to eliminate nor reduce existing reliance on backup generation. Load modifying non-wires alternatives (e.g., energy efficiency measures or demand response) could potentially reduce peak demand and overall energy consumption but, when transmission supply is interrupted due to Sturgeon Falls outages, they cannot replace the need for backup generation. Similarly, distributed energy resources can reduce peak demand below the station LTR but, during outages, the distribution system served by Crilly DS must still rely on backup diesel generation. Frequent reliance on backup diesel generation results in poor reliability and is technically challenging due to difficulties in staying connected and maintaining power quality when supplying loads on a long single-phase distribution line. The long-term solution for Crilly DS station capacity should ideally provide reliability on par with other single circuit supply stations (where regular supply interruptions are not required for generator maintenance outages).

Second, structures and equipment at Crilly DS are approaching end-of-life in the near future. While the specific end-of-life dates vary based on asset conditions, existing structures and equipment are expected to require refurbishment/replacement over the next 10 years. Even if non-wires alternatives can address overloads due to incremental growth above the current station capacity, the station must still be rebuilt/refurbished at end-of-life.

Third, Crilly DS serves a small pool of customers (approximately 500 homes and businesses) in a remote location. This customer pool is too small to cost-effectively target energy efficiency or demand response measures since the overhead costs will likely be prohibitive compared to the potential savings in deferred or upsized infrastructure. Furthermore, while voluntary energy efficiency and demand response programs can produce predictable results when applied over large populations, the demand savings when targeted to a small group of customers is unreliable.

Since non-wires alternatives are not suitable for Crilly DS, Hydro One Distribution is considering the follow wires options:

- Refurbish Crilly DS at its current location (and continue to rely on backup power during outages),

- Rebuild Crilly DS at a different location as a 115/25 kV HVDS (close to the existing station/supply point),
- Rebuild Crilly DS at a different location as a 230/25 kV HVDS (connected to F25A closer to the community served by Crilly DS), or
- Replace Crilly DS with 115:25 kV padmount transformer (transformer enclosed in a grounded cabinet that can be accommodated outside the existing station fence).

The cost of these wires options ranges from $7.5-15M (including line work required for connection) and will address both the station capacity and end-of-life needs. Refurbishing Crilly DS at its current location is likely the least costly option but is undesirable due to the continued reliance on backup power. Furthermore, the incremental capacity that can be accommodated at the existing location may be limited due to the space constraints. Rebuilding Crilly DS as a full HVDS (either at 115 kV or 230 kV) would offer the best reliability and performance but also at the greatest cost. Replacing Crilly DS with a padmount transformer may be a more cost-effective option but there are still technical hurdles to be further investigated such as the ability for 115 kV protections to be accommodated within a padmount configuration.

Since non-wires alternatives are not suitable and there are no upstream supply capacity needs that require further regional coordination, the IRRP recommends that Hydro One Distribution conduct local planning, in coordination with the Regional Infrastructure Plan, to refine refurbishment/new station options identified in the IRRP with the goal of balancing reliability improvements and cost.

7.1.3 Options and Recommendation for Margach DS

Margach DS is expected to reach capacity in 2023 due to a large existing industrial customer seeking to be resupplied from a nearby CTS. Margach DS is approximately 10 km east of Kenora.

Non-wires alternatives are not suitable for addressing the Margach DS station capacity need due to the timing and magnitude of the demand increase. Resupplying the large industrial customer causes the forecast demand at Margach DS to jump by 40% from 2022 to 2023. Energy efficiency measures are typically only feasible if the demand exceeding station capacity is a small percentage of the total demand in each year. Similarly, historical zonal demand response auction data indicates that demand response is only feasible to reduce peak demand levels by single digit percentages. While distributed generation can technically be sized to accommodate any demand growth (within station short circuit and thermal limitations) this would functionally be the same as the new customer self-generating rather than seeking grid supply and is unlikely to be cost effective. The near-term timing of the demand growth is also problematic for implementing non-wires alternatives since many of the technical and regulatory barriers for implementing non-wires alternatives are still being tested.

The IRRP recommends that Hydro One Distribution install transformer fan monitoring which will increase the station capacity above forecast demand levels. Installing fan monitoring is an inexpensive method to increase the station LTR by enabling the use of higher thermal ratings on the existing transformers. The cost of installing fan monitoring is in the range of $1-1.5M compared to the cost of adding a new transformer which would be greater than $3M. Fan monitoring will increase the station capacity from approximately 10 MW today to 16 MW.

If additional capacity needs arise, a second transformer at the station which currently acts as a spare can be brought into service, but no recommendation beyond the fan monitoring is required based on the current forecast.

7.1.4 Options and Recommendations for Kenora MTS

Kenora MTS serves the City of Kenora and is expected to reach capacity in 2029 with a moderate annual growth rate of 1.25%. The station has an LTR of 23.4 MW and demand will exceed the LTR by approximately 4 MW by the end of the forecast horizon (2040).

Non-wires alternatives are promising for addressing the Kenora MTS station capacity need. The magnitude of the need relative to the total demand is moderate which makes targeting load modifying non-wires alternatives like energy efficiency and demand response feasible. The timing of the need is in the mid-term, so the forecast confidence is reasonably high while still having adequate lead time to demonstrate the efficacy of relatively untested non-wires alternatives and navigate technical and regulatory barriers. The timing of the need also means that lessons learned from the IESO's York Region Non-Wires Alternative Demonstration Project can be leveraged for implementing non-wires alternatives for Kenora MTS.

The following subsections discuss the wires options for Kenora MTS, non-wires alternatives, and recommendations.

7.1.4.1 Wires Options

There are two high-level wires options:

- Expand Kenora MTS with an additional transformer and associated protections, control, and structures at a cost of approximately $5M. This can be accommodated on existing land owned by the distributor, Synergy North, within the station. This option assumes that feeder loads can be rebalanced and servicing these loads on existing distribution system infrastructure is possible.

- Construct a new substation located across the city from the existing station at a cost of approximately $30M. The new station would be supplied from Rabbit Lake SS.

The existing Kenora MTS station is located on the northern edge of the city. The proposed new substation would be located on the far west side of the city and, in addition to addressing station capacity needs, would provide substantial distribution system benefits by reducing the length of feeders required to reach customers and improving voltage and frequency regulation. The long feeders to the western parts of the system currently experience voltage and frequency issues especially during outages requiring parts of the distribution system to be resupplied from alternate feeders. Synergy North is also aware of significant development interest along the western outskirts of the city, but no formal agreements have been finalized. A new station would provide a supply point close to these customers and improve distribution system performance.

A new station would also provide a redundant transmission supply point that is connected to a different bus/breaker at Rabbit Lake SS than the existing station. If a new station is built, the distribution system could be designed with tie points and reclosers to enhance the overall reliability across Kenora.

The distribution system benefits above have only been qualitatively described in the IRRP. As discussed in the following subsections, the cost effectiveness of the non-wires alternatives may hinge on whether they can provide similar distribution system benefits as a new station. Future analysis by Synergy North should further quantify the value of these benefits.

7.1.4.2 Non-wires Alternatives

Three non-wires alternatives for Kenora MTS were identified and sized according to the characteristics of the hourly demand profile described in Section 5.6:

- A 4 MW gas generation facility (aero engine). The cost estimate for gas generation is based on the IESO's internal benchmark cost reports. To estimate its contribution to provincial system adequacy, its effective capacity was assumed to be 93% of its installed capacity, which is the lesser of its unforced capacity and the zonal capacity maximums reported in the 2021 IESO Annual Planning Outlook.[22]
- A 6-hour 4 MW (24 MWh) battery. The cost estimate for battery storage is based on data from the National Renewable Energy Laboratory. Note that local generation (e.g., wind or solar) was not required to complement the battery due to the relatively low energy requirement (i.e., the battery can be recharged from existing grid power when it is not needed).

[22] The 2021 Annual Planning Outlook is available on the IESO's Planning and Forecasting webpage.

- A combination of energy efficiency measures and demand response. The availability and cost of incremental energy efficiency measures (i.e., in addition to the conservation and demand management programs already included in the demand forecast) are based on the IESO's 2019 Conservation Achievable Potential Study[23]. The 2019 Achievable Potential Study and incremental energy efficiency savings for Kenora MTS are further described in Appendix E. Demand response costs are estimated from average capacity auction values from 2018-2021 for the Northwest zone.

The net present value (NPV) of each wires and non-wires alternative's cost is shown in Table 7-1. The NPV includes the levelized unit energy cost as well as bulk system energy and capacity costs and benefits associated with each option over a 45-year asset life (which is typical for station equipment).

Table 7-1 | Kenora MTS Wires and Non-wires Alternative Costs

Option	Cost NPV ($2021 Real)
Expand Kenora MTS	$4 M
New Station	$25 M
4 MW Gas Generation	$22 M[24]
24 MWh Battery Storage	$10 M[24]
Combination of Energy Efficiency and Demand Response	$1-9 M[25]

7.1.4.3 Recommendation

The cost of the non-wires alternatives generally falls between the cost of expanding the existing station and a new station (which also improves reliability and performance on the distribution system). Therefore, the decision to pursue non-wires alternatives versus traditional wires options rests on distribution system benefits that can be realized by each option. For example, battery storage can be sited on the distribution system such that it improves voltage regulation along lengthy feeders. If the value of the distribution system benefits is greater than the cost difference between the battery and station expansion, the battery may be the most cost-effective solution for ratepayers overall.

[23] The 2019 Conservation Achievable Potential Study can be found on the IESO's website.
[24] Assumes full (unforced capacity) credit for system capacity value. Actual cost could be higher depending on the deliverability of the NWA resource.
[25] Cost ranges from $1-9 M depending on whether the energy efficiency measures are part of provincially cost-effective CDM (i.e implemented through the IESO's Local Initiative Program) or if they are incremental to provincially cost-effective CDM.

The technologies, regulatory framework, and protocols required to implement dispatchable non-wires alternatives (e.g., batteries, gas generation, or demand response) for the purpose of meeting local capacity needs are still being tested. The IESO's York Region Non-Wires Alternative Demonstration Project[26] is currently exploring market-based approaches to secure energy and capacity services from distributed energy resources (DERs) for local needs. There is a window of opportunity between today and 2029 when the Kenora MTS capacity need arises to leverage learnings from the York Region Pilot and further refine the procurement and operation of non-wires alternatives for Kenora MTS.

Since there are no upstream constraints on the transmission system requiring further regional coordination, the IRRP recommends that Synergy North lead further NWA analysis and refinement as part of local planning. Synergy North should monitor load growth at Kenora MTS to determine when a firm commitment for additional capacity is required and implement non-wires alternatives if they remain feasible and cost-effective. Furthermore, the IESO will consider Kenora MTS as a potential focus area for the Local Initiatives Program[27] under the 2021-2024 Conservation and Demand Management Framework. The IESO will collaborate with Synergy North in 2023 as further details for the next round of the Local Initiatives Program become available. In addition to the energy efficiency measures that may result from the IESO's Local Initiative Program, Synergy North may also use the Ontario Energy Board's Conservation and Demand Management Guidelines[28] to leverage distribution rates for non-wires alternatives.

7.2 Options for Improving Customer Reliability at Fort Frances TS

As discussed in Section 2.1.4, the IRRP will not make a specific recommendation for improving customer reliability since Fort Frances Power's roadmap for Fort Frances MTS is still under development. However, this section will document the options considered during the IRRP process and the IRRP recommends that Fort Frances Power and Hydro One continue to collaborate and select a preferred option in local planning.

The Fort Frances TS 115 kV station layout and connection to Fort Frances MTS is shown in Figure 7-1. The 115 kV side of Fort Frances TS is comprised of a 6-breaker ring bus with connections to the station's two autotransformers and circuits K6F, F3M, F2B, and F1B. Fort Frances MTS is currently connected to the L1-bus (which connects to F1B) and is physically located immediately adjacent to Fort Frances TS. Transmission outages to F1B and the L1 bus have accounted for 90% of Fort Frances Power's customer interruptions over the last 10 years. Therefore, Hydro One has proposed reconfiguration options with the goal of reducing Fort Frances MTS' exposure to transmission outages.

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[26] For more information on the pilot and latest developments, please see the York Region Non Wires Alternatives Demonstration Project engagement webpage.

[27] For more information on the Local Initiatives Program, please see the Save ON Energy Local Initiatives webpage and the 2021-2024 Conservation and Demand Management Framework webpage.

[28] More information about the Conservation and Demand Management Guidelines is available on the OEB's website (link).

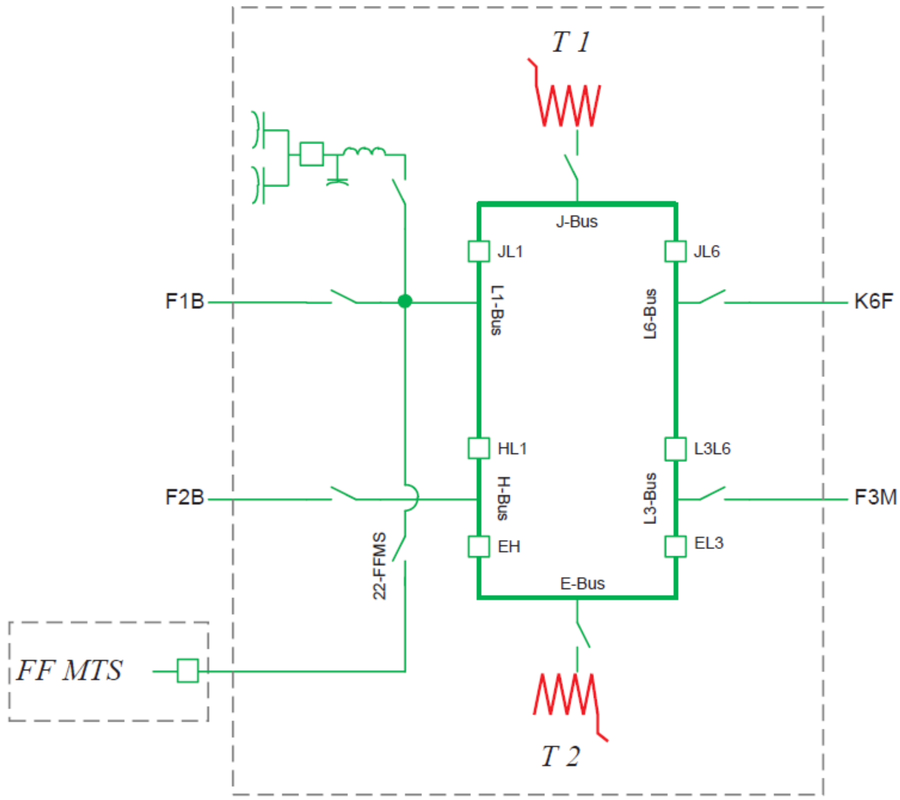

Figure 7-1 | Fort Frances TS 115 kV Single Line Diagram

The following options, in order of increasing complexity and cost, were contemplated:

- Replace the existing 22-FFMS air-break switch with an interrupter switch (still connected to F1B) and install a second interrupter switch to connect Fort Frances MTS to F2B. One of the two switches would be operated normally open, but the switches would allow Fort Frances MTS to be transferred between F1B and F2B to avoid any supply interruptions during planned outages on either of the two circuits or buses.
- Install a new 115 kV breaker on the L1 bus and move the Fort Frances MTS termination between this new breaker and the HL1 breaker. This would form a 7-breaker ring bus and Fort Frances MTS would have its own position separate from any other circuit.

- Install a second breaker at Fort Frances MTS and connect it to the H-bus via a new air-break switch. Since Fort Frances MTS already has two transformers, if both Fort Frances MTS breakers are normally closed, this configuration could provide fully redundant transmission supply. However, the feasibility of having both supply points normally closed is still being reviewed; a normally open point may be required to manage short circuit levels. If either the L1-bus or H-bus supply points needs to be operated normally open, this option would be functionally the same as the first option (but more expensive).

8. Supply to the Ring of Fire

The Ring of Fire is a remote area covering 5000 km^2 located 500 km north of Thunder Bay with rich deposits of critical minerals.[29] There is strong interest in developing mining activities in this area, however as it is located far from established infrastructure, it is currently without all-season road access or grid power supply. Transmission supply to the Ring of Fire was contemplated in the 2015 cycle of regional planning for Northwest Ontario. With renewed interest in developing the Ring of Fire from both government and mining companies, the IESO is updating its Supply to the Ring of Fire study in parallel with the ongoing Northwest IRRP. This report provides an update on preliminary findings as of Q4 2022 including:

- Transmission supply options and high-level cost estimates;
- Key opportunities for alignment that should be considered in the decision to pursue transmission supply to the Ring of Fire as well as its routing and connection point;
- Avoided diesel system costs from connecting remote communities to the grid via a transmission line to the Ring of Fire; and
- Greenhouse gas reductions associated with connecting remote communities and Ring of Fire mines to the grid, as opposed to self generation.

Note that the decision to pursue transmission supply to the Ring of Fire ultimately lies with mining companies and remote communities as the direct beneficiaries of such a project, and with the provincial and federal governments to advance broader policy objectives. The purpose of the renewed Supply to the Ring of Fire study is to help inform government policy and potential customers seeking connection.

8.1 Background

A map of the Ring of Fire area and nearby features of interest are shown in Figure 8-1. Interest in developing the Ring of Fire has varied over the years and there is a high degree of uncertainty in the eventual mining sector electrical demand that may materialize. However, with the current focus on developing critical minerals to support decarbonisation, interest in developing the Ring of Fire area is growing.

[29] Ontario's critical mineral list can be found in the 2022-2027 Critical Mineral Strategy is available on Ontario's Mining and Minerals website.

In addition to potential mining loads, there are five off-grid Matawa First Nation communities in the vicinity of the Ring of Fire. These communities rely on diesel generation systems that are expensive to operate, produce environmental pollutants, and may constrain the communities' growth. Enabling grid supply for these communities is an important factor contributing to the overall rationale for transmission supply to the Ring of Fire. The transmission supply routing and connection point to the existing electricity system should also consider the significant potential for hydro generation in the area which may be able to connect to the grid via the transmission line to the Ring of Fire.

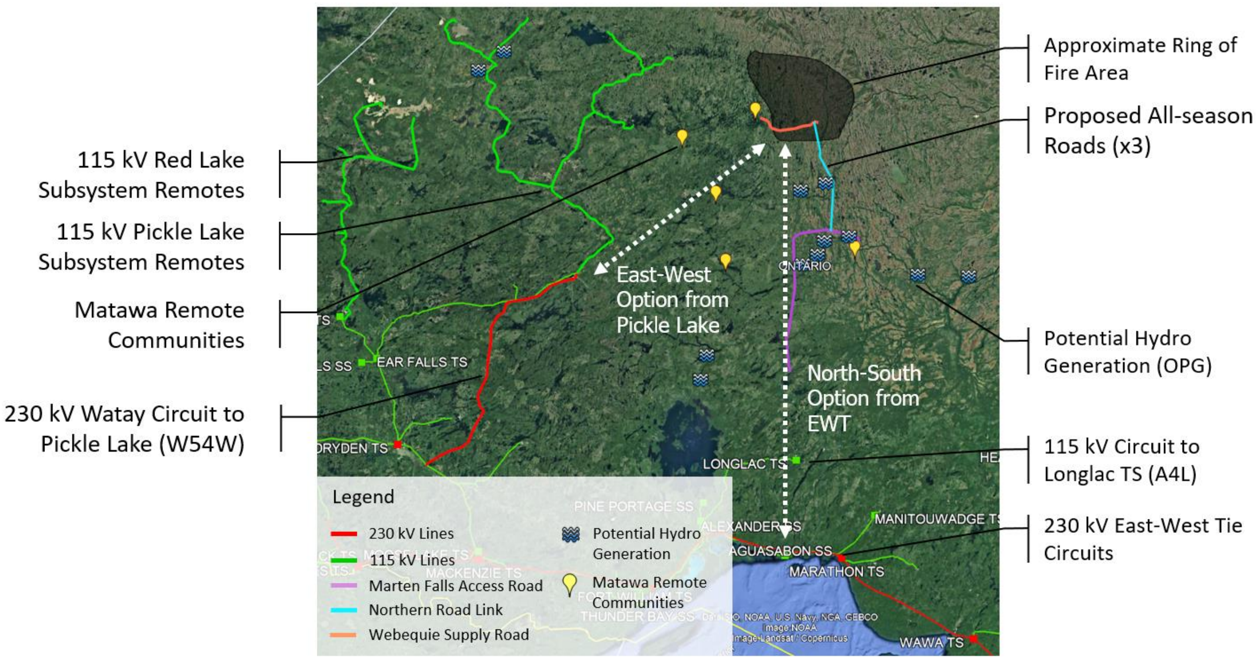

Figure 8-1 | Ring of Fire and Surrounding Area Map

Transmission supply to the Ring of Fire was contemplated in the 2015 North of Dryden IRRP and the 2016 Greenstone-Marathon IRRP. The North of Dryden IRRP outlined potential transmission supply options with the goal of connecting remote communities as well as serving mining electricity demand at the Ring of Fire if it were to materialize. This plan contemplated reinforcing the existing transmission system from the Dryden area to Pickle Lake and building a new transmission line from Pickle Lake to the Ring of Fire. The North of Dryden IRRP, in conjunction with the 2014 Remote Connection Plan, culminated in the indigenous-led Wataynikaneyap Transmission Project.

The Wataynikaneyap Transmission Project includes a new 230 kV line from Dinorwic Junction (near Dryden) to Pickle Lake as well as 115 kV transmission lines extending north of Pickle Lake and Red Lake to connect remote communities. The Matawa area remote communities chose not to participate in the Wataynikaneyap Transmission Project and no transmission lines were built from Pickle Lake to the Matawa communities or the Ring of Fire. This transmission supply option to the Ring of Fire is referred to as the East-West option in Figure 8-1.

The Greenstone-Marathon IRRP extended this analysis to consider potential cost optimization opportunities between new customers in the Greenstone area and remote communities/mines at the Ring of Fire. This entailed a North-South transmission supply option extending from the existing East-West Tie circuits northwards through Greenstone (which is electrically supplied from Longlac TS) and onwards to the Ring of Fire. The largest new customer in the Greenstone area at the time choose to self-generate instead of pursuing transmission supply and the North-South transmission supply option did not proceed.

To date, there have been no firm commitments from customers seeking transmission connection in the Ring of Fire area.

8.2 Policy Drivers and Demand Forecast

Enabling development in the Ring of Fire area is an important policy objective for the provincial government. Ontario's Critical Mining Strategy[30] identifies the Ring of Fire as a "priority project" and a "transformative opportunity for unlocking multi-generational development of critical minerals." The strategy also highlights the importance of Ontario's relatively clean electricity system for enabling development of lower-emissions mining compared to other jurisdictions.

The province has also expressed support for a "Corridor to Prosperity" comprised of three proposed all-season roads led by First Nations partners that connects to the existing highway system and extends northwards towards the Ring of Fire. These proposed roads include the Marten Falls Community Access Road, Webequie Supply Road, and Northern Road Link. The proposed roads are at various stages in their provincial and federal Environmental and Impact Assessments. Taken together, they would provide a continuous all-season transportation corridor to the Ring of Fire that would be necessary to facilitate mining development. Ontario has committed $1 billion to support these road infrastructure projects on the basis that federal contributions will match provincial commitments.

There is a high degree of uncertainty in terms of both the magnitude and timing of mining electricity demand at the Ring of Fire. The IESO's latest mining demand forecast includes approximately 30 MW of electricity demand associated with two proposed mining projects. The 2015/6 IRRP forecasts included up to 70 MW of demand at the Ring of Fire but some proponents have since walked away from their development plans. If transmission and

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[30] The 2022-2027 Critical Mineral Strategy is available on Ontario's Mining and Minerals website.

transportation infrastructure were developed, mining demand would almost certainly be much higher than currently forecast. As of January 2022, there are approximately 26,000 active mining claims held by 15 companies in the Ring of Fire. The IESO will continue monitoring development plans and intends to update the mining forecast in Q1 2023 to better capture Ring of Fire growth scenarios.

The five Matawa area remote communities have a total demand of approximately 4 MW today and are forecast to grow at 4% per year.[31] This forecast was last updated in 2019 and will be updated as new information becomes available.

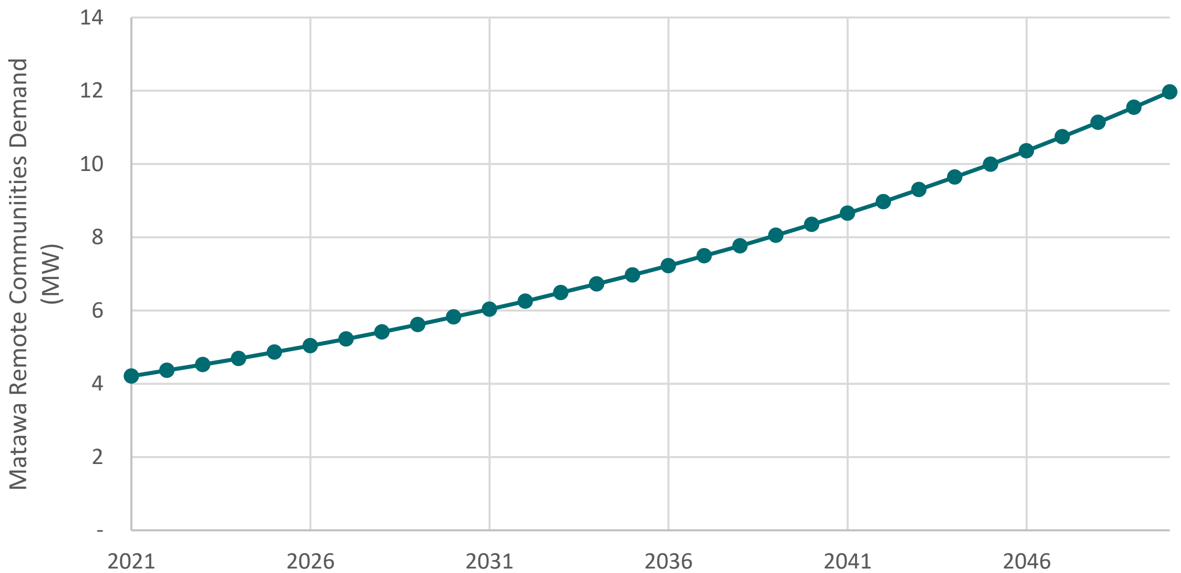

Figure 8-2 | Matawa Remote Communities Demand Forecast

[31]The forecast 4% growth rate reflects potential demand growth if the remote communities are grid connected and no longer constrained by diesel supply capacity.

8.3 Transmission Supply Options and Cost Estimates

As discussed in Section 8.1, at a high level, there are two transmission supply options to the Ring of Fire that could be pursued: a North-South option connecting to the East-West Tie circuits between Marathon and Thunder bay and an East-West option connecting to the new Wataynikaneyap TS near Pickle Lake. The conceptual electrical elements of each option are listed in Table 8-1. Note that at this stage, no detailed engineering design or routing work has been performed. The transmission options are presented here for discussion purposes and to facilitate high-level cost estimation (-50% to +100%).

The North-South option is estimated to cost between $860M and $1.08B while the East-West option is estimated to cost between $600M and $780M ($2022 real, overnight capital cost). The cost ranges reflect uncertainty in the final station configurations as well as in the per unit (km) cost of transmission lines which can vary depending on the technology type and geography. These cost estimates are not inclusive of step-down transformer stations at the loads themselves nor reactive compensation devices which will depend on the magnitude of the demand. Note that material and labour costs have increased rapidly over the COVID-19 period and there is a high degree of uncertainty in future costs.

Table 8-1 | Ring of Fire Transmission Option Conceptual Elements

Transmission Supply Option	Element #	Description	Length (km)	Cost ($2022 real)
North-South	1	230 kV single circuit line from East-West Tie circuits to Longlac	120	$170-215M
	2	New stations at East-West Tie connection point[32] and Longlac (to enable connection to A4L);	N/A	$115-125M
	3	230 kV single circuit line from Longlac to McFaulds Lake; roughly parallel to proposed roads	410	$575-740M
East-West	1	230 kV single circuit line from Wataynikaneyap TS near Pickle Lake to McFaulds Lake; roughly along route envisioned in the 2014 Remote Connection Plan	370	$580-745M
	2	Wataynikaneyap TS modifications	N/A	$20-30M

[32] Connecting the Ring of Fire line directly to East-West Tie lines between Lakehead TS and Marathon TS minimizes costs since it is the closest 230 kV supply point to the Ring of Fire. However, connecting to only one (or any subset) of the four parallel East-West Tie lines will unbalance flows between Marathon TS and Lakehead TS and may decrease the overall transfer capability of the East-West Tie. Future studies should weigh the costs and benefits of connecting to either Lakehead TS or Marathon TS versus a new junction and/or switching station on the East-West Tie.

While the East-West option is less expensive than the North-South option, it would provide less incremental capacity to supply load and would also increase exposure to outages. The load meeting capability for a radial expansion of the transmission system like the Ring of Fire is typically constrained by thermal, voltage, and load security limits. The thermal rating of a 230 kV single circuit line is unlikely to be constraining; as an example, a single East-West Tie circuit has a continuous rating of approximately 320 MW in the summer and 390 MW in the winter. This far exceeds the current known mining and remote community demand forecast. Voltage limits can be managed by installing voltage regulation devices at the loads and can be sized according to the expected demand, however this would add incremental cost and operational complexity. Load security limits, however, may become the most limiting factor depending on future mining developments.

Ontario Resource and Transmission Assessment Criteria (ORTAC) Section 7.1 load security criteria specifies the maximum amount of load that can be interrupted after certain contingencies. For the loss of a single element (i.e. single circuit supply to the Ring of Fire), no more than 150 MW may be interrupted. This limits the total load served on the North-South option to 150 MW. The East-West option is connected downstream of the new single circuit Wataynikaneyap line (W54W). The total load served by W54W is also limited to 150 MW including the all existing loads and their growth, new mining customers along W54W, and the Ring of Fire and Matawa communities. Existing load served on W54W totals approximately 45 MW today and is expected to grow to 80 MW by 2040. While the remaining room is sufficient for serving the currently forecast demand at the Ring of Fire (30 MW mining plus Matawa area communities), it leaves relatively little room to accommodate additional development. Furthermore, the IESO is aware of several additional mining projects potentially seeking connection along W54W. While these projects are not yet certain enough to be included in the IRRP reference forecast, they could significantly reduce the available capacity for growth at the Ring of Fire.

While not addressed by ORTAC criteria, another consideration is the level of exposure to outages. The East-West option would involve connecting the Ring of Fire and Matawa communities to a radial system that already spans several hundred kilometers of transmission lines (W54W and D26A). Each time any part of this system is faulted (e.g., in an electrical storm or fire), the whole system is removed from service until the fault can be addressed. By comparison, the North-South option can be connected to the East-West Tie (or nearby station) which are more robust and has redundant supply.

Due to the uncertainty in future mining developments, it is too early to rule out the East-West option at this time. However, the potential capacity constraints and customer reliability impacts related to the East-West option should be considered when selecting a preferred transmission option. The next section discusses opportunities for alignment and further considerations that may impact the preferred transmission option.

8.4 Opportunities for Alignment

A decision to pursue transmission supply to the Ring of Fire, and decisions on its preferred routing, should consider alignment with four opportunities in addition to supplying mining demand at the Ring of Fire:

- Supplying Matawa Remote Communities
- Enabling potential hydro generation
- Improving supply to Longlac
- Co-locating with transportation corridor

These opportunities for alignment are discussed in turn below.

8.4.1 Supplying Matawa Remote Communities

There are five Matawa indigenous remote communities in the vicinity of the Ring of Fire:

- Webequie
- Nibinamik
- Neskantaga
- Marten Falls
- Eabametoong

These communities were previously identified as economic for grid connection in the 2014 Remote Connection Plan but elected not to participate in the Wataynikaneyap Transmission Project. The 2014 Remote Connection Plan found that it was more cost-effective to supply the communities via a single circuit 115 kV transmission line (either from Pickle Lake or the East-West Tie circuits) than continued reliance on off-grid diesel generation systems. Transmission supply to the Ring of Fire could also enable connection of the Matawa remote communities. Both the North-South and East-West transmission options would serve this purpose. Updated potential avoided diesel generation system costs are discussed in Section 8.4.2.

Note that the decision to pursuing grid connection is up to the communities. The IESO will continue to engage with the Matawa communities to inform future studies. Furthermore, grid connection of remote communities does not preclude local energy projects such as the installation of distributed generation and storage. The IESO continues to support broad equitable participation in Ontario’s energy sector through its Energy Support Programs including the Indigenous Energy Projects (IEP) Program[33] which provides funding support to First Nation and Metis communities to assess and develop energy projects and partnerships.

8.4.2 Enabling Hydro Generation

In Jan 2022, the Ontario government asked Ontario Power Generation to examine opportunities for new hydroelectric development in northern Ontario. New hydroelectric generation could address the growing long-term electricity needs forecast for the province, with the potential for economic benefits for local and Indigenous communities in the north. Ontario Power Generation has shared this work with the Ministry of Energy and the IESO so that it can be considered as part of the IESO's work towards developing an achievable pathway to zero emissions in the electricity sector. Development of transmission supply to the Ring of Fire should consider the connection of potential hydro generation in the area.

There is significant hydroelectric generation potential in the vicinity of the Ring of Fire. Due to the geographic distribution of these potential generation facilities, the North-South transmission option is better suited than the East-West option to connect these facilities on the way to the Ring of Fire. Furthermore, the North-South option connects to a more robust point in the bulk transmission system which may result in fewer deliverability constraints and lower overall losses. The Ring of Fire North-South transmission line is not necessarily the optimal connection point for potential hydro generation near the Ring of Fire. Other connection options, to Pinard TS for example, may reduce the overall bulk system reinforcements needed to deliver the hydro generation capacity to southern Ontario. However, connecting to the Ring of Fire transmission line could significantly reduce the length of connection lines required for these potential hydro generators and future studies should consider the synergies between Ring of Fire transmission supply and enabling the connection of potential hydro generation.

8.4.3 Improving Supply to Longlac

The existing radial 115 kV circuit, A4L, to Longlac TS is near capacity and customers have expressed concern about poor reliability due to long and frequent outages. While no firm growth plans or new customer connection requests were received during this IRRP, there continues to be a high degree of interest for mining and industrial developments in the Greenstone and Geraldton areas supplied by A4L. There are also existing customers along A4L who have elected to self-generate rather than connect to the transmission system due to capacity constraints.

A4L refurbishment is underway and distance-to-fault relays have been installed which should decrease the frequency of outages and improve restoration times. However, these improvements do not increase the load meeting capability on A4L and, as with many other areas in the Northwest region, growth can materialize quickly.

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[33] For more information, please visit the Indigenous Energy Projects Program webpage.

The North-South transmission option passes directly by Longlac TS and could help increase capacity and provide a secondary supply path to further improve reliability. The North-South option conceptual elements in Table 8-1 includes a 230/115 kV transformer station at Longlac for this purpose. Note that the East-West option is not suitable for reinforcing Longlac.

8.4.4 Co-locating with Transportation Corridor

The proposed Marten Falls Community Access Road, Webequie Supply Road, and Northern Road Link will provide a continuous all-season transportation corridor to the Ring of Fire. While detailed routing has not yet been performed, the North-South transmission option is well aligned with the proposed roads. The line length determined for the North-South option in Table 8-1 assumes that the transmission corridor runs parallel to the proposed roads wherever possible but the potential cost savings associate with colocation has not been factored into the transmission cost estimate yet. This likely overestimates the cost of the North-South transmission option compared to the East-West option; future studies should conduct more detailed engineering design and routing analysis to better quantify the benefits of colocation.

Co-locating linear infrastructure is consistent with provincial policy as articulated in Section 1.6.8 of the 2020 Provincial Policy Statement[34] and may help reduce environmental impacts. The roads would also provide easier access to the transmission line which could simplify construction as well ongoing operation and maintenance. Note that there are no proposed all-season roads along the East-West option route.

8.5 Avoided Matawa Communities Diesel System Costs

The Matawa remote communities are currently supplied by remote on-site diesel generation which is costly to operate. Up to 70% of the fuel must be flown in when winter roads are not available contributing to high costs and increased emissions from fuel transport. The costs of supplying electricity from remote diesel generation systems versus the grid over the first 20 years of transmission connection are shown in Figure 8-3. The net present value of remote diesel generation costs is estimated to be $446M over this period, while serving the same load from the provincial grid is estimated to be roughly $35M.[35] These net present values are expressed in real dollars in the year when transmission connection is hypothetically brought in-service. For the purpose of this assessment, it was assumed that transmission connection occurs in 2030 given the typical 7-year lead time of new transmission projects.

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[34] The 2020 Provincial Policy Statement can be found on the Ontario government's Land Use Planning webpage.

[35] The cost of serving loads on the provincial grid is solely based on the system's marginal cost of energy. It does not include cost of transmission connection itself. Connecting remote communities is one of multiple potential benefits (other benefits include supplying mining loads and enabling hydro generation) that contribute towards a rationale for transmission supply. The cost of transmission supply should be compared against this full suite of benefits.

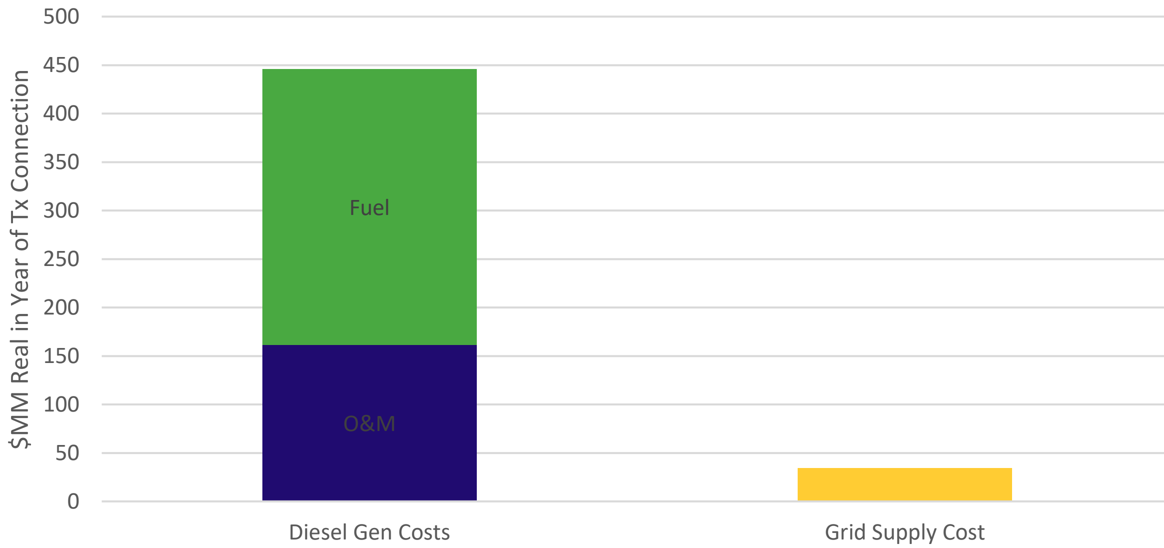

Figure 8-3 | NPV of Electricity Supply Costs from Diesel Generation versus the Provincial Grid for Matawa Remote Communities over the First 20 Years of Grid Connection

The cost of continuing to supply electricity to the remote Matawa communities by local diesel generation was estimated using the IESO's internal fuel forecast and aggregated cost data for remote communities served by Hydro One Remote Communities.[36] Generally speaking, economic and cost assumptions were consistent with the 2014 Remote Connection Plan adjusted for inflation. The cost of supplying electricity from local diesel generation is comprised of two components:

- Fuel costs including the cost for the fuel itself, winter road/air transportation, and the cost of carbon;
- Operating and maintenance costs estimated from historical revenue requirement and rate application regulatory submissions as a percentage of fuel costs.

[36] Not all Matawa communities are served by Hydro One Remote Communities. For communities served by Independent Power Authorities for which cost data was not directly available, system costs were estimated based the size of their load and Hydro One Remote Communities' system costs.

Of the $446M net present value, $284M is associated with fuel costs and $162M with operating and maintenance costs. Note that this cost estimate does not include the capital costs associated with expanding existing diesel systems to meet future capacity growth. This enables an apples-to-apples comparison with the cost of grid electricity which also did not include the incremental resource capacity cost of serving the newly connected remote communities. Furthermore, since the incremental capacity requirement is dependent on the year in which transmission connection occurs and the system needs/market conditions in the period following grid connection, capital costs associated with this capacity cannot be accurately calculated today. Future studies should refine the consideration of capacity costs when there is more certainty on when transmission supply will proceed.

The cost of serving Matawa remote communities should they be connected to the provincial electricity grid was based on the system marginal cost forecast in the 2021 Annual Planning Outlook.

8.6 Avoided Greenhouse Gas (GHG) Emissions

Avoided GHG emissions was estimated for the Matawa communities and the future mining load through the comparison of emissions on the electricity system (consistent with the 2021 Annual Planning Outlook emission rate per MWh) versus diesel generation for remote communities and natural gas generation for mining loads.[37]

The GHG reduction associated with connecting Matawa communities depends on the forecast demand levels and growth rate when transmission connection occurs. Consistent with the diesel system cost savings estimates in the previous section, transmission connection was assumed to occur in 2030. On average, over the first 20 years of transmission connection (i.e. 2030-2049), GHG reductions are expected to be approximately 27,000 tCO2e per year.

The GHG reduction associated with mining loads depends on the amount of demand that materializes. As discussed in Section 8.2, there is a high degree of uncertainty in terms of both the magnitude and timing of this demand. For illustrative purposes, if 30 MW of demand materializes (consistent with demand from known projects), GHG reductions would total 68,000 tCO2e per year. If 70 MW of demand materializes (consistent with demand from the 2015 IRRP forecasts), GHG reductions would total 160,000 tCO2e per year. The true avoided GHG emissions associated with connecting mining loads instead of on-site generation could be much higher given the large number of active mining claims in the Ring of Fire.

[37] The natural gas generation was assumed to be a combined cycle gas turbine (CCGT) facility with a heat rate of 7.265 MW/MMbtu and a natural gas emission intensity of 53.157 kgCO2e/MMbtu. For diesel generation emissions, the Hydro One Remote Communities fleet average generator efficiency and a diesel emission intensity of 75.22 kgCO2e/MMbtu was assumed.

8.7 Next Steps

The sections above provide an overview of preliminary findings to date of the Supply to the Ring of Fire Study and highlights some areas of uncertainty that will require further investigation. The IESO will continue the Supply to the Ring of Fire Study in 2023. The scope, timing, and engagement process will evolve with government policy direction. The IESO will share updates with the Working Group to inform upcoming regional planning activities such as the Regional Infrastructure Plan.

9. Engagement

Engagement is critical in the development of an IRRP. Providing opportunities for input in the regional planning process enables the views and preferences of communities to be considered in the development of the plan and helps lay the foundation for successful implementation. This section outlines the engagement principles as well as the activities undertaken for this Northwest IRRP.

9.1 Engagement Principles

The IESO's engagement principles[38] help ensure that all interested parties are aware of and can contribute to the development of this IRRP. The IESO uses these principles to ensure inclusiveness, sincerity, respect, and fairness in its engagements, striving to build trusting relationships as a result.

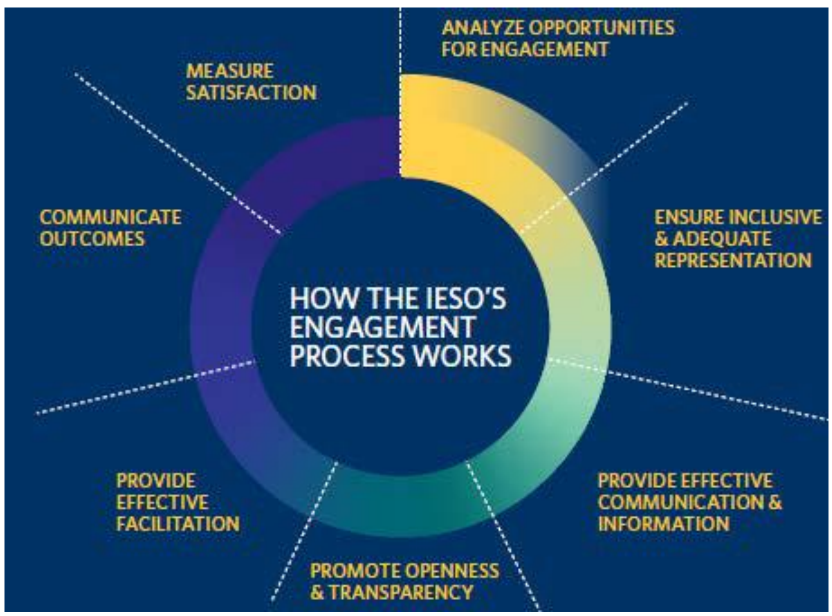

Figure 9-1 | IESO's Engagement Principles

[38] https://www.ieso.ca/en/sector-participants/engagement-initiatives/overview/engagement-principles

9.2 Creating an Engagement Approach for the Northwest

The first step in ensuring that any IRRP reflects the needs of community members and interested stakeholders is to create an engagement plan to ensure that all interested parties understand the scope of the IRRP and are adequately informed about the background and issues to provide meaningful input on the development of the IRRP for the region.

Creating the engagement plan for this IRRP involved:

- Targeted discussions to help inform the engagement approach for this planning cycle;
- Communications and other engagement tactics to enable broad participation, using multiple channels to reach audiences; and
- Identifying specific stakeholders and communities who may have a direct impact in this initiative and that should be targeted for further one-on-one consultation, based on identified and specific needs in the region.

As a result, the engagement plan for this IRRP included:

- A dedicated webpage[39] on the IESO website to post all meeting materials, feedback received and IESO responses to the feedback throughout the engagement process;
- Regular communication with interested communities and stakeholders by email and through the IESO weekly Bulletin;
- Public webinars;
- Targeted discussions sessions;
- Face-to-face meetings; and
- One-on-one outreach with specific communities and stakeholders to ensure that their identified needs are considered (see Sections 9.4 and 9.5).

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[39] https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Regional-Electricity-Planning-Northwest-Ontario

9.3 Engage Early and Often

The IESO held preliminary discussions to help inform the engagement approach for this round of planning, leveraging existing relationships built through the previous planning cycle. This started with the Scoping Assessment Outcome Report for the Northwest region. An invitation was sent to targeted municipalities, Indigenous communities, and those with an identified interest in regional issues to announce the commencement of a new regional planning cycle and invite interested parties to provide input on the Northwest Scoping Assessment Report before it was finalized.

Feedback was received and focused on the need to ensure that municipal energy planning, including the need to recognize climate change priorities, as well as economic development and industrial growth (including forestry and mining) were in scope of the development of the IRRP. In addition, reliability remained a paramount concern within this region. Along with a response to the feedback received, the final Scoping Assessment was posted on January 13, 2021, which identified the need for a coordinated regional planning approach across the Northwest region – particularly important since the previous planning cycle targeted regional plans within five identified sub-regions.

Following the finalization of the Scoping Assessment, outreach then began with targeted municipalities to inform early discussions for the development of the IRRP including the IESO's approach to engagement. The launch of a broader engagement initiative followed with an invitation to IESO subscribers of the Northwest planning region as well as all identified municipalities and Indigenous communities to ensure that all interested parties were made aware of this opportunity for input. Four public webinars were held at key stages during the IRRP development to give interested parties an opportunity to hear about progress and provide comments on various components of the plan.

All these engagement sessions received strong participation with a cross-representation from stakeholders and community representatives. Feedback was received as a result each engagement meeting which was considered in each of the stages in the IRRP development.

The public webinars invited input on:

1. The draft engagement plan, the electricity demand forecast and the early identified needs to set the foundation of this planning work.

2. The defined electricity needs for the region and potential options to meet the identified needs.

3. The analysis of options and draft IRRP recommendations.

In addition, three targeted discussions were held virtually to uncover specific feedback from communities and stakeholders on the following three topics:

1. Customer Reliability Concerns
2. Emerging Local Initiatives
3. Emerging Electricity Needs in the North of Dryden Area

Comments received during this engagement focused on the following major themes:

- Given the large geographic area for this planning region, consideration throughout the engagement should be given to targeted discussions to address local reliability and priorities. Education and support should be available to enable purposeful engagement for all interested parties
- Consideration in the demand forecast should be given to local developments, growth plans and climate change goals (i.e., electrification) – particularly in communities where capacity may be limited
- Non-wires alternatives should be considered to meet needs and, in particular, climate change priorities; existing resources in the region should be considered where contracts are due to expire
- Due consideration should be given to providing capacity for new commercial and industrial (mining and forestry) growth as well as electrification of existing industry
- Opportunities for future proponents to leverage existing partnerships or create new relationships among local and Indigenous communities to have due consideration of priorities and provide business prospects, where possible

Feedback received during the written comment periods for these webinars helped to guide further discussion throughout the development of this IRRP as well as add due consideration to the final recommendations.

All interested parties were kept informed throughout this engagement initiative via email to Northwest region subscribers, municipalities, and Indigenous communities as well as the members of the Northwest Regional Electricity Network.

Based on the discussions through the Northwest IRRP engagement initiative and broader network dialogue, there is a clear interest to further discuss the potential for development of the mining sector in this region and to look for alternative energy solutions to meet local needs, particularly as communities and industries shift towards electrification. This insight has been valuable to the IESO and will help to inform future discussions to examine and consider these types of initiatives and the opportunities that they may present in future planning efforts. To that end, ongoing discussions will continue through the IESO's Northwest Regional Electricity Network to keep interested parties engaged in a two-way dialogue on local developments, priorities, and planning initiatives to prepare for the next planning cycle.

All background information, including engagement presentations, recorded webinars, detailed feedback submissions, and responses to comments received, are available on the IESO's Northwest IRRP engagement webpage.

9.4 Bringing Municipalities to the Table

The IESO held meetings with municipalities to seek input on their own planning and priorities to ensure that these plans were taken into consideration in the development of this IRRP. At major milestones in the IRRP process, meetings were held with targeted municipalities in the region to discuss: key issues of concern, including forecast regional electricity needs; options for meeting the region's future needs; reliability concerns; and broader community engagement. These meetings helped to inform the municipal/community electricity needs and priorities and provided opportunities to strengthen this relationship for ongoing dialogue beyond this IRRP process.

9.5 Engaging with Indigenous Communities

The IESO remains committed to an ongoing, effective dialogue with communities to help shape long-term planning across Ontario. To raise awareness about the regional planning cycle in Northwest Ontario and provide opportunities to provide input, the IESO invited Indigenous communities located in or near the Northwest region to participate in webinars that were held on:

- December 8, 2020
- May 20, 2021
- September 27, 2021
- November 2, 18, 29, 2021
- April 25 and 26, 2022
- November 3, 2022

The First Nation communities that were invited to the webinars were:

- Animakee Wa Zhing No. 37
- Animbiigoo Zaagi'igan Anishinaabek
- Anishinaabeg of Naongashiing (Big Island)
- Anishinabe of Wauzhushk Onigum
- Aroland
- Bearskin Lake
- Big Grassy River (Mishkosiminiziibiing)
- Biinjitiwaabik Zaaging Anishinaabek
- Bingwi Neyaashi Anishinaabek
- Cat Lake
- Constance Lake
- Couchiching
- Deer Lake
- Eabametoong
- Eagle Lake
- Fort William
- Grassy Narrows
- Iskatewizaagegan No. 39
- Kasabonika Lake
- Keewaywin
- Kiashke Zaaging Anishinaabek
- Kingfisher Lake
- Kitchenuhmaykoosib Inninuwug
- Lac des Mille Lacs
- Lac La Croix

- Lac Seul
- Long Lake No. 58
- Marten Falls
- McDowell Lake
- Michipicoten
- Mishkeegogamang
- Mitaanjigamiing
- Muskrat Dam Lake
- Naicatchewenin
- Namaygoosisagagun
- Naotkamegwanning
- Neskantaga
- Netmizaaggamig Nishnaabeg (Pic Mobert)
- Nibinamik
- Nigigoonsiminikaaning
- Niisaachewan Anishinaabe Nation
- North Caribou Lake
- North Spirit Lake
- Northwest Angle No. 33
- Ojibway Nation of Saugeen
- Ojibways of Onigaming
- Pays Plat
- Pikangikum
- Poplar Hill
- Rainy River
- Red Rock Indian Band
- Sachigo Lake
- Sandy Lake
- Seine River
- Shoal Lake No. 40
- Slate Falls
- Wabaseemoong
- Wabauskang
- Wabigoon Lake
- Wapekeka
- Washagamis Bay (Obashkaandagaang)
- Wawakapewin
- Webequie
- Whitesand
- Wunnumin Lake

The Métis communities that were invited to the webinars were:

- MNO Atikokan Métis Council
- MNO Greenstone Métis Council
- MNO Kenora Métis Council
- MNO Northwest Métis Council (Dryden)
- MNO Sunset Country Métis Council (Fort Frances)
- MNO Superior North Shore Métis Council (Terrace Bay)
- MNO Thunder Bay Métis Council
- Red Sky Independent Métis Nation

9.5.1 Information about Indigenous Participation and Engagement in Transmission Development

By conducting regional planning, the IESO determines the most reliable and cost-effective options after it has engaged with stakeholders and Indigenous communities and publishes recommendations in the applicable regional or bulk planning report. Where the IESO determines that the lead time required to implement the recommended solutions requires immediate action, the IESO may provide those recommendations ahead of the publication of a planning report.

In instances where transmission is the recommended option, a proponent applies for applicable regulatory approvals, including an Environmental Assessment that is overseen by the Ministry of Environment, Conservation and Parks (MECP). This process includes, where applicable, consultation regarding Aboriginal and treaty rights, with any approval including steps to avoid or mitigate impacts to said rights. MECP oversees the consultation process generally but may delegate the procedural aspects of consultation to the proponent. Following development work, the proponent will then apply to the OEB for approval through a Leave to Construct hearing and, only if approval is granted, can it proceed with the project. In consultation with MECP, project proponents are encouraged to engage with Indigenous communities on ways to enable participation in these projects.

There are no new transmission projects recommended as a result of this Northwest planning initiative.

10. Conclusion

The Northwest IRRP identifies electricity needs in the region over the 20-year period from 2021-2040, recommends a plan to address immediate and near-term needs, and lays out actions to monitor long-term needs. The IESO will continue to participate in the Working Group during the next phase of regional planning, the Regional Infrastructure Plan, to provide input and ensure a coordinated approach with bulk system planning where such linkages are identified in the IRRP.

In the near term, the IRRP recommends new and/or upgraded stations to address station capacity needs at Crilly DS and Margach DS, further refinement of non-wires alternatives at Kenora MTS, reconfiguration of Fort Frances TS to improve customer reliability at Fort Frances MTS, and additional reactors at or near Pickle Lake SS to manage high voltages so that E1C can be operated normally open. Responsibility for these actions has been assigned to the appropriate members of the Technical Working Group.

The IRRP recommends that the Working Group monitor growth, particularly in the Red Lake and Fort Frances areas. The IRRP studied high growth sensitivities to establish load meeting capabilities in these areas against which growth should be monitored to determine when future regional planning activities should be triggered. The IESO will update its mining sector demand forecast in early 2023 and provide updates to the Working Group. Electricity demand at White Dog DS and Marathon DS should also be monitored to confirm the timing of station capacity needs emerging in the 2030's. No firm recommendations are required for these potential long-term needs at this time.

The IESO will continue the Supply to the Ring of Fire Study in 2023. The scope and timing will evolve with government policy direction and the IESO will share updates with the Working Group to inform upcoming regional planning activities.

The Working Group will meet at regular intervals to monitor developments and track progress toward plan deliverables. If underlying assumptions change significantly, local plans may be revisited through an amendment, or by initiating a new regional planning cycle sooner than the five-year schedule mandated by the OEB.

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Integrated Regional Resource Plan Appendices

Northwest Region
Jan 2023

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Appendix A – Overview of the Regional Planning Process

In Ontario, meeting the electricity needs of customers at a regional level is achieved through regional planning. This comprehensive process starts with an assessment of the needs of a region—defined by common electricity supply infrastructure—over the near, medium, and long term and results in the development of a plan to ensure cost-effective, reliable electricity supply. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluate options for addressing needs, and recommend actions.

Regional planning has been conducted on an as-needed basis in Ontario for many years. Most recently, planning activities to address regional electricity needs were the responsibility of the former Ontario Power Authority (OPA), now the Independent Electricity System Operator (IESO), which conducted joint regional planning studies with distributors, transmitters, the IESO and other stakeholders in regions where a need for coordinated regional planning had been identified.

In the fall of 2012, the Ontario Energy Board (OEB) convened a Planning Process Working Group (PPWG) to develop a more structured, transparent, and systematic regional planning process. This group was composed of electricity agencies, utilities, and other stakeholders. In May 2013, the PPWG released its report to the OEB (PPWG Report), setting out the new regional planning process. Twenty one electricity planning regions were identified in the PPWG Report, and a phased schedule for completion of regional plans was outlined.[1] The OEB endorsed the PPWG Report and formalized the process timelines through changes to the Transmission System Code and Distribution System Code in August 2013, and to the former OPA's licence in October 2013. The licence changes required the OPA to lead two out of four phases of regional planning. After the merger of the IESO and the OPA on January 1, 2015, the regional planning roles identified in the OPA's licence became the responsibility of the IESO.

[1] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2011-0043/PPWG_Regional_Planning_Report_to_the_Board_App.pdf

The regional planning process begins with a Needs Assessment process performed by the transmitter, which determines whether there are needs that should be considered for regional coordination. If further consideration of the needs is required, the IESO conducts a Scoping Assessment to determine what type of planning should be carried out for a region. A Scoping Assessment explores the need for a comprehensive IRRP, which considers conservation, generation, transmission, and distribution solutions, or whether a more limited "wires" solution is the preferable option, in which case a transmission- and distribution-focused Regional Infrastructure Plan ("RIP") can be undertaken instead. There may also be regions where infrastructure investments do not require regional coordination and can be planned directly by the distributor and transmitter outside of the regional planning process. At the conclusion of the Scoping Assessment, the IESO produces a report that includes the results of the needs assessment process and a preliminary terms of reference. If an IRRP is the identified outcome, the IESO is required to complete the IRRP within 18 months. If a RIP is the identified outcome, the transmitter takes the lead and has six months to complete it. Both RIPs and IRRPs are to be updated at least every five years. The draft Scoping Assessment Outcome Report is posted to the IESO's website for a two-week public comment period prior to finalization.

The final Needs Assessment Reports, Scoping Assessment Outcome Reports, IRRPs and RIPs are posted on the IESO's and the relevant transmitter's web sites, and may be referenced and submitted to the OEB as supporting evidence in rate or "Leave to Construct" applications for specific infrastructure investments. These documents are also useful for municipalities, First Nation communities and Métis community councils for planning, and for conservation and energy management purposes. They are also a useful source of information for individual large customers that may be involved in the region, and for other parties seeking an understanding of local electricity growth, CDM and infrastructure requirements. Regional planning is not the only type of electricity planning undertaken in Ontario. As shown in Figure 1, three levels of electricity system planning are carried out in Ontario:

- Bulk system planning
- Regional system planning
- Distribution system planning

Planning at the bulk system level typically considers the 230 kV and 500 kV network and examines province-wide system issues. In addition to considering major transmission facilities or "wires", bulk system planning assesses the resources needed to adequately supply the province. Distribution planning, which is carried out by local distribution companies ("LDCs"), considers specific investments in an LDC's territory at distribution-level voltages.

Regional planning can overlap with bulk system planning and with the distribution planning of LDCs. For example, overlaps can occur at interface points where there may be regional resource options to address a bulk system issue or when a distribution solution addresses the needs of the broader local area or region. As a result, it is important for regional planning to be coordinated with both bulk and distribution system planning, as it is the link between all levels of planning.

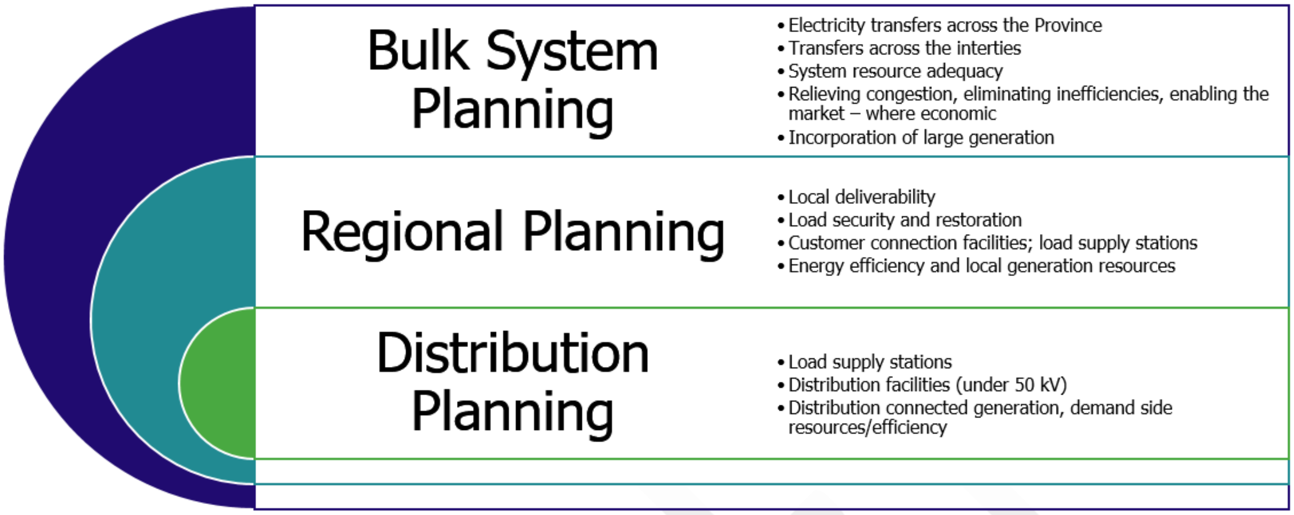


Figure 1 | Levels of Electricity System Planning

By recognizing the linkages with bulk and distribution system planning, and coordinating the multiple needs identified within a region over the long term, the regional planning process provides a comprehensive assessment of a region's electricity needs. Regional planning aligns near- and long-term solutions and puts specific investments and recommendations coming out of the plan into perspective. Furthermore, in avoiding piecemeal planning and asset duplication, regional planning optimizes ratepayer interests, allowing them to be represented along with the interests of LDC ratepayers, and individual large customers. IRRPs evaluate the multiple options that are available to meet the needs, including conservation, generation, and "wires" solutions. Regional plans also provide greater transparency through engagement in the planning process, and by making plans available to the public

Appendix B – Demand Forecast

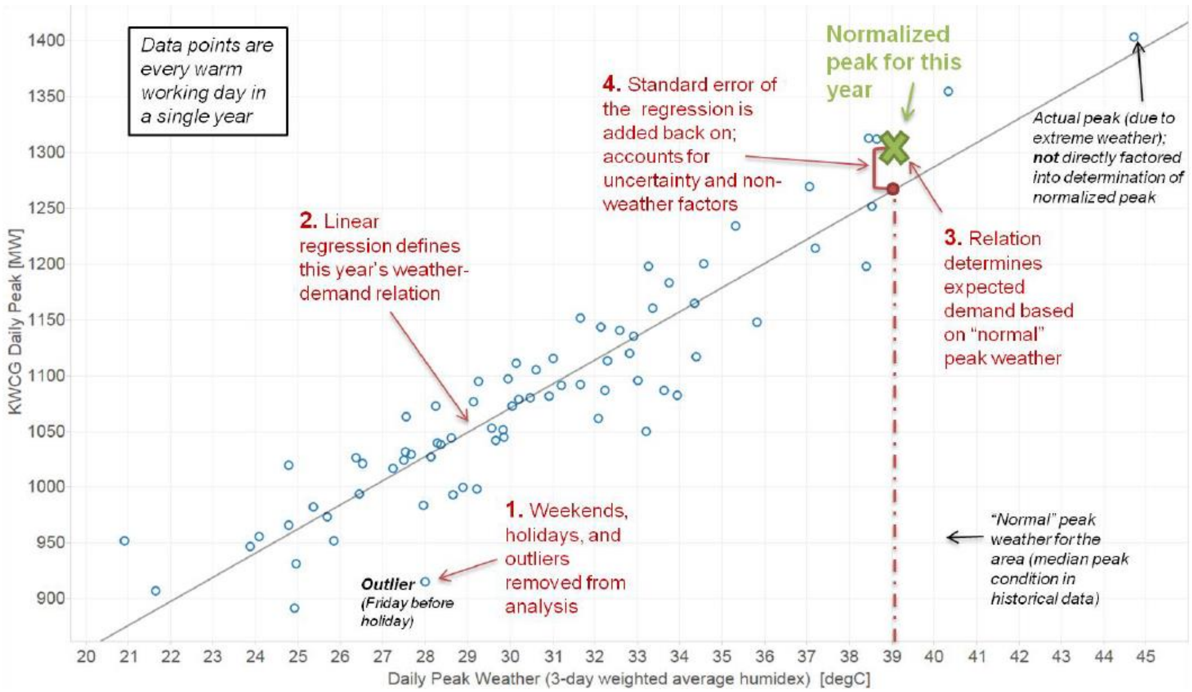
Appendix B describes the methodologies used to develop the demand forecast (peak and duration) for the Northwest IRRP studies. Forward-looking estimates of electricity demand were provided by each of the participating LDCs and informed by the forecast base year and starting point provided by the IESO. The sections that follow describe the weather correction methodology, the approaches and methods used by each LDC to forecast demand in their respective service area, and the conservation and DG assumptions.

B.1 Method for Accounting for Weather Impact on Demand

Weather has a large influence on the demand for electricity, so to develop a standardized starting point for the forecast, the historic electricity demand information is weather-normalized. This section details the weather-normalization process used to establish the starting point for regional demand forecasts.

First, the historical loads were adjusted to reflect the median peak weather conditions for each transformer station in the area for the forecast base year (i.e. 2020 for the Northwest IRRP). Median peak refers to what peak demand would be expected if the most likely, or 50th percentile, weather conditions were observed. This means that in any given year there is an estimated 50% chance of exceeding this peak, and a 50% chance of not meeting this peak. The methodological steps are described in Figure 2.

Figure 2 | Method for Determining the Weather Normalized Peak (Illustrative)



The 2018 median weather peak on a station and LDC load basis was provided to each LDC. This data was used as a start point from which to develop 20-year demand forecasts, using the LDCs preferred methodology (described in the next sections).

Once the 20-year horizon, median peak demand forecasts were returned to the IESO, the normal weather forecast was adjusted to reflect the impact of extreme weather conditions on electricity demand. The studies used to assess the adequacy and reliability of the electric power system generally require studies to be based on extreme weather demand, or, expected demand under the hottest weather conditions that can be reasonably expected to occur. Peaks that occur during extreme weather (e.g. summer heat waves in southern Ontario) are generally when the electricity system infrastructure is most stressed.

B.2 Hydro One Forecast Methodology

Hydro One's demand forecast includes all areas in the Northwest region that are not reflect in the other distributors' service territories. The area served by Hydro One are mostly rural areas in the region. It is expected that the growth would occur mostly close to urban / built-up areas. Hydro One's forecast also includes demand from Sioux Lookout Hydro (embedded distributor).

Hydro One's conducts econometric and end-use forecasting. The main forecast drivers are Ontario GDP and housing starts. Load growth in the area relative to provincial trends was also taken into account. The following demand growth rate were assumed:

Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Growth Rate (%)	4.5	4.2	2.2	2.0	2.1	2.0	1.9	1.8	1.8	1.8

Year	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Growth Rate (%)	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8

New developments where assumed to have an average demand of 4.5 kW per residential unit with non-electric heat source 14.5 kW per residential unit with electric heat source. Residential demand growth was estimated based on Ontario housing starts (in thousands) shown below:

Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Housing Starts	75.2	76.5	77.0	76.9	75.3	69.9	69.6	69.2	68.6	68.6
Year	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Housing Starts	68.6	68.5	68.4	68.4	68.3	68.2	68.2	68.1	68.0	68.0

Provincial/regional development plans and known private/First Nations developments were taken into account.

B.4 Fort Frances Power Forecast Methodology

Fort Frances Power Corporation ("Fort Frances Power") provides service to all consumers residing within the town of Fort Frances. Fort Frances is located approximately 300 km west of Thunder Bay, Ontario, approximately 250 km east of the Manitoba Border and is adjacent to the Town of International Falls, Minnesota, USA. The town is located on the edge of the Canadian Shield and is subjected to extreme weather conditions including cold winters and hot summers. The town is currently the third largest community of northwestern Ontario, after Thunder Bay and Kenora.

Fort Frances Power distributes electricity to approximately 3746 customers, over 32 square-kilometers, of which 88% are residential and 12% commercial. The community receives its supply of electricity from a Hydro One Networks Inc. owned transmission line. The transmission line supplies Fort Frances Power's transformer station Fort Frances MTS with a single 115 kV point of supply. The Fort Frances MTS transformer station steps down the incoming transmission supply to a distribution voltage of 12.47 kV, which is the primary distribution voltage of the entire distribution network within Fort Frances.

The Fort Frances MTS transformer station is the heart of the electrical distribution system for Fort Frances and will require considerable reinvestment over the next 10 to 15 years. The station was built in the early 1970s with some components being manufactured in the 1960s. The station and is projected to reach the end of its useful service life by 2034. Fort Frances Power is currently in the early stages of planning a complete transformer station rebuild over the next 10 – 15 years. The planned rebuild will also address potential load growth as well as customer reliability concerns associated the station being supplied from a single point of supply. Fort Frances Power is working with Hydro One Networks Inc. to bring a second point of supply to the station which would essentially eliminate Loss of Supply type outages that account for more than 90% of all customer interruption hours.

Factors that Affect Electricity Demand

Over the next 20 years changes to electricity demand for Fort Frances are expected to be dependent on several factors including weather/climate conditions, the economic prosperity of the community, and government policy. 2022 year-to-date metering data indicates increases of 4.8% in electricity consumption and 3.1% in electricity demand, relative to 2021.

Fort Frances has a relatively extreme humid continental climate with bitterly cold winters and temperate summers. Temperatures beyond 34 degrees Celsius have been measured in all five late spring and summer months. Summer highs are comparable to Paris and the Los Angeles Basin coastline in California, whereas winter lows on average resemble southern Siberia and polar subarctic inland Scandinavia. As such Fort Frances is a winter peaking region with more electricity being consumed for the purpose of heating as opposed to cooling. A significant number of customers still use electric heat as their primary heat source due to natural gas only becoming available in the 1990s. Prolonged periods of hot or cold weather have a considerable impact on local electricity demand. Fort Frances Power anticipates that electric heat related demand will remain relatively stable with modest growth due to the increasing affordability of electricity in Fort Frances versus natural gas. The community currently enjoys among the lowest rates for electricity in all of Ontario, which makes electric heat more attractive than in other parts of the Province. Government policy such as carbon taxation and the new ultra-low overnight electricity rate are expected to drive consumer fuel switching from natural gas to electricity. Consumers switching appliances such as furnaces and hot water tanks from natural gas over to electricity is expected to result in modest increases to electricity demand.

The economic prosperity of Fort Frances is anticipated to have the most impactful affect on electricity demand for the community. The community suffered a temporary downturn in 2014 due to the permanent closure of the local pulp and paper mill, resulting in the loss of over 800 direct jobs. The impact from the closure was partially mitigated by the start-up of the New Gold Rainy River Mine just west of Fort Frances in 2017. Considerable effort is being exerted towards sparking new economic development in Fort Frances, and towards the rebuilding a commercial and industrial employment base. The town has received proposals from a variety of investors regarding economic development initiatives, however, they are not included in the forecast as no firm commitments have been received to date.

The electrification of transportation is also anticipated to have a significant affect on increasing the demand for electricity in Fort Frances. Again, government policy such as electric vehicle rebates could have a significant impact on the adoption rate of electric vehicles, however, it is difficult to quantify the overall impact at this time.

Forecast Methodology and Assumptions

Historical peak demands from the years 2016 to 2020 were used to calculate Fort Frances Power's 2021 base (starting point) Peak Demand of 15.2 MW at its transformer station Fort Frances MTS. The 2021 starting point was found by calculating the slope and intercept of the historical peaks and calculating the "projected" 2020 value. The following factors were taken into consideration for the establishment of the 0.5% year-over-year projected increase in demand.

- Embedded Generation: 0% - Peak demands are usually set throughout the extremely cold winter nights, at times where no Photo Voltaic Embedded Generation is being produced.
- Annual Growth Factor: 0.5% - Conservative growth factor, taking into account electric vehicle adoption, natural gas to electricity fuel switching, and increasing customer base.
- Large Commercial/Industrial Developments: 0% - Could have the potential for significant demand increase, however, set to 0% as no firm commitments have been made to date.

B.5 Atikokan Hydro Forecast Methodology

Atikokan Hydro Inc. ("Atikokan Hydro") provides service to the Township of Atikokan.

Atikokan Hydro distributes electricity to approximately 1630 customers, over 320 square kilometers, of which 85% are residential and 15% are commercial. Commercial customers make up over 50% of Atikokan's base load.

Electricity is transmitted from Hydro One Network's Moose Lake TS to Atikokan Hydro's substations via Atikokan Hydro's two 44 KV circuits; comprised of the 3M2 and 3M3. Atikokan Hydro has three substations in the most densely populated customer area that distributes the electricity at 8320/4800 volts. Atikokan Hydro's distribution system then delivers electricity at the appropriate voltage to residential and commercial customers. Atikokan Hydro territory has both rural and urban; totaling 92 km of line that serves the Town of Atikokan.

Factors that Affect Electricity Demand

Atikokan Hydro is a winter peaking utility with a pelletizing plant representing a significant portion of base load demand. There are no new local developments projected to significantly drive electricity requirements. Potential for slight increase as a result of local expansions and development of potential new construction but no certainty or known details of impacts to load at this time.

There is no forecast load reduction, but if Atikokan's pelletizing plant were to shut down, the forecast could change significantly as a significant portion of the electricity demand is associated with the plant. Of recent, no reduction to electrical demand other than CDM savings and a decline in customer accounts due to abandoned buildings and an aging population.

All demographic and economic conditions have been assumed to remain status quo. Trends in population have been declining. Statistics Canada Census profile indicates Atikokan with a population of 3,293 in 2006 and a population of 2,642 in 2021. This represents nearly a 20% decline in overall population in the community. Any growth potentials break even with a reduction in customers.

Forecast Methodology and Assumptions

Atikokan Hydro's forecast was developed by examining historical actual system peak load data for each year and applying local knowledge of any known economic developments. Historically new development has not driven the local electricity demand.

The peak demand historically has been impacted by the forestry industry in Ontario. The main factors affecting forecast and loads has been the closure of sawmills and a particle board plant, and re-opening of an existing plant. The geographical location and resources of our community limits the growth opportunities. The industry can be volatile and significantly impact with abrupt changes.

For forecast purposes, stability and current load was assumed.

2022 is forecasted to increase to 5.88 mw which is the four-year historical average of 2016 through 2019 (2020 was excluded due to the anomaly of COVID-19). This assumes COVID impacts have flattened, and electrical consumption and demands are closer if not back to normal levels and Atikokan has some new load from new build construction underway (multi-residential building and renovation and expansion of a school). New load is not believed to significantly change the overall Atikokan load based on the knowledge the LDC has. 2023 is forecasted to have a 1% influx from the year prior for potentials of other construction underway assuming the remainder of buildings, facilities and commercial establishments maintain status quo. 2025 assumed to reach 6 mw and assumed to plateau at 6 mw with no evidence of other significant load impacts. 6 mw is achievable based on historical loads and knowledge of local economic developments. It can additionally be accommodated under the current transformer ratings.

B.6 Synergy North Forecast Methodology

1. Background Information

1.1. Historic Peak information

Load transfers are a regular occurrence in the operation of the system in Thunder Bay. Load is frequently moved from one station to another for routine maintenance or during abnormal conditions. Although some of the peaks coincide with load transfers, it can be expected that load transfers will occur in any given year. Kenora MTS is a radial feeder and does not have capabilities to perform any load transfers.

1.1.1. Birch TS

2016 through 2019 peaks for Birch TS all occurred under normal operating conditions. The 2020 peak occurred during a temporary load transfer of a section feeder 2M4 (normally PATS) fed by 17M2 from Birch TS for scheduled maintenance by Hydro One at PATS.

1.1.2. Fort William TS

2016 through 2018 and 2020 peaks for FWTS all occurred under normal operating conditions. The 2019 peak occurred during scheduled maintenance on Birch TS T3. FWTS feeder 10M3 was used to pick-up a section of 17M1 normally fed by Birch TS.

1.1.3. Port Arthur TS

The 2016 peak occurred during a load transfer of 17M5 (normally BRTS) to 2M3 on PATS due to an issue at an LDC DS. The 2017 peak occurred during a load transfer of 17M5 (normally BRTS) to 2M2 on PATS due to maintenance at BRTS. The 2018 peak occurred during normal operating conditions. The 2019 peak during a load transfer of 17M2 (normally BRTS) to 2M4 on PATS due to T3 maintenance at BRTS. The 2020 peak occurred during a load transfer of 17M5 (normally BRTS) to 2M5 on PATS due to a protection update for the feeder at Birch.

1.1.4. Kenora MTS

All the peaks for the station occurred during normal operating conditions. Kenora MTS does not have capability to transfer load as it is on a radial feed.

1.2. Electrical Load in Study Area

100% Synergy North's load is within the study area for the Integrated Regional Resource Plan for the Northwest Region.

1.3. Market and Rate Segmentation of Load

Station	Residential Customers	Commercial Customers	Industrial Customers	Total Customers
Birch TS	14,617	2,078	5	16,700
Fort William TS	22,300	2,103	7	24,410
Port Arthur TS	8,879	735	3	9,617

Note: Rate segmentation only available by customer counts and not MW. No data available for Kenora MTS.

2. Methodology

- Hourly net load and generation data was gathered from 2010 to 2020.
    - Aggregate micro and small generation data were split among stations based on percentage of allocated capacity at the station in relation the total.
- CDM program data and generation were added to the net load data to determine gross peaks.
    - CDM program benefits were carried from year to year with a considered depreciation value of 5% per year.
    - No new CDM was added for the forecast period, although depreciated existing CDM was included in gross totals.
- Monthly peaks were plotted against the average monthly temperature to generate a 3rd order polynomial line of best fit for weather dependence at each station.

  - The gross data was normalized for weather by subtracting the weather dependence per the 3rd order polynomial.
  - Multi-linear regression was performed on the weather normalized monthly gross load data using economic factors selected based on R2 correlation values to provide a model based on predicted factors. These factors include grain prices index, Thunder Bay unemployment rate, metal prices index, Thunder Bay CPI and Canada unemployment rate.
- Weather was added back into the forecast using the 3rd order polynomials per station and the assumed average monthly temperatures over the past 10 years to create the monthly forecast models.
- Modest growth factors were then added to forecast model to account for future development.
  - 0.5% for Birch TS
  - 0.5% for Fort William TS
  - 0.5% for Port Arthur TS
  - 1.25% for Kenora MTS (higher for Kenora as more interest in development)
- The annual gross peak was then determined from the final model.
- Note that the numbers provided were based on gross load (including DG and CDM) and the actual station peak demand provided did not include most DG or CDM.

3. Drivers of Load Growth

The municipal growth plan for Thunder Bay was high level and did not go into enough specifics to speculate on future load. No specific large load projects have been applied for in Synergy North’s service territory at this time and therefore no specific project is included in the forecast. We have had interest from potential customers about future projects (including a possible 4MW project in Kenora), but no formal agreements have been signed. We have decided to roll these projects into the modest growth factors applied.

4. Behind the Meter Generation

No new behind the meter generation projects are currently in progress. Therefore, none have been included in the forecast. There has been some interest from proponents, but no connection impact assessments are currently underway. We have experienced a significant drop in all embedded generation applications including micro sized projects with the end of the FIT program. Two existing CHP load displacement generation projects connected to BRTS at 2.0MW and 1.984MW (3.984MW total) have been added to the effective winter capacity sheet.

5. EV Adoption

Synergy North used the 2020 Annual Planning Outlook (APO) as a base to predict the average hourly MW increase for the province, then applied that value to Thunder Bay and Kenora based on population as a portion of the provincial population. As the loads for EV's were expected to occur during non-peak times mainly, the average hourly increase was determined to be appropriate and was added to the original peak load forecast to come up with the attached high electrification forecast.

B.7 Projects Included in IRRP Mining Sector Forecast

The lists below reflect known projects as of Q4 2021.

Existing Active Mines in the Northwest Region

Mine Name	Owner	Location	Peak Demand	End date	Information Source
Helmo Property Mines	Barrick Gold Cop	Marathon	Known	2029	MDNM, Generation Mining Data Online,
Musselwhite Mine	Newmont Goldcorp	Pickle Lake	Known	2030	Generation Mining Data Online
Rainy River Mine	New Gold	Fort Frances Nestor Falls	Known		
Red Lake Complex	Evolution Mining	Red Lake	Known	2033	Generation Mining Data Online, Company Web site
Lac Des Iles Palladium Mine	Impala Canada Limited	Thunderbay	Known	2030	Generation Mining Data Online
PureGold (Madsen) Gold Mine	Pure Gold Mining	Red Lake	Known	2031	Generation Mining Data Online
Sugar Zone Mine	Harte Gold	Marathon	Known	2033	Generation Mining Data Online, Company Web site

Future Mines and/or Mining Exploration in the Northwest Region

Project Name	Owner	Location	Peak Demand	i/s	o/s	Information Source
Greenstone Gold Mines Project	Orion Mine/Premier Gold Mines	Greenstone	Known	2021	2036	CVNW, OMED

Battle North (Bateman) Gold Project	Evolution Mining	Red Lake	Known	2021	2030	CVNW, OMED, Hydro One
Marathon PGM-CU Project	Generation Mining	Marathon	Known	2024	2040+	CVNW, OMED, Hydro One
Hammond Reef Gold Project	Agnico - Eagle	Atikokan	Known	2025	2036	CVNW, Hydro One
Springpole Gold Project	First Mining Finance	Cat Lake	Known	2025	2035	CVNW, OMED, Hydro One
Eagle's Nest	Noront	Ring of Fire	Known	2025	2035	CVNW, OMED
Black Bird	Noront	Ring of Fire	Known	2028	2037	CVNW
Goliath Gold Project	Treasure Metals	Dryden	Known	2024	2033	CVNW, OMED
PAK Lithium Project	Frontier Lithium	Red Lake	Known	2025	2040+	CVNW, OMED, Hydro One
Moss Lake Project	Wesdome Gold	Thunderbay	Known	2025	2034	CVNW
AMI Project	Ambershaw Metallics	Ignace	Known	2025	2040+	CVNW
Separation Rapids Project	Avalon Advanced Metals	Kenora	Known	2025	2040+	CVNW, OMED
Georgia Lake Project	Rock Tech Lithium	Thunderbay	Known	2026	2040+	CVNW
Cameron Gold Project	First Mining Finance	Nestor Falls	Known	2026	2040+	CVNW, OMED
Winston LK Project	CROPS	Marathon	Known	2026	2040+	CVNW, OMED, Hydro One
Thunder Bay North PGM Project	Clean Air Metals	Thunder Bay North	Known	2029	2040+	CVNW, OMED, Hydro One
Theirry Project	Cadillac Ventures	Pickle Lake	Known	?	?	OMED
Albany Project	Zen Graphene	Hearst	Known	?	?	CVNW, OMED
Eagle Island/St Joseph Project	Rockex Mining Corp	NoD	Known	?	?	CVNW
Griffith	Lithium Energy Products	NoD	Known	?	?	CVNW
Sturgeon Lake Project	Glencore/Odin/FQML	Ignace	?	?	?	Company's website
Dixie Project	Great Bear Resources	Red Lake	?	?	?	CVNW
Mt. Jamie North Gold Project	Stone Gold	Red Lake	?	?	?	Company's website

Sunday Lake Project	Transition Metals	Thunder Bay	?	?	?	CVNW
Rowan Mine Project	West Red Lake Gold	Red Lake	?	?	?	Company's website
Horseshoe Island Project	First mining Gold	Red Lake	?	?	?	Company's website
Kyle Lake (U2 Kimberlite) Project	Metalex Ventures	?	?	?	?	OMED

B.8 IRRP Mining Demand Forecast Scenarios

The IRRP mining sector demand forecast scenarios can be found in the accompanying Excel spreadsheet Table B.8.

B.9 Conservation and Demand Management Assumptions

Energy efficiency measures can reduce the electricity demand and their impact can be separated into the two main categories: Building Codes & Equipment Standards, and Energy Efficiency Programs. The assumptions used for the Northwest IRRP forecast are consistent with the energy efficiency assumptions in the IESO's 2020 Annual Planning Outlook including the 2021 – 2024 CDM Framework. The savings for each category were estimated according to the forecast residential, commercial, and industrial gross demand. A top down approach was used to estimate peak demand savings from the provincial level to the Northwest IESO transmission zone and then allocated to the Northwest region. This appendix describes the process and methodology used to estimate energy efficiency savings for the Northwest region and provides more detail on how the savings for the two categories were developed.

B.9.1. Estimated Savings from Building Codes and Equipment Standards

Ontario building codes and equipment standards set minimum efficiency levels through regulations and are projected to improve and further contribute to demand reduction in the future. To estimate the impact on the region, the associated peak demand savings for codes and standards by sector were estimated for the Northwest zone and compared with the gross peak demand forecast for each zone. From this comparison, annual peak reduction percentages were developed for the purpose of allocating the associated savings to each station in the region, as further described below.

Consistent with the gross demand forecast, 2020 was used as the base year. New peak demand savings from codes and standards were estimated from 2021 to 2040. The residential annual peak reduction percentages for each year were applied to the forecast residential peak demand at each station to develop an estimate of peak demand impacts from codes and standards. By 2040, the residential sector in the region is expected to see about 6.6% peak demand savings through codes and standards. The same is done for the commercial sector, which will see about 0.8% peak-demand savings through codes and standards by 2040. The sum of the savings associated with the two sectors are the total peak demand impact from codes and standards. It is assumed that there are no savings from codes and standards associated with the industrial sector.

B.9.2. Estimated Savings from Energy Efficiency Programs

In addition to codes and standards, the delivery of CDM programs reduces electricity demand. The impact of existing and planned CDM programs were analyzed, which include the 2021 – 2024 CDM Framework, the existing federal programs, and the forecasted long term energy efficiency programs. A top down approach was used to estimate the peak demand reduction due to the delivery of these programs, from the province, to the Northwest zone, and finally to the stations in the region. Persistence of the peak demand savings from energy efficiency programs were considered over the forecast period.

Similar to the estimation of peak demand savings from codes and standards, annual peak demand reduction percentages from program savings were developed by sector. The sectoral percentages were derived by comparing the forecasted peak demand savings with the corresponding gross forecasts in Northwest zone. They were then applied to the sectoral gross peak forecast of each station in the region. By 2030, the residential sector in the region is expected to see about 0.2% peak demand savings through programs, while commercial sector and industrial sector will see about 1.6% and 1.9% peak reduction respectively.

B.9.3. Total Energy Efficiency Savings and Impact on the Planning Forecast

As described in the above sections, peak demand savings were estimated for each sector, and totalled for each station in the region. The analyses were conducted under normal weather conditions and can be adjusted to reflect extreme weather conditions. The resulting forecast savings were applied to gross demand to determine net peak demand for further planning analyses.

The IRRP CDM forecast for each station can be found in the accompanying Excel spreadsheet Table B.9.3.

B.10 Installed Distributed Generation and Contribution Factor Assumptions

The distributed generation contribution factor assumptions station can be found in the accompanying Excel spreadsheet Table B.10.1. The distributed generation output assumptions for each station can be found in Table B.10.2.

B.11 Final Peak Forecast by Station

The final peak station-level demand forecast can be found in the accompanying Excel spreadsheet Table B.11.

Appendix C – Northwest IRRP Technical Study

C.1 Description of Study Area

The Northwest region bounded by Marathon TS to the east and the Minnesota and Manitoba interties to the west. The 230 kV system is comprised of the following lines and stations: WxM lines from Wawa TS to Marathon TS, the MxL lines from Marathon TS to Lakehead TS, the AxL lines from Lakehead TS to Mackenzie TS, and Mackenzie TS-Dryden TS-Kenora TS-Fort Frances TS loop formed by the D26A/K23D/K24F/F25A lines. A new 230 kV circuit, W54W, was recently added between Dinorwic Junction (near Dryden TS on D26A) and Wataynikaneyap TS near Pickle Lake. Interconnections to Minnesota and Manitoba are provided via F3M from Fort Frances TS and K21W/K22W from Kenora TS, respectively. The Northwest region also includes 230/115 kV autotransformers each of the 230 kV stations listed above and the respective 115 kV subsystems supplied from these autotransformers. A single line diagram of this region is shown in **Error! Reference source not found.** below.

C.2.1 Load Forecast

The initial need identification study used net winter extreme weather forecast snapshots in 2023, 2027, 2032, and 2040 (end of planning horizon). The station level forecast is provided in Appendix B.7 and B.11 above. The 2027 snapshot has the highest overall regional peak load because the mining sector forecast peaks in 2027 and declines thereafter.

A power factor of 0.90 was assumed unless there was specific information indicating that a higher power factor assumption was appropriate. An 0.95 power factor was assumed for Crilly DS loads (consistent with historical and expected future load characteristics) for the purpose of determining the station capacity need date. An 0.9 power factor was assumed for all other stations.

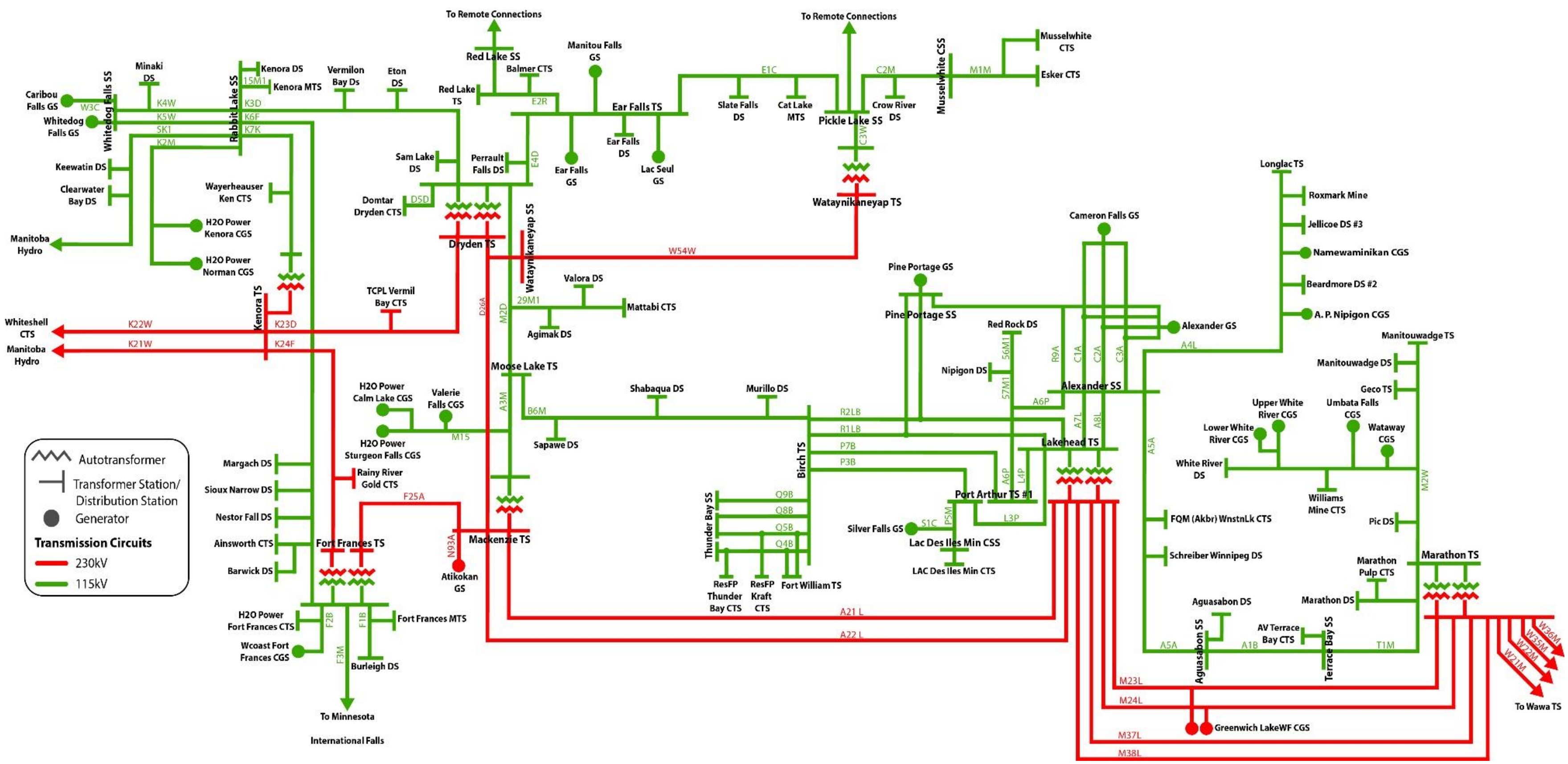


Figure 3 | Single Line Diagram of the Northwest Region

C.2.2 Local Generation Assumptions

Dependable 98th percentile and 85th percentile hydro generation output is tabulated in Table 1. All-in-service base cases used 98th percentile dependable hydro (consistent with ORTAC criteria) while outage condition base cases used 85th percentile hydro (consistent with historical best practices). Note that numbers in Table 1 are non-coincident (i.e. each facility at their individual 98th/85th percentile output). Coincident dependable hydro for any given subsystem (i.e. several facilities' combined 98th/85th percentile output) will usually be higher than the sum of the non-coincident output at each facility within the subsystem.

Table 1 | Dependable Hydro Assumptions (Non-Concident) in the Northwest Region

Hydro Facility	Winter 98th (MW)	Winter 85th (MW)	Summer 98th (MW)	Summer 85th (MW)
ABKENORA	8.6	9.5	0.4	4.7
AGUASABON	11.0	29.7	0.0	11.3
ALEXANDER	39.0	41.6	24.6	26.7
CALMLAKE	6.9	8.1	3.3	5.9
CAMERONFALLS	47.0	53.1	27.4	32.8
CARIBOUFALLS	43.4	66.6	7.8	29.0
EARFALLS	16.9	21.5	4.9	10.9
FORTFRANCS	3.3	4.7	4.0	4.1
KAKABEKA	9.0	14.6	1.7	5.4
LOWERWHITE	3.5	4.4	2.2	2.5
MANITOUFALLS	43.0	50.7	7.3	22.9
MANITOUWATS	0.2	0.5	0.0	0.1
NAMEWAM	2.3	2.7	0.0	0.4
PINEPORTAGE	45.6	74.3	14.5	39.5
SILVERFALLS	30.6	32.9	0.0	0.0
STURGEONFALL	4.9	6.6	2.2	4.3
UMBATAFALLS	5.0	8.6	1.8	4.2
UPPERWHITE	3.1	3.1	1.9	3.4
VALRIEFALLS	2.9	4.5	0.4	1.6
WAWATAY	1.2	2.5	0.2	1.1
WHITEDOG	22.5	38.6	6.3	27.6
Total Non-Coincident	348.3	478.8	111.1	238.3
Total Coincident	481.3	512.0	268.8	317.4

Table 2 below shows the non-hydro transmission-connected generation. Atikokan GS and Nipigon GS were assumed to be out-of-service since their current contract term date ends in the near term. Greenwich Lake Wind Farm was also assumed to be out-of-service for simplicity but this generator does not materially impact the IRRP study since it is connected along the MxL East-West Tie (EWT) lines. While Greenwich Lake Wind Farm does impact the overall flow along the EWT, the EWT transfer capability was not in scope for the IRRP and the wind farm does not impact any of the local subsystems' load meeting capability.

Table 2 | Non-Hydro Transmission-Connected Generation in the Northwest Region

Facility Name	Contract Capacity	Term Start Date	Term End Date
Atikokan GS	205 MW	2014	2024
Nipigon GS	16 MW	2018	2022
Greenwich Lake Wind Farm	99 MW	2011	2031

Note that the tables above do not include distribution-connected generation nor generation at transmission-connect customer stations. Distribution-connected generation are accounted for directly in the demand forecast. There is no contractual mechanism to rely on generation at transmission-connected customer stations for capacity during peak demand conditions.

---- End of Section ---

C.3 System Topology

C.3.1 Monitored Circuits and Stations

Table 3 lists the monitored transformers station in the Northwest Region.

Table 3 | Monitored Stations in the Northwest Region

Station Names	
Agimak DS	Margach DS
Ainsworth CTS (Voyageur CTS)	Minaki DS
Balmer CTS	Moose Lake TS
Barwick TS	Murillo DS
Beardmore DS #2	Musselwhite CTS
Birch TS	Musselwhite CTS
Bowater Thunder Bay CTS	Nestor Falls DS
Burleigh DS	Nipigon DS
Cat Lake MTS	Perrault Falls DS
Clearwater Bay DS	Pic DS
Crow River DS	Port Arthur TS #1
Dryden TS	Rainy River CTS (Rainy River Gold CTS)
Ear Falls TS	Red Lake TS
Esker CTS	Red Rock DS
Eton DS	Sam Lake DS
Fort Frances MTS	Sapawe DS
Fort Frances TS	Schreiber Winnipeg DS
Fort William TS	Shabaqua DS
Geco Mines Xstrata CTS	Sioux Narrows DS
Jellicoe DS #3	Slate Falls DS
Keewatin DS	TCPL Vermillion Bay CTS
Kenora MTS	Teck Corona CTS (Williams Mine CTS)
Kenora TS	Terrace Bay CTS
Lac des Iles Mine CTS	Valora DS
Lakehead TS	Vermilion Bay DS
Longlac TS	Wataynikaneyap TS
Mackenzie TS	Wayerheauser Dryden CTS
Manitouwadge DS #1	Wayerheauser Ken CTS
Manitouwadge TS	White River DS
Marathon DS	Winston Lake CTS
Marathon TS	Xstrata Mattibi Mine CTS

Table 4 lists the monitored circuits in the Northwest Region. Note that the summer ratings have in Table 4 have not been updated to reflect the latest 35 degree ratings which were introduced during the IRRP. Since the IRRP technical studies were already underway, the initiate needs identification studies were not repeated with the new ratings but, where thermal constraints were identified, the new 35 degree ratings were used to determine the load meeting capability.

Table 4 | Monitored Circuits and Ratings

Circuit	Section	From	To	Winter Ratings (A)			Summer Ratings (A)		
				Cont	LTE	STE	Cont	LTE	STE
A1B	1	Aguasabon SS	AV Terrace Bay JCT	680	680	680	570	570	570
A1B	2	AV Terrace Bay JCT	Terrace Bay SS	720	870	1020	620	790	960
A1B	3	AV Terrace Bay JCT	AV Terrace Bay CTS	720	870	1020	620	790	960
A21L	1	Mackenzie TS	Lakehead TS	1020	1020	1020	880	880	880
A21L	1	Mackenzie TS	Lakehead TS	1020	1020	1020	880	880	880
A22L	1	Mackenzie TS	Lakehead TS	1020	1020	1020	880	880	880
A22L	1	Mackenzie TS	Lakehead TS	1020	1020	1020	880	880	880
A23P	1	Algoma TS	Mississagi TS	1020	1230	1510	880	1120	1430
A24P	1	Algoma TS	Mississagi TS	1020	1230	1510	880	1120	1430
A4L	1	Alexander SS	A4L STR 217 JCT	390	390	390	310	310	310
A4L	2	Beardmore JCT	Namewaminikan JCT	330	330	330	260	260	260
A4L	6	Jellicoe DS #3 JCT	Longlac TS	330	330	330	260	260	260
A4L	7	Beardmore JCT	Beardmore DS #2	430	510	570	370	470	530
A4L	10	A.P. Nipigon JCT	Beardmore JCT	390	390	390	310	310	310
A4L	11	A.P. Nipigon JCT	A.P. Nipigon CGS	580	600	610	500	530	530
A4L	12	Jellicoe DS #3 JCT	Jellicoe DS #3	330	330	330	260	260	260
A4L	13	Namewaminikan JCT	Jellicoe DS #3 JCT	330	330	330	260	260	260
A4L	14	Namewaminikan JCT	Namewaminikan CGS	580	690	710	500	630	660
A4L	15	A4L STR 217 JCT	A.P. Nipigon JCT	390	390	390	310	310	310
A5A	1	Alexander SS	Minnova JCT	580	580	580	430	430	430
A5A	1	Alexander SS	Minnova JCT	580	580	580	430	430	430
A5A	2	Minnova JCT	Schreiber JCT	580	580	580	430	430	430
A5A	3	Schreiber JCT	Aguasabon SS	580	580	580	430	430	430
A5A	4	Schreiber JCT	Schreiber Winnipg DS	330	330	330	260	260	260
A5A	6	Minnova JCT	Minnova JCT	430	430	430	340	340	340
A6P	1	Alexander SS	Reserve JCT	640	680	680	520	520	520
A6P	2	Reserve JCT	Port Arthur TS #1	630	630	630	540	540	540
A7L	1	Alexander SS	Reserve JCT	430	430	440	340	340	340
A7L	2	Reserve JCT	Lakehead TS	430	430	430	340	340	340
A8L	1	Alexander SS	Lakehead TS	540	540	540	420	420	420
B15	1	Thunder Bay SS	Abitibi JCT	1300	1580	1780	1110	1440	1660
B15	2	Abitibi JCT	James Street JCT	1000	1090	1140	850	970	1030
B15	3	James Street JCT	St.Paul JCT	1000	1090	1140	850	970	1030

Circuit	Section	From	To	Winter Ratings (A)			Summer Ratings (A)		
				Cont	LTE	STE	Cont	LTE	STE
B15	4	St.Paul JCT	Walsh Street JCT	1000	1200	1490	850	1100	1410
B15	5	Walsh Street JCT	Birch TS	1000	1200	1490	850	1100	1410
B15	6	James Street JCT	ResFP Thundr Bay CTS	1000	1200	1430	850	1100	1350
B15	7	St.Paul JCT	ResFP Kraft CTS	720	870	940	620	790	870
B15	8	Walsh Street JCT	Fort William TS	1000	1090	1140	850	960	1020
B3E	1	Blind River TS	Elliot Lake JCT	580	700	720	500	640	670
B3E	2	Elliot Lake JCT	Elliot Lake TS	580	700	720	500	640	670
B5	1	Thunder Bay SS	Abitibi JCT	1300	1580	1780	1110	1440	1660
B5	2	Abitibi JCT	James Street JCT	1000	1200	1490	850	1100	1410
B5	3	James Street JCT	St.Paul JCT	1000	1200	1490	850	1100	1410
B5	4	St.Paul JCT	Walsh Street JCT	1000	1200	1490	850	1100	1410
B5	5	Walsh Street JCT	Birch TS	1000	1200	1490	850	1100	1410
B5	6	Abitibi JCT	Erco JCT	720	870	950	620	790	880
B5	7	Erco JCT	Q5B STR A6 JCT	720	870	950	620	790	880
B5	8	James Street JCT	ResFP Thundr Bay CTS	1000	1200	1490	850	1100	1410
B5	9	St.Paul JCT	ResFP Kraft CTS	720	810	840	620	720	760
B5	10	Walsh Street JCT	Fort William TS	1000	1000	1000	850	850	850
B6M	1	Birch TS	Murillo JCT	590	590	590	440	440	450
B6M	2	Stanley JCT	Shabaqua JCT	580	580	580	430	430	430
B6M	3	Shabaqua JCT	Shebandowan JCT	610	610	610	470	470	470
B6M	4	Shebandowan JCT	Kashabowie JCT	600	600	600	460	460	460
B6M	5	Kashabowie JCT	Sapawe JCT	580	580	580	430	430	430
B6M	6	Caland Ore JCT	Moose Lake TS	720	820	850	620	740	770
B6M	7	Shabaqua JCT	Shabaqua DS	430	510	570	370	470	530
B6M	12	Murillo JCT	Stanley JCT	580	580	580	430	430	430
B6M	15	Sapawe JCT	Caland Ore JCT	720	820	850	620	740	770
B6M	16	Sapawe JCT	Sapawe DS	580	690	790	500	630	740
B6M	17	Murillo JCT	Murillo DS	330	330	330	260	260	260
B9	1	Thunder Bay SS	Birch TS	1270	1530	1730	1090	1390	1600
C1A	1	Cameron Falls GS	Alexander SS	720	870	920	620	790	840
C1A	2	Alexander SS	Alexander GS	720	870	920	620	790	840
C1A	3	Alexander SS	Alexander SS	540	540	540	420	420	420
C2M	1	Pickle Lake SS	C2M T#NB1 JCT	480	480	480	380	380	380
C2M	2	C2M T#NB1 JCT	Placer JCT	430	430	430	340	340	340
C2M	3	Placer JCT	Placer JCT	280	280	280	230	230	230
C2M	4	Placer JCT	Crow River DS	280	280	280	230	230	230
C2M	5	C2M T#NB1 JCT	Musselwhite CSS	430	430	430	340	340	340
C2M	6	Placer JCT	Crow River DS	280	280	280	230	230	230
C3A	1	Cameron Falls GS	Alexander SS	720	870	920	620	790	840
C3A	2	Alexander SS	Alexander GS	720	870	920	620	790	840
C3A	3	Alexander SS	Alexander SS	720	870	920	620	790	840
C3W	1	Pickle Lake CTS	Pickle Lake SS	730	730	730	550	550	550

Circuit	Section	From	To	Winter Ratings (A)			Summer Ratings (A)		
				Cont	LTE	STE	Cont	LTE	STE
D26A	1	Dryden TS	Mackenzie TS	1020	1020	1020	880	880	880
D26A	1	Dryden TS	Dinorwic JCT	1020	1020	1020	880	880	880
D26A	2	Dinorwic JCT	Mackenzie TS	1020	1020	1020	880	880	880
D26A	4	Dinorwic JCT	Dinorwic JCT	1020	1020	1020	880	880	880
D5D	1	Dryden TS	Dryden JCT B	720	870	1020	620	790	960
D5D	2	Dryden JCT B	Domtar Dryden CTS	670	670	670	550	550	550
D5D	3	Dryden JCT B	Dryden JCT B	670	670	670	550	550	550
E1C	1	Ear Falls TS	Selco JCT	280	280	280	230	230	230
E1C	2	Selco JCT	Slate Falls JCT	280	280	280	230	230	230
E1C	3	Etruscan JCT	Placer JCT	280	280	280	230	230	230
E1C	3	Etruscan JCT	E1C T#NA1 JCT	280	280	280	230	230	230
E1C	5	Etruscan JCT	Etruscan Entrprs CTS	280	280	280	230	230	230
E1C	8	Golden Patricia JCT	Etruscan JCT	280	280	280	230	230	230
E1C	8	Golden Patricia JCT	Etruscan JCT	280	280	280	230	230	230
E1C	11	Slate Falls JCT	Golden Patricia JCT	280	280	280	230	230	230
E1C	11	Slate Falls JCT	Golden Patricia JCT	280	280	280	230	230	230
E1C	12	Slate Falls JCT	Slate Falls DS	280	280	280	230	230	230
E1C	13	Placer JCT	Crow River DS	280	280	280	230	230	230
E1C	14	Placer JCT	Placer JCT	280	280	280	230	230	230
E1C	15	Placer JCT	Crow River DS	280	280	280	230	230	230
E1C	16	Placer JCT	Musselwhite CSS	430	430	430	340	340	340
E1C	17	Golden Patricia JCT	Golden Patricia JCT	280	280	280	230	230	230
E1C	18	E1C T#NA1 JCT	Placer JCT	280	280	280	230	230	230
E1C	19	E1C T#NA1 JCT	Pickle Lake SS	480	480	480	380	380	380
E2R	1	Ear Falls TS	Pakwash JCT	540	540	540	420	420	420
E2R	2	Pakwash JCT	Balmer JCT	540	540	540	420	420	420
E2R	4	Balmer JCT	Red Lake TS	540	540	540	420	420	420
E2R	4	Balmer JCT	Red Lake JCT	540	540	540	420	420	420
E2R	6	Red Lake JCT	Red Lake TS	540	540	540	420	420	420
E2R	7	Red Lake JCT	Red Lake CSS	540	540	540	420	420	420
E4D	1	Ear Falls TS	Scout Lake JCT	610	610	610	470	470	470
E4D	2	Scout Lake JCT	Dryden TS	610	610	610	470	470	470
E4D	3	Scout Lake JCT	Perrault Falls DS	280	280	280	230	230	230
F1B	1	Fort Frances TS	Fort Frances JCT	550	550	550	460	460	460
F1B	2	Burleigh JCT	Burleigh DS	1000	1200	1490	850	1100	1410
F1B	3	Fort Frances TS	Fort Frances MTS	430	430	430	340	340	340
F1B	4	Fort Frances JCT	Burleigh JCT	550	550	550	460	460	460
F1B	5	Burleigh JCT	Hwy #11 JCT	600	600	600	280	280	280
F25A	1	Fort Frances TS	Mackenzie TS	1020	1020	1020	880	880	880
F2B	1	Fort Frances TS	H2O Pwr FtFrnces CGS	720	830	860	620	740	780
F3M	1	Fort Frances TS	H2O Pwr FtFrnces CGS	920	920	920	750	750	750
F3M	2	H2O Pwr FtFrnces CGS	Int'l Bdy Minn JCT	850	920	920	730	750	750

Circuit	Section	From	To	Winter Ratings (A)			Summer Ratings (A)		
				Cont	LTE	STE	Cont	LTE	STE
K21W	1	Kenora TS	IPB Manitoba 230 JCT	1020	1020	1020	880	880	880
K22W	1	Kenora TS	IPB Manitoba 230 JCT	1020	1020	1020	880	880	880
K23D	1	Kenora TS	TCPL Vermill Bay JCT	1020	1020	1020	880	880	880
K23D	2	TCPL Vermill Bay JCT	Dryden TS	1020	1020	1020	880	880	880
K23D	3	TCPL Vermill Bay JCT	TCPL Vermill Bay CTS	1020	1020	1020	880	880	880
K24F	1	Kenora TS	Rainy River Gold JCT	1020	1170	1250	880	1060	1140
K24F	2	Rainy River Gold JCT	Fort Frances TS	1020	1170	1250	880	1060	1140
K24F	3	Rainy River Gold JCT	Rainy River Gold CSS	1020	1170	1250	880	1060	1140
K2M	1	Rabbit Lake SS	Norman JCT	710	710	710	600	600	610
K3D	1	Rabbit Lake SS	K3D-10 SW JCT	610	610	610	470	470	470
K3D	2	K3D-10 SW JCT	Vermilion Bay JCT	610	610	610	470	470	470
K3D	3	Vermilion Bay JCT	Eton JCT	610	610	610	470	470	470
K3D	4	Vermilion Bay JCT	Vermilion Bay DS	430	510	570	370	470	530
K3D	5	Dryden TS	Sam Lake DS	540	540	540	420	420	420
K3D	6	Eton JCT	Dryden TS	610	610	610	470	470	470
K3D	7	Eton JCT	Eton DS	430	510	570	370	470	530
K4W	1	Rabbit Lake SS	Minaki JCT	580	580	580	430	430	430
K4W	2	Minaki JCT	Whitedog Falls SS	720	790	810	620	700	720
K4W	3	Minaki JCT	Minaki DS	580	580	580	430	430	430
K4W	4	Minaki JCT	Minaki DS	580	580	580	430	430	430
K5W	1	Rabbit Lake SS	Minaki JCT	580	580	580	430	430	430
K5W	3	Minaki JCT	Whitedog Falls SS	720	720	720	610	610	610
K6F	1	Rabbit Lake SS	Margach JCT	650	650	650	530	530	530
K6F	2	Margach JCT	Sioux Narrows JCT	580	580	580	430	430	430
K6F	3	K6F-10 SW JCT	Nestor Falls JCT	610	610	610	470	470	470
K6F	4	Nestor Falls JCT	Ainsworth JCT	610	610	610	470	470	470
K6F	5	Sioux Narrows JCT	Sioux Narrows DS	720	870	1020	620	790	960
K6F	6	Nestor Falls JCT	Nestor Falls DS	370	440	490	320	400	460
K6F	7	Sioux Narrows JCT	K6F-10 SW JCT	650	650	650	530	530	530
K6F	8	Ainsworth JCT	Fort Frances JCT	610	610	610	470	470	470
K6F	10	Margach JCT	Margach DS	370	440	490	320	400	460
K6F	11	Margach JCT	Margach DS	370	440	490	320	400	460
K6F	12	Ainsworth JCT	Barwick JCT	430	450	450	370	390	400
K6F	13	Fort Frances JCT	Fort Frances TS	610	610	610	470	470	470
K6F	14	Fort Frances JCT	Fort Frances JCT	610	610	610	470	470	470
K6F	15	Barwick JCT	Ainsworth Str #4 JCT	430	450	450	370	390	400
K6F	16	Barwick JCT	Barwick TS	1000	1200	1490	850	1100	1410
K6F	17	Barwick JCT	Barwick TS	1000	1200	1490	850	1100	1410
K7K	1	Kenora TS	Kenora TS	720	870	1020	620	790	960
K7K	2	Kenora TS	Rabbit Lake SS	720	870	970	620	790	910
K7K	3	Kenora TS	Weyerhaeuser Ken CTS	360	360	360	280	280	280
L3P	1	Lakehead TS	Port Arthur TS #1	840	1000	1200	720	920	1130

Circuit	Section	From	To	Winter Ratings (A)			Summer Ratings (A)		
				Cont	LTE	STE	Cont	LTE	STE
L4P	1	Lakehead TS	Port Arthur TS #1	720	870	1020	620	790	960
M1S	1	Moose Lake TS	Valerie Falls JCT	450	450	450	320	320	320
M1S	2	Mill Creek JCT	H2O Pwr SturgFls CGS	540	540	540	450	450	460
M1S	4	Mill Creek JCT	H2O Pwr Calm Lk CGS	340	340	340	280	280	280
M1S	6	Valerie Falls JCT	Mill Creek JCT	450	450	450	320	320	320
M23L	1	Marathon TS	Greenwich WF CGS JCT	1020	1070	1100	880	940	970
M23L	1	Marathon TS	Greenwich WF CGS JCT	1020	1070	1100	880	940	970
M23L	2	Greenwich WF CGS JCT	Lakehead TS	1020	1230	1510	880	1120	1430
M23L	2	Greenwich WF CGS JCT	Lakehead TS	1020	1230	1510	880	1120	1430
M23L	4	Greenwich WF CGS JCT	Greenwich LakeWF CSS	1020	1030	1040	880	890	900
M24L	1	Marathon TS	Greenwich WF CGS JCT	1020	1140	1210	880	1020	1090
M24L	1	Marathon TS	Greenwich WF CGS JCT	1020	1140	1210	880	1020	1090
M24L	2	Greenwich WF CGS JCT	Lakehead TS	1020	1230	1510	880	1120	1430
M24L	2	Greenwich WF CGS JCT	Lakehead TS	1020	1230	1510	880	1120	1430
M24L	4	Greenwich WF CGS JCT	Greenwich LakeWF CSS	1020	1030	1040	880	890	900
M2D	1	Ignace JCT	Dryden TS	540	540	540	420	420	420
M2D	1	Ignace JCT	Dryden TS	540	540	540	420	420	420
M2D	2	Moose Lake TS	Ignace JCT	670	670	670	550	550	550
M2D	4	Dryden TS	Dryden TS	670	670	670	550	550	550
M2D	5	Dryden TS	Dryden JCT B	670	670	670	550	550	550
M2W	1	Marathon TS	Pic JCT	720	870	1020	620	790	960
M2W	1	Marathon TS	Pic JCT	720	870	1020	620	790	960
M2W	2	Pic JCT	Manitouwadge JCT	430	450	460	350	350	350
M2W	4	Manitouwadge JCT	Willroy JCT	580	690	790	500	630	740
M2W	6	Manitouwadge JCT	Manitouwadge JCT B	580	690	720	500	630	660
M2W	8	Marathon TS	Black River JCT	430	510	570	370	470	530
M2W	8	Marathon TS	Black River JCT	430	510	570	370	470	530
M2W	9	Williams Mine JCT	Hemlo Mine JCT	330	330	330	230	230	240
M2W	10	Hemlo Mine JCT	Animki JCT	430	510	570	370	470	530
M2W	10	Hemlo Mine JCT	Animki JCT	430	510	570	370	470	530
M2W	15	Marathon TS	Pic DS	370	440	490	320	400	460
M2W	16	Black River JCT	Umbata Falls JCT	430	510	570	370	470	530
M2W	16	Black River JCT	Umbata Falls JCT	430	510	570	370	470	530
M2W	22	Manitouwadge JCT B	Manitouwadge DS #1	370	440	470	320	400	440
M2W	25	Umbata Falls JCT	Williams Mine JCT	330	330	330	230	230	240
M2W	25	Umbata Falls JCT	Williams Mine JCT	330	330	330	230	230	240
M2W	26	Manitouwadge JCT B	Manitouwadge TS	580	690	790	500	630	740
M2W	27	Animki JCT	White River DS	430	510	570	370	470	530
M2W	27	Animki JCT	White River DS	430	510	570	370	470	530
M37L	1	Lakehead TS	M37L_M38L T#A001 JCT	1300	1580	1780	1120	1440	1650
M37L	3	M37L_M38L T#C279 JCT	Marathon TS	1300	1580	1780	1120	1440	1650
M38L	1	Lakehead TS	M37L_M38L T#A001 JCT	1300	1580	1780	1120	1440	1650

Circuit	Section	From	To	Winter Ratings (A)			Summer Ratings (A)		
				Cont	LTE	STE	Cont	LTE	STE
M38L	3	M37L_M38L T#C279 JCT	Marathon TS	1300	1580	1780	1120	1440	1650
N93A	1	Atikokan TGS	Marmion Lake JCT	1020	1230	1510	880	1120	1430
N93A	2	Marmion Lake JCT	Mackenzie TS	1300	1580	2030	1120	1440	1920
P1P	1	Port Arthur TS #1	Port Arthur JCT	430	510	570	370	470	530
P1T	1	Port Arthur TS #1	TBPI Thunder Bay JCT	580	690	710	500	630	660
P1T	2	TBPI Thunder Bay JCT	TBPI Thunder Bay CTS	430	510	570	370	470	530
P1T	3	TBPI Thunder Bay JCT	TBPI Thunder Bay JCT	580	690	710	500	630	660
P1T	4	TBPI Thunder Bay JCT	TBPI Thunder Bay CTS	430	510	570	370	470	530
P21G	1	Mississagi TS	P21G POLE 261 JCT	1020	1230	1510	880	1120	1430
P21G	2	P21G POLE 261 JCT	Third Line TS	1128	0	1200	963	0	1068
P22G	1	Mississagi TS	Echo River TS	1128	0	1200	963	0	1068
P22G	2	Echo River TS	Third Line TS	1128	0	1200	963	0	1068
P25W	1	Mississagi TS	Aubrey Falls JCT	1020	1130	1190	880	1010	1070
P25W	2	Aubrey Falls JCT	Wawa TS	1020	1020	1020	880	880	880
P25W	3	Aubrey Falls JCT	Aubrey Falls CGS	1020	1130	1190	880	1010	1070
P26W	1	Mississagi TS	Aubrey Falls JCT	1020	1130	1190	880	1010	1070
P26W	2	Aubrey Falls JCT	Wawa TS	1020	1020	1020	880	880	880
P26W	3	Aubrey Falls JCT	Aubrey Falls CGS	1020	1130	1190	880	1010	1070
P3B	1	Port Arthur TS #1	Birch TS	720	830	860	620	740	780
P5M	1	Port Arthur TS #1	Conmee JCT	580	610	620	500	530	540
P5M	4	P5M STR 603 JCT	P5M STR 608 JCT	580	580	580	430	430	430
P5M	6	P5M STR 621 JCT	P5M STR 626 JCT	580	580	580	430	430	430
P7B	1	Port Arthur TS #1	P7B STR 320 JCT	840	920	960	720	830	860
P7B	2	P7B STR 320 JCT	Birch TS	720	870	940	620	790	870
Q4B	1	Thunder Bay SS	Abitibi JCT	1300	1580	1780	1110	1440	1660
Q4B	2	Abitibi JCT	James Street JCT	1000	1090	1140	850	970	1030
Q4B	3	James Street JCT	St.Paul JCT	1000	1090	1140	850	970	1030
Q4B	4	St.Paul JCT	Walsh Street JCT	1000	1200	1490	850	1100	1410
Q4B	5	Walsh Street JCT	Birch TS	1000	1200	1490	850	1100	1410
Q4B	6	James Street JCT	ResFP Thundr Bay CTS	1000	1200	1430	850	1100	1350
Q4B	7	St.Paul JCT	ResFP Kraft CTS	720	870	940	620	790	870
Q4B	8	Walsh Street JCT	Fort William TS	1000	1090	1140	850	960	1020
Q5B	1	Thunder Bay SS	Abitibi JCT	1300	1580	1780	1110	1440	1660
Q5B	2	Abitibi JCT	James Street JCT	1000	1200	1490	850	1100	1410
Q5B	3	James Street JCT	St.Paul JCT	1000	1200	1490	850	1100	1410
Q5B	4	St.Paul JCT	Walsh Street JCT	1000	1200	1490	850	1100	1410
Q5B	5	Walsh Street JCT	Birch TS	1000	1200	1490	850	1100	1410
Q5B	6	Abitibi JCT	Erco JCT	720	870	950	620	790	880
Q5B	7	Erco JCT	Q5B STR A6 JCT	720	870	950	620	790	880
Q5B	8	James Street JCT	ResFP Thundr Bay CTS	1000	1200	1490	850	1100	1410
Q5B	9	St.Paul JCT	ResFP Kraft CTS	720	810	840	620	720	760
Q5B	10	Walsh Street JCT	Fort William TS	1000	1000	1000	850	850	850

Circuit	Section	From	To	Winter Ratings (A)			Summer Ratings (A)		
				Cont	LTE	STE	Cont	LTE	STE
R1LB	1	Pine Portage SS	Lakehead TS	410	410	410	330	330	330
R1LB	2	Lakehead TS	Birch TS	720	860	910	620	790	840
R2LB	1	Pine Portage SS	Lakehead TS	540	540	540	420	420	420
R2LB	2	Lakehead TS	Birch TS	720	870	920	620	790	840
R9A	1	Pine Portage SS	Alexander SS	540	540	540	420	420	420
R9A	2	Alexander SS	Alexander GS	430	430	430	340	340	340
R9A	3	Alexander SS	Alexander SS	540	540	540	420	420	420
S1C	1	Conmee JCT	Lac Des Iles JCT	560	560	560	400	400	400
S1C	2	Lac Des Iles JCT	Silver Falls GS	560	560	560	400	400	400
S1C	6	Lac Des Iles JCT	Lac Des Iles Min CSS	430	450	450	370	390	400
T1M	1	Terrace Bay SS	Angler Switch JCT	600	600	600	460	460	460
T1M	2	Angler Switch JCT	Pic JCT	600	600	600	460	460	460
T1M	3	Pic JCT	Marathon TS	720	870	1020	620	790	960
T1M	3	Pic JCT	Marathon TS	720	870	1020	620	790	960
T1M	4	Pic JCT	Marathon DS JCT	430	490	490	370	440	450
T1M	5	Marathon DS JCT	Marathon DS	430	490	490	370	440	450
W21M	1	Wawa TS	Marathon TS	1020	1020	1020	880	880	880
W21M	1	Wawa TS	Marathon TS	1020	1020	1020	880	880	880
W22M	1	Wawa TS	Marathon TS	1020	1140	1200	880	1020	1080
W22M	1	Wawa TS	Marathon TS	1020	1140	1200	880	1020	1080
W35M	1	Marathon TS	W35M_W36M T#D001 JCT	1300	1580	1780	1120	1440	1650
W35M	4	W35M T#F235 JCT	Wawa TS	1300	1580	1780	1120	1440	1650
W36M	1	Marathon TS	W35M_W36M T#D001 JCT	1300	1580	1780	1120	1440	1650
W36M	4	W36M T#F233 JCT	Wawa TS	1300	1580	1780	1120	1440	1650
W3C	1	Whitedog Falls SS	Caribou Falls GS	670	670	670	550	550	550

C.3.2 Special Protection Systems

Table 6 below shows the available special protection systems in the study region.

Table 5 | Relevant Special Protection Systems

Facility	Description
NW-SPS	The Northwest SPS is used to prevent instability in the West system, prevent low and high voltage in Wawa area, and prevent high voltages in Algoma Area. Following the loss of East-West 230kV tie between Wawa and Mississagi, Algoma and Mississagi, Algoma and Sudbury with flows west, it rejects load in Lakehead area, Great Lakes Power and/or Algoma and/or trip capacitor at Algoma.
NW-SPS2	Northwest SPS 2 has the capability of cross-tripping multiple 115 kV circuits. The scheme initiates cross-tripping based on single or double circuit contingencies on the 230 kV lines.

---- End of Section ---

C.4 Credible Planning Events and Criteria

C.4.1 Studied Contingencies

Table 7 below shows the types of contingencies assessed and how they map to applicable standards. The table also specifies the amount of load rejection/curtailment allowed as per ORTAC.

Table 6 | Types of Contingencies Assessed

Pre-contingency	Contingency[2]	Type	Mapping to TPL/Directory 1 Event	Rating[3]	Maximum Allowable Load Loss
All elements in-service	None	N-0	P0	Continuous	None
	Single	N-1	P1, P2	LTE	150 MW by-configuration
	Double	N-2	P7, P4, P5	STE, reduced to LTE	150 MW lost by curtailment; 600 MW Total
All Transmission Elements in-service, local generation out-of-service, followed by system adjustments (Satisfy ORTAC 2.6 Re: local generation outage)	None	N-0	N/A	Continuous	None
	Single	N-1	P3	LTE	150 MW by-configuration; >0 MW lost by curtailment[4]; Total 150 MW
	Double	N-2	N/A	STE, reduced to LTE	>150 MW lost by curtailment[3] ; 600 MW Total
Transmission element out-of-service, followed by system adjustments	Single	N-1-1	P6	STE, reduced to LTE	150 MW lost by curtailment; Total 600 MW

---

[2] Single contingency refers to a single zone of protection: a circuit, transformer, or generator. Double contingency refers to two zones of protection; the simultaneous outage of two adjacent circuits on a multi-circuit line, or breaker failure.

[3] LTE: Long-term emergency rating. 50-hr rating for circuits, 10-day rating for transformers.

STE: Short-term emergency rating. 15-min rating for circuits and transformers.

[4] Only to account for the magnitude of the generation outages

The tables below show the single, common tower, and breaker failure contingencies. Note that:

- Breaker failures and transformer failures that result in the same post-contingency state as the N-1 already documented are omitted.
- The outage events used for the N-1-1 studies are very similar to the N-1 contingencies documented in Table 8 but may be slightly different in some cases to reflect the fact that outages are the removal of a single element rather than all elements in a single zone of protection.

Table 7 | Studied N-1 Contingencies

			Contingencies			
15M1	C2A	Fort Frances T1	Lac Des Iles Mine T5	Murillo T3	Sachigo TS T1	W2
29M1	C2M	Fort Frances T2	Lakehead R1	Muskrat TS T1	Sachigo TS T2	W21M
56M1	C3A	Fort William EG	Lakehead SC11	Muskrat TS T2	Sam Lake T1	W22M
57M1	C3W	Fort William T5	Lakehead SC21	Mussel White T1	Sam Lake T2	W35M
A1B	Calm Lake T1	Fort William T6	Lakehead T7	Mussel White T2	Sandy Lake T1	W36M
A21L	Cameron Falls T1	Geco T1	Lakehead T8	N93A	Sandy Lake T2	W3C
A22L	Cameron Falls T2	Greenwich T1	Long Rapids Gen	Namewamns s T1	Sapawe T1	W54W
A23L	Cameron Falls T3	Greenwich T2	Longlac T2	Nestor Falls T1	Sapawe T2	W8C
A24L	Caribou Falls T1	Jellico T1	Longlac T3	Nipigon 24T1	Schreiber T1	WCD
A3M	Cat Lake T1	K21W	Lowerwhite T1	Nipigon GS T1	Shabaqua T1	WCJ
A4L	Clearwater Bay T1	K22W	M1S	Norman 20T1	Silver Falls T1	WDE
A5A	Crow River T1	K23D	M23L	North Caribou Lake T1	Sioux Narrows T1	WEF
A6P	Crow River T2	K24F	M24L	North Caribou Lake T2	Sioux Narrows T2	WEG
A7L	D26A	K2M	M2D	P1T	Slate Falls T1	WJK
A8L	D5D	K3D	M2W	P3B	South Bay T1	WKM
Agimak T1	Deer Lake TS T1	K4W	M37L	P5M	Spirit Lake T1	WPQ
Agimak T2	Deer Lake TS T2	K5W	M38L	P7B	Spirit Lake T2	WQR
Aguasabo n T1	Dryden Gen EG	K6F	M3E	Perrault Falls T1	Sturgeon Falls T1	WRS

Contingencies

Ainsworth T1	Dryden T22	K7K	Mackenzie T3	Pic T1	T1M	WRT
Alexander T1	Dryden T23	Kakabeka G1	Manitou Falls T1	Pic T2	Tbaybowater T04	WTU
Alexander T2	Dryden T4	Kakabeka G2	Manitou Falls T2	Pikangi TS T1	Tbaybowater T1	WTZ
Alexander T3	Dryden T5	Kakabeka G3	Manitouwa DS T1	Pikangi TS T2	Tbaybowater T2	WVY
Alexander T4	E1C	Kakabeka G4	Manitouwa T1	Pine Portage T1	Tbaybowater T3	WZV
Atikokan T1	E2R	Keewatin T1	Marathon DS 2735T1	Pine Portage T2	Tbaybowater T6	WZW
B6M	E4D	Keeway TS T1	Marathon R11	Poplar Lake T1	Tbaybowater TA	Wapekeka TS T1
BOWATR T26903	Ear Falls T1	Keeway TS T2	Marathon R12	Poplar Lake T2	Tbaybowater TB	Wapekeka TS T2
Balmer T1	Ear Falls T2	Kenora Abitibi AT1	Marathon R3	Port Arthur T1	Tbaybowater TC	Watay TS T1
Balmer T2	Ear Falls T5	Kenora DS T1	Marathon R4	Port Arthur T2	Tbaybowater TD	Wawakape TS T1
Barwick T1	Esker T1	Kenora DS T2	Marathon SC21	Q4B	Tbaybowater TJ	Wawakape TS T2
Barwick T2	Esker T2	Kenora MS T1	Marathon SC29	Q5B	Tbaybowater TK	Wawakape TS T3
Beardmore T1	Eton T1	Kenora MS T2	Marathon T11	Q8B	Tcplvermil T1	Wawatay T1
Beardmore T2	Eton T2	Kenora MS T4	Marathon T12	Q9B	Thunderbay LT2	Weyerhaeuser Dryden T1
Bearskin TS T1	F1B	Kenora TS T1	Margach T1	R1LB	Thunderbay LT3	Weyerhaeuser Dryden T2
Bearskin TS T2	F25A	Kimberclark T3	Margach T2	R2LB	Thunderbay T2	Weyerhaeuser Dryden T3
Birch SC11	F2B	Kimberclark T4	Mattabi T1	R9A	Thunderbay T3	Weyerhauser T1
Birch T2	F3M	Kingfisher TS T1	Mattabi T2	Rainy River T1	Twin Falls Gen	White River T1
Birch T3	Fort Frances MS T1	L3P	Minaki T1	Rainy River T2	UB3B	White River T2
Birch T4	Fort Frances MS T2	L4P	Minaki T2	Red Lake T3	Umbata Falls MPT1	Whitedog Falls T1
Bowater 2690	Fort Frances R2	Lac Des Iles Mine 1209T1	Moose Lake T2	Red Lake T4	Upperwhite T1	Williams Mine T1
Bowater T1	Fort Frances SC1	Lac Des Iles Mine 310TRF001	Moose Lake T3	Redrock DS T1	Valora T1	Williams Mine T2
Burleigh T1	Fort Frances SC2	Lac Des Iles Mine 310TRF002	Murillo T1	S1C	Valrie Falls T1	Winston T1
C1A	Fort Frances SC3	Lac Des Iles Mine T4	Murillo T2	SK1	Vermillion Bay DS T1	

Table 8 | Studied N-2 Contingencies

Contingencies						
A21L+A22L	M2W+M38L	Alexander GS G3T4	Dryden HL26	Lakehead New L4	Marathon L21L23	Rabbit Lake DL2
A23L+A24L	M2W+T1M	Alexander GS G4G5	Dryden JL23	Lakehead PL22	Marathon L22L24	Rabbit Lake DL6
A4L+A5A	M2W+W21M	Alexander GS G4T4	Dryden JL26	Lakehead PL24	Marathon PL1	Rabbit Lake HL3
A7L+R1LB	M2W+W22M	Alexander GS G5T1	Ear Falls L1L4	Lakehead PL37	Marathon PL2	Rabbit Lake HL6
A8L+R2LB	M2W+W35M	Alexander HL6	Ear Falls L3L4	Lakehead W1L37	Marathon W1L36	Rabbit Lake HL7
B6M+P5M	M2W+W36M	Alexander HL7	Ear Falls W1L1	Lakehead W1L38	Marathon W1L38	Rabbit Lake L2L4
C1A+C2A	M37L+M38L	Alexander HL8	Ear Falls W1L3	Lakehead W2L21	Marathon W2L35	Rabbit Lake L2L7
C2A+C3A	M37L+T1M	Alexander KL2	Ebane CB3	Lakehead W2L24	Marathon W2L37	Rabbit Lake L3L4
C3A+R9A	M38L+T1M	Alexander KL4	Fort Frances AK1	Mackenzie HL21	Moose Lake L1L2	Terrace Bay T1M
D26A+F25A	P3B+R1LB	Alexander KL9	Fort Frances AK2	Mackenzie HL93	Moose Lake L1L3	Thunder Bay 30Q5B
F1B+F25A	P7B+R2LB	Alexander L2L7	Fort Frances EH	Mackenzie L21L25	Moose Lake L3L6	Thunder Bay 30Q8B
K21W+K22W	Q4B+Q5B	Alexander L4L5	Fort Frances EL3	Mackenzie L22L93	Moose Lake TL2	Wawa AL21
K24F+K6F	Q8B+Q9B	Alexander L5L6	Fort Frances HL1	Mackenzie New L2	Moose Lake TL6	Wawa AL22
K2M+SK1	R1LB+R2LB	Alexander L8L9	Fort Frances JL1	Mackenzie New L3	Musselwhite 1210M1M	Wawa AL36
K4W+K5W	W21M+W22M	Birch AL1	Fort Frances JL6	Mackenzie New M2	Pine Portage L1L2	Wawa DL1
L3P+L4P	W21M+W35M	Birch AL4	Fort Frances L3L6	Mackenzie PL22	Pine Portage T1L2	Wawa DL2
L3P+P7B	W21M+W36M	Birch AL5	Kenora L21L23	Mackenzie PL25	Pine Portage T1L9	Wawa HL35
M23L+M24L	W22M+W35M	Birch AL8	Kenora L21L24	Marathon AL22	Pine Portage T2L1	Wawa L21L26
M23L+M2W	W22M+W36M	Birch KL2	Kenora L22L23	Marathon AL23	Pine Portage T2L9	Wawa L22L23
M23L+M37L	W35M+W36M	Birch KL4	Kenora PL22	Marathon AL36	Port Arthur 2A6P	Wawa L35L36
M23L+M38L	Aguasabon T1L1	Birch KL6	Kenora PL24	Marathon AL37	Port Arthur 2L3P	Whitedog F L3L4
M23L+T1M	Aguasabon T1L5	Birch KTL3	Lakehead HL21	Marathon HL21	Port Arthur 2L4P	Whitedog F L3L5
M24L+M2W	Alexander GS G1T1	Birch L2L8	Lakehead HL23	Marathon HL24	Port Arthur 2P1P	Whitedog F T1L4
M24L+M37L	Alexander GS G1T2	Birch L5L6	Lakehead HL38	Marathon HL35	Port Arthur 2P1T	Whitedog F T1L5

M24L+M38L	Alexander GS G2T2	Birch TL3L1	Lakehead L22L23	Marathon HL38	Port Arthur 2P3B
M24L+T1M	Alexander GS G2T3	Bowater 2660	Lakehead New L1	Marathon KL1	Port Arthur 2P5M
M2W+M37L	Alexander GS G3T3	Dryden HL23	Lakehead New L3	Marathon KL2	Port Arthur 2P7B

C.4.2 Planning Criteria

The study will use the planning criteria in accordance with events and performance as detailed by:

- North American Electric Reliability Corporation ("NERC") TPL-001 "Transmission System Planning Performance Requirements" ("TPL-001"),
- Northeast Power Coordinating Council ("NPCC") Directory 1 "Design and Operate of the Bulk Power System" (where appropriate), and
- IESO Ontario Resource and Transmission Assessment Criteria ("ORTAC").

---- End of Section ---

C.5 Study Result Findings

With recent and ongoing transmission reinforcement projects (East-West Tie Reinforcement, Waasigan Transmission Line Project Phase 1, and the Wataynikaneyap Transmission Project) in-service, the Northwest region will be generally adequate to support forecast growth.

Technical studies did not identify any firm supply capacity needs. Nonetheless, high growth sensitivities were studied for the Red Lake/Ear Falls/Dryden and Fort Frances subsystems. IRRP studies explored the existing limitations in these areas to identify the remaining LMC and inform future planning activities should higher growth materialize. The limiting phenomena for these subsystems are fully described in the IRRP report body.

Appendix D – Kenora MTS Demand Profiling

D.1 General Methodology

An hourly demand forecast consists of a series of year-long hourly profiles ("8760 profile", based on the number of hours in a year), which have been scaled to the appropriate annual peak demand. These profiles are developed to help determine which non-wires options may be best suited to meet regional needs.

For the Niagara IRRP, hourly load forecasting was conducted on a station-level, using a multiple linear regression with approximately five years' worth of historical hourly load data. Firstly, a density-based clustering algorithm was used for filtering the historical data for outliers (including fluctuations possibly caused load transfers, outages, or infrastructure changes). Subsequently, the historical hourly data was combined with select predictor variables to perform a multiple linear regression and model the station's hourly load profile. The following predictor variables were used:

- Calendar factors (such as holidays and days of the week);
- Weather factors (including temperature, dew point, wind speed, cloud cover, and fraction of dark; both weekday and weekend heating, cooling, and dead band splines were modelled);
- Demographic factors (population data[5]); and
- Economic factors (employment data[6]).

Model diagnostics (training mean absolute error, testing mean absolute error) were used to gauge the effectiveness of the selected predictor variables and to avoid an over-fitted model. While future While values for calendar, demographic, and economic variables were incorporated in a relatively straightforward manner, the unreliability of long-term weather forecasts necessitated a different approach for predicting the impact of future weather.

Each future date was first modelled using historical weather data from the equivalent day of year throughout the past 31 years. Additionally, to fully assess the impact of different weather sequences against the other non-weather variables, the historical weather for each of the 31 previous years was shifted both ahead and behind up to seven days, resulting in 15 daily variations. This approach ultimately led to 465 possible hourly load forecasts for each future year being forecast. For example: 31 years of historical weather data × 15 weather sequence shifts = 465 weather scenarios for each year being forecast. June 2nd 2025 was forecast assuming the historical weather from every May 26th to June 9th period that occurred between 1991 and 2021.

Subsequently, the list of 150 forecasts were ranked in ascending order based on their median energy values. Load duration curves which illustrate this ranking can be seen in Figure 4**Figure 4 | Illustrative Example: Ranking Hourly Load Profiles by Energy**

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5 Sourced from the Ministry of Finance and Statistics Canada

6 Sourced from the Centre for Spatial Economics, IHS Markit Ltd., and the Conference Board of Canada

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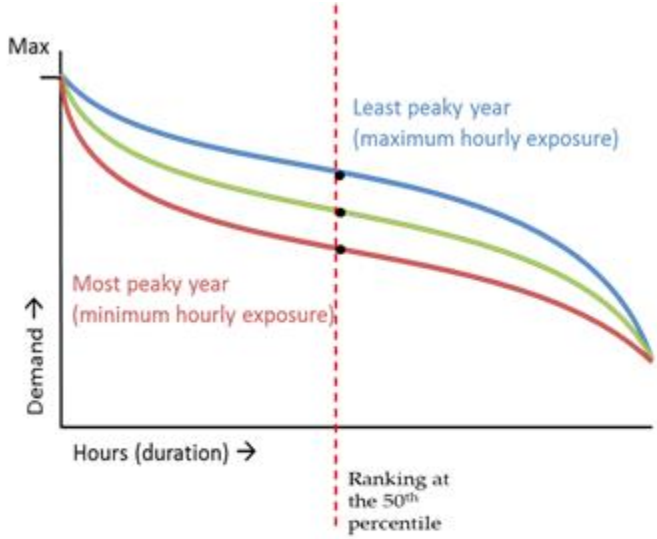
Figure 4 | Illustrative Example: Ranking Hourly Load Profiles by Energy



The forecast in the 3rd percentile was considered the "Extreme Peak" (extreme profile, red curve) and the forecast in the 50th percentile was chosen was the "Median Peak" (median profile, green curve). For the Northwest IRRP, the median profiles were scaled to their respective maximums from the peak demand forecast.

D.2 Kenora MTS Demand and Energy-not-Served Profiles

The Kenora MTS hourly demand forecast can be found in the accompanying Excel spreadsheet Table D.2.

Appendix E – Energy Efficiency

Energy efficiency is a low cost resource that offers significant benefits to individuals, businesses and the electricity system as a whole. Targeting energy efficiency in areas of the province with regional and local needs can help offset investments in new power plants and transmission lines, defer this spending to a later date and/or can compliment these investments as part of an integrated solution for the area.

To understand the scale of opportunity and associated costs for targeting energy efficiency in a local area, data and assumptions can be leveraged from provincial energy efficiency potential forecasts. In 2019, the IESO and the Ontario Energy Board completed the first integrated electricity and natural gas achievable potential study in Ontario (2019 APS)[7]. The main objective of the APS was to identify and quantify energy savings (electricity and natural gas) potential, GHG emission reductions and associated costs from demand side resources for the period from 2019-2038. This achievable potential modeling is used to inform:

- future energy efficiency policy and/or frameworks;
- program design and implementation; and
- assessments of Conservation and Demand Management (CDM) non-wires potential in regional planning.

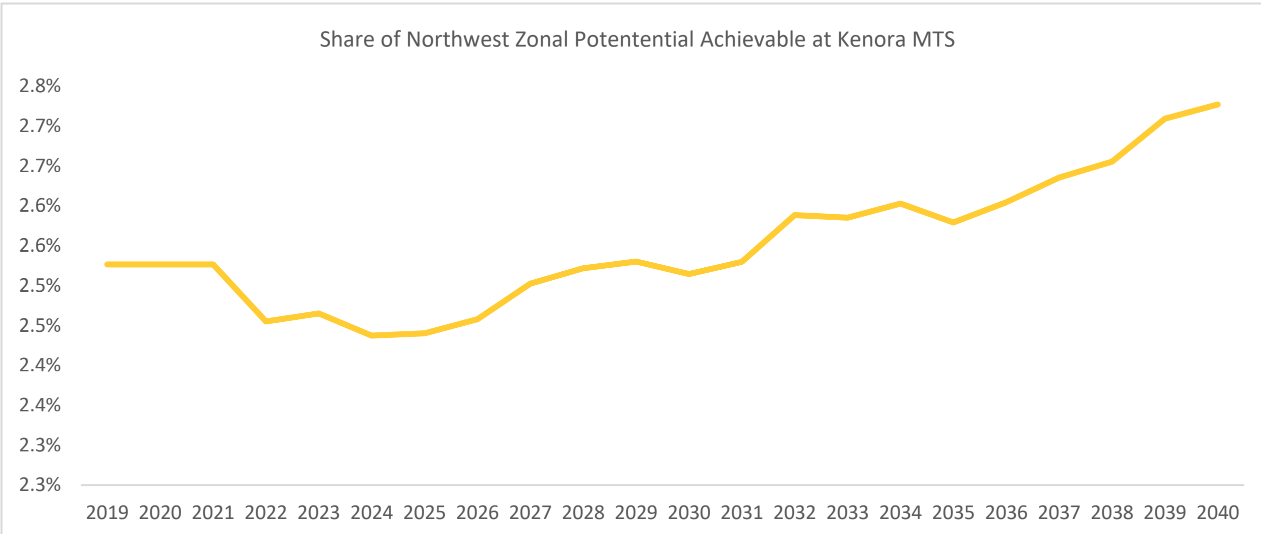
1. The 2019 APS determined that both electricity and natural gas have significant cost-effective energy efficiency potential in the near and longer terms. In particular, the maximum achievable potential scenario is one scenario in the APS that estimates the available potential from all CDM measures that are cost effective from the provincial system perspective – i.e., they produce benefits from avoided energy and system capacity costs that are greater than the incremental costs of the measures. Under this scenario, the study shows that CDM measures have the potential to reduce summer electricity peak demand by up to 3,000 MW in the province over the 20-year forecast period and can produce up to 24 TWh of energy savings over the same period.

2. After scaling this level of forecasted maximum achievable savings potential to the local area, the committed savings that are expected to come from existing provincial and federal CDM programs as well as from codes and standards have been netted out and the remaining uncommitted achievable savings potential is presented below. This uncommitted potential provides an estimate of the amount of incremental CDM savings potential that is available to help address emerging local needs in the Northwest region.

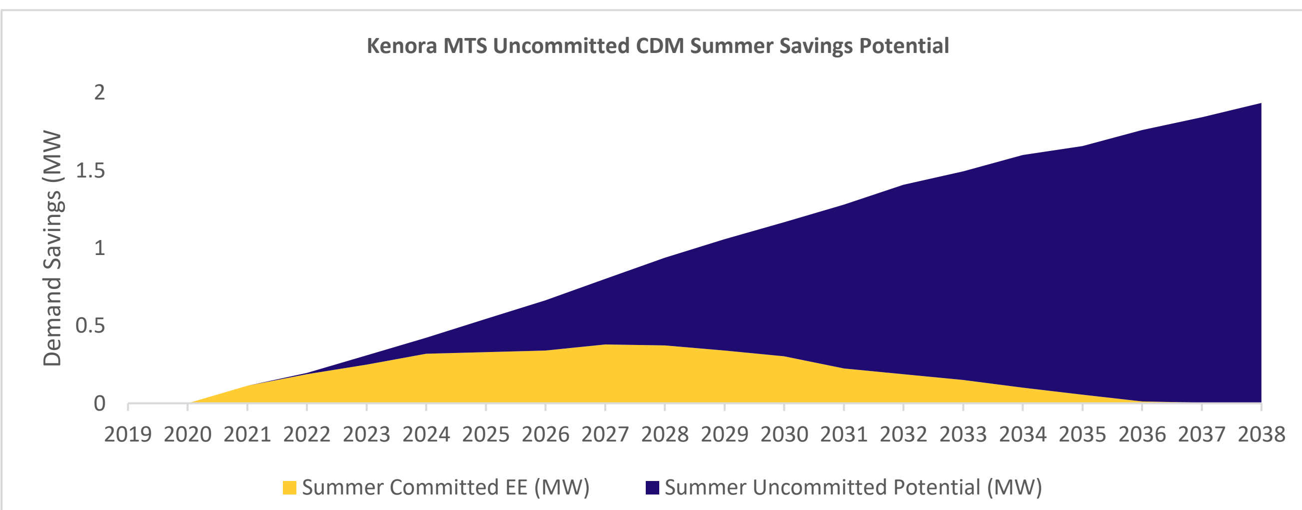
E.1 Incremental CDM for Kenora MTS

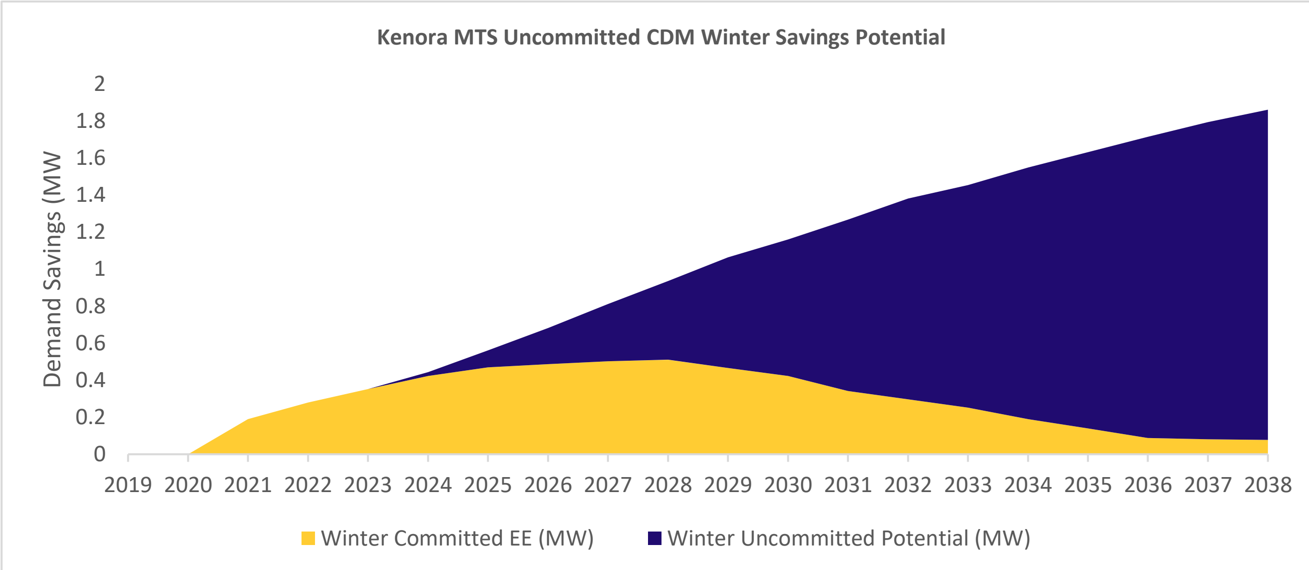
[7] More information about the 2019 Conservation Achievable Potential Study is available on the IESO website (link)

Comparing the regional planning forecast at the Kenora MTS to the zonal energy forecast used for the 2019 APS, it is estimated that approximately 2.5% of the savings potential modeled in the Northwest zone is achievable at the Kenora MTS on average over the forecast period. The rate of zonal savings that is expected to be achievable at the Kenora MTS in each year is illustrated in the graph below.



Applying these rates to Northwest zonal forecasted savings potential provides the maximum achievable savings potential that is expected to be achievable at Kenora MTS. In the near-term, a portion of these achievable savings opportunities are captured by the 2021-2024 CDM Framework programs. Overtime, new opportunities emerge with savings potential available across all sectors in this zone. The figures below illustrate the total committed savings potential that is expected to be achieved by existing programs as well as the uncommitted savings potential, which together add to the total forecasted maximum achievable potential for winter and summer.





Kenora MTS	**2026**	**2040**
Max Achievable CDM Potential Summer (MW)	0.66	1.9
Committed CDM Potential Summer (MW)	0.34	0
Uncommitted CDM Potential Summer (MW)	0.32	1.9
Max Achievable CDM Potential Winter (MW)	0.68	1.9
Committed CDM Potential Winter (MW)	0.49	0.1
Uncommitted CDM Potential Winter (MW)	0.20	1.8

At the Kenora MTS, is estimated that this 1.9 MW of summer savings potential and 1.8 MW of winter potential would cost $7 million dollars to deliver over the forecast period.

Appendix E – Economic Assumptions

The following is a list of the assumptions made in the economic analysis:

- The NPV of the cash flows is expressed in 2021 CAD.
- The USD/CAD exchange rate was assumed to be 0.76 for the study period.
- Natural gas price forecast is as per Sproule Outlook @ Dawn used in the 2021 Annual Planning Outlook (APO)
- The NPV analysis was conducted using a 4% real social discount rate. An annual inflation rate of 2% is assumed.
- The life of the station upgrades was assumed to be 45 years; the life of the line was assumed to be 70 years; and the life of the reciprocating engine generation and storage assets was assumed to be 30 years and 15 years respectively. Cost of asset replacement were included where necessary to ensure the same NPV study period.
- Development timelines for generation and storage were assumed to be 3 years.
- The size of the resource option was determined by a deterministic capacity assessment.
- A reciprocating gas engine was identified as one of the lowest-cost gas generation resource alternatives for the Northwest region, based on escalating values from a previous study independently conducted for the IESO.8
- A battery energy storage system was identified as another low-cost resource alternative. Total battery storage system costs are composed of capacity and energy costs (I.e. energy storage devices are constrained by their energy reservoir). The battery storage capacity and energy costs are based on the 2021 National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB).
- Sizing of the battery storage solution was based on meeting the peak capacity and peak energy requirements for the local reliability need, such that the reservoir size is capable of using existing resources to sufficiently charge to meet the hours of unserved energy.
- System capacity value was $144 k/MW-yr (2021 CAD) based on an estimate for the Cost of the Marginal New Resource (Net CONE), a new simple cycle gas turbine (SCGT) in Ontario.
- Production costs were determined based on energy requirements to serve the local reliability need, assuming the fixed and variable operating and maintenance costs for the resource (i.e., battery energy storage system or gas generation)
- Carbon pricing assumptions are based on the proposed Federal carbon price increase of a carbon price that escalates to $170/tCO2e by 2030. Thereafter, the $170/tCO2e assumption is held

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[8] New natural gas-fired generation was considered in the economic analysis for illustrative purposes to represent the lowest option of new generation.

constant in real dollars for the forecast period. The benchmark (tCO_2e/GWh) for new gas facilities is assumed to be eliminated by 2030.

- The assessment was performed from an electricity consumer perspective and included all costs incurred by project developers, which were assumed to be passed on to consumers.

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APPENDIX C: MAINTENANCE AND INSPECTION PROGRAM

Synergy North Co.

Asset Inspection &Maintenance Program

Overhead Asset Classifications and Inspection Considerations

Due to the subjective nature of performing a visual inspection, it is important to provide a reasonably objective set of inspection points for the inspector to review. These inspection points alert the inspector to consider a common set of defects. Where no defect is discovered no report is required. However, where a defect has been discovered, a maintenance request is generated using a standardized template for the purposes of assigning the priority of the request when measured against the request population.

Initial Vehicular Inspection

For the purposes of efficiency and completing the annual inspection in a timely fashion, much of the overhead inspection is conducted from a vehicle. Where a noted defect warrants, a detailed inspection takes place.

The initial vehicular inspection reviews the following inspection points. Where a defect is found, the related follow up action takes place;

Inspection Point	Potential Findings	Indication	Follow Up Action
Base of pole	Pole perforations or treated butt is not visible above ground or is within 1' of ground level	-Pole is not set to ideal depth -grade may have changed since pole setting -Oversetting of poles may result in premature rotting of pole butt	Detailed inspection
	Pole tapers slightly at base	-Pole butt rot has begun to set in	Detailed inspection
	Fresh sawdust, hole, and/or cracking	-Pest infiltration, either carpenter ants, woodpecker, or both	Detailed inspection of associated pole and each adjacent pole
	Fibre depressions, split fibres, fibre void	-vehicle impact (passenger vehicle, snow plow) -vandalism	Detailed inspection
	Soil is soft or eroding near pole base	-soil erosion due to washout -improper backfilling/tamping	Detailed inspection
Pole length (butt to top)	Pole tapers non-uniformly or has mottled surface	-shell rot	Detailed inspection
	Hole(s)	-Woodpecker infiltration	Detailed inspection
	Substantially jagged pole top	-pole top rot/deterioration	Detailed inspection
	Pole is leaning, angle exceeds 10 degrees (1' out of vertical 6' above the ground)	-unstable soil conditions -broken pole butt -broken/loose/missing guy wire	Detailed inspection
Down Ground	Truncated down ground	-copper theft/vandalism	Submit maintenance request
	Exposed ground rod	-rod heaved to surface by frost action	Submit maintenance request
Terminations, Insulators, & Cutouts	Dark spots near contact point with live parts	-flashover	Submit maintenance request
	Primary conductor not resting uniformly on glass insulator or small	-broken tie wire	Submit maintenance request

Inspection Point	Potential Findings	Indication	Follow Up Action
	gauge wire visibly dangling from insulator		
	Glass standoffs: 	-Glass standoffs are known to fail unexpectedly during routine maintenance or while performing work on the associated pole	Submit maintenance request
Lightning Arrestor	Dark marks on or separation of insulative material.	-Arrestor has failed during a temporary overvoltage condition	Submit maintenance request
Overhead Conductors	Distance between primary and secondary circuit is insufficient	-minimum clearances are violated	Contact Engineering for verification Submit maintenance request following verification
	Distance between circuit and neutral and/or guy wire is insufficient	-minimum clearances are violated	Contact Engineering for verification Submit maintenance request following verification
	Distance from lowest conductor/cable to grade is insufficient	-minimum clearances are violated	Contact Engineering for verification Submit maintenance request following verification
	Jumper to take-off is under high tension	-take-off is too tight, can result in hot spot and eventual failure	Detailed inspection
	Open wire secondary is not evenly spaced	-broken/missing mid-span bracket -service tension is excessive	Submit maintenance request
	System neutral is not in contact with insulator spool	-broken tie wire	Submit maintenance request
In-Line Switches	All in-line switches are subject to detailed inspection		Detailed Inspection
Guys & Anchoring	Guy wire is in/near contact with live parts	-insufficient tensioning -compromised anchor points	Submit maintenance request
	Guy wire not clearly marked	-missing guy guard	Submit maintenance request
	Guy wire is slack	-insufficient tensioning -compromised anchor points	Detailed inspection
	Discoloration of strain insulator	-insulator is making contact with live parts -insulator is breaking down due to UV exposure	Submit maintenance request
	Anchor Rod protrudes > 6" from finished grade	-compromised anchor point -unstable soil conditions	Detailed inspection
	Circuit, neutral, or third party attachment has no associated guy	-construction incomplete or guy is missing	Contact Engineering for verification Submit maintenance request upon verification
Distribution Transformer	Discoloration at transformer bushings, below lid, or at any point on can	-oil leak	Submit maintenance request
	Discolouration of bushings	-flashed insulators	Detailed inspection
	Significant tank rust	-missing paint -can produce oil leaks	Submit maintenance request

Inspection Point	Potential Findings	Indication	Follow Up Action
Framing & Hardware	Splintering or jagged ends on wooden crossarm	-rotten crossarm	Submit maintenance request
	Insulator in crossarm is leaning significantly or is sitting directly on crossarm with no clearance	-broken insulator pin (possibly wood pin) -rotted crossarm pin seats	Submit maintenance request
	Single phase insulator mount (in top of pole) is leaning	-pole top has rotted and insulator mount is pivoting	Submit maintenance request
	Hardware is loose or compromised		Submit maintenance request
Vegetation	Vegetation is encroaching on primary conductor	-may produce ground fault	Submit maintenance request
	Trees are resting on neutral, 3rd party, or secondary	-mechanical straining of connections and cables	Submit maintenance request
Third Party Attachments	Numerous		Submit maintenance request

Detailed Inspection

In certain cases the inspector may suspect that a defect exists but cannot confirm that suspicion from the vehicle. In these cases a detailed inspection is required prior to submission of a maintenance request.

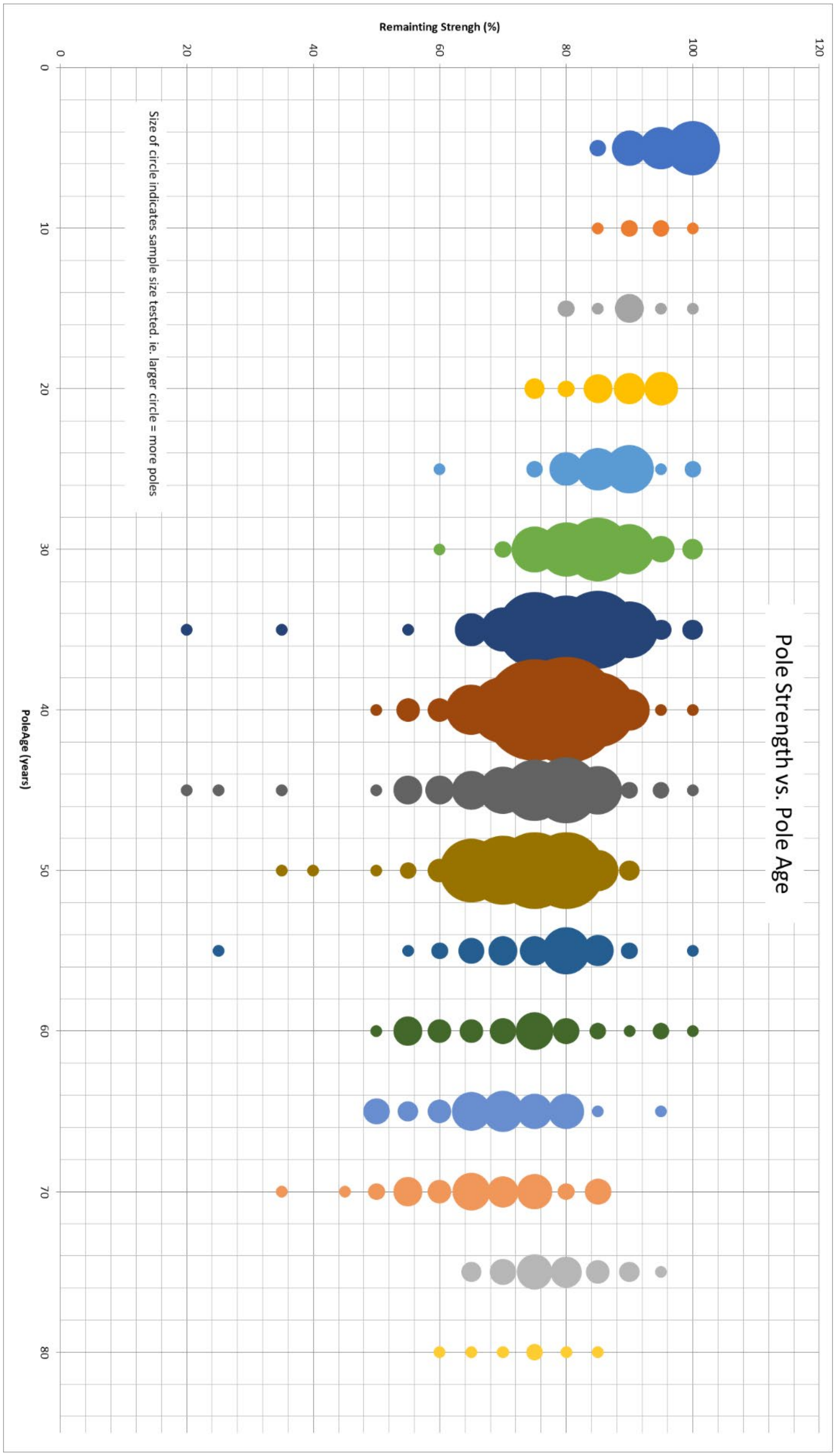
The following table presents SNs presently accepted methodology for performing a detailed inspection of a utility pole installation and/or in-line switch installation.

Inspection Point	Activity	Observations	Result Which Produces Maintenance Request
Pole	Sound pole from base to 7' above grade with hammer	Note the sound of the impact. A compromised pole (ie. significant heart rot) will produce a hollow sound	• Any two quadrants have less than 2" of sound wood • Any three quadrants have less than 3" of sound wood
	Pound screwdriver into pole butt at ground level (pound at 45 degrees to grade level) in 4 quadrants	Estimate thickness of healthy shell in each of the quadrants	
	Pound screwdriver into pole 5' above ground level (pound at 45 degrees to grade level) in 4 quadrants	Estimate thickness of healthy shell in each of the quadrants	
	Pound screwdriver into area(s) with significant shell rot	Estimate depth of shell rot	
	Visual Inspection	Estimate extent of pest, vandalism, or collision damage	• Depth of depression or void exceeds 30% of pole's diameter
		Review extent of soil erosion	• Missing or depressed soil poses a public hazard • Significant erosion of soil directly opposite of conductor or guy tension at pole top

Inspection Point	Activity	Observations	Result Which Produces Maintenance Request
		Use binoculars to determine extent of pole top rot	• Pole top rot has compromised a framing connection point
		Observe angle of pole	• Measured pole angle exceeds 10° (1' out of vertical 6' above grade)
Overhead Conductors, Terminations, Insulators, connection points & Bushings	Visual Inspection (Binoculars)	Dark spots on insulator	• Clearly verified flash points on insulators • Obvious insulator soiling
		Insulator tie wires	• Broken tie wires on neutral or circuit conductors
	Visual Inspection (Thermographic Camera)	Review all terminations, connection points, and insulators	• The temperature of any energized component is 20°C hotter than adjacent components
In-line Switches	Visual Inspection (Binoculars)	Dark spots on insulator	• Clearly verified flash points on insulators • Obvious insulator soiling
		Switch operation mechanism is not parallel to ground	• Switch is twisted to the point of being non-operational from ground level
	Visual Inspection (Thermographic Camera)	Review all terminations, connection points, switch blades and insulators	• The temperature of any energized component is 20°C hotter than adjacent components

Inspection Point	Activity	Observations	Result Which Produces Maintenance Request
Guying and Anchoring	Review of anchor points (Binocular inspection of pole connection points and ground level inspection of ground penetrations)	Pole connection points are compromised by pole rot	• Guy/strut attachment is clearly sinking into pole
		Ground anchor is receding from original set point	• Top of anchor rod is >1' above grade
Distribution Transformer	Visual Inspection (Binoculars)	Presence of oil on exterior of transformer tank	• Oil pattern extends from point of leak to bottom of tank • Oil leak apparent from 2 or more bushings
		Significant rust on transformer surface	• Transformer tank is clearly compromised by rust • Surface rust covers >50% of exposed surface
	Visual Inspection (Thermographic Camera)	Transformer tank	• Transformer temperature exceeds energized component temperature by 40°C
		Transformer connections	• The temperature of any energized component is 20°C hotter than adjacent components

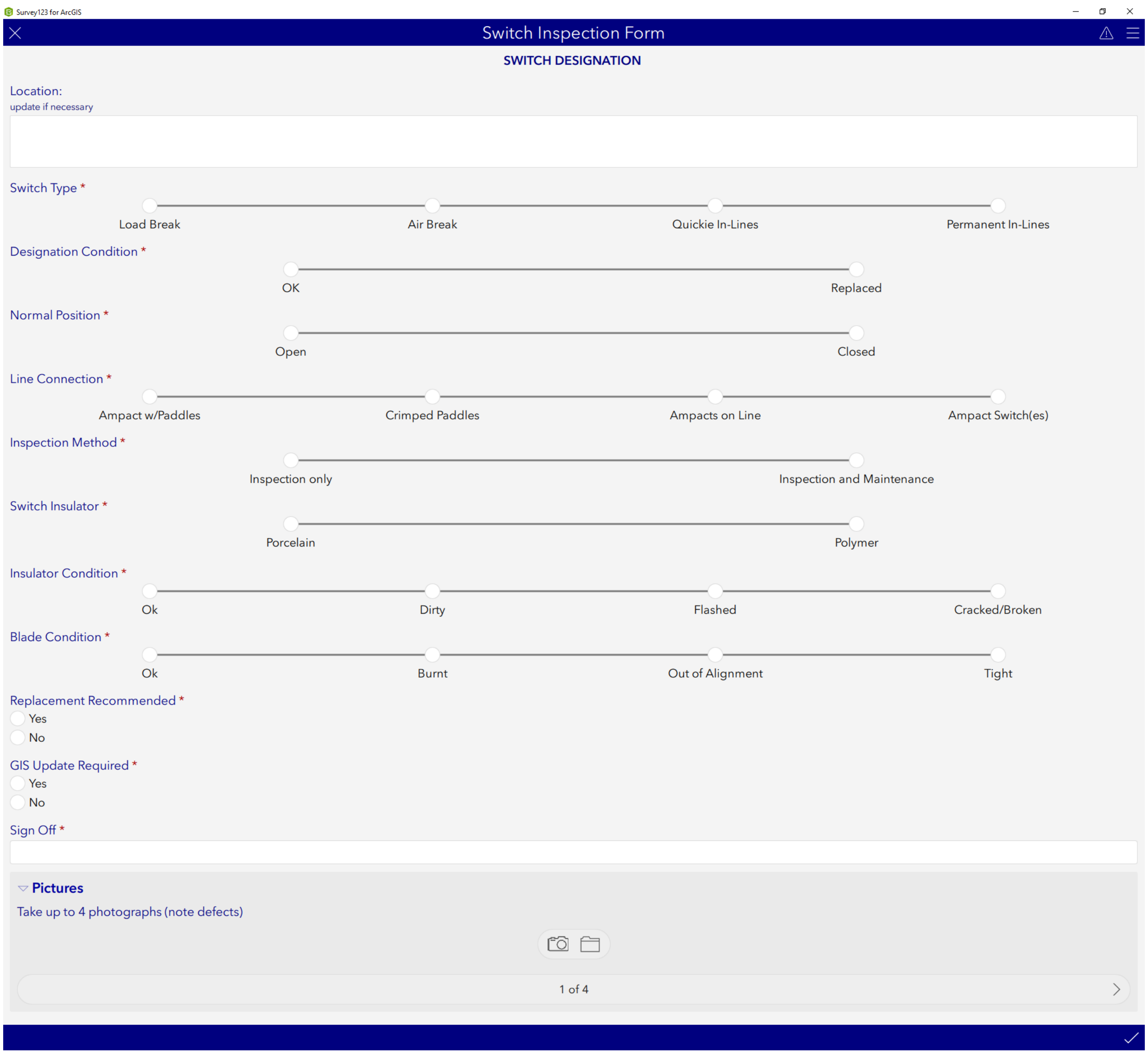
FIGURE 1 – Wood Pole Testing Results



Overhead Switch Inspection Considerations

Due to the subjective nature of performing a visual inspection, it is important to provide a reasonably objective set of inspection points for the inspector to review. These inspection points alert the inspector to consider a common set of defects. Where no defect is discovered no report is required. However, where a defect has been discovered, a maintenance request is generated using a standardized template for the purposes of assigning the priority of the request when measured against the request population.

The following image represents Synergy North's presently deployed template for performing a detailed inspection of an overhead switch installation. This information is captured using an ESRI's Survey123 inspection form and Workforce task manager.


Survey123 for ArcGIS

Switch Inspection Form

SWITCH DESIGNATION

Location:
update if necessary

Switch Type *
Load Break | Air Break | Quickie In-Lines | Permanent In-Lines

Designation Condition *
OK | Replaced

Normal Position *
Open | Closed

Line Connection *
Ampact w/Paddles | Crimped Paddles | Ampacts on Line | Ampact Switch(es)

Inspection Method *
Inspection only | Inspection and Maintenance

Switch Insulator *
Porcelain | Polymer

Insulator Condition *
Ok | Dirty | Flashed | Cracked/Broken

Blade Condition *
Ok | Burnt | Out of Alignment | Tight

Replacement Recommended *
Yes
No

GIS Update Required *
Yes
No

Sign Off *

Pictures
Take up to 4 photographs (note defects)

1 of 4

Underground Asset Classifications and Inspection Considerations

Due to the subjective nature of performing a visual inspection, it is important to provide a reasonably objective set of inspection points for the inspector to review. These inspection points alert the inspector to consider a common set of defects. Where no defect is discovered no report is required. However, where a defect has been discovered, a maintenance request is generated using a standardized template for the purposes of assigning the priority of the request when measured against the request population.

High Level Inspection

For the purposes of efficiency and completing the annual inspection in a timely fashion, 100% of pad mounted distribution transformers contained within the inspection zone are subject to a high level inspection.

The high level inspection may take place from a vehicle where possible and by foot patrol where necessary. The high level inspection reviews the following inspection points. Where a defect is found, the related follow up action takes place;

Inspection Point	Potential Findings	Indication	Follow Up Action
Access	Blocked Access	-Vegetation built up around transformer -Customer equipment/materials on or around unit -Grade changes or significant lean make door unable to be opened	Submit maintenance request. Customer notifications will be generated by Engineering accordingly.
Tank	Dented	-Vandalism -Vehicle impact	Detailed inspection
	Paint condition & corrosion	-significant rust can produce oil leaks	Detailed inspection
	Dark pattern on tank exterior or pad	-Oil leak	Detailed inspection
Door	Nomenclature or warning signs missing	-Complicates switching/restoration procedures -signage necessary for public safety	-Verify nomenclature with Engineering and affix -Apply new signage
	Penta bolt and/or lock missing	-Represents a public safety concern	Detailed inspection
Foundation	Sinking foundation	-significant lean, to the degree where door cannot be opened or lean exceeds 15 degrees (6 inches in 2 feet)	Submit maintenance request
	Gap under foundation	-provides unauthorized access (public, animals, etc.) to transformer terminations	Submit maintenance request

Inspection Point	Potential Findings	Indication	Follow Up Action
	Ground wires/grid exposed	-change in grade, frost heave, or soil erosion has exposed grounding infrastructure	Submit maintenance request
Cooling Fins	Exposure of fins is restricted	-Vegetation growth in and around fins -Foreign materials blocking air flow around fins	Clear blockage where possible Submit maintenance request where follow up required. Customer notifications will be generated by Engineering.

Detailed Inspection

In certain cases, the inspector may suspect that a defect exists but cannot confirm that suspicion from the high-level inspection. In these instances, a detailed inspection may be required. Detailed inspections require the assistance of qualified lines personnel and are performed on a case by case basis.

The following table presents SN's presently accepted methodology for performing a detailed inspection of a pad mounted distribution transformer installation. **In all cases, the inspector must collect photos of all inspection points. Where no maintenance request is generated the photos will provide a reference point in the event of future deterioration. The detailed inspection is conducted with the transformer doors opened**;

Inspection Point	Activity	Observations	Result Which Produces Maintenance Request
Tank	Visual Inspection	Dent from impact	• Significant oil leakage
		Significant rust	
		Compromised seals	
Door	Visual/Operational Inspection	Penta bolt, lock , or other door fastening devices	• Missing • Seized
		Hinge function	• Door will not open sufficiently to allow for live operation
Termination Enclosure	Visual Inspection	Vegetation	• Growth is encroaching on live components
		Pest infiltration	• Nests or substantial soiling
		Hygene	• Significant soiling of insulators
		Staining of concrete pad	• Significant oil leakage
		Condition of fiber board	• Significant sagging above live parts
Terminations	Visual Inspection	Condition of glass	• Cracked or broken
		Dark spots on cable terminations or transformer bushings	• Evidence of flashing
	Visual Inspection (Thermographic Camera)	Primary Terminations/Elbows	• The temperature of any energized component is 20°C hotter than adjacent components
		Secondary Terminations	
		Fuse clips	

Substation Asset Classifications and Inspection Considerations

Due to the subjective nature of performing a visual inspection, it is important to provide a reasonably objective set of inspection points for the inspector to review. These inspection points alert the inspector to consider a common set of defects. Where no defect is discovered no report is required. However, where a defect has been discovered, a maintenance request is generated using a standardized template for the purposes of assigning the priority of the request when measured against the request population.

The detailed inspection requirements, along with inspection frequencies for various types of assets are found in the Inspection Requirements Table below.

Continuing with our systems from 2019, Synergy North utilized mobile workforce application to assign, monitor and complete various inspection and maintenance activities for stations assets in Thunder Bay. A combination of applications from ESRI GIS were utilized including Workforce, Survey123 and Operations Dashboard.

The inspection and maintenance results are summarized in the following tables.

Table 1 – Description of Tasks/Frequency of Tasks

Task	Frequency	Description of Activities
Monthly Inspection	Monthly	Check buildings for issues, lighting, heating, leaks etc. Check structure for broken or flashed glass. Check fences for security (holes, missing barbwire, correct signage). Check eyewash, fire extinguisher. Check any oil filled equipment for leaks -transformers, oil filled breakers etc. Visually inspect batteries
Battery Inspection	Annually	Check battery bank & battery cells, Float voltage & 5 min voltage Check connections for cleanliness & fluid levels
DGA Sampling	Annually	Inspect and test fire alarms.
Fire Alarm	Annually	Inspect and test fire alarms.
SCADA Switch Inspection	Annually	Check box condition, internal components, batteries , switch components
B.E.L.T.	Bi-Annual	Apply temporary battery set Disconnect battery bank Apply a load to the battery bank using A/H rating to calculate load for 5 hr test Populate belt testing worksheet
Infrared Inspection	Annually	SNC will thermal image the following apparatus every year; a. all substation transformers, b. all exposed substation structure components, c. all substation battery connections
Switchgear & Relay Maintenance	Every 3 Years	Check cubicles for correct operation of racking systems, cubicle wiring & transducer operation Test all relays for operation within set parameters record all data on worksheets
Breaker Maintenance	Every 3 Years	Check function of all breaker parts, test operate & record all data on work sheets
Transformer Fans	Annually	Inspect & test all transformer fans
Asbestos Inspection	Annually	Inspect all stations for asbestos

	Inspection Activity	Potential Findings/Inspection Points	Results	Inspection Frequency (Months)			
				>5 years to Removal	<5 years to Removal	115	12
Monthly Inspection	Visual Inspection All Stations	Check buildings for issues, lighting, heating, leaks etc.	Pass/Fail	1	1	1	1
		Check structure for broken or flashed glass.	Pass/Fail				
		Check fences for security (holes, missing barbwire, correct signage).	Pass/Fail				
		Check eyewash, fire extinguisher.	Pass/Fail				
		Check any oil filled equipment for leaks -transformers, oil filled breakers etc.	Pass/Fail				
Power Transformers	Visual/Infrared/Operational Inspection	Tank and Gasket Integrity	G/F/P/NA	12	12	12	12
		Sampling valve seals	G/F/P/NA				
		Oil Level	OK/Defect				
		Oil conservator condition	G/F/P/NA				
		External tank condition	G/F/P/NA				
		Fan & pump condition/operation	G/F/P/NA				
		Bushing external condition and termination integrity	G/F/P/NA				
		Surge arrester condition	G/F/P/NA				
		Tap changer Position	OK/Defect				
		Condition of pressure relief devices	G/F/P/NA				
		Verify Nomenclature/PCB Labelling (where applicable)	G/F/P/NA				
		Clean bushings and control cabinet	NA				
		Perform thermographic survey of bolted connections	Report				
	Oil Screen & Moisture Content Testing	Soluble contaminants and oxidation products - sludging characteristics of the transformer	Pass/Fail	12	12	12	12
		Moisture content which may lead to degraded dielectric strength	Pass/Fail				
	Dissolved Gas Analysis	Gases formed during periods of fault or overload	Pass/Fail	12	12	12	12
	Furanic Compound Testing	Dissolved compounds indicative of cellulose breakdown/decomposition caused by sustained periods of overheating	Pass/Fail	12	N/A	12	12
	Electrical Testing	Insulation resistance tests, winding-winding, and winding-ground	Report	N/A	N/A	36	36
		Turns-ratio test at designated tap					
		Insulation power factor test on all windings					
		Power factor test on all bushings					
		Measure winding resistance at each winding					
		If core ground strap available, measure insulation resistance @ 500V DC					
		Test instrument transformers (see appropriate section)					
		Perform excitation current tests using manufacturer data					
		Test surge arresters (see appropriate section)					
Circuit Breakers	Visual/Operational Inspection	Drawout Assembly Function	Pass/Fail	36	36	N/A	N/A
		Arcing Contacts Integrity	Pass/Fail				
		Main Contacts Integrity	Pass/Fail				
		Insulator Hygiene	G/F/P/NA				
		Tank Condition	G/F/P/NA				
		Internal Mechanisms	Pass/Fail				
		Pallet Switch Condition	G/F/P/NA				
		Closing Mechanism Condition	G/F/P/NA				
		Trip Mechanism Condition	G/F/P/NA				
		Arc Chutes (air insulated)	G/F/P/NA				
		Motor Operator Function	Pass/Fail				
		Time-Travel analysis	Pass/Fail				
		Lubricate moving parts	N/A				
		Inspect vacuum bottles (where applicable)	G/F/P/NA				
	Oil Sampling (where applicable)	Dielectric breakdown voltage ASTM D877	Report	36	N/A	N/A	N/A
		Color ASTM D1500	Report				
	Electrical Testing	Heater operation	Pass/Fail	36	N/A	N/A	N/A
		Trip Free and Anti-pump Operation	Pass/Fail				
		Trip/Close with breaker control switch	Pass/Fail				
		Trip/Close with each relay	Pass/Fail				
		Perform insulation resistance tests for one minute each pole, phase-phase, phase-ground in open and closed positions	Report				
		Perform contact/pole resistance test	Report				
		Perform power factor test on each pole in open position, and each phase in closed position	Report				
		Perform power factor test on each bushing	Report				
Batteries	Visual Inspection	Verify electrolyte levels	Pass/Fail	12	12	12	12
		Inspect battery support racks	Pass/Fail				
		Verify presence of flame arresters	Pass/Fail				
		Clean corroded/oxidized terminals					
		Check Battery Terminal Voltage	Pass/Fail				
	Electrical Testing	Perform resistance measurements through bolted connections	Report	12	N/A	12	12
		Measure charger float and equalizing voltages	Report				
		Verify all charger functions	Report				
		Measure each cell voltage and total battery voltage in charging and float mode	Report				
		Measure intercell connection resistances	Report				
		Perform load test in accordance with ANSI/IEEE 150 (optional)	Pass/Fail	24	N/A	24	24
Battery Charger	Visual Inspection	Inspect for physical and mechancial condition	G/F/P/NA	12	12	12	12
	Electrical Testing	Perform resistance measurements through bolted connections	Report	24	N/A	24	24
		Verify float voltage, equalize voltage and high-voltage shut down settings	Report				
		Verify current limit	Report				
		Verify operation of alarms	Report				
		Mesure and record ac ripple current and/or voltage imposed on the battery	Report				
		Measure and record input and output voltage/current	Report				
Recloser/ SCADA Switch	Visual Inspection	Overall Condition	G/F/P/NA	12	12	12	12
		Cracked or deteriorated insulators	Pass/Fail				
		Terminations	G/F/P/NA				
		Nameplate data legible	Pass/Fail				
Switchgear/Switchboard	Visual/Infrared/Operational Inspection	Inspect physical, electrical and mechanical condition for evidence of moisture or corona	G/F/P/NA	12	24	12	Balsam
		Inspect anchorage, alignment, grounding and required clearances	G/F/P/NA				
		Clean the unit where necessary	G/F/P/NA				
		Verify fuse and/or circuit breakers sizes/types correspond to drawings and coordination package	G/F/P/NA				
		Verify CT/PT ratios conform to drawings	G/F/P/NA				
		Confirm correct operation and sequencing of electrical and mechanical interlocks	G/F/P/NA				
		Lubricate moving parts	G/F/P/NA				
		Verify barrier and shutter installation and operations	G/F/P/NA				
		Exercise all active components	G/F/P/NA				
		Inspect mechanical indicating devices for correct operation	G/F/P/NA				
		Verify filters are in place and vents are clear	G/F/P/NA				
		Perform visual inspection of instrument transformers (see appropriate section)	G/F/P/NA				
		Inspect control power transformers for physical damage. Verify fuse ratings and correct functioning of draw-out mechanism	G/F/P/NA				
	Electrical Testing	Inspect bolted connections using low resistance ohmmeter or infrared (if suitably loaded)	Report	36	N/A	36	Balsam
		Perform insulation resistance tests for one minute each bus section, phase-phase, phase-ground in open and closed positions	Report				
		Perform electrical tests on instrument transformers (see appropriate section)	Report				
		Perform ground-resistance tests (see appropriate section)	Report				
		Perform insulation resistance tests, winding-winding, winding-ground	Report				
		Verify heater operation	Pass/Fail				
		Perform system function checks	Pass/Fail				
Power Cables	Visual/Infrared/Operational Inspection	Inspect exposed sections of cables for physical damage and signs of overheating	G/F/P/NA	12	24	12	12
		Inspect terminations for physical damage and signs of overheating	G/F/P/NA				
		Inspect shield grounding and cable support	G/F/P/NA				
		Verify cable bends meet or exceed minimum allowable bending radius	G/F/P/NA				
		If terminated through window CT's verify the neutral and ground conductors are correctly terminated	G/F/P/NA				
	Electrical Testing	Inspect bolted connections using low resistance ohmmeter or infrared (if suitably loaded)	Report	N/A	N/A	36	36
		Perform Insulation-resistance tests individually on each conductor with all other conductors and shields grounded.	Report				
		Perform shield continuity test on each cable	Report				
		Cable testing (diagnostic, overpotential withstand)	Report				
Grounding	Visual/Operational Inspection	Inspect physical and mechanical condition		12	12	12	12
		Verify tightness of bolted electrical connections					
	Electrical Testing	Perform fall-of-potential test on the main ground electrode		N/A	N/A	48	48
		Perfrom point-to-point tests to determine resistance between main grounding and all major equipment electrical frames					
Instrument Transformers	Visual/Operational Inspection	Inspect physical and mechanical condition	G/F/P/NA	12	24	12	12
		Inspect bolted connections using low resistance ohmmeter or infrared (if suitably loaded)	G/F/P/NA				
		Verify that all required grounding ans shorting connections provide contact					
		Verify correct primary/secondary fuze sizes for VT's					
	Electrical Testing		Report	N/A	N/A	36	36
			Report				
		When applicable perform insulation resistance test on the primary winding w/secondary grounded (CT's only)	Report				
		When applicable perform insulation resistance test on the secondary winding w/primary grounded (CT's only)	Report				
		Perform insualtion-resistance tests for 1 minute on each winding-winding, winding-ground (PT's)	Report				
		Perform turns ratio test on each transformer at all tap positions (PT's)	Report				
		Verify that all circuits are grounded and only have one grounding point					
Meters	N/A						
Regulating Devices	Visual/Operational Inspection	Inspect physical and mechanical condition	G/F/P/NA	1			
		Record positon indicator as-found	G/F/P/NA				
		Verify motor drive train for correct operation and automatic motor cutoff at max lower and max raise	G/F/P/NA				
		Verify correct liquid level in all tanks	G/F/P/NA				
	Operational	Internal inspection - remove oil inspect contacts for wear (based on operation internval)	G/F/P/NA	120			
	Electrical Testing	Perform insulation-resistance test through boltec connections using low-resistance ohmmeter	Report	24			
		Perform insulation-resistance test of each wiring to ground in any off-neutral position	Report				
		Perform insualtion power-factor tests on windings	Report				
		Perform power factor tests on each bushing	Report				
		Measure widnding resistance of source windings in neutral position	Report				
		Perform turns-ratio test on each voltage step position. Verify that the tap position indicator correctly identifies all tap positions	Report				
		Verify acurate operation of the range limiter	Report				
		Verify operation and accurac	Report				
	Oil Screen & Moisture Content Testing	Soluble contaminants and oxidation products - sludging characteristics of the transformer	Pass/Fail	24			
		Moisture content which may lead to degraded dielectric strength	Pass/Fail				
	Dissolved Gas Analysis	Gases formed during periods of fault or overload	Pass/Fail	24			
Surge Arresters	N/A						
Outdoor Bus Structure	Visual/Operational Inspection	Inspect physical and mechanical condition		1		1	1
		Inspect anchorage, alignment, grounding and required clearances					
		Inspect insulator hygeine					

APPENDIX D: FINO STRATEGY

FINO STRATEGY

Prepared By :

Karla Bailey

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Executive Summary

The energy transition is a global shift away from using fossil fuels (like oil, gasoline, and coal) to a more sustainable, renewable energy future that includes more innovation and customer choice. It can be thought of in relation to the "Four Ds" - Decarbonization, Digitalization, Decentralization, and Democratization. (Figure 1). As a result of this shift, Synergy North needs to manage the risk of reliability issues resulting from customer adoption of new behind-the-meter technologies and ensure accommodation of customer energy choices.

Figure 1 – The Four Ds of Energy Transition[1]

This report provides an overview of the technologies that are expected to enable customer choices such as battery storage, distributed energy resources, electric vehicles (EV), and smart grid devices. It also provides an analysis of the current state of both Synergy North-owned assets and grid supply for the connection of these technologies.

Moving towards a fully electrified, sustainable future, requires our utility to be armed with intelligent solutions that address what is projected to be increased consumer demand and an increase in outages due to extreme weather. As government policies and regulatory frameworks continue to evolve at a rapid rate, becoming trusted partners to our customers for energy and related services will include the actions below.

- Ongoing data predictions of electrification
- Proactive monitoring of transformers
- Coordinating with Regulators on Program Administration
- Coordinating with Commercial Customers and City of Thunder Bay on Transit Electrification
- Installation of Smart Devices
- Customer Engagement
- Provision of EV support and services

- Preparation for control and enabling of Customer Owned Resources

With the milestones proposed, Synergy North can advance towards becoming a Fully Integrated Network Operator in the next 3 years by investing $300k in capital and $45k-$90k in OM&A annually.

Background

Defining FINO

Fully Integrated Network Operators (FINO) is a term first used in the paper released by the Electricity Distributors Association (EDA) titled “The Power to Connect: Advancing Customer-Driven Electricity Solutions for Ontario”. In this paper[2], the EDA presented the role of Local Distribution Companies (LDC) as leaders in integrating and enabling new technology in the transition to a cleaner, decentralized grid. This term was later referenced by the Energy Transformation Network of Ontario in July of 2021 indicating that to achieve a DER-integrated future, there would need to be more flexible regulations.

For an LDC such as Synergy North to become a FINO requires the LDC to

1. Enable,
2. Control, and
3. Integrate Distributed Energy Resources (DER) within its distribution service territory.

The EDA anticipated that each LDC would evolve to a FINO at a different pace and a different extent and there will need to be a significant collaboration amongst LDCs. This collaboration related to DER enablement, control, and integration will naturally occur as LDCs learn and evolve to become FINOs over the next ten to fifteen years and beyond.

The use of the term FINO comes on the heels of extensive discussions in the sector regarding DERs and their predicted impacts on the grid. DERs are projected to play an important role in meeting new supply needs given their affordability, ease of deployment, and ability to locate in regions of the grid that serve the greatest benefit. DERs that are managed and connected by LDCs at the distribution level can only be unleashed for their full value by LDCs. The benefit can come at the distribution level but can also contribute to Ontario’s future resource adequacy needs. For example, a customer-owned DER could have a contribution that when used would reduce the amount of capacity needed for the grid, helping the IESO reduce its future procurements province-wide.

As more DERs are adopted by customers or considered by LDCs as Non-Wires Alternatives (NWAs), distribution system plans will need to evaluate multiple options (e.g., integrated resource plans may be required to evaluate multiple resource options). This adds complexity to regulatory review and creates risk for LDCs; if the OEB does not agree with the options an LDC selects for rate recovery that may be required to support DER adoption and integration.

Given customer adoption of DERs and deployment of DERs as NWAs, the role of LDCs is expected to expand. In the future, it will include integrated distribution system planning to enable customer connections and evaluate grid expansion investments and new operation protocols to coordinate DERs in the distribution system.

Types of DERs that can be Enabled, Controlled, and Integrated

DERs can be an essential piece in providing demand response services to wholesale electricity markets, electricity infrastructure (i.e., transmission and distribution network needs), and direct-to-customer benefits. There are numerous types listed below, and it is expected that as the market innovates this list will continue to expand.

A. Utility-scale battery storage
B. Commercial & industrial Behind the Meter (BTM) battery storage
C. Residential scale aggregated BTM battery storage
D. Aggregated residential smart thermostats
E. Load curtailment of commercial & industrial load

Given the commercially available options to customers, these resources are expected to be a rapidly growing share of new supply resources. Demand response will have the potential to make electrification and decarbonization more affordable for corporations and residents alike. If residents can charge an electric vehicle at ultra-low rates at night rather than on-peak more expensive rates at 6 pm, the business case for owning an electric vehicle becomes more alluring. As Ontario businesses continue down its decarbonization and net-zero path, it is expected that electrification will be one of the solutions that are implemented, and demand response can make full use of that generated capacity to make that power go further.

The Ontario Energy Board is in the final stages of its *Framework for Innovation* (FEI)[8] working group papers which seek to provide increased regulatory clarity in the treatment of innovative energy services technologies and approaches and support the deployment and adoption of novel, cost-effective solutions in the electricity and gas services by utilities and other sector participants. The reports indicate that the sector should prepare for a high-DER penetration future. The role of the distributor is one of the clarifications that has not yet been determined. Regulations do not allow for distributors to carry on any business activity other than distributing electricity. The exception is that distributors may own and operate a renewable energy generation facility that does not exceed 10 MW or energy storage facilities that are used for electricity load management.

Regulatory and Government Initiatives

IESO is working through its DER Roadmap and has laid out a work plan that runs through 2026. The four streams are:

a. Ownership opportunities for DER for SNC.
b. Non-Wires Alternatives for capital investments.
c. Capitalization of reliability and societal benefits.
d. Incentive Programs available for Customers – ICI, battery storage, virtual net metering.

Additionally, Energy Minister Todd Smith had asked the IESO to suggest new conservation initiatives, as the province seeks to manage rising demand from electrification. On October 4th, 2022, it was announced that he accepted its recommendations and will roll out new and expanded programs starting next year, with a cost to the province of $342 million for a total framework budget of just over $1 billion[3,4].

The directive was specific in stating its support of electricity distributors taking the lead on CDM opportunities eligible for distribution rate funding under the Ontario Energy Board (OEB)'s December 2021 CDM Guidelines for Electricity Distributors. "By the IESO working together with local distribution companies, which can leverage their close customer connections, there are opportunities to provide value for ratepayers and support both local and system reliability."[3,4]

One of the programs will let households with central air conditioning and a smart thermostat volunteer to allow the IESO to lessen their cooling load to reduce peak demand on certain summer days and get paid an as-yet unspecified incentive. The programs will have a significant benefit for all ratepayers by 2025 and provide opportunities for Synergy North to participate and support customers.

The programs are detailed below, with Synergy North's experience in implementing programs of this nature.

1. A new Residential Demand Response Program for homes with existing central air conditioning and smart thermostats to help deliver peak demand reductions. Households who meet the criteria could voluntarily enroll in this program to be paid an incentive in return for the IESO being able to reduce their cooling load on a select number of summer afternoons to reduce peak demand. There are an estimated 600,000 smart thermostats installed in Ontario.

In 2014 Synergy North (at the time Thunder Bay Hydro) deployed 409 in-home displays in its peak saver plus program. This program was a residential demand response program to allow customers and the utility to control air conditioners and hot water tanks when necessary to curb load.

2. Enhancements to the Save On Energy Retrofit Program for businesses, municipalities, and institutional and industrial consumers to include custom energy-efficiency projects. Examples of potential projects could include chiller and other HVAC upgrades for a local arena, building automation and air handling systems for a hospital, or building envelope upgrades for a local business.

From 2011 to 2014 Thunder Bay Hydro Utility Services implemented the Conservation and Demand Management portfolio of programs designed by IESO with input from the LDC and achieved 99.2% of its energy savings target of 47.38 GWh.

3. Enhancements to the Local Initiatives Program (LIP) to reduce barriers to participation and to add flexibility for incentives for DER solutions.

Although applications for LIP are restricted to recommendations from the IESO through the Integrated Regional Resource Planning (IRRP) process. Synergy North has been working with IESO on its Northwestern Ontario IRRP with the final report supporting the inclusion of Kenora as an identified area of need.

Grid Capacity Planning

Synergy North has been participating in several planning exercises both internal and external to understand the new “electrification” landscape. Beginning with the IESO, at the transmission level of the power system, and then reaching down into the interface of the transmission and distribution systems at the station level with Hydro One Networks (HONI). Finally, an internal review of the capacity of Synergy North infrastructure was completed to gain an understanding of how the grid can be operated to meet customer additional loads while still meeting expected service levels.

IESO Regional Planning Processes

Participating in the IESO Regional Planning Processes (IRRP) produced a 20-year forecast of electricity demand based on customer and utility forecasted connections and growth in the Northwest Region planning region. Both of Synergy North’s distribution territories are included in the Northwest Region and the below figure shows the Thunder Bay and Greenstone area Demand until 2039. Based on projections there are no capacity constraints in the next 20 years for Synergy North’s Thunder Bay service territory. Additionally, the East-West tie was placed into service in March of 2022 and has added 450 MW transfer capacity into the Northwest region[5].

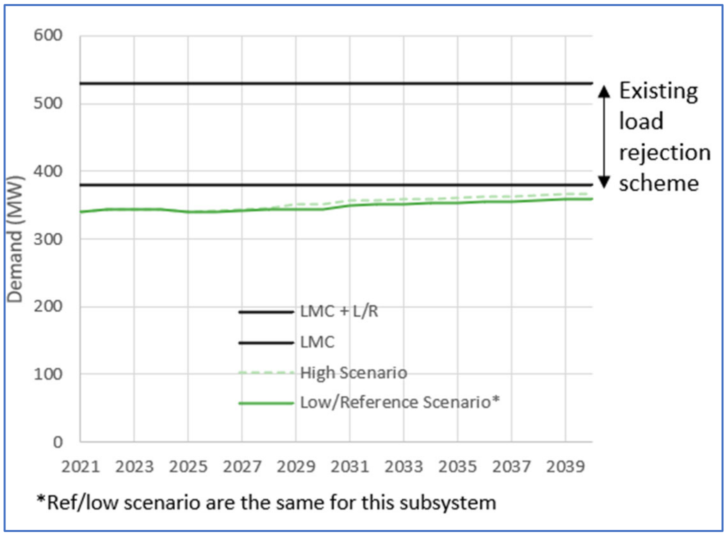

Figure 2 - Thunder Bay Region – Load Forecast 2021-2039

In the Kenora service territory, the demand is set to exceed the station capabilities around 2029, based on forecasts of load growth being realized in the next 7 years. It is important to note that the forecast is based on modest growth of 1.25% and IESO's 2020 adoption rates of electric vehicles.

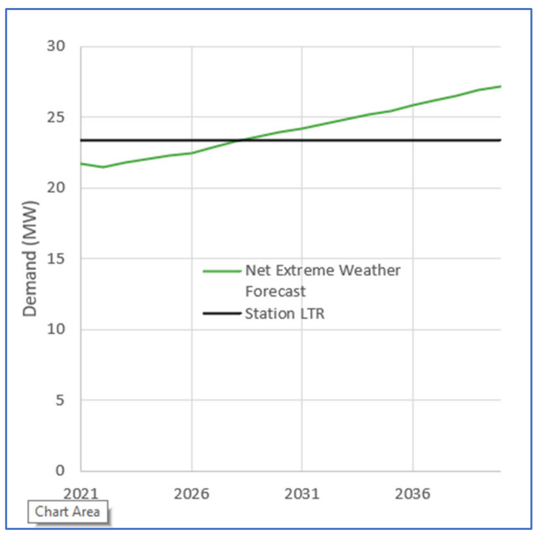

Figure 3 - Kenora Region - Load Forecast 2021-2039

Based on the results, the IESO investigated traditional "Wires" versus "Non-Wires Alternatives" (NWA) to meet the upcoming capacity constraints. Several NWA options included energy storage devices, dispatchable local generation, demand response, or energy efficiency (See slide below). The results indicate that the NWA costs to meet Kenora MTS' capacity need to fall between the $5M station expansion cost and the $30M new station cost. The results indicate that the least expensive wires solution is likely more cost-effective than any NWAs, however, NWAs may be more cost-effective than a new station situated on the other side of the town. Distribution system benefits have not yet been factored into the analysis and may impact the ultimate cost-effectiveness of a solution.

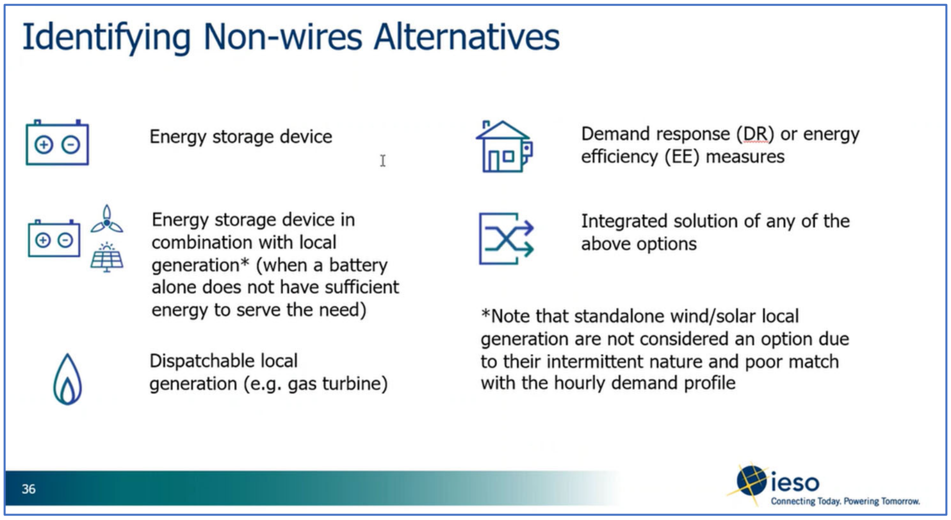

Figure 4 - IESO - Northwest Region Integrated Resource Planning Working Group – Presentation on NWA

Ultimately, the IRRP's (Integrated Regional Resource Plan's) recommendation was left to be as permissive as possible to provide rationale and support for Synergy North to pursue NWAs further and avoid constraining to a single option. This is in part because of the difficulty to quantify considerations such as how valuable the additional resilience of having a second transmission supply is. Another reason is that NWAs are relatively untested at this point – the IESO/Alectra's York Region pilot is just now testing a model for how local DER resources can be procured and dispatched to meet a local capacity constraint (not to mention how to contribute to and derive revenue from provincial system capacity and energy needs). This need is still several years in the future, so this is an optimal time for Synergy North to further study and explore options.

Station Capacity for Load Connections

The below chart provided by Hydro One Networks Inc (HONI) indicates the ability of Hydro One to provide additional load capacity to Synergy North. There is still significant available capacity at Birch TS and Fort William TS and even Port Arthur TS could handle a new large industrial customer or significant growth in the electrification of existing customers. An example of a large retail customer size and consumption is approximately 1MW connection and a consumption of 750 kW load. There are less than 15 of these customers in Thunder Bay and none in Kenora. Historically, customers over 10MW connected directly to the transmission system, but now have the option for Synergy North to build a dedicated municipal transformer station (MTS) for their specific needs.

Station	Available Station Capacity (as of Nov 1, 2021)	Existing Station 10-day LTR (MVA)
Birch TS	36.65	111
Fort William TS	23.85	109
Port Arthur TS	13.27	61

Table 1 - Thunder Bay Station Capacity to connect Load customers

Feeder Capacity for Generation and Load Connections

Customer-owned generation has been connected to the Synergy North distribution grid for over 11 years, with the original offering of Feed-In Tariff (FIT) contracts through the IESO. This program was launched in 2009 to incentivize greater use of renewable energy sources including wind, biomass, and solar. In 2016 the program ceased accepting applications, and new residential and commercial renewable applications have been connected as net metering connections. These connections allow the customer to offset costs incurred by generating their energy and only drawing from the grid when needed. The total amount of connected generation amounts to 30,309 kW across all of Synergy North's feeders. Even with this large amount of connected generation, there is still capacity to accommodate additional generation sources. Below are charts that indicate the available capacity of Medium and Large Sized Generators as well as Micro and Small Sized Generators on a per-feeder basis.

Medium and Large Generators have the telemetry back to Synergy North's control room to allow the control operators to disable and enable the generators to feed energy onto the grid. This is the basis of a FINO, and Synergy North has experience in doing so for operational purposes. The evolution is to potentially utilize this existing capacity to create demand response programming.

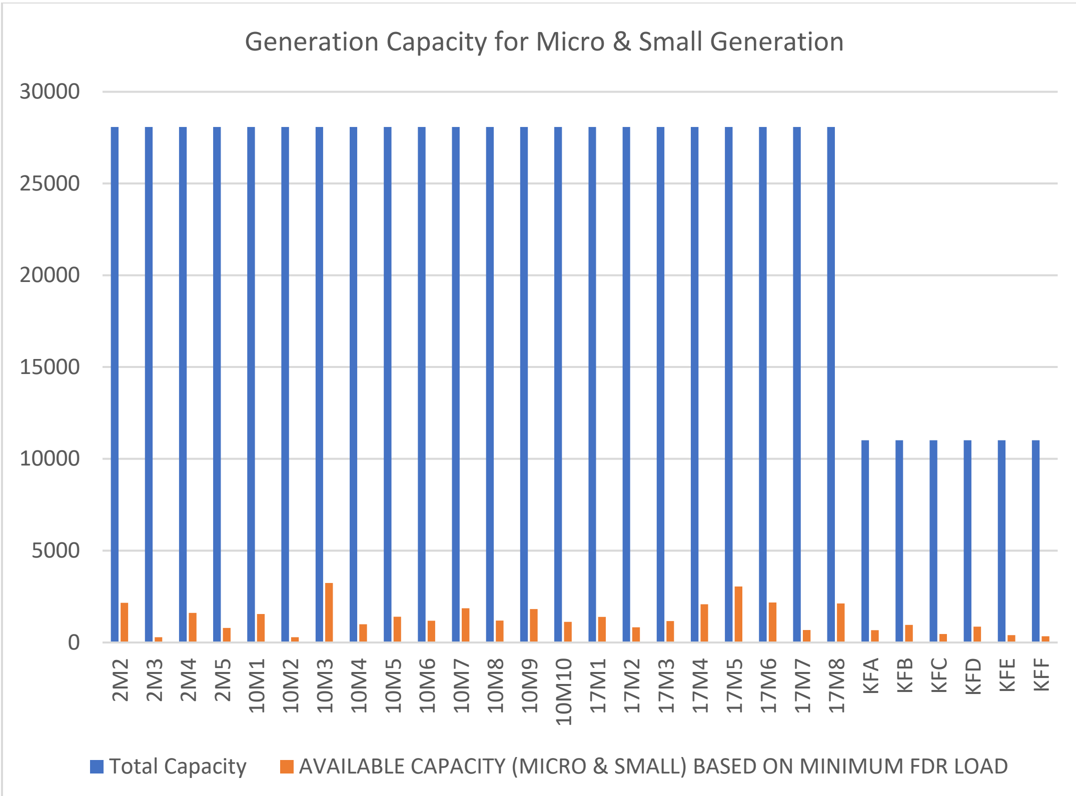

Figure 5 -Available Capacity for Medium and Large Generation across Synergy North Feeders

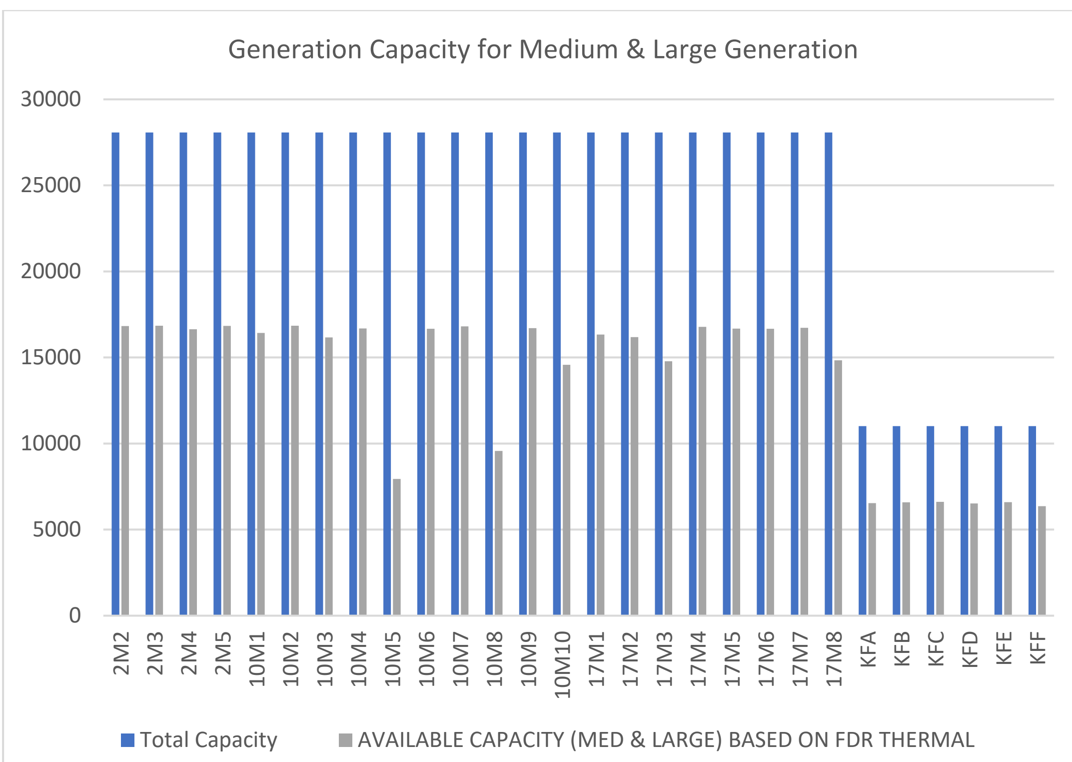

Figure 6-Available Capacity for Micro and Small Generation across Synergy North Feeders

Due to electrification driving demand growth, Synergy North performed an internal feeder study to determine the loading on each feeder and their available capacity to connect additional electric loads.

During times of planned and unplanned outages, the system is often reconfigured to connect pockets of load from different sources. Capacity must be available on each feeder to meet this operational need. The two charts below indicate that Synergy North's main feeder conductors which were purposely engineered and built with 556 Aluminium, can carry a maximum of 703A. This conductor size is the largest standard size across Ontario that is installed on distribution overhead systems. It allows Synergy North the flexibility to accommodate the neighboring feeder load on one overhead line.

In the Kenora region, the system was engineered and built with 336 Aluminium overhead conductors which can carry a maximum load of 513A. This capacity is sufficient for the current feeder loading scenarios in Kenora but will allow less flexibility than the higher-rated 556 Aluminium when loads increase. It may require capital investment in the future.

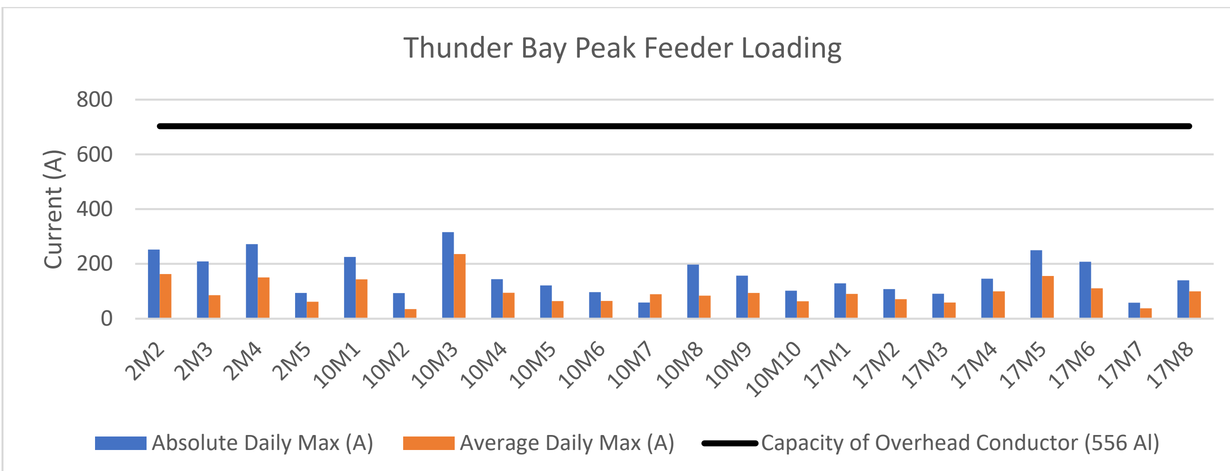

Figure 7- Thunder Bay Peak Feeder Loading (2022)

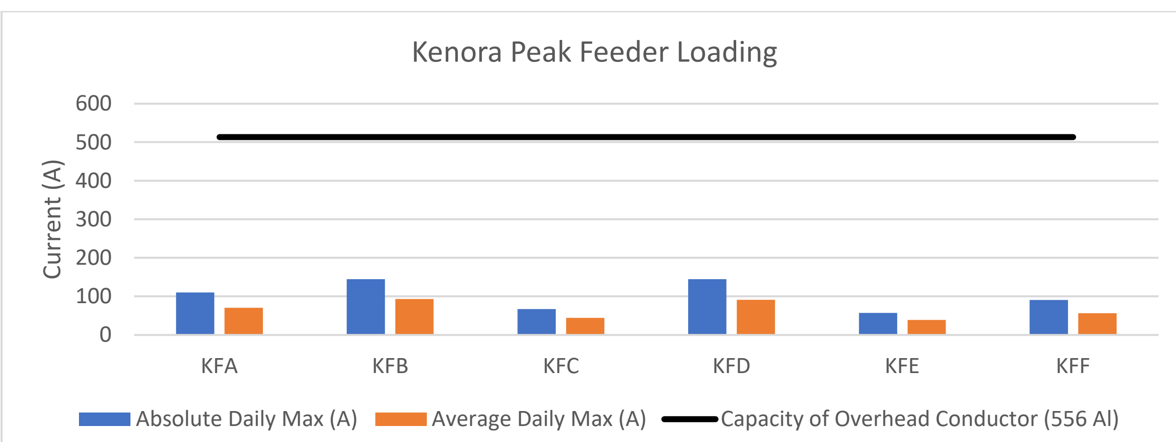

Figure 8 - Kenora Peak Feeder Loading (2022)

Grid Modernization

Thunder Bay Hydro Distribution Inc. (TBHEDI) prepared and submitted a Grid Modernization plan with its Cost-of-Service application in 2016. The plan addressed the need for creating a 'modernized' distribution grid that met the changing needs of customers, industry, and regulators. At the time a modernized grid facilitated the use of automated and self-healing devices to distribute electricity more effectively, economically, and securely. Although TBHEDI had been purposefully renewing its grid by converting voltages from 4kV to 25kV and installing telemetry-based switching points for the last 5 years, a true modernization of the grid would allow for the deliberate incorporation of intelligent devices that would provide better visibility and operational flexibility to minimize outage impacts and identify areas to achieve better grid performance. Over the 5 years (2017-2021), TBHEDI forecasted approximately $1.39 million of capital spend on grid modernization projects. The investments included installing 10 reclosers (automated switches), valued at $900,000, an Outage Management System valued at $290,000, and distributed automation valued at $200,000. (These investments are in 2016 prices). When TBHEDI merged with Kenora Hydro Electrical Corporation Ltd. to become SYNERGY NORTH CORPORATION INC. in 2019, the modernizing of the grid continued in both Thunder Bay and Kenora districts. We believe that continuing to invest in intelligent devices forms the basis for a smart grid. It will allow Synergy North to enable and control devices owned by the utility and others connected to the distribution grid.

Customer Choice

Synergy North is driven to understand how customers wish to participate with the utility to improve their affordability and reliability. Residential customers have historically stated that affordability and reliability are their top priorities. In the recent Customer Satisfaction Survey from October 2022 when asked what the single most important new service or change that Synergy North could make to improve its service, the top three responses were; 44% "Lower Rates", 28% "Don't Know" and 6% "Fewer Outages". As the DER and EV landscape evolves, allowing customers to take advantage of using behind-the-meter devices will be key to achieving their reliability or affordability needs.

Additionally, we are interested in working with our business customers to meet their energy needs. For some, this will mean a reduction of carbon footprint or Environmental Social and Governance "ESG" initiatives, and Synergy North wants to be involved in the planning stages to ensure the distribution system will be prepared to handle the service needs of the future. Synergy North is currently engaging on its Cost-of-Service Application and has been meeting with its Class A customers such as Confederation College, Lakehead University, and Alstrom, to understand future expansion and carbon reduction initiatives. Through the key accounts advisor, there have been 27 large customers engaged with 50 different programs with a goal to save 5% on each customer's bill.

Synergy North has engaged customers on an ongoing basis and continues to foster excellent relationships with its customers through surveys and the local advisory committee. This outreach allows customers the ability to provide input on programs and initiatives to service their customers. In October of 2022 Synergy North obtained a Net Promoter Score of 36 which is well above excellent.

Preparing a Strategic Framework

To evaluate the strategic path forward, Hambrick and Fredrickson's strategic framework and guidance were utilized. This framework ensures an integrated overarching concept of how Synergy North will achieve its objective of being "A trusted partner for energy and related services". The strategy diamond is illustrated below.

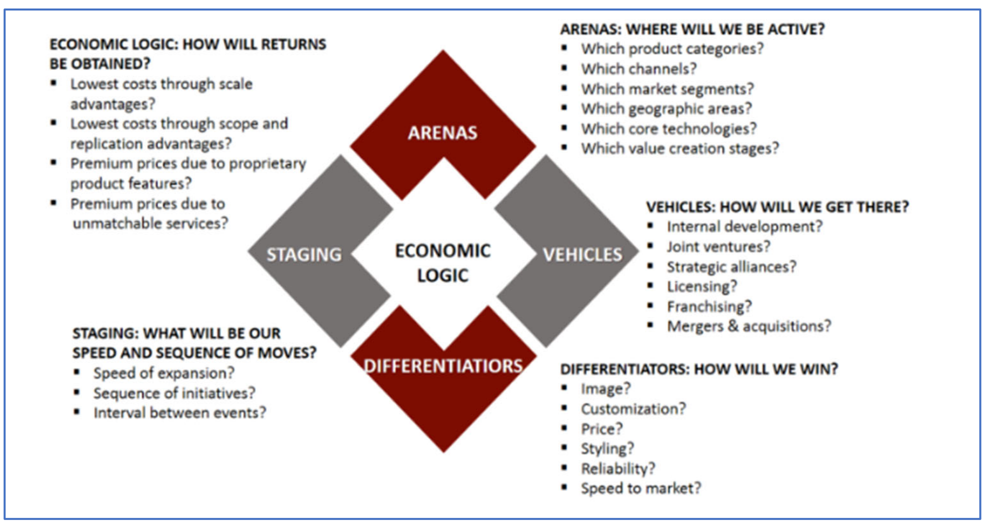

Figure 9 - Hambrick and Fredrickson's Strategy Diamond

Where will we be active?

To answer where Synergy North will be active, we look to what our customers and shareholders want and need to participate in the Energy Transition. Synergy North engaged customers on the "Customer Satisfaction Survey" in October of 2022 and heard that although only 4% of customers currently own a fully electric vehicle, in 2 years 22% will be purchasing one, and in 5 years 45% of customers plan on purchasing an electric vehicle.

Our shareholder, the City of Thunder Bay is engaging a consultant to review electrifying transit services in 2023. Additionally, the expansion of conservation and demand programming by the province will likely cause an influx of options available to customers to manage their energy costs, and Synergy North is prepared to administrate those programs

Because of the developments in transportation electrification, Synergy North plans to support our customers and shareholders by ensuring that we have the knowledge and expertise in connections to the distribution grid, whether they be electric vehicles, battery storage, or other renewable DERs. Our experiences and participation in IESO Conservation and Demand Programs, Market Renewal Activities, Feed-In-Tariff generation connections, Grid Modernization initiatives, and the Power.House pilot project has prepared us, and we will continue to actively seek out and participate in energy sector working groups to be fully informed for our customers.

We will continue to expand and leverage our existing software platforms to manage new loads by enabling customer choice on demand management, conservation, and price responsivity.

We are also preparing to meet our customers where they already connect with us, on our portal, through our website and when they contact our customer service center. We plan to connect with our customers as trusted advisors and continue to provide value to those customers by offering expertise and programs to enable the energy transition.

How will we get there?

To meet our customers where they are, Synergy North sees the need to expand its internal knowledge of DERs and EVs. We plan on educating our internal staff so that we can then pass on this knowledge and advice to our customers. These services will be provided to customers who are already connecting to Synergy North through our Key Accounts Advisor, Customer Service Representatives, and website.

Our Key Accounts Advisor recently prepared an EV Tactical Plan which directs activities for 2023 such as strategic alliances with car dealerships in Thunder Bay and Kenora. This alliance intends to have customers register their EVs as they are purchased to provide insight into the utility as to the location of the load and provide the customer with the latest news from the EV world.

Synergy North plans to expand its existing relationships with electrical contractors and energy management software providers from the Power.House project, to provide information and recommendations on installations of residential and commercial EV chargers and software systems.

Synergy North predicts that building new relationships with grid-scale battery manufacturers/operators and residential EV chargers and battery storage vendors will be important as customers continue down their path to owning EVs and DERs. There will be future opportunities for Synergy North to enter joint ventures with service providers selling EV chargers and devices to manage home energy. Preliminary discussions with HomeServe USA are preparing Synergy North to understand this business model and how our interests could align for the benefit of our customers.

Synergy North has signed an agreement with Lakehead University, the City of Thunder Bay, and Blue Wave AI to perform research on using an AI Data-driven simulation framework for an electric transit system and its integration with the power distribution network. By participating in this project in the next 2 years, we expect to gain insights into how electric bus load will affect the distribution grid. This will provide learning opportunities that can be leveraged for future projects and provide the required mechanisms for future electric loads and the measures to respond to the increased load.

Synergy North plans to continue to work closely with the IESO for the next 3 years in the implementation of recommendations from our IRRP on Non-Wires Alternatives for the Kenora Station Capacity need in 2029. This timing provides Synergy North with the ability to access government funding and other conservation and demand programs to continue to defer expensive station investments. As the programs evolve, we are committed to investigating all alternatives before determining the final solution.

How will we win?

Local hydro utilities in Ontario are the part of the electricity system that is closest to customers. We are on the front lines of power, and work to keep our electricity system safe, reliable, and affordable for households, small businesses, commercial, and industrial customers. Because we are so close to our customers, Synergy North is a crucial source of information and helpful advice. In fact, a February 2022 poll conducted by Campaign Research found that 85% of Ontarians interested in energy efficiency and conservation programs for residents and businesses preferred that their local hydro utility design and deliver such programs in their communities.

Synergy North has determined that Relationship Differentiation will have the most impact on the Energy Transition. Our customers already trust that we can advise them on new connections to the grid, and by providing additional tools through our website, such as bill impacts for charging EVs or when service upgrades are needed, we can provide additional value to existing customers.

What will be our speed and sequence of moves?

The speed at which Synergy North invests in assets and programs will be in lockstep with the needs of our customers. Our first stage of the Energy Transition will be to understand the current EV and DER landscape and the speed at which it will affect our distribution grid. There is much controversy regarding the regional differences in the adoption of EVs and developing a customized prediction in 2023 through customer engagement in our service territories. Continuing to engage customers in 2024-2026, will allow us to incorporate any changes in the timing of EV adoption on an annual basis. As EVs become more commercially available and price parity becomes a reality, we expect that more customers will adopt these technologies at a greater rate. However, with global events and supply chain constraints, continuing to engage with customers will be the most accurate reflection of what to expect on the grid. Creating this evolving prediction will ensure that we manage any impacts or risks to the reliability of the system.

We believe that the learnings that we have obtained through our experiences in Conservation and Demand Programming, Feed-In-Tariff generation connections, and the Power.House can be expanded and shared with customers to support their EV and DER path. Synergy North plans to leverage these experiences as we prepare customized tools for customers to be accessed on the Synergy North portal/website in 2023. Training of our Customer Service Representatives will be done before the tools are available to customers in 2024.

As energy management technologies become more mainstream and utilized by commercial customers, being informed through working groups and customer engagements throughout the 2023-2026 timeline ensure that Synergy North will be prepared to connect the latest innovative technologies to our grid.

We are also prepared to evaluate non-wires alternatives in 2025 when we issue a Request for Information to the market regarding our Energy needs in the Kenora region.

The trust that has been built with our customers will be crucial in the later stages of the Energy Transition (2026 and beyond) when the regulations become permissive to allow bidirectional charging for energy storage and EVs. Providing the ability for Synergy North to send signals and enable demand response to customer-owned assets behind the meter.

How will we obtain our returns?

Synergy North's mission is to provide outstanding energy services in a safe, reliable, and trusted manner to our communities to power people's lives. By providing EV support and services to our customers, not only are we able to provide added value to our customers but we are also better able to manage customer-connected assets in a manner that ensures that we can deliver on our promise of safe and reliable power. When outages occur due to poorly planned asset replacement or monitoring programs, the customer suffers. This can result in a loss of revenue and a suspension of services to the community. Synergy North intends to ensure that the system will be able to operate dependably with additional generation and loads, through informed long-term planning.

As a monopoly, Synergy North is accountable to our customers and shareholders to make smart decisions regarding how to replace our assets and make efficient use of the rates we collect. By evaluating non-wires alternatives against traditional investments Synergy North may be able to defer costly asset expansions and renewals. This leads to efficient use of the capacity available to the grid and cost savings to customers.

Working with the OEB and IESO to provide conservation and demand management and energy efficiency programming for customers will ultimately continue our vision of being a trusted partner for energy and related services. We are ready to move towards a fully electrified, sustainable future by providing the services that are needed for our customers to reach their goals.

Recommendations

Milestones

Based on the above strategic framework, two clear pathways for Synergy North become clear in concurrently managing the risk of reliability and accommodating customer choice through FINO. Capacity and EV support and services. Each of these initiatives has projects that are new to the utility with execution dates identified.

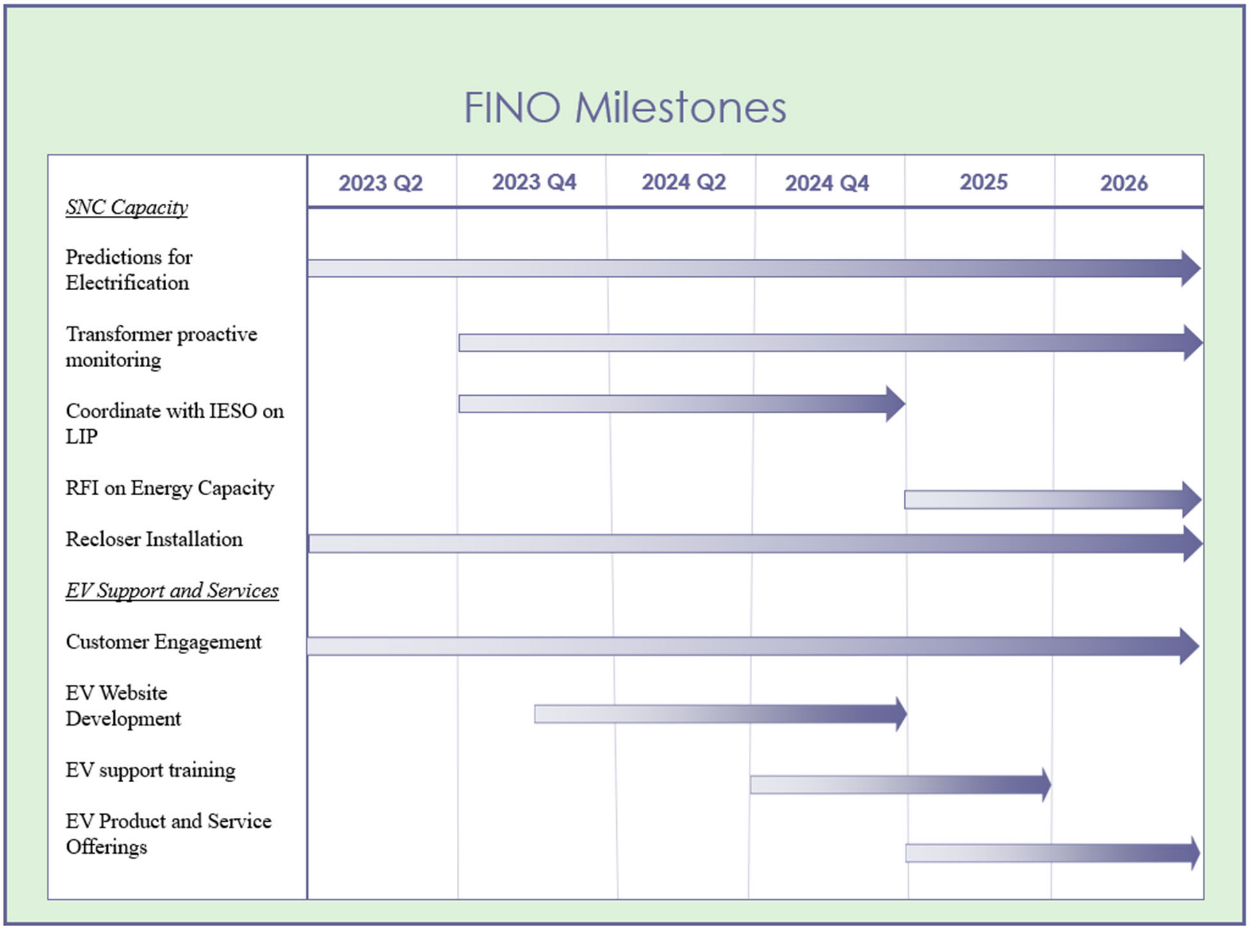

Figure 10- Milestones for FINO Implementation 2023-2026

Investments

A breakdown of the investments directly related to the milestone indicated for the period 2023-2026 is shown below. Most of the capital activities that Synergy North will continue to invest in are "grid modernizing" devices that prepare the grid to enable and control loads and DERs. This includes the installation of smart switches (reclosers) and upgrades to telemetry as stations come offline through the voltage conversion process. This is a continuation of the "Grid Modernizing" activities that occurred from 2016-2021.

Many of the new projects for the utility will utilize internal resources with support from contractors to prepare further website development, customer engagement, and procurement processes for energy capacity.

The investments beyond 2026 are still unknown due to the cost-of-service application that is occurring in 2023. The potential large investments in grid-scale battery storage or additional transformation will be incorporated into a separate ICM (Incremental Capital Module) or ACM (Additional Capital Module) application due to the magnitude of the solution appropriate for KMTS capacity constraints.

FINO Plan- Capital	***2023***	***2024***	***2025***	***2026***
Recloser (Reliability)	$272,000	$277,440	$282,989	$288,649
BTM Batteries (Planned Outages)	$ -	$ 45,000	$ -	$ -
SNC Capacity - System Upgrades due to EV	$ -	$ -	$ 55,000	$ 66,100
SNC Capacity - SCADA Upgrades	$ 20,000	$ 20,400	$ 20,808	$ 21,224
Total Capital Expenditure	$292,000	$342,840	$358,797	$375,973
FINO Plan - OM&A	***2023***	***2024***	***2025***	***2026***
SNC Capacity	$ 35,000	$ 25,000	$ 50,000	$ 50,000
EV Support and Services	$ 10,000	$ 25,000	$ 25,000	$ 10,000
FINO Software Upgrades	$ -	$ -	$ 15,000	$ 25,000
Total OM&A Expenditure	$ 45,000	$ 50,000	$ 90,000	$ 85,000

Figure 11 - FINO Investments 2023- 2026

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APPENDIX E: VEHICLE AND EQUIPMENT RESOURCE PLAN

SYNERGY NORTH's

Vehicle and equipment

Resource Justification Plan

2023

May 1, 2023

Contents

1) Introduction

SYNERGY NORTH CORPORTATION (SNC) covers a large service territory and requires a fleet of specialized vehicles to complete the daily activities associated with operating a safe and efficient distribution system. As part of its mandate, SNC aims to ensure that any customer outage event(s) and/or system maintenance activity is managed in a safe and timely manner. SNC's Vehicle and Equipment Resource Justification Plan provides the rationale as to why specific vehicle types are required, the current quantity of vehicles and equipment in service, information on which assets require replacement, and when that replacement is proposed based on the criteria detailed within. Furthermore, it also includes vehicle rental options if applicable and opportunities to reduce the number of assets within the fleet.

2) Specialty Line Vehicle Quota Rationale

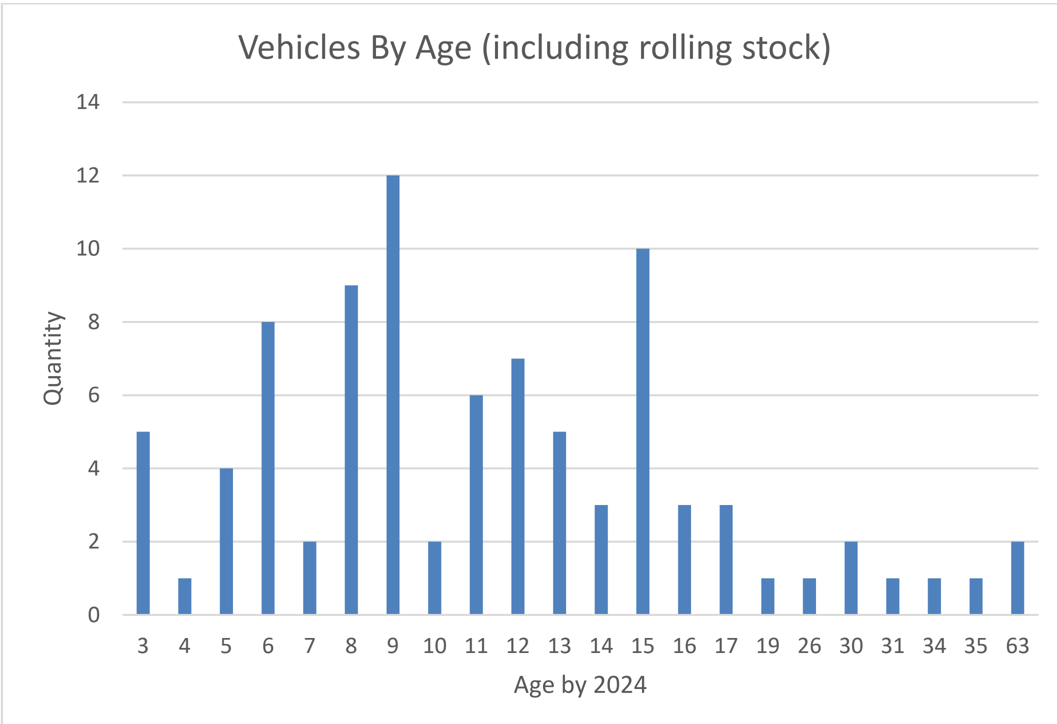
SNC currently has 91 assets that make up its fleet contingent. Each vehicle has specific functions or limitations and are required to fulfill and or enhance worker safety, ergonomics, and operational activities. The utilization of any specialty vehicle varies depending on the type and quantity of work each day. However, the fleet size is currently matched to SNC's field staff complement and utilized by numerous work groups within the utility. Due to the unpredictable nature of system disturbances, equipment failures, and maintenance/construction activities, determining when a particular vehicle may be required to manage a given situation is not always possible.

Where it is practical to do so, SNC attempts to coordinate work activities such as construction, maintenance, and metering to the same geographic location. In many cases this is not possible, and it results in overlap of vehicle types. These activities can include:

- Planned Construction – these activities are generally well defined, and the fleet assets associated with them are known in advance of the project. However, there may be multiple construction projects throughout the service territory requiring similar vehicles and equipment where a reduced vehicle complement requiring vehicle sharing, would make construction inefficient.
- Unplanned activities – the scope of these activities, by their nature, are variable and unforeseeable; one task may require a single light duty vehicle, while another task may require numerous trucks and/or support equipment.
- Metering, Protection & Control (P&C) and Stations use of the specialty vehicles varies to facilitate the needs of other departments such as:
    - Billing – smart meter collector maintenance/repairs.
    - System control – switching device maintenance/repairs.
    - Engineering – communication/ protection & control system installation/ maintenance.
    - Operations – building security cameras and station maintenance.

3) Vehicle Replacement Criteria

SNC anticipates a useful service life for light vehicles of typically twelve (12) years, and a useful service life of heavy vehicles for typically fifteen (15) years. As displayed by the chart below, there are many vehicles expected to reach their end of service life within the next few years.



To enhance fleet reliability and work crew productivity, some older vehicles may be rotated from their current daily use duty into a seasonal or less critical type role. SNC's intent is not to increase the overall fleet vehicle count. Thus, any vehicle(s) placed into the seasonal or less critical role categories may be included as trade-in vehicles during the purchase process or may be surplus/scrapped. SNC anticipates 10,000 – 15,000km per vehicle as a yearly average, however certain assets may require replacement sooner depending upon the overall mileage accumulated and the physical condition of the vehicle (exterior body panel or chassis/ structural component deterioration).

It is important to note that this plan also considers a vehicle/ equipment's repair history, reliability (uptime percentage), and or the vehicle/ equipment's operating costs due to repetitive breakdowns which may mandate the early replacement of that vehicle/ equipment

SNC's speciality items which can be rented locally (ie. easement machine, etc.) will be monitored for increasing annual safety inspection costs and to limit any large repair expenditures on a case-by-case basis to a reasonable amount. If the cost of annual maintenance or individual repair becomes excessive, the equipment will be removed from service and disposed of. Future needs for a similar equipment type will be sourced via rental options.

4) Current Vehicle and Equipment Justification (as of May 2023)

The following list provides a detailed explanation of both the vehicles and equipment owned by SNC and their users. Furthermore, it provides an understanding for the use of each vehicle within the corporation.

1. Double Buckets (8): utilized by Lines, P&C and Stations staff.
   a. They are 0 to 65 foot insulated work platforms with material handling capabilities and provisions for the storage of tools, material, and equipment which are utilized for overhead power line construction/ maintenance, radio communication testing/ confirmation, and substation maintenance work

2. Single Buckets (8): utilized by Lines, Metering, P&C and Stations staff.
   a. They are 0 to 47 foot insulated work platforms with provisions for the storage of tools, material, and equipment which are utilized for overhead line construction/ maintenance, substation maintenance, smart metering collection, and miscellaneous building lighting/ camera work

3. Radial Boom Derricks (6): utilized by Lines and Stations staff.
   a. They are 0 to 47 foot 16,000 pound material handling/ hoisting/ towing platforms with provisions for the storage of tools, material, and equipment which are utilized for overhead line construction, maintenance, station cabling/ structure, and trailer towing work

4. Light Trucks, SUV and Mini Vans (30): utilized by the Lines and Engineering & Operations Departments personnel for all their associated duties.

5. Dump Truck (1): utilized by Lines and Stations for trailer/ equipment towing, and aggregate movement/ placement work (rear dumping only)
   a. SNC can utilize local equipment and operator service providers to back-fill any dump truck short falls

6. Mini Dump Trucks (3): utilized by Lines and Stations for trailer towing and aggregate movement/ placement work (rear and side dumping capable).

7. Super Cab Flat Deck (with lift gate) (3): utilized by Stations and Lines for transportation, material hauling, and for yard/ work area sanding purposes.

8. Cube Vans (2): utilized by Stations and Lines (underground crew) for transportation and material hauling purposes.

9. Backhoes (2): utilized by Lines for trenching, LHD of aggregate material, snow removal, rock breaker, and forklift/ material handling work.
   a. SNC can utilize a local equipment and operator service supply contract to back-fill any backhoe loader short falls

10. Stringing Trailer/ Machines/ Puller Tensioners (4): utilized by Lines for power distribution construction and maintenance activities.
    a. As of this report, SNC does not rent this type of equipment due to the uniqueness of the assembly, associated components, and the need to train the user’s prior to utilizing this equipment

11. Reel Trailer (4): utilized by Lines for power distribution construction and maintenance activities.
    a. As of this report, SNC does not rent this type of equipment due to the uniqueness of the assembly, associated components, and the need to train the user's prior to utilizing this equipment

12. Pole Trailers (4): utilized by Lines to move hydro poles for power distribution construction and maintenance activities.
    a. SNC can utilize an equipment and operator service supply contract to back-fill any pole trailer short falls

13. Easement Machine and Trailer (2): utilized by Lines for power distribution construction and maintenance activities.
    a. SNC can utilize a local equipment and operator service supply contract to back-fill any easement machine short falls

14. Compressor Trailer (3): utilized by Lines for emergency power distribution activities.

15. Equipment Float Trailers (2): utilized by Lines/ equipment operators to transport the backhoe, large transformers and or material.

16. Rear Dump Trailers (4): utilized by Lines to place aggregate or to transport transformers or material.

17. Three Way Dump Trailer (2): utilized by Lines to place aggregate or to transport transformers or material.

18. Forklift (1): utilized by Lines, Stations, and Stores to place, transport, and or move transformers or material.

19. Work Boat (1): utilized by Lines in Kenora service territory for water only access to distribution assets on islands.

5) Recommendations and Equipment Renting

As most of the speciality line vehicles in Thunder Bay and Kenora are not readily available for rent, it is recommended that to ensure our business continuity and commitment to customer satisfaction, SNC maintains their current vehicle fleet complement based on the following variables:

1. SNC's geographic location is, by nature, a detriment as it does not allow for a timely response for acquiring rental vehicles if they were required for either daily work objectives or outage management scenarios.
    - Based on immediate availability from a rental company, internal purchasing approvals, establishing insurance, providing an "in service" vehicle orientation etc.; SNC could expect a 3–4-week lead time or;
    - If the required vehicle is not immediately available, a 2 to 6 month delay in acquiring the requested vehicle(s) is probable.
2. Costs associated with acquiring specialty power line vehicles (RBDs, bucket trucks) includes delivery/ pick up fees, monthly fees, any associated damage and minimum rental term obligation.
    - RBD rental is $6,100 monthly, delivery fee is $3,500, and the pick-up fee is $3,500 with a minimum rental term of 1 month

- Double Bucket rental is $6,100 monthly, delivery fee is $3,500, and the pick-up fee is $3,500 with a minimum rental term of 1 month
- Single Bucket rental is $3,800 monthly, delivery fee is $2,500, and the pick-up fee is $2,500 with a minimum rental term of 1 month

6) New Vehicle Costs

New speciality line vehicle purchase costs that have been used for budgeting purposes (as of 2023) are as follows;

- Radial Boom Derrick = $555,000
- Double Bucket = $650,000
- Single Bucket = $500,000

7) Vehicle and Equipment Acquisition Plan and Expenditures 2024-2028

The following charts provide an explanation (per year) on the number of vehicles projected to be purchased, and which vehicles they will be replacing within the corporation. Additionally, the charts outline the projected (and where applicable), actual costs of the new vehicle or equipment.

Projected Fleet Purchases and Costs for 2024 to 2028

2024	
Fleet Description	Projected Purchase Cost
Light truck to replace #84 (2012)	$70,000
Space Kap to replace an existing kap	$25,000
Electric or gasoline powered SUV to replace #59 (2009)	$90,000
Light truck to replace #55 (2009)	$70,000
Light truck to replace #69 (2012)	$70,000

Space Kap to replace an existing kap	$25,000
Drop bow type work boat, outboard motor and trailer to replace #950 (2015)	$250,000
2024 Projected Fleet Purchase Amount	$600,000
2025	
Fleet Description	Projected Purchase Cost
Large single bucket to replace #71 (2012) and #97 (2009)	$500,000
SUV to replace #91 (2013)	$50,000
F-350 Crew cab truck to replace #8 (2013)	$70,000
Light truck to replace #122 (2012)	$70,000
Space Kap to replace an existing kap	$25,000
2025 Projected Fleet Purchase Amount	$715,000
2026	
Fleet Description	Projected Purchase Cost
Large single bucket to replace #121 (2012)	$525,000
Light truck to replace #92 (2013)	$70,000
Light truck to replace #93 (2015)	$70,000
Space Kap for #92’s replacement	$25,000
Space Kap for #93’s replacement	$25,000
2026 Projected Fleet Purchase Amount	$715,000
2027	
Fleet Description	Projected Purchase Cost
Double bucket to replace #60 (2010) or #61 (2011)	$650,000
Light truck to replace #94 (2015)	$75,000
Light truck to replace #96 (2015)	$75,000
2027 Projected Fleet Purchase Amount	$800,000
2028	
Fleet Description	Projected Purchase Cost
2 Stringing Machines	$340,000
Electric or gasoline powered SUV to replace #101 (2016)	$100,000
Electric or gasoline powered SUV to replace #102 (2016)	$100,000
Electric or gasoline powered SUV to replace #103 (2016)	$100,000
F-350 Crew cab truck to replace #98 (2015)	$80,000
Space Kap for #98’s replacement	$25,000
F-350 Crew cab truck to replace #106 (2016)	$80,000
Space Kap for #106’s replacement	$25,000
2028 Projected Fleet Purchase Amount	$850,000

L&O will contact rental suppliers to confirm that availability exists and will ensure delivery occurs as per the following

1 RBD to be rented for capital work as of January 2026 and another RBD to be rented for capital work as of January 2027

L&O will start the tender process in Q4 of 2027 for the proposed purchase below so the RBD is delivered in January 2029

1 RBD is planned to be purchased in 2029 (estimated cost is $525,000)

APPENDIX F: METERING MASTER PLAN

SYNERGY NORTH

METER MASTER PLAN

Smart Meter Inventory, Pre-Sampling, Compliance Sampling,
Reverifications, Primary Metering, Commercial/Large Residential,
Installation Testing, and Collectors

2024 - 2028

Prepared By:
Duane Szyszka
Operations Superintendent
May 12, 2023

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1.0 GENERAL

New electronic smart meters are shipped from the factory with a defined meter seal expiry period of 10 years.

As per Measurement Canada and the Electricity and Gas Inspections Act, a meter that has an expired seal cannot be left in service for revenue collection purposes.

Synergy North Corporation (SNC) has the following four options to ensure ongoing meter seal compliancy.

1. replace the expiring meter with a new meter and scrap the original meter or
2. have the expiring meter replaced and reverified so it can be used again or
3. complete a compliance testing program so the meters can continue to remain in service or
4. submit a “Risk Management Framework Plan” (RMFP) to the Director of Measurement Canada with the intent to solicit dispensation for only the meters that are detailed within the RMFP **(this option is not guaranteed and is limited to extenuating circumstances and needs to be submitted and approved by Measurement Canada prior to expiry of any meter seals)

If the RMFP is approved by the Director of Measurement Canada; the subsequent dispensation would allow the expiring meters defined within the submitted RMFP to remain in service for an additional period as prescribed by Measurement Canada.

Meter Service Provider (MSP) activities have not been included within this MMP as they are overseen by SNC’s sister company Thunder Bay Hydro Utility Services Inc. (TBHUSI). However, meter types that could be utilized within either the MSP or MV90 customer base are included and will be evaluated, selected, and used by SNC Engineering to ensure that acquisitions of these specialty meters only occur if necessary.

2.0 PURPOSE

This MMP will document SNC’s metering activities that are required for legislative, billing, and or customer satisfaction purposes.

SNC’s MMP will also detail the components that are required to ensure success when SNC is completing pre-sampling, compliance testing, reverification activities, installation testing, collector maintenance, or meter inventory reviews, including the departmental assignments for those tasks.

3.0 METER INVENTORY MANAGEMENT AND COST REDUCTION RATIONALE

To mitigate unnecessary costs during meter reverification activities compatible inventoried meters will be utilized in a reverify/replace/reverify/replace… strategy in lieu of purchasing larger quantities of new meter(s). As another cost reduction, SNC will reprogram LAN ID’s from their existing compatible meter inventories so meters can be utilized within their other service territories (ie. Thunder Bay meters have LAN ID 133 when changed to LAN ID 134 these meters can be used in Kenora and vice versa).

For example, if 100 meters of a specific meter type are required to be replaced and the on-hand inventory count is only 25 meters, those 25 meters would be used to replace 25 of the 100 targeted meters. The removed 25 meters would be sent for reverification and once returned the meter replacement process would continue until all 100 meters have been replaced. This strategy would result in only 25 meters being left in inventory and avoids having 100 meters (if purchased just for this activity), left sitting on the shelf at the conclusion of a specific reverification effort. This strategy would result in only 25 meters being left in inventory and avoids having 100 meters (if purchased just for this activity), left sitting on the shelf at the conclusion of a specific reverification

effort. This strategy is effective however as seen in 2022; SNC experienced a 40% R2S meter failure rate during reverification activities due to blank LCD display screens on the meters.

The above reverify/replace/reverify/replace (repeat) strategy will not work for compliance testing activities as specified quantities of meters as per Measurement Canada's criteria need to be sent for testing at the same time.

The utilization of alternative meter types which have equivalent or increased capabilities with a similar per unit cost may occur as well to keep inventoried quantities and costs reduced (ie. A3RL meters being used if there are not enough A3TL meters in inventory).

SNC will reverify and when possible reuse their A3TL type meters. SNC will no longer purchase new A3TL type meters, as the A3RL/A3XL meter types will be SNC's future polyphase meter type.

As Honeywell (Elster) develops new meter types, SNC's engineering group will continue to review SNC's meter inventories to determine if there are opportunities to consolidate existing meter types.

Due to long lead times (~12 months) to receive new meters, Engineering and Operations will convene by March of each year to review the following: meter seal expiries (for the next year's compliance sampling / reverification activities), meter failures quantities, anticipated new commercial / residential customers, and determine what meter types and quantities will be required to fulfill the future years' meter replacement or installation targets. Once known, a meter purchase request will be drafted, approved, and then submitted to purchasing to acquire the necessary meter types and quantities.

Regardless of the activity (compliance testing, reverifications, warranty repair); prior to any meters being shipped off-site; stores needs to be advised of the applicable meter stock number and applicable quantity being shipped via a "Meter Transaction Form". Stores will update/change the meters' location within their inventory database (ie. from "Meter Room or In-Stores" to "Off-Site"). After the meters have been returned to SNC, metering will advise stores accordingly so those meters can be removed from the "Off-Site" location and put back into the "In-Stores" location status.

4.0 Smart Meter Pre-Sampling

For 2024 and beyond, SNC will forgo all smart meter pre-sampling related costs based on the results received from the 2016 / 2017 / 2018-meter pre-sampling activities and from the 2019 compliance testing program whereby all tested meter lots received 8-year seal extensions (less those meters that were deemed **excluded).

5.0 Smart Meter Compliance Testing

Reference Appendix A -- 2025 to 2028 Expiring Meter Quantity and Test Group Information for Thunder Bay and Kenora.

Compliance meter testing criteria is defined within Measurement Canada's Specification S-S-06 and is essentially a confirmation of accuracy on a small quantity of meters that are randomly selected from a larger quantity meter lot for conformance. If compliance testing is successful, then **most/all the meters associated with that meter lot will have their seals extended by a specified period.

If a compliance tested meter test group attains a level 1 acceptance, **most/all the meters associated with that meter lot will have their seals extended by another 8 years. If the same meter test group is successfully compliance tested again, **most/all those meters would receive a 6-year extension and so on down to a minimum seal expiry period of 2 years. After the final 2-year period has elapsed those meters can no longer be compliance tested.

For any meters associated with a successful compliance testing effort, metering is required to update the CX meter “test group/seal expiry information” database to reflect the new seal expiry date for all meters associated with that compliance test.

Note: the meter seal on compliance tested meters will not be replaced with a new seal. It is imperative that the CX meter “test group/seal expiry information” database information is reviewed prior to visually concluding that a meter needs to be removed from service because it has an expired seal affixed to it. (ie. an in-service meter may still have a 2009/2010/2011/2012 seal affixed to it, but due to compliance testing activities its actual seal expiry could be 2027/2028/2029/2030).

**Any meters that were deemed non-conforming as per the compliance testing criteria are “excluded” from receiving the applicable “meter lot” seal extension. These meters need to be removed from service before the seal expiry occurs and need to be removed from the applicable CX meter database “test group” by metering. These meters are not without value as they can be reverified individually and once they are returned to SNC, metering will add them into a newly created CX meter database “test group”, so the meters can eventually be returned to service.

6.0 SMART METER REVERIFICATIONS

Reference Appendix A -- 2025 to 2028 Expiring Meter Quantity and Test Group Information for Thunder Bay and Kenora.

If/when individual meters are reverified, the original seal is replaced with a new seal that will display the year in which the reverification occurred. A new meter inspection certificate with updated seal expiry date is also provided for each meter when they are returned to SNC.

If a meter is reverified the meter seal will expire after 8 years.

For any reverified meters, metering will update the existing or create a new CX meter “test group/seal expiry information” database to reflect the meter’s new expiry date based on the meter inspection certificate information.

7.0 COMMERCIAL / LARGE RESIDENTIAL CUSTOMERS

Customers that have services sized larger than 200 amps will utilize a transformer type meter that is wired to instrument transformer(s) which reduce either the voltage and current or just the current to a value that can be safely utilized within a transformer type meter for consumption recording and revenue determination.

As of this draft, SNC has approximately 2,000 commercial / large residential customers that utilize transformer type meters.

8.0 PRIMARY METERED CUSTOMERS

Customers that are metered on the primary side of a transformer utilize a self-contained assembly called a primary metering unit (PMU). The PMU incorporates instrument transformers that reduces the voltage and current to a value that can be safely utilized within a transformer type meter for consumption recording and revenue determination.

As of this draft, SNC has 50 PMU in service.

9.0 Installation Tests

An installation test is a single or poly phase post-meter equipment construction verification activity that is completed by metering personnel with a specialized analyzer to confirm that all associated potential transformer (PT), current transformer (CT), meter link box, meter wiring is correct, the PT/CTs are functioning as per design, the CT is un-shorted and that the billing multiplier on the service order for the specific customer location is correct.

Installation tests are completed for all transformer type meter installations (primary, commercial, or large residential customers). Installation tests are preferably completed at the time of energization of a new service, occasionally a return to the customers location for secondary installation test may be required if the customer's service loading does not allow for a successful initial installation test (ie. if the customer's current loading value is less than 10% of the service size, it does not provide the necessary accuracy for the test due to insufficient CT burdening which impacts the vector diagram length and increases the error percentage).

Additional installation tests for primary, commercial, or large residential customers will be completed if/when their meter is replaced because of seal expiry or meter failure.

It takes approximately 2 hours to complete all the activities associated with an installation test. All installation tests are documented and tracked with a "meter installation test service work order" and results of the test are recorded on a Measurement Canada 636 Form and filed as per the locations address.

10.0 Energy Axis (EA) Gatekeepers (Collectors)

An EA Gatekeeper is an integral part of SNC's smart grid (SG) and advanced meter infrastructure (AMI).

The EA Gatekeeper is a powered communication module that resides within a pole mounted weatherproof enclosure and via a "overlapping / blanket type deployment strategy", to collect and forward smart meter consumption information from SNC's 56,000+ customers back to a corporate repository for billing purposes. The EA Gatekeepers are also secure communication hubs that can transmit instructions (meter circuit open/close) and or updates to individual or multiple meters. The Gatekeeper can also communicate any smart meter tampering event and or meter outage "last gasp" information.

Gatekeepers do not have seal expiry limits and only need to be replaced if they have an internal issue, error or are damaged by external forces.

As of this draft, SNC has 94 Gatekeepers deployed throughout its service territories, 86 in Thunder Bay and 8 in Kenora.

In addition to general service calls to reset a tripped collector overcurrent device or to replace a failed modem or antennas, SNC completes documented annual inspection / maintenance activities and any identified items for repair on each collector. (ie. battery voltage – cable connection checks, internal wiring terminals tightened, external antenna connections are confirmed/sealed, enclosure condition, presence / operation of security locks, batteries are replaced every 5 years etc.)

APPENDIX A
2024 TO 2028 EXPIRING METER QUANTITY INFORMATION
(as of Jan. 2022)

In 2024, 1,042 meters in Thunder Bay, and 18 meters in Kenora have expiring seals.

Of these 1,060 meters 379 meters will be replaced as per the following.

- 223 meters will be reverified and,
- 156 meters from meter test group 1081 will be removed for compliance testing.

In 2025, 1,642 meters in Thunder Bay, and 4 meters in Kenora have expiring seals.

Of these 1,646 meters, 501 will be replaced as per the following.

- 245 meters will be reverified and
- 156 meters from meter test group 1087 and 100 meters from test group 1097 will be removed for compliance testing.

In 2026, 1,669 meters in Thunder Bay have expiring seals, and 191 meters in Kenora have expiring seals.

Of these 1,860 meters, 679 will be replaced as per the following.

- 523 meters will be reverified and
- 156 meters from meter test group 1337 will be removed for compliance testing.

In 2027, 41,825 meters in Thunder Bay have expiring seals, and 5,691 meters in Kenora have expiring seals.

Of these 46,548 meters, 3,813 will be replaced as per the following.

- 1,052 meters will be reverified and
- 2,761 meters from meter test groups 1022, 1003, 1015, 1026, 1030, 1035, 1104, 1020, 1021, 1022, 1000, 1009, 1008, EST2, EST8, 2001 will be removed for compliance testing.

In 2028, 2,090 meters in Thunder Bay have expiring seals, and 65 meters in Kenora have expiring seals.

Of these 2,137 meters, 1,023 will be replaced as per the following.

- 467 meters will be reverified and
- 556 meters from meter test groups 1106, 1131, 1107, 1109, 1108, 1114 will be removed for compliance testing.

APPENDIX H: MATERIAL INVESTMENT REPORTS

MATERIAL INVESTMENT REPORT

Program/Project

Capital Recoverable

Investment Category

SYSTEM ACCESS

A. General Information on the Program/Project

1. Overview

This program is comprised of customer driven work for additions or changes to SNC's distribution system. This includes work related to motor vehicle accidents (MVA), customer requests for relocation of services and make-ready work for third party attachers.

Much of the work in the historical period centered around make-ready work. SNC works closely with multiple communication companies who request to attach to SNC poles to efficiently utilize infrastructure. SNC charges a monthly rental fee established in agreements with each company. These communications companies will routinely apply for revisions or additions to their current attachment count to align with their business objectives and their customers' demands. When this occurs, SNC reviews the request and determines if existing infrastructure can support the new/revised attachment. If changes to SNC's infrastructure is required to support this change, the make-ready work is performed by SNC. This may include installation or replacement of poles and anchors and related infrastructure as required to meet both current standards and accommodate the revised attachment.

These types of projects are generally expected to decrease from recent levels due to completion of a large-scale attachment effort to bring fibre to the home from a local telecommunications company. Notwithstanding 2025, where Bell will be completing their AHSIP projects within the Thunder Bay service territory.

Capital contributions for these projects are collected in accordance with the DSC and the provisions of its COS.

2. Timing

a. Beginning: January 2024
b. In-Service: Through to December 2028
c. Factors that may impact timing: This program is scheduled and dictated by the requirements of third-party companies and is largely outside of SNC's control. Other key factors that may impact timing include legislation changes (e.g., BBFA) that further accelerate the response required by SNC.

3. Historical and Forecast Capital Expenditures

Table 1 Historical & Forecast Capital Expenditures ($'000)

Category	Historical Period						Bridge Year	Forecast Period				
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	691	258	764	1,350	1,421	1,062	420	434	2,232	349	356	364
Contributions	(315)	(110)	(331)	(1,319)	(1,210)	(949)	(400)	(412)	(2,121)	(332)	(339)	(345)
Capital (Net)	376	148	433	32	211	113	20	22	112	17	18	18

Category	Historical Period						Bridge Year	Forecast Period				
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Motor Vehicle Accidents	17	14	11	14	16	14	14	14	14	14	14	14

SNC received notification from Infrastructure Ontario in June of 2023 that Bell Canada had been awarded the AHSIP (Accelerated High-Speed Internet Program) for the Thunder Bay service territory to be constructed in 2025. SNC has begun discussions with Bell to share information regarding the impact to 2025 budgets. Based on these preliminary discussions it is anticipated that approximately 2,000 poles will require attachment. This accounts for the significant increase in gross expenditures in 2025. Contributions for this program are expected to be 100% of the work.

4. Economic Evaluation

Economic evaluations are not performed.

5. Comparative Historical Expenditure

Section 3 of this document identifies the historical costs for recoverable work. The quantity and scope of requests made by customers varies year-to-year, however SNC forecasts based on the best available data considering historical drivers and plans provided by telecommunication providers. When comparing costs over the historical period large unique projects must be accounted for. For example, increased costs for the period 2019 to 2022 are attributable to Tbaytel's Fiber-to-the-home (FTTH) program where Tbaytel attached new infrastructure to approximately 6500 poles. This required significant make-ready work to ensure SNC's infrastructure was ready to accept these attachments. Forecast expenditures are informed by ongoing conversations with all third-party communication companies.

6. Investment Priority

Capital recoverable investments are non-discretionary investments driven by customer requests and SNC is obligated to fulfill them to meet its regulatory compliance. Thus, these requests are balanced against other mandatory system access programs but take precedence over other discretionary programs.

7. Alternatives Analysis

Alternatives are considered on individual basis for each third-party attachment request. Newly installed assets will be designed and constructed in the most cost-effective manner. Where possible, in the case of an MVA, repairs are completed to restore power and additional tasks are completed during regular time to ensure cost-effectiveness. For example, an accident pole may be braced in the middle of the night and then replaced the following day.

8. Innovative Nature of the Project

SNC found no innovative elements within this project.

9. Leave to Construct Approval

Currently there are no Leave to Construct (LTC) approvals required as part of this program.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability and Safety

Criteria	Description
Efficiency	SNC works closely with third-party communication companies to ensure the attachments process is as efficient as possible. For example, SNC will present these communication partners with advance notice of upcoming pole replacement projects to prevent a duplication of work (i.e., attaching to the old pole, then having to move to the new pole). This leads to less conflict in the field and the need for old poles to remain in service, maximizing operation efficiency.
Customer Value	By allowing third-party companies to attach to SNC's infrastructure in a safe and economical manner, customers benefit from a smaller overall infrastructure footprint, as well as the economic growth and development that often follows improved communication capabilities. Additionally, SNC can offset project costs with revenue received, thereby reducing impact to customer rates.
Reliability	Alterations to SNC's distribution equipment are completed in such that reliability is not negatively impacted.
Safety	Safety is a top consideration when it comes to work completed as part of this program. All work is designed/installed to meet the latest industry standards and/or is approved by a Professional Engineer.

2. Investment Need

Primary Driver:

Regulatory Obligation - This program is driven primarily by customer demand and therefore falls under SNC's regulatory compliance. Timelines are based the nature of the work, either unplanned (e.g., MVA's) or planned work by third-party companies (Joint-use attachments).

Secondary Drivers:

Customer Service Requests – As part of its planning process SNC regularly interacts with its customers to identify needs and incorporate those into its planning forecast.

Provision of High Speed Internet (Broadband) - An increase in attachments from our third-party communication partners to increase service coverage for their customers.

Corporate Objectives - This project aligns with SNC's vision and mission of being a trusted partner in the community and building a stronger community.

Information Used to Justify the Investment:

Joint-use forecasts are budgeted based on historical expenditure trends, growth predictions and consultations with the third-party communication companies in Thunder Bay and Kenora. SNC sought specific feedback from these communication companies to support its DSP. Additional information on SNC's engagement efforts can be found in Section 5.2.2 of the DSP.

3. Investment Justification

Demonstrated Utility Practice

All proposed assets are reviewed against the most recent issue of CSA, USF and SNC standards and any newly installed or revised assets are completed using these standards. This method aligns with industry standard practice across the sector.

Cost-Benefit Analysis

Alternatives are considered on a case-by-case basis to provide the most practical and cost-effective solution for all parties.

Historical Outcomes

Projects in this program are routinely incorporated into SNC's service territory. These investments enable customers and communications companies to effectively operate within SNC's service territory. Additionally, joint-use attachments improve communication capability and facilitates continued growth and development with the cities of Thunder Bay and Kenora.

SNC can establish its forecast based on historical data like that shown in Figure 1 below. It can be noted that there has been a significant increase in the number of third-party requests between 2017 and 2022, approximately 2000 on average annually, as compared to 1100 for the 5-year preceding period.

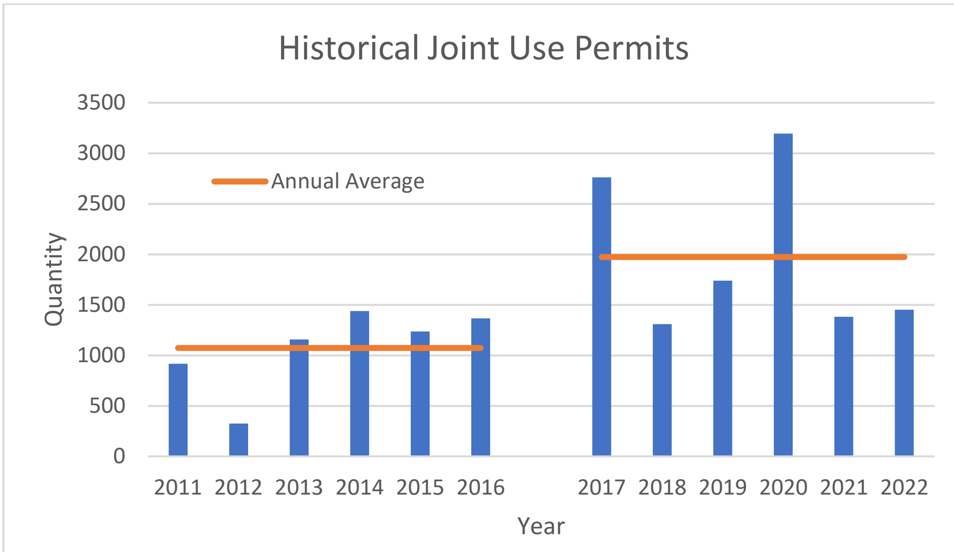


Figure 1 Historical Joint-Use Permits

Substantially Exceeding Materiality

Not Applicable.

4. Conservation and Demand Management

CDM is not applicable.

MATERIAL INVESTMENT REPORT

Program/Project

General Services

Investment Category

SYSTEM ACCESS

A. General Information on the Program/Project

1. Overview

Customer initiated requests for new services are budgeted based on historical expenditure trends, growth predictions and consultations with the Cities of Thunder Bay and Kenora regarding new developments. The quantity of service projects varies annually and may include installations of new/upgraded residential services, commercial services, replacement/relocation of infrastructure and other miscellaneous requests from customers. New connections and service upgrades are planned using standardized designs that meet the requirements of O.Reg 22/04, made under the Electricity Act, 1998. SNC's contribution level is determined using the methodology set forth in the DSC.

SNC typically installs between 15 and 37 new general services annually and anticipates this trend to continue. Many of the new services are installed in areas requiring minimal distribution system upgrades. In other areas, SNC system upgrades are required to service the customer. These can include pole replacements, transformer replacements or new transformer installations and system expansions.

2. Timing

a. Beginning: January 2024
b. In-Service: Through to December 2028
c. Factors that may impact timing: annual variation in the number of customers connected will impact the volume of work performed in this program each year. The timing of execution depends on when the customer initiates the request.

3. Historical and Forecast Capital Expenditures

Table 1 Historical & Forecast Capital Expenditures ($'000)

Category	Historical Period						Bridge Year	Forecast Period				
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	517	566	939	489	447	804	514	652	765	780	796	812
Contributions	(315)	(350)	(860)	(399)	(430)	(800)	(509)	(645)	(757)	(772)	(788)	(804)
Capital (Net)	203	215	79	90	17	4	5	7	8	8	8	8

Table 2 Quantities of New General Service Connections

Category	Historical Period						Bridge Year	Forecast Period				
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
New Services	17	21	24	37	15	31	25	25	25	25	25	25

4. Economic Evaluation

Economic evaluations are generally not applicable. Occasionally SNC requires an extension of our distribution system. In these cases, SNC follows the regulated process prescribed in the DSC to expand the electrical network.

5. Comparative Historical Expenditure

Section 3 of this document identifies the historical costs for services. The quantity and scope of requests made by customers varies year-to-year, however SNC forecasts based on the best available data considering potential growth and development.

6. Investment Priority

Services are non-discretionary investments driven by customer requests and SNC is obligated to fulfill them to meet its regulatory compliance. Thus, customer service and upgrade requests are balanced against other mandatory system access programs but take precedence over other discretionary programs.

7. Alternatives Analysis

Alternatives are considered on individual basis for each connection request considering safety, economics, regulatory compliance, system reliability and customer relations to develop the most effective solution. For example, a new customer connection may require a road crossing. SNC may consider the cost of servicing the customer overhead, underground via buried trench, or underground via directionally drilling. Each method has potential advantages and disadvantages from a cost (i.e., typically overhead will be less expensive vs. underground), timeliness (i.e., some installation methods may require third party involvement, potentially impacting installation timelines), and aesthetics (i.e., many customers prefer the unobtrusiveness of underground installations).

8. Innovative Nature of the Project

SNC found no innovative elements within this project.

9. Leave to Construct Approval

Not applicable to this program.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability and Safety

Criteria	Description

Efficiency	SNC considers all available construction methods and materials on an individual basis to offer customers the most cost-effective and timely solutions for their new connection. This may include a revision to previously planned work in the area to align both SNC and customer objectives.
Customer Value	Customers value timely connections to the electrical system. Having access to safe and reliable electricity promotes economic wellbeing in the community. SNC takes all reasonable steps necessary to ensure we continue to meet the regulated timelines for new connections.
Reliability	This project will have a negligible effect on reliability. In very limited cases does new equipment fail prematurely impacting reliability.
Safety	All new and upgraded services are designed and installed to meet or exceed current safety standards thus ensuring safe distribution of electricity for our customers.

2. Investment Need

Primary Driver:

Regulatory Obligation - This program is driven primarily by customer demand and therefore falls under SNC's regulatory compliance.

Secondary Drivers:

Reduced losses - SNC can review the loading on service upgrades to optimize service sizes and reduce losses.

Corporate Objectives - This project aligns with SNC's vision and mission of being a trusted partner in the community.

Information Used to Justify the Investment:

Customer initiated requests for new services are budgeted based on historical expenditure trends, growth predictions and consultations with the Cities of Thunder Bay and Kenora regarding new developments. SNC meets with the cities and other stakeholders in the city on a semi-annual basis to discuss development and coordination. Additional information on SNC's engagement efforts can be found in Section 5.2.2 of the DSP.

3. Investment Justification

Demonstrated Utility Practice

SNC Plans and executes its new connections to accommodate customers and comply with regulations. All new connections installed comply with the latest standards and regulations, and all metering services will be carried out in accordance with SNC's standards and practices.

Cost-Benefit Analysis

The alternatives analysis in section A.7 of this document discusses some of the conditions SNC weighs as part of this program.

Historical Outcomes

The historical costs and number of General Service customers connected during the historical period are detailed in sections 3 and 5 in part A of this document. Through its General Services connections program, SNC has been able to continue to connect commercial customers in a timely manner.

4. Conservation and Demand Management

CDM is not applicable for new customer load connections or service upgrades.

MATERIAL INVESTMENT REPORT

Program/Project

Meters

Investment Category

SYSTEM ACCESS

A. General Information on the Program/Project

1. Overview

SNC owns and operates approximately 57,000 revenue meters installed on customers' premises which measure the power consumption and demand of connected load for the purpose of billing. All existing residential and general service customers were equipped with smart meters in 2009 following the government legislated program.

This program includes expenditures related to the supply, installation and maintenance of revenue meters installed at each customer service point for retail settlement and billing purposes for each customer connected to SNC's distribution system. This program includes the replacement of failed meters and the process required for compliance testing & resealing.

Failed Meter Program:

This program includes the replacement of faulty or expired meters and the supporting meter infrastructure over the forecast period. Meters to be purchased by SNC for the forecast period are based on historical information for the number of failures experienced annually. This program also includes the purchase of ancillary items required to replace the failed meters (e.g., meter seals, meter rings, disconnect sleeves, etc.). SNC anticipates replacing 1200 failed meters annually. This number is reviewed annually to ensure forecast quantities are appropriate.

Sampling and Reverification Program:

As per Measurement Canada requirements a meter with an expired seal cannot be left in service for revenue/billing purposes. Utilizing the S-S-06 Specification Measurement Canada has defined how an electronic smart meter owner can utilize meter compliance sampling for the purposes of extending the seal expiry period of an in-service lot of meters. The project expenditures within this account encompasses the capitalized activities necessary for SNC to establish a smart meter pre-sampling and final compliance sampling program which aligns with the requirements detailed within the specification so the utility can extend their smart meter's in-service life and ultimately maximize the return on investment (ROI). SNC anticipates meter expiries to remain consistent at between 1500-2000 meters annually for 2024-2028, with 2027 being the exception. For 2027, approximately 42,000 meters will expire which will require an increase in cost to accommodate reverification and resealing activities.

Further details regarding the sampling and reverification program can be found in Appendix F – Meter Master Plan.

2. Timing

a. Beginning: January 2024
b. In-Service: Through to December 2028
c. Factors that may impact timing: This program is scheduled and dictated by the unscheduled replacement of failed meters as well as the quantity of meters requiring reverification. Other

key factors that may impact timing include procurement of labour and materials to complete installations.

3. Historical and Forecast Capital Expenditures

Table 1 Historical & Forecast Capital Expenditures ($'000)

Category	Historical Period						Bridge Year	Forecast Period				
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	221	287	256	119	212	145	181	270	275	281	522	357
Contributions	-	-	-	-	-	-	-	-	-	-	-	-
Capital (Net)	221	287	256	119	212	145	181	270	275	281	522	357

4. Economic Evaluation

Economic evaluations are not applicable.

5. Comparative Historical Expenditure

Section 3 of this document identifies the historical costs for metering. Over the historical period SNC replaced the quantity of meters show in Table 2.

Table 2: Historical Replacements

Category	Historical Period						Bridge Year
	2017	2018	2019	2020	2021	2022	2023
Failed Meter Replacements	696	1018	932	1679	1547	1223	1385
Sampling and Reverification	867	1435	2974	300	438	275	408

SNC considered the historical expenditure, existing meter information, forecast failures and supply chain as factors to generate the forecast under this program.

6. Investment Priority

Metering investments are non-discretionary investments driven by mandatory obligations to connect customers and the need to comply with mandated service obligations as defined by the DSC and Measurement Canada. Thus, these requests are balanced against other mandatory system access programs but take precedence over other discretionary programs.

7. Alternatives Analysis

This investment is non-discretionary. Failure to perform the work to install, repair, replace and/or reseal meters would be in violation of the DSC and Measurement Canada Guidelines, and has the potential to negatively impact the reliable source of billing and settlement data.

1. The alternative of purchasing all new meters was considered, and not chosen due to the low failure rates of meters, the necessity to keep capital expenditures at a low level, and the minimal change in residential metering technological capabilities.

8. Innovative Nature of the Project

SNC found no innovative elements within this project.

9. Leave to Construct Approval

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability and Safety

Criteria	Description
Efficiency	This program is unlikely to impact existing system efficiency, however SNC attempts to be better in everything we do. A possible outcome may include utilizing existing internal resources to complete the meter sampling campaign that aligns with areas of work where these staff will have other assigned tasks.
Customer Value	By upgrading and renewing existing meters that are expiring, this ensures that customer meters continue functioning, capturing accurate electricity usage, and therefore enabling SNC to produce an accurate bill. Customers can also monitor their historical consumption through SNC's web portal.
Reliability	Individual revenue meters have little impact on reliability. However, by installing new meters that are up to current standards, this ensures that the reliability of the meters themselves continues to be maintained, thus enabling a reliable source of billing settlement data.
Safety	All meter installations are installed using the latest safety standards.

2. Investment Need

Primary Driver:

Regulatory Obligation - The main driver for this program is SNC's obligation related to metering services as defined by the DSC and Measurement Canada. SNC is obligated to install and maintain meters at all customer connection points from both residential and commercial customers. By replacing meters that have expired with new meters, SNC ensures that it complies with its obligations to provide, install, and maintain a meter installation for retail settlement and billing purposes for each customer connected to the distribution system.

Secondary Driver:

Failure Risk – By addressing expired meters, this reduces the risk of the meters failing and ensures the continued delivery of reliable and accurate bills.

Information Used to Justify the Investment:

SNC replaces failed meters when they occur to maintain their regulatory obligations. SNC also collects and tracks data on its existing meters, and this information is used to determine when a meter requires testing, resealing, or replacing.

3. Investment Justification

Demonstrated Utility Practice

SNC plans and executes its metering program to accommodate failed meters and comply with regulations. All new meters installed comply with the latest standards and regulations, and all metering services will be carried out in accordance with SNC's standards and practices.

Cost-Benefit Analysis

A cost-benefit analysis was done to determine whether to continue to utilize the option of reverifying its meters for another sample period. The reduced cost of reverifying and performing sampling programs vs replacement far and above outweighed the minimal benefits received by upgrading to new meters.

Historical Outcomes

The historical costs and number of meters replaced during the historical period are detailed in sections 3 and 5 in part A of this document. Through its metering program, SNC has been able to continue to accurately bill customers.

4. Conservation and Demand Management

CDM is not applicable for meters.

MATERIAL INVESTMENT REPORT

Program/Project

Residential Services

Investment Category

SYSTEM ACCESS

A. General Information on the Program/Project

1. Overview

Customer initiated requests for new services are budgeted based on historical expenditure trends, growth predictions and consultations with the Cities of Thunder Bay and Kenora regarding new developments. The quantity of service projects varies annually and may include installations of new/upgraded residential services and replacement/relocation of infrastructure and other miscellaneous requests from customers. New connections and service upgrades are planned using standardized designs that meet the requirements of O.Reg 22/04, made under the Electricity Act, 1998. SNC's contribution level is determined using the methodology set forth in the DSC.

SNC typically installs an average of 100 new residential services annually and anticipates this trend to continue. Many of the new services are installed in subdivisions requiring minimal distribution system upgrades. In other areas, SNC system upgrades are required to service the customer. These can include pole replacements, transformer replacements/installations and system expansions.

2. Timing

a. Beginning: January 2024
b. In-Service: Through to December 2028
c. Factors that may impact timing: annual variation in the number of customers connected will impact the volume of work performed in this program each year. The timing of execution depends on when the customer initiates the request.

3. Historical and Forecast Capital Expenditures

Table 1 Historical & Forecast Capital Expenditures ($'000)

Category	Historical Period						Bridge Year	Forecast Period				
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	398	309	381	398	452	332	400	447	456	465	474	484
Contributions	(235)	35	(349)	(304)	(348)	(250)	(360)	(402)	(410)	(418)	(427)	(435)
Capital (Net)	164	344	32	94	104	83	40	45	46	46	47	48

Table 2 Quantities of New Residential Service Connections

Category	Historical Period						Bridge Year	Forecast Period				
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
New Services	110	99	95	105	107	80	92	100	100	100	100	100

4. Economic Evaluation

Economic evaluation is generally not applicable. Occasionally SNC requires an extension of our distribution system. In these cases, SNC follows the regulated process prescribed in the DSC to expand the electrical network, and these costs are covered under the customer driven expansions program.

5. Comparative Historical Expenditure

Section 3 of this document identifies the historical costs for services. The quantity and scope of requests made by customers varies year-to-year, however SNC forecasts based on the best available data considering potential growth and development.

6. Investment Priority

Services are non-discretionary investments driven by customer requests and SNC is obligated to fulfill them to meet its regulatory compliance. Thus, customer service and upgrade requests are balanced against other mandatory System Access investments but take precedence over other discretionary programs.

7. Alternatives Analysis

Alternatives are considered on individual basis for each connection request considering safety, economics, regulatory compliance, system reliability and customer relations to develop the most effective solution. In most cases, residential services are fulfilled where secondary infrastructure already exists making connections straightforward and analysis of alternatives unnecessary. In some cases (e.g., semi-rural), however, several aspects must be considered when performing the connection. For instance, the size and location of the lot may require installing additional infrastructure to service the customer, also under consideration is whether the existing primary is overhead or underground which will impact cost. There are by-laws in place that SNC must follow in the City of Thunder Bay that require all new residential services be installed as an underground service, however this is not the case in Kenora where rock blasting an underground service would make the cost prohibitive for customers.

8. Innovative Nature of the Project

SNC found no innovative elements within this project.

9. Leave to Construct Approval

Not applicable to this program.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability and Safety

Criteria	Description
Efficiency	SNC considers all available construction methods and materials on an individual basis to offer customers the most cost-effective and timely solutions for their new connection. This may include a revision to previously planned work in the area to align both SNC and customer objectives.
Customer Value	Customers value timely connections to the electrical system. Having access to safe and reliable electricity promotes economic wellbeing in the community. SNC takes all reasonable steps necessary to ensure we continue to meet the regulated timelines for new connections.
Reliability	This project will have a negligible effect on reliability. In very limited cases does new equipment fail prematurely impacting reliability.
Safety	All new and upgraded services are designed and installed to meet or exceed current safety standards thus ensuring safe distribution of electricity for our customers.

2. Investment Need

Primary Driver:

Regulatory Obligation - This program is driven primarily by customer demand and therefore falls under SNC's regulatory compliance.

Secondary Drivers:

Reduced losses - SNC can review the loading on service upgrades to optimize service sizes and reduce losses.

Corporate Objectives - This project aligns with SNC's vision and mission of being a trusted partner in the community.

Information Used to Justify the Investment:

Customer initiated requests for new services are budgeted based on historical expenditure trends, growth predictions and consultations with the Cities of Thunder Bay and Kenora regarding new developments. SNC meets with the cities and other stakeholders in the city on a semi-annual basis to discuss development and coordination. Additional information on SNC's engagement efforts can be found in Section 5.2.2 of the DSP.

3. Investment Justification

Demonstrated Utility Practice

SNC Plans and executes its new connections to accommodate customers and comply with regulations. All new connections installed comply with the latest standards and regulations, and all metering services will be carried out in accordance with SNC's standards and practices.

Cost-Benefit Analysis

See section A.7 for alternatives analysis.

Historical Outcomes

The historical costs and number of services replaced during the historical period are detailed in sections 3 and 5 in part A of this document. Through its residential service connections program, SNC has been able to continue to connect residential customers in a timely manner.

4. Conservation and Demand Management

CDM is not applicable for new customer connections or service upgrades.

MATERIAL INVESTMENT REPORT

Program/Project

Line Safety Reports

Investment Category

SYSTEM RENEWAL

A. General Information on the Program/Project

1. Overview

This program is intended to cover the costs associated with unplanned asset renewal typically resulting from asset inspections. It is comprised of replacement of wood poles, overhead conductor, porcelain insulators, wood cross arms, or wood pins that are identified to be in poor condition and that pose a potential risk to public safety and/or customer reliability. The selected assets are either at the end of their useful life or have prematurely degraded beyond what could be expected of assets of similar age.

The assets replaced in this project are identified through field inspections and lines safety reports submitted from both customers and internal staff. The assets are scheduled for replacement within the year and the scope varies widely depending on several factors, such as location, installation complexity and when the failure occurs.

These projects are typically below 5 poles in scope and use USF standards for like-for-like construction with installation framed to conform to O. Reg. 22/04. Table 1 highlights the estimated number of replacements by asset category. As these are reactive replacements, the quantity may vary annually based on findings each year. Where applicable, SNC will incorporate these replacements into a larger program, however these assets are generally replaced when identified.

Table 1-1: Forecast Quantity of Replacements by Type

Category	Forecast Period				
	2024	2025	2026	2027	2028
Poles	40	40	40	40	40
Insulators	30	30	30	30	30

This program is expected to address aspects of SNC's asset management objectives related to Health and Safety and Regulatory/Legal Compliance while simultaneously addressing issues of Asset Performance.

2. Timing

a. Beginning: January 2024
b. In-Service: Through to December 2028
c. Factors that may impact timing: Assets in this category pose a risk to the health and safety of staff and public and are completed as high priority, no factors should affect timing.

3. Historical and Forecast Capital Expenditures

Table 3-1 Historical & Forecast Capital Expenditures ($'000)

Category	Historical Period						Bridge Year	Forecast Period				
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	644	789	1,066	910	1,445	842	1,268	859	876	894	911	930
Contributions	-	-	-	-	-	-	-	-	-	-	-	-
Capital (Net)	644	789	1,066	910	1,445	842	1,268	859	876	894	911	930

The increase in 2021 above typical expenditures was largely driven by replacements through the joint-use attachment program. The condition of the poles necessitated replacement to allow attachment, however these costs could not be fully recovered by the utility.

It should be noted that the increase in 2023 is due to selecting the most complex and challenging porcelain insulator replacements in commercial areas. These locations would have the longest duration of outage, should the insulators fail unexpectedly. These replacements were prioritized due to their impact to commercial customers when the insulators unexpectedly fail.

4. Economic Evaluation

Economic evaluation is generally not applicable.

5. Comparative Historical Expenditure

Section 3 of this document identifies the historical Line Safety Reports costs. Historical values for this program are tracked closely and budget forecasts are based on average replacement costs by asset type. However, several factors such as time of replacement (overtime), complexity of installation (multi-circuit poles), location (back yard easement requiring cranes), and time of year (winter) can all significantly impact costs, making precise forecasts difficult.

6. Investment Priority

The timing of these projects is affected by the urgency of resolving the potential risk of failure. This means this program is a high priority with a rank of 1 out of 9 for SNC with a score of 67.5. If an asset is identified as more urgent (e.g., failure has occurred or is imminent), it will be prioritized for replacement, rather than completing replacements based on the timing of their identification. The program has been prioritized through the program ranking process as follows:

Health and Safety - Serious injury requiring medical attention or serious security incident is very likely (occur more than once in 5yr).

Assets that are removed as part of this program have failed to meet the criteria to remain in service either through the results of empirical testing (e.g., remaining pole strength) or because of mechanical/structural failure. If these assets are not addressed in a timely manner, they will likely progress to catastrophic failure in the very near term and have the potential to cause significant injury.

Environmental Impact - Addresses two (2) or more of SNC's identified environmental risks and provides risk mitigation to those risks.

Environmental considerations in this program include elements of climate change adaptation and system hardening as all installations are designed to the latest standards. Additionally, vegetation contacts are mitigated as trees are trimmed to accommodate renewed overhead infrastructure.

Regulatory/Legal Compliance - Addresses a currently non-conformant issue with respect to best practices.

As detailed in Section B.2, porcelain post insulators used in armless construction on the 25kV network have been known to fail unexpectedly and catastrophically. This has the potential for injury for both SNC staff and third party attachers if special requirements are not followed during maintenance (e.g., phase catchers installed on adjoining structures). SNC is following industry best practices by removing these from service as part of this program.

Customer Preference - Delivers on two of the top 3 priorities of customers (Affordability, Safety for Employees and the Public and Reliability).

This program ensures that two of the main customer concerns, safety for employees and the public, as well as reliability are addressed through the removal of failed assets.

Asset Performance - >50% of assets in poor condition or non-system assets operating within extended manufacturer support.

This program targets only those assets that are in poor condition, as identified through field assessments and testing.

Operational Efficiency - Aligns with 1.

SNC decreases its potential liability by addresses assets that have or are likely to fail.

System Reliability - Sustained interruption of <1.5 MW of distribution load (100-300 residential customers).

SNC is unable to predict how many customers are impacted as part of this program as assets could potentially fail anywhere in the system. However, highly critical assets (those that impact a large number of customers) are generally addressed proactively through other programs and are therefore unlikely to be captured as part of Line Safety Reports.

7. Alternatives Analysis

The projects listed in this category have been identified based on the outcome of the asset condition assessment, flagged for action plan and review by subject matter experts.

Alternatives for Line Safety Program are considered and are captured below.

a. Do nothing approach – this results in reactive replacement of poles which would result in potential long outages for those customers affected, and potentially after business hours, resulting in a higher cost for replacement, for these reasons this alternative is not considered. Additionally, the assets in this program have been identified due to their poor condition and pose a potential risk to public safety and/or customer reliability. The selected assets cannot be ignored or scheduled for replacement beyond a year.

b. Use of concrete, composite or alternative material poles – this alternative would result in a higher initial cost which would not necessarily provide more value to the utility or the customer.

c. Removing line and placing overhead section of line underground which would result in improved reliability but according to SNC metrics, underground construction results in significant cost increases compared to overhead. For this reason, this alternative is not considered.

d. Like-for-like replacement- provides the least impact to the customer, the land, and the utility. It is also the most cost-effective and efficient option, and for those reasons is the best alternative.

8. Innovative Nature of the Project

There are no innovative elements within this program.

9. Leave to Construct Approval

Not applicable to this program.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability and Safety

Criteria	Description
Efficiency	This program has minimal effect on system efficiency, however failure to replace deteriorating assets might result in untimely failure and system reliability concerns. This will have a negative impact on the efficiency of the distribution system at a given time. In addition, SNC considers replacement of associated assets (conductor, pole-mount transformer, switches) that are also in poor condition, rather than return at a later date.
Customer Value	The net benefit to customers is to reduce the potential for a risk in failure and to ensure that any safety hazards are eliminated while maintaining reliability.
Reliability	Replacement of these assets will have a positive impact on reliability performance and safety in the following ways; a) Tree trimming due to replacement will improve reliability by reducing the amount of tree contacts b) Installation of new assets will provide for safer working conditions for both SNC and Third party employees c) Installation of new standards includes animal protection which will reduce the number of animal contact related outage, improving reliability Improved reliability by reducing potential failures prior to failure and greatly decreasing restoration times.
Safety	This investment will maintain SNC's safety to the public, as well as worker safety by replacing failing poles and their associated framing with newer standards of framing which allow for improved safe work practices. In areas of these projects where porcelain insulators are discovered these will be replaced with polymer insulators thereby greatly reducing the risk of failure and eliminating a safety hazard to the public.

2. Investment Need

Primary Driver:

Failure Risk - The main drivers for this project are Asset Retirement and Health and Safety. SNC seeks to prioritize project selection based on assets that are in poor health, and SNC is obligated to ensure that the way it executes its initiatives does not negatively impact the health and safety of the public, customers or SNC's employees. The assets identified in this project have a high probability of failure which is a result of the condition of the assets.

SNC tests the remaining strength at the groundline of a subset of poles annually as part of its inspection and testing programs. Generally, the results of the testing supply empirical data into the condition assessment for wood poles. However, a portion of these assets that fall below 50% remaining strength at the groundline are reviewed for their suitability to remain in service. Assets that fail to meet the criteria to remain in service are scheduled for proactive replacement within the year to ensure they do not fail and require reactive replacement.

The premature and unexpected failure of porcelain-type standoff insulators pose an increased risk to reliability, as well as a hazard to the public, 3rd party attachers and SNC employees. For these reasons it is prudent to formulate a plan to remove these insulators from the 25kV network to maintain a safe and reliable distribution.

Secondary Drivers:

Reliability - The secondary driver is Reliability. The risk to the utility and the customer is that the asset will fail and result in an outage that negatively affects reliability and customer satisfaction.

Information Used to Justify the Investment:

The assets identified in this program pose an imminent risk of failure and safety concern to the public and are identified as urgent meaning they are required to be attended to in a timely fashion. In addition to this SNC also evaluates how asset replacement may affect public safety, employee safety, environmental impacts, reliability and power quality, operational efficiency, and customer satisfaction. The timing of the program also considers the benefits and costs described in this project summary.

Wood Poles

Poles that have deteriorated to the point where the remaining strength has fallen below 20% or fail to meet the criteria set out in CSA 22.3 No.1 8.3.4.3 are considered to have failed and are removed from service. The following figures detail the historical pole testing results for the years 2019 through 2022.

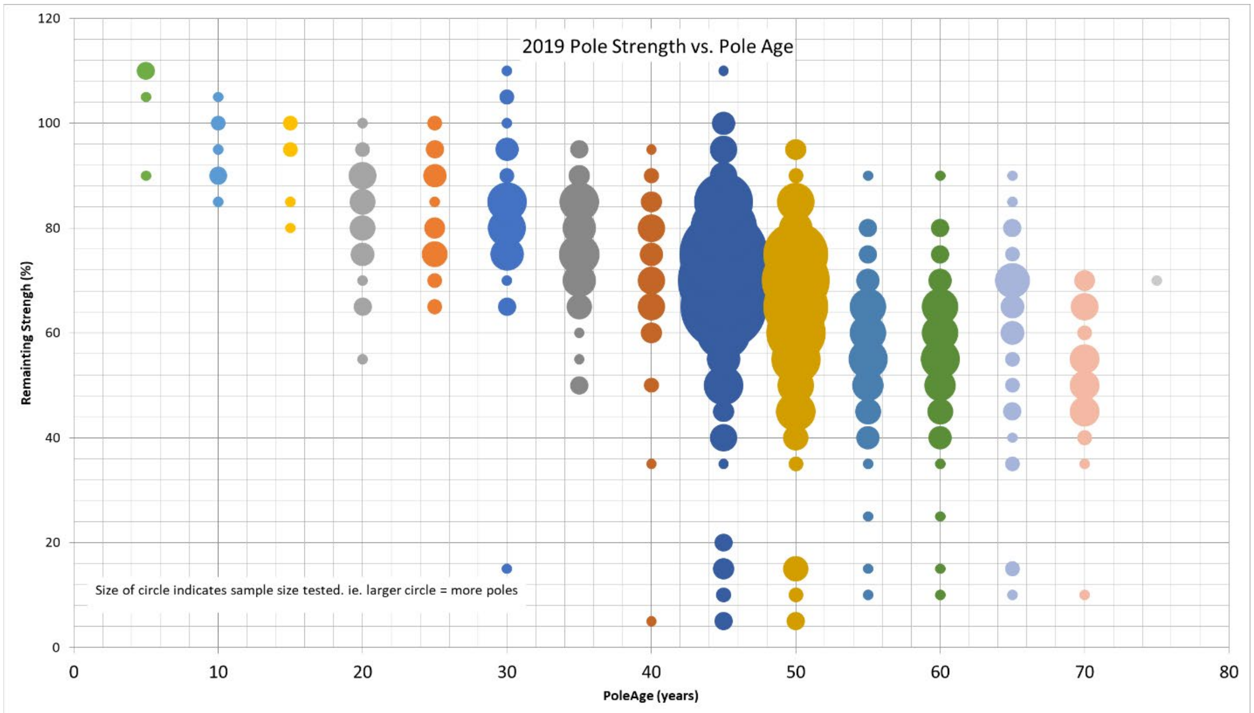


Figure 2-1 2019 Remaining Strength Test Results

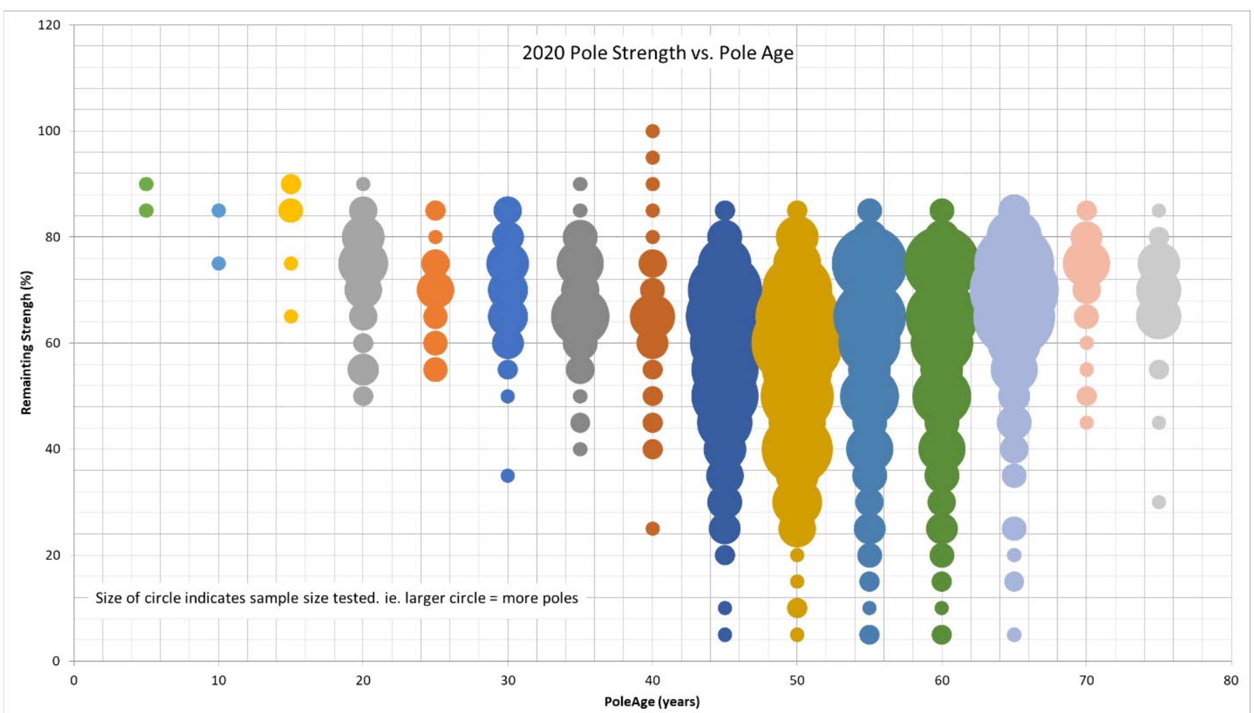


Figure 2-2 2020 Remaining Strength Test Results

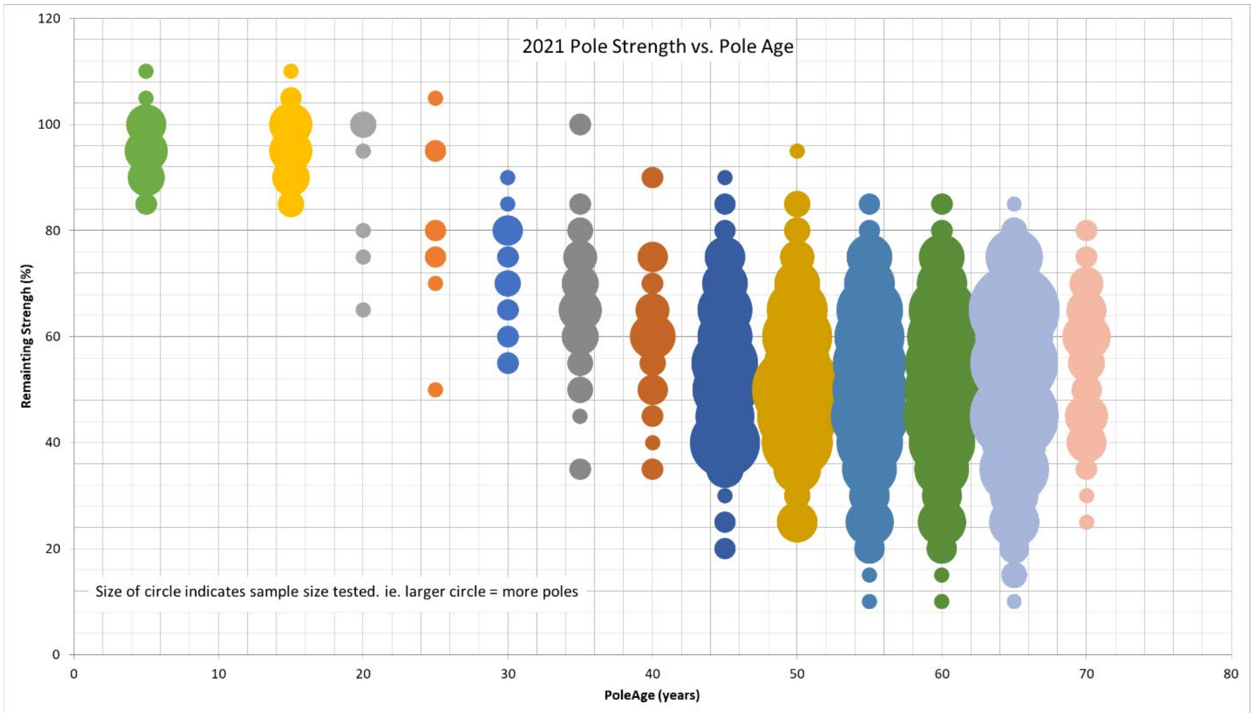


Figure 2-3 2021 Remaining Strength Test Results

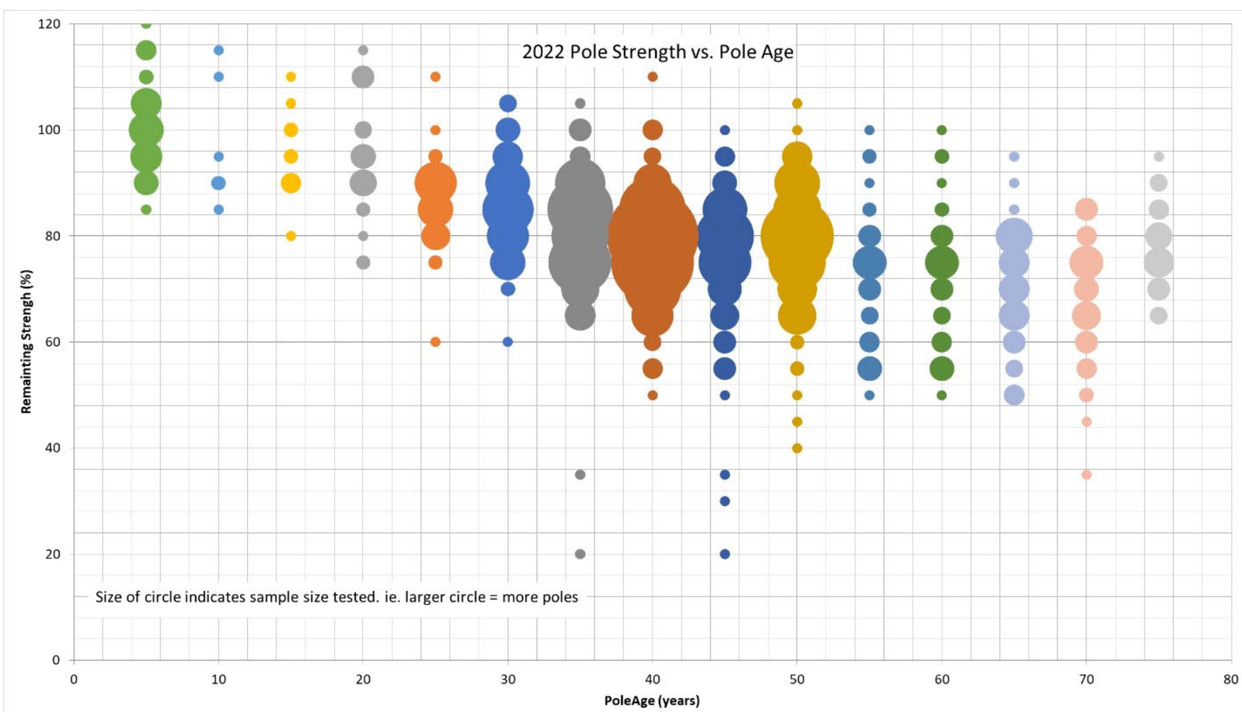


Figure 2-4 2022 Remaining Strength Test Results

Additionally, SNC tracks the reason-for-removal to capture and refine future failure statistics. This was identified as a data gap in SNC's previous filing, and the data has been tracked since 2019. This will assist with refining the health index for these assets and will improve future modelling of failure rates for SNC distribution system. The reason-for-removal for wood poles is detailed in Table 2-1. The failure coding is captured in Table 2-2.

Table 2-1 Wood Pole Removal Codes

REMOVAL CODE	DESCRIPTION	FAILURE CODE
SVUP	Service Upgrade	C
JUUP	Joint-use Upgrade	C
CONV	Conversion Related Replacement	LOS
RELO	Relocation	LOS
MKRD	Make-ready Work	LOS
FIRE	Replaced due to Fire	M
MVAR	Motor Vehicle Accident Related	M
STRF	Structural Failure	M
INTR	Rotted - External/Internal	M
SYSH	System Health Improvements	M

Table 2-2 Asset Failure Codes

FAILURE CODE	DESCRIPTION	DEFINITION	CAUSE/TACTICAL ASPECTS
C	CAPACITY	VOLUME OF DEMAND EXCEEDS DESIGN CAPACTIY	GROWTH, SYSTEM EXPANSION
LOS	LEVELS OF SERVICE	FUNCTIONAL REQUIRMENTS EXCEEDS DESIGN CAPACITY	CODES & LEGISLATION, SAFETY, SERVICE REQUIREMENTS, NOISE ETC.
M	MORTALITY	CONSUMPTION OF ASSET REDUCES PERFORMANCE BELOW ACCEPTABLE LEVEL	PHYSICAL DETERIORATION DUE TO AGE/USAGE (INCLUDING OPERATING ERROR), ACTS OF NATURE

Figure 2-5 shows the reason for removal statistics for wood poles. Historically, 44% of poles have been replaced as part of the 4kV conversion program. However, 29% of poles are replaced due to failure because of a mortality code. This program is designed to specifically address these poles, both proactively through the results of pole testing, and reactively through unexpected failure.

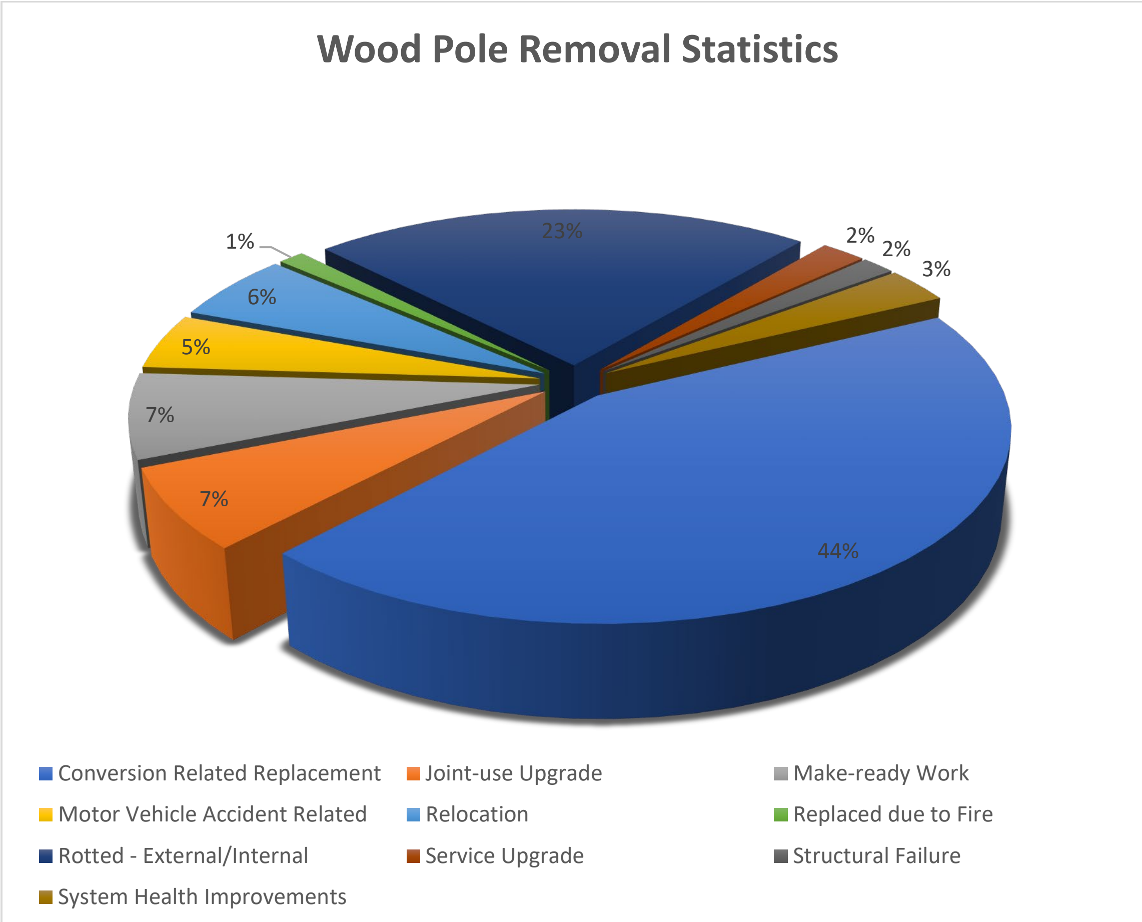


Figure 2-5 Wood Pole Removal Statistics 2019-2022

SNC inspects visually inspects wood poles every 3 years and tests the remaining strength at the groundline of a subset of poles annually. SNC replaces poles based on the inspection and testing results using the forward looking, flagged for action plan as a basis for the volume of poles and the health to identify specific assets. The inspection parameters are found in Table 2-3.

Table 2-3 Wood Pole Condition Parameters

CONDITION PARAMETER	WEIGHT
Pole Remaining Strength	38%
Overall Condition	19%
Ground Line Rot	6%
Mechanical Damage	6%
Age	5%
Shell Rot	3%

Split	3%
Woodpecker Hole	3%
Insect Damage	3%
Leaning	3%
Feathering	3%
Crossarm	3%

Insulators

This program covers the replacement of porcelain-type post insulators used in armless (stand-off) construction on the 25kV overhead system with silicone polymer insulators. SNC has approximately 30,000 insulators in its distribution system and approximately 2% are this type. Porcelain insulators have several known failure modes.

a. Radial Cracking

This failure mode can be attributed to cement growth whereby the expansion of the cement within the insulator causes radial fractures of the porcelain discs. Wet conditions can further accelerate the process by moisture be absorbed by the cement. This condition can be further exacerbated in cold climates where moisture has penetrated the shell, upon freezing expands and forms large cracks eventually leading to catastrophic failure.

b. Internal Puncture

This failure mode can be attributed to problems with raw material and manufacturing defects. Fissures or voids can form in the microstructure of the insulator during manufacturing. These conditions can grow under the multiple stresses generated by service conditions and eventually lead to electrical breakdown of the dielectric medium.

c. External Flashover

This failure mode can be attributed to conditions external to the insulator which result in the temporary loss of insulation strength. The occurrence depends largely on insulator contamination and lighting activity, as well to key electrical system parameters (leakage distance and insulation coordination). Comparatively to other insulating mediums, flashover is more common in porcelain and glass due to the relative wettability of the material. Typically, porcelain insulators can become further compromised during flashover events when the arc causes the glaze on the unit to melt, leaving behind a rough surface more susceptible to pollution accumulation and water ingress leading to eventual failure.

d. Partial Breakage/Damage in Dielectric Material

This type of failure is generally caused by vandalism or poor handling during storage and installation. Typically, only a section of the porcelain disc is broken, and any internal cracking is not easily ascertained.

SNC uses an ESRI product, Workforce, to monitor the location of these installations. The current system has approximately 450 insulators in 134 locations throughout the Thunder Bay service territory as show in Figure 2-6.

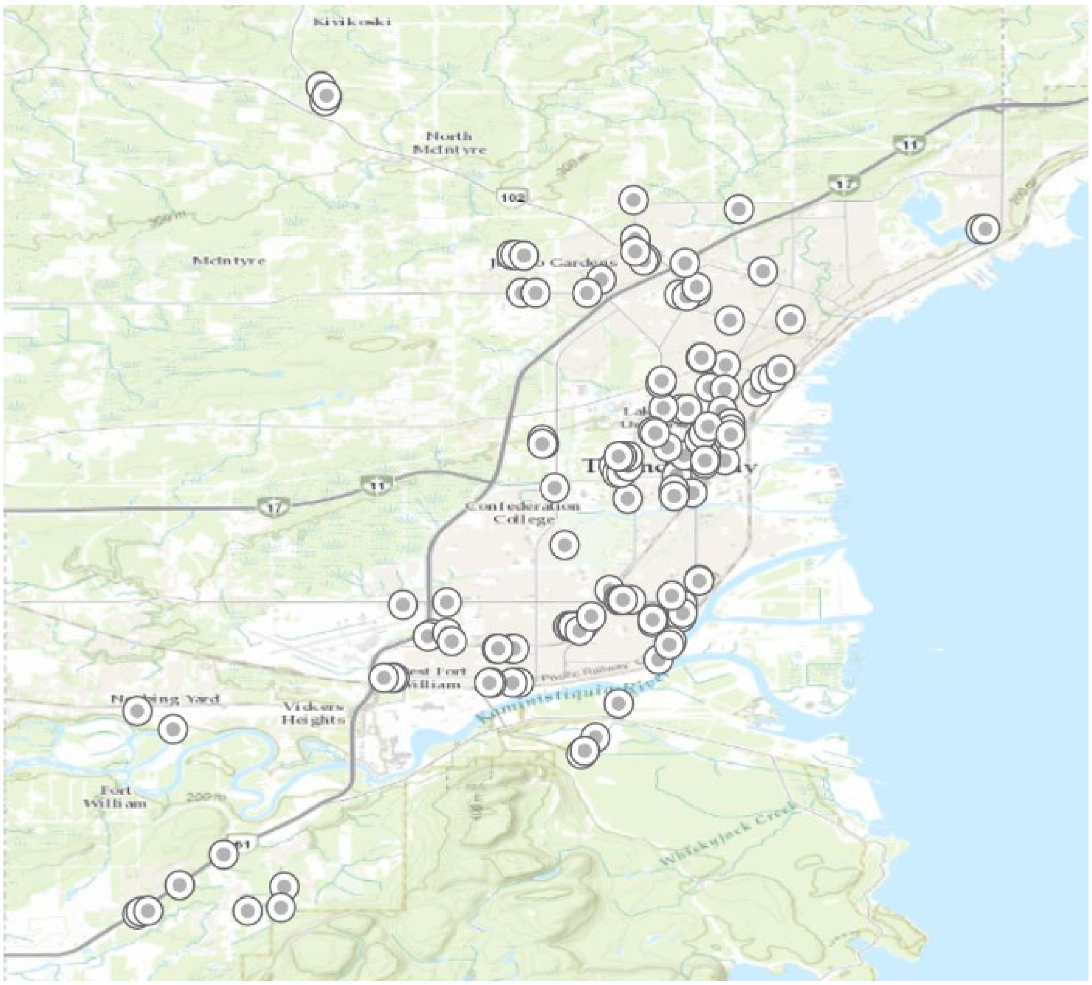


Figure 2-6 Porcelain Standoff Insulator Locations

Like poles, SNC tracks the reason-for-removal data for insulators. The reason-for-removal for insulators is detailed in Table 2-4.

Table 2-4 Insulator Removal Codes

REMOVAL CODE	DESCRIPTION	FAILURE CODE
SVUP	Service Upgrade	C
CONV	Conversion Related Replacement	C
JUUP	Joint-use Upgrade	LOS
RELO	Relocation	LOS
MKRD	Make-ready Work	LOS
FIRE	Replaced due to Fire	M
MVAR	Motor Vehicle Accident Related	M
BRKN	Broken Cracked	M
MCHF	Mechanical Failure (of component)	M
SYSH	System Health Improvements	M

Figure 2-7 shows the reason for removal statistics for insulators poles. Typically, 40% of insulators have been replaced as part of the Relocations program. Approximately, 18% of insulators are replaced due to failure because of a mortality code. This program is designed to specifically address these insulators, both proactively through the identification of porcelain standoffs, and reactively through unexpected failure.

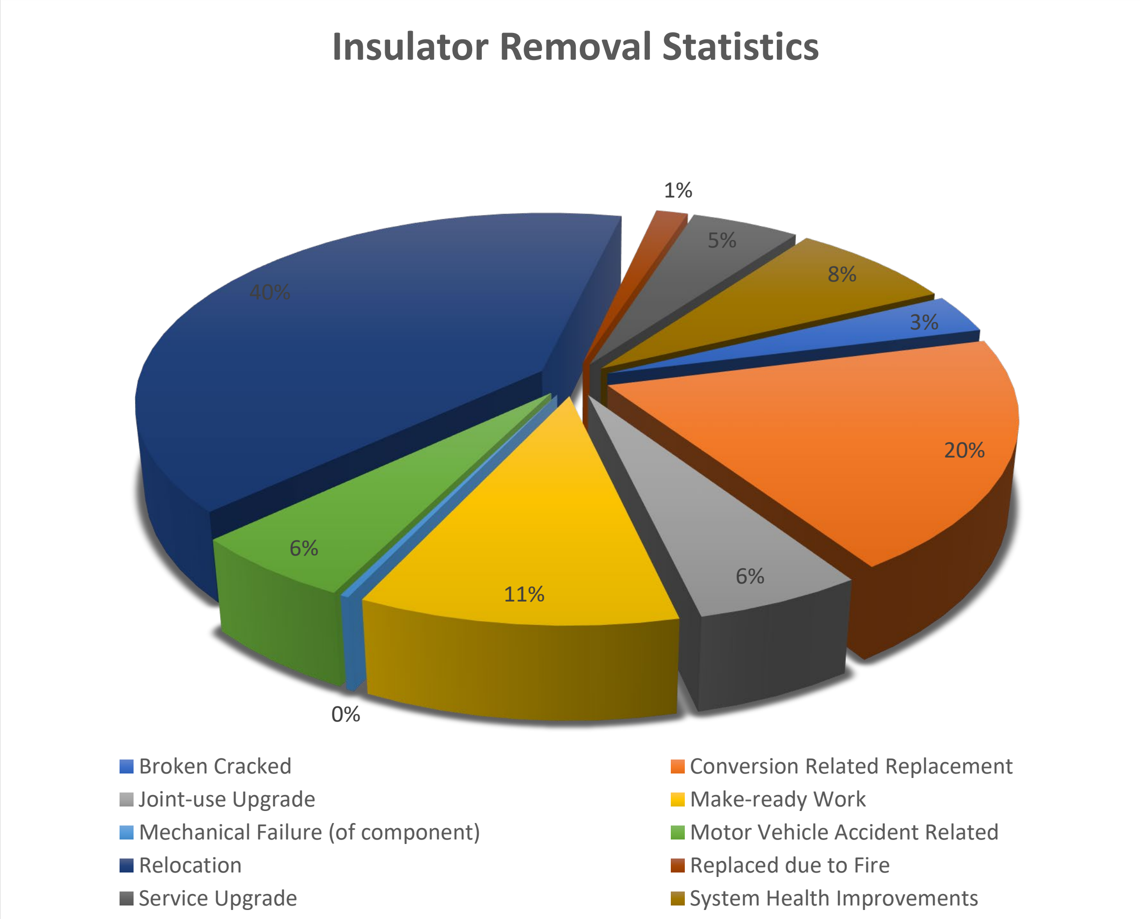


Figure 2-7 Insulator Removal Statistics 2019-2022

3. Investment Justification

Demonstrated Utility Practice

To ensure that SNC can deliver safe, reliable, and efficient service, it is fundamental that SNC has the necessary foundations in place. SNC is a member of the Utilities Standards Forum ("USF") and uses USF standards, supplemented by standards developed internally. The use of USF standards ensures that the design and construction of this project will be done according to a set of standards utilized by many other utilities in Ontario.

CSA 22.3 No.1 – Overhead Systems

This standard applies to overhead electric supply, communication lines and equipment placed outside of buildings and fenced supply stations. The standard details best practices for the materials, configuration, and strength requirements of poles and accessories. It also includes factors which are required to determine the load bearing characteristics for poles in the system. The standard also sets the requirements of the support systems accessories such as guy wires and braces. The standard includes clause 8.3.4.3 which states that when the strength of a wood pole structure has deteriorated to 60% of its required design capacity the structure shall be reinforced or replaced. This program is designed to comply with this clause.

Ontario Regulation 22/04

This is a set of regulations that was incorporated into the Electricity Act, 1998 and covers various elements of electrical distribution safety. Section 4 discusses safety standards, specifically, 4.(4).5 structures supporting energized conductors shall have sufficient strength to withstand the loads imposed on the structure by equipment and weather. This regulation informs part of SNC's renewal programs as compliance with this regulation is tracked by SNC and the OEB. SNC has achieved compliance with this regulation annually for the entire historical period. This program will ensure that SNC can continue this trend.

Distribution System Code: Appendix C

Under this code set forth by the OEB, the distributor must maintain is distribution system considering good utility practice and reliability on a short-term and long-term basis. SNC performs it inspections to comply with the requirements found in the Code. This program allows SNC to react to unexpected failures within the system to ensure that customers experience as short a disruption to their service as possible.

Cost-Benefit Analysis

A formal cost/benefit analysis was not completed, however, SNC does consider the following:

Customer impact in terms of potential failure is high for the affected customers and medium on a system level. Depending on the location of a failure, the outage impact and duration will vary depending on the location of the disconnect / isolating device. An outage resulting from a failed asset could result in a loss of economic productivity, and a risk to public safety as street lighting and traffic signals could be affected.

Each project is reviewed on a case-by-case basis to determine if these risks can be mitigated in other ways, however, there are typically no practical alternatives to replacement, and it is critical that SNC do so to ensure the safe, reliable and efficient supply to customers.

Historical Outcomes

SNC tracks the average historical costs to develop the budget for the forecast period. However, as these are a mix of planned and unplanned replacements, the cost can vary widely due a variety of factors such as location (backyard easement requiring a crane), complexity (multi-circuit poles), timing of replacement (overtime requirements), and time of year (frozen ground). For these reasons it is difficult to create a precise forecast. These replacements have minimal impact to other SNC programs. The historical replacements are found in Table 3-1. It indicates that this program has been successfully removing aging and deteriorating assets from the system.

Table 3-1 2019-2022 Historical Replacements by Major Asset Type

Asset	Quantity	Average Age
Cable (m)	149	1962
Insulators	1064	1969
Poles	382	1968
Switch	2	1970
Transformer	45	1976

4. Conservation and Demand Management

CDM is not applicable.

MATERIAL INVESTMENT REPORT

Program/Project

Overhead Renewal

Investment Category

SYSTEM RENEWAL

A. General Information on the Program/Project

1. Overview

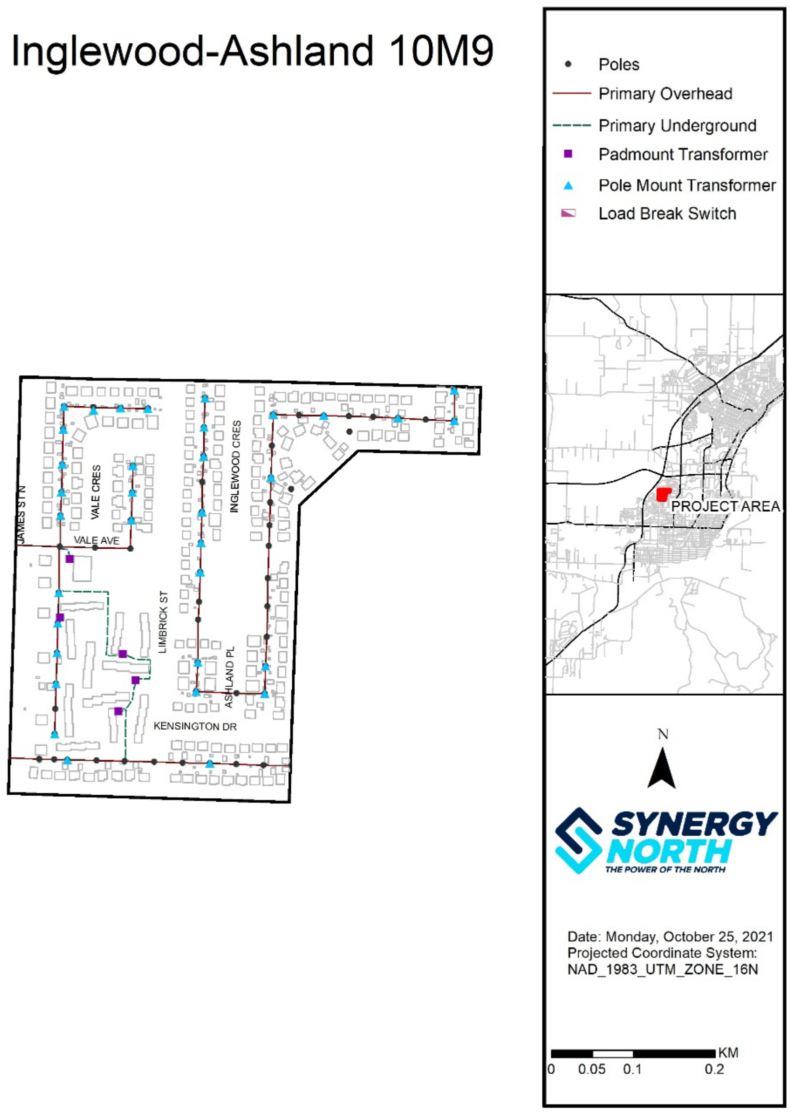
SNC has approximately 18,000 poles that comprise this category, all of which are outside of the 4kV conversion program areas. The poles identified for replacement under this program are in poor condition and past their typical useful life (TUL). Alternatively, the identified poles have prematurely degraded beyond what could be expected of poles of similar age. Identification of poles as part of this program is a multi-step process beginning with the field inspection and testing data collected as part of the asset management process. The data collected as part of this effort informs the asset condition assessment and this data is then imported into GIS. Using an internal GIS model, poles in the worst health and highest criticality are identified for replacement.

Following the identification process, subject matter experts complete a review of the selection. This process results in replacing only those assets which have a high risk and probability of failure. Each project scope includes design, construction and installation of new poles framed to conform to O. Reg. 22/04 compliant standards.

In certain cases where overhead conductor, porcelain insulators or overhead transformers are identified as end of life, within these projects, replacement will also occur. Through this project, SNC plans to improve the level of safety and reliability associated with newer standards and materials. As part of this program SNC plans to replace 60-100 poles per year.

The Overhead Renewal program addresses proactive replacements outside of the Voltage Conversion program and fulfills several asset management objectives identified in Section A.6 of this document.

For the 2024 Test Year, the following activities are planned:



Major Assets Impacted:

Assets identified below are shown by asset quantity. The quantity of assets have been identified as those requiring replcement or refurbishment as part of this project as determined by the project type and project scope. These assets directly or indirectly impact the total expenditure required to complete this project.

Street Front Poles	2		1 Phase Pad Transformers	0
Easement Poles	53		3 Phase Pad Transformers	0
Reframe Poles	1		Vault Transformers	0
Reclosers	0		Pole Mount Transformers	5
UG Primary	0		Bored Duct	0

Figure 1-1: Inglewood/Ashland Area Renewal – Full Project

2. Timing

a. Beginning: January 2024
b. In-Service: Through to December 2028
c. Factors that may impact timing: Project execution may be impacted by unplanned and/or higher priority work arising, resulting in resource constraints.

3. Historical and Forecast Capital Expenditures

Table 3-1 Historical & Forecast Capital Expenditures ($'000)

Category	Historical Period						Bridge Year	Forecast Period				
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	172	1,274	1,642	1,066	824	4,557	2,610	1,557	764	975	2,498	7,334
Contributions	-	-	-	-	-	-	-	-	-	-	-	-
Capital (Net)	172	1,274	1,642	1,066	824	4,557	2,610	1,557	764	975	2,498	7,334

The increase found in 2022 was the result of a targeted program in several easement areas in Thunder Bay where, through the asset management process, several areas were identified that needed renewal. This resulted in deferrals in other programs, particularly in Small Pole Replacements.

It should be noted that the increase in 2028 is due the completion of the 4kV Conversion Program (i.e., the volume of asset replacements targeted through that program will now shift into overhead renewal). It is at this point that SNC will continue to target a minimum volume of asset renewal based on the flagged for action plan as identified through the asset condition assessment, this increase does not translate into a significant increase in overall capital expenditure.

4. Economic Evaluation

Economic evaluation is generally not applicable.

5. Comparative Historical Expenditure

Section 3 of this document identifies the historical Overhead Renewal costs. SNC has extensive information on executing projects of this nature. Metrics for these projects have been captured (labour hours based on installation method) and based on this data, each project receives a detailed estimate annually based upon completed designs. SNC incorporates the latest resource metrics for both labour and material and includes several factors which may impact both. These may include:

- Existing overhead framing on pole
- Third party plant location
- Restricted access to proposed construction location
- Type of ground excavation (auger, vacuum excavation, hand dig, rock set)

- ROW locations requiring off-road equipment
- Vegetation encroachment
- Coordination with third party activities
- Utility easements and corridors that contain underground SNC infrastructure and 3rd party infrastructure
- Crew make-up (number of PLT, lead hand)
- Location in which existing pole/anchors is located (e.g., city sidewalk slab / asphalt paved area)

SNC evaluates project estimates, based on project type, against historical hours per pole figures to ensure that present estimates align with past project performance.

6. Investment Priority

The Overhead Renewal program is a discretionary investment and ranks 3rd overall out of 9 with a score of 53.1. As these are discretionary expenditures, they are performed after System Access projects and prioritized against other discretionary spending. The asset management objectives that follow, combined with targeted asset volumes are factors that influence this investment.

Health and Safety - Moderate injury requiring first aid or moderate security incident likely (expected to occur in 5yr).

As with other overhead programs, the likelihood of failure combined with the fact that overhead systems have a higher impact on customer and employee safety (as compared to underground) translate to a relatively high potential for an incident to occur. The assets that comprise this program are proactively replaced and make up a portion of the actionable assets identified through the asset condition assessment (ACA).

Environmental Impact - Addresses two (2) or more of SNC's identified environmental risks and provides risk mitigation to those risks.

The potential impacts due to climate change (i.e., system hardening through the replacement of higher standard infrastructure) and vegetation management (i.e., encroachments) are addressed through this program.

Regulatory/Legal Compliance - No impact on regulatory compliance.

Customer Preference - Delivers on all of the top 3 priorities of customers (Affordability, Safety for Employees and the Public and Reliability).

This program addresses assets that have been identified for replacement through the ACA process which are generally in poor condition. Doing so helps to maintain SNC's current reliability and safety performance. The assets in this program are operating at 25kV and in some cases, there may be several assets within the project scope that are of acceptable condition to remain in service (or capable of returning to service). In these circumstances, SNC will not replace these assets thereby improving the affordability of the program.

Asset Performance - >50% of assets in poor condition or non-system assets operating within extended manufacturer support.

This program specifically targets projects where there is a minimum complement of assets in poor condition, see Figure 2-7.

Operational Efficiency – Aligns with 1

The poles identified for replacement in this program are in backyard easements, and in many cases the overhead secondaries are aerially trespassing. These operational issues will be addressed during the execution of this program.

System Reliability - Sustained interruption of <1.5 MW of distribution load (100-300 residential customers)

The test year program includes a residential rebuild containing approximately 300 customers.

7. Alternatives Analysis

The projects listed in this category have been identified based on the outcome of the asset condition assessment, flagged for action plan and reviewed by subject matter experts.

Alternatives for overhead renewal are considered and are captured below.

a. Do nothing approach – this results in reactive replacement of poles which would result in potential long outages for those customers affected, and potentially off business hours, resulting in a higher cost for replacement, for these reasons this alternative is not considered.

b. Use of concrete, composite or alternative material poles – this alternative would result in a higher initial cost which would not necessarily provide more value to the utility or the customer.

c. Removing line and placing overhead section of line underground which would result in improved reliability but according to SNC metrics, underground construction results in significant cost increases compared to overhead. For this reason, this alternative is not considered.

8. Innovative Nature of the Project

There are no innovative elements within this program.

9. Leave to Construct Approval

Not applicable to this program.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability and Safety

Criteria	Description
Efficiency	This program has minimal effect on system efficiency, however failure to replace deteriorating poles and transformers might result in untimely asset failure and system reliability concerns. This will have a negative impact on the efficiency of the distribution system at a given time. In addition, SNC considers replacement of associated assets (conductor, pole-mount transformer, switches) that are also in poor condition, rather than return at a later date.
Customer Value	The net benefit to customers is to reduce the potential for a risk in failure and to ensure that any safety hazards are eliminated while maintaining reliability.
Reliability	Replacement of these poles will have a positive impact on reliability performance and safety in the following ways; a) Tree trimming due to replacement will improve reliability by reducing the amount of tree contacts b) Installation of new standards will enhance clearance providing for safer working conditions for both SNC and Third party employees c) Installation of new standards includes animal protection on overhead transformers which will reduce the number of animal contact related outage, improving reliability Maintain reliability by reducing potential failures prior to failure and greatly decreasing restoration times.
Safety	This investment will maintain SNC's safety to the public, as well as worker safety by replacing existing poles and their associated framing with newer standards of framing with allow for improved safe work practices. In areas of these projects where porcelain insulators are discovered these will be replaced with polymer insulators thereby greatly reducing the risk of failure and eliminating a safety hazard to the public.

2. Investment Need

Primary Driver:

Failure Risk - The main drivers for this project are Asset Retirement and Health and Safety. SNC seeks to prioritize project selection based on assets that are in poor health, and SNC is obligated to ensure that the way it executes its initiatives does not negatively impact the health and safety of the public, customers or SNC's employees. The assets identified in this project have a high probability of failure which is a result of the condition of the assets.

The assets operating at 25/12kV encompass most of SNC's distribution system. The figures shown below detail the assets operating at these voltages. The asset condition is determined using the asset management process with each asset having unique condition parameters which form the basis of the asset condition assessment. The health of these assets is calculated from the inspection data collected by subject matter experts and are grouped into 5 categories: very good, good, fair, poor, and very poor.

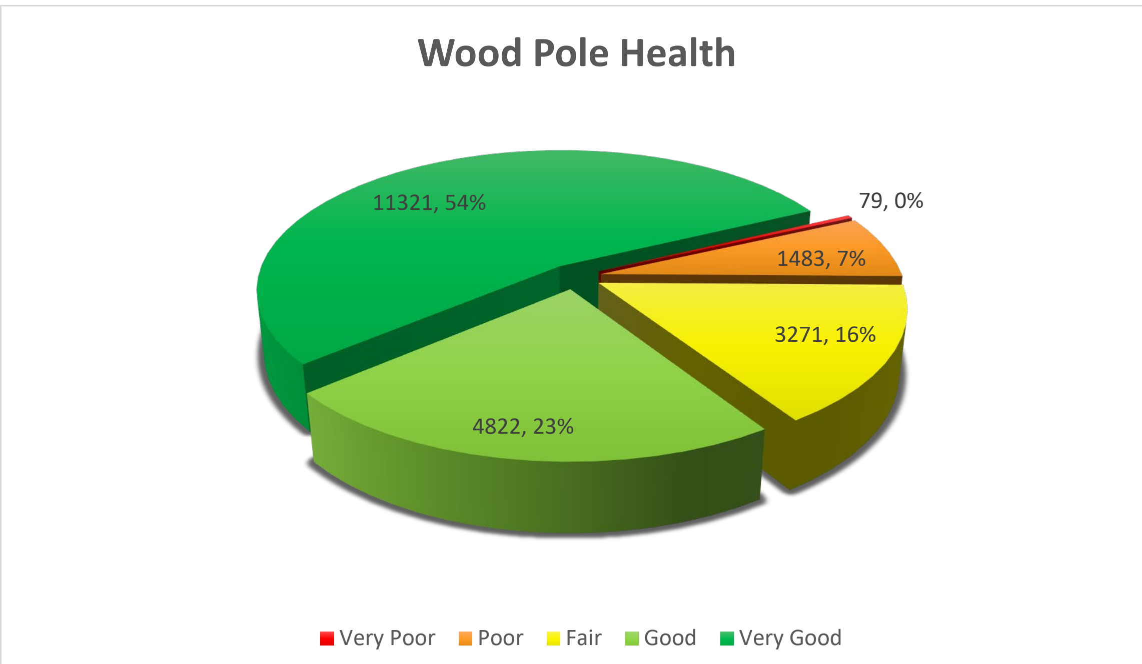


Figure 2-1 2022- 25/12kV Wood Pole Condition Demographics

Figure 2-1 shows that the SNC's wood poles are in overall good condition as of the 2022 with 77% in good/very good condition. Many poles are in fair condition, and statistically a percentage of this population will deteriorate into poor or very poor condition over the forecast period. These assets, along with the poles in poor/very poor condition will be prioritized for replacement.

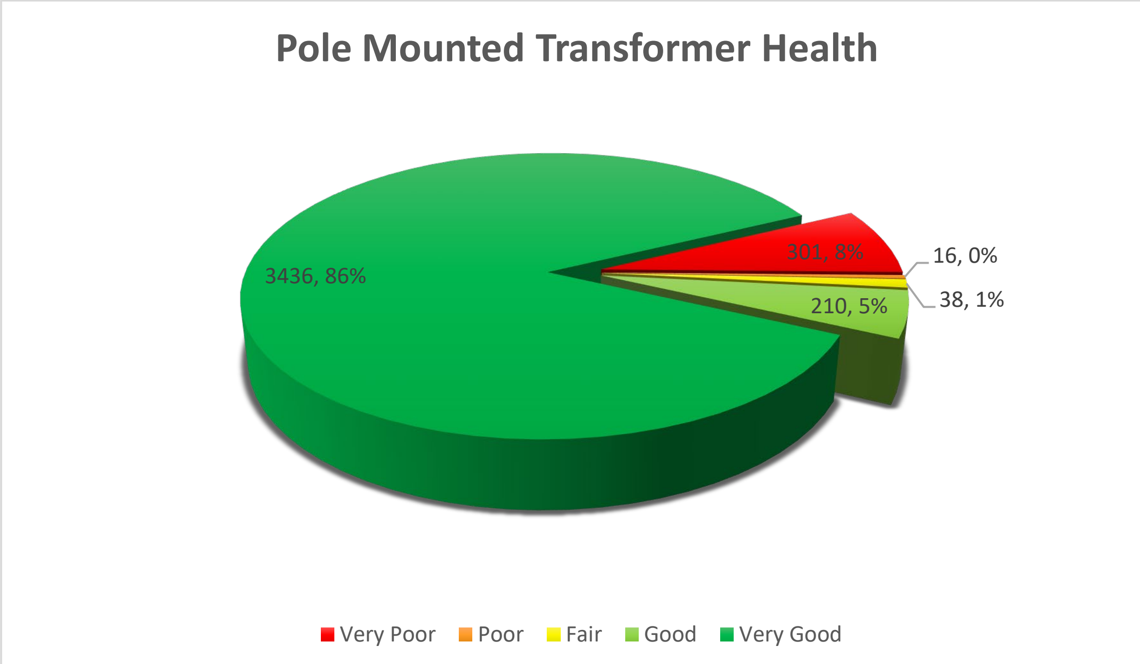


Figure 2-2 2022- 25/12kV Pole Mounted Transformer Condition Demographics

Like wood poles, Figure 2-2 show that the SNC's 25/12kV pole mounted transformers are in overall good condition as of 2022 with 86% respectively in good/very good condition. Pole mounted transformers are typically replaced upon failure, however the population identified in poor and very poor condition are targeted for replacement as part of this program.

Secondary Drivers:

Reliability - The secondary driver is Reliability. The risk to the utility and the customer is that the asset will fail and result in an outage that negatively affects reliability and customer satisfaction.

Information Used to Justify the Investment:

SNC's asset management process (Section 5.3.1 of the DSP) and asset lifecycle optimization practices (Section 5.3.3 of the DSP) inform the execution of the Overhead Renewal program. The average health of these assets is 83%. The planned replacements in this program (approximately 60-100 poles, 0.5%) ensures that SNC continues to mitigate the risk of unplanned outages and provides a safe electrical system by controlling hazards.

The results of the asset condition assessment yield the flagged-for-action plan for all assets. Table 2-1 suggest the replacement levels for the assets targeted as part of this and other programs.

Table 2-1 Flagged-for-Action Asset Volume

ASSET	FLAGGED FOR ACTION BY YEAR				
	2024	**2025**	**2026**	**2027**	**2028**
WOOD POLES	420	341	335	336	336
POLE MOUNTED TRANSFORMERS	141	141	141	141	141

The planned replacement of assets identified through this analysis are essential in maintaining the reliable supply of electricity for SNC's customers.

Wood Poles

Poles reaching the end of their service life may experience rapid decline in remaining strength, which SNC considers the most important factor influencing pole health, as their primary function is to support other distribution assets. The deterioration often occurs due to the presence of wood rot due to moisture ingress and other forms of decay. As poles decay, they become vulnerable to mechanical failure for several reasons. External forces on the pole such as physical impact and adverse weather can cause a pole or poles to fail catastrophically. Snow, wind, and ice loading can cause a compromised pole to fail, when an otherwise healthy pole would remain in service.

Since poles generally support other distribution infrastructure, their failure often leads to damage of other assets, such as overhead lines, transformers, and switches. An increase in outages would be expected if no action is taken to address failing poles which would result in a negative customer experience.

There are also negative impacts to the financial and operational performance of the utility if poles are only addressed when they fail to restore service to customers. Reactive replacements are more costly and less efficient than proactive replacements, often requiring resources to be diverted from other activities, and/or after regular working hours. This can cause delays in other planned work. SNC accounts for reactive replacements in other programs, the Overhead Renewal program is designed to address proactive replacement of poles.

Customers expect high quality electrical service from SNC and by proactively addressing deteriorating assets, SNC can maintain or improve the health of poles that serve the distribution system thereby reducing their negative impact.

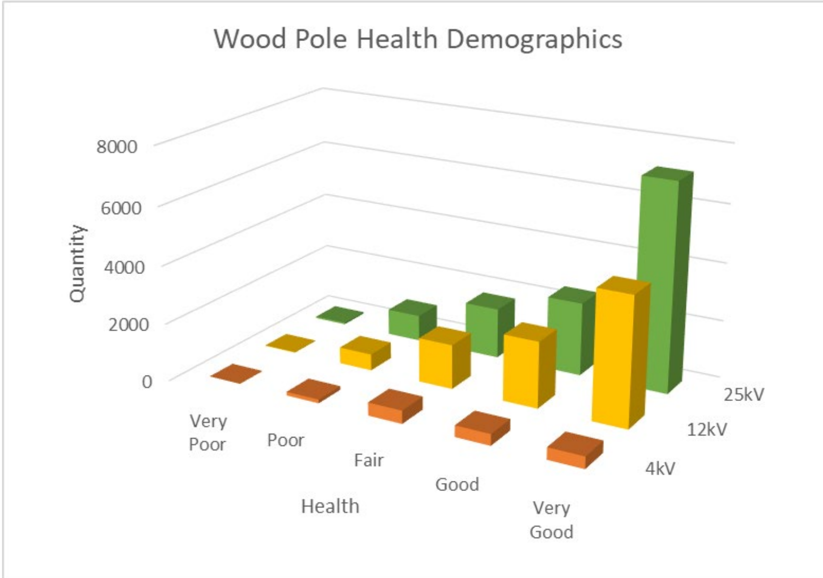


Figure 2-3 2022-Wood Pole Condition Demographics

Pole Mounted Transformers

Pole mounted transformers operating at12/25kV are assessed on a case-by-case basis to determine their requirement for replacement. Often, these assets are found to be in good condition, and many are either returned to service or remain in service. Those found to be in poor/very poor health are replaced.

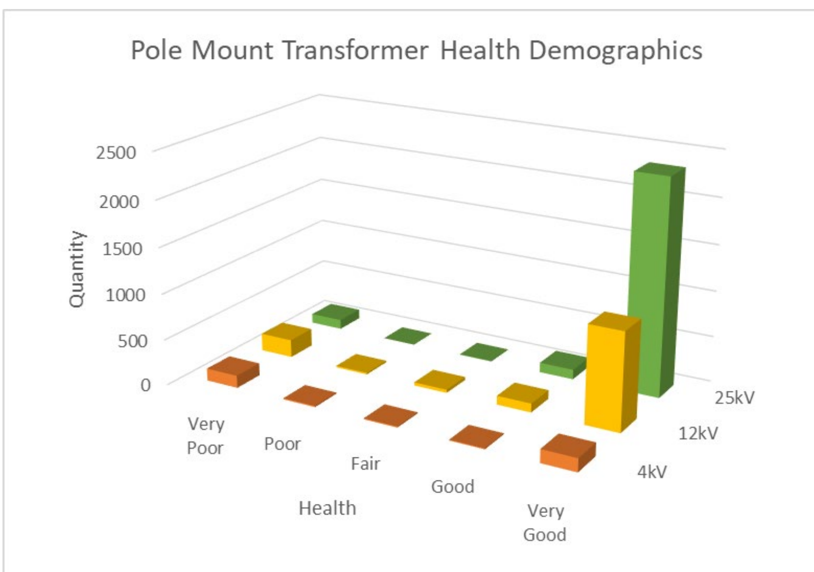


Figure 2-4 2022 - Pole Mounted Transformer Health Demographics

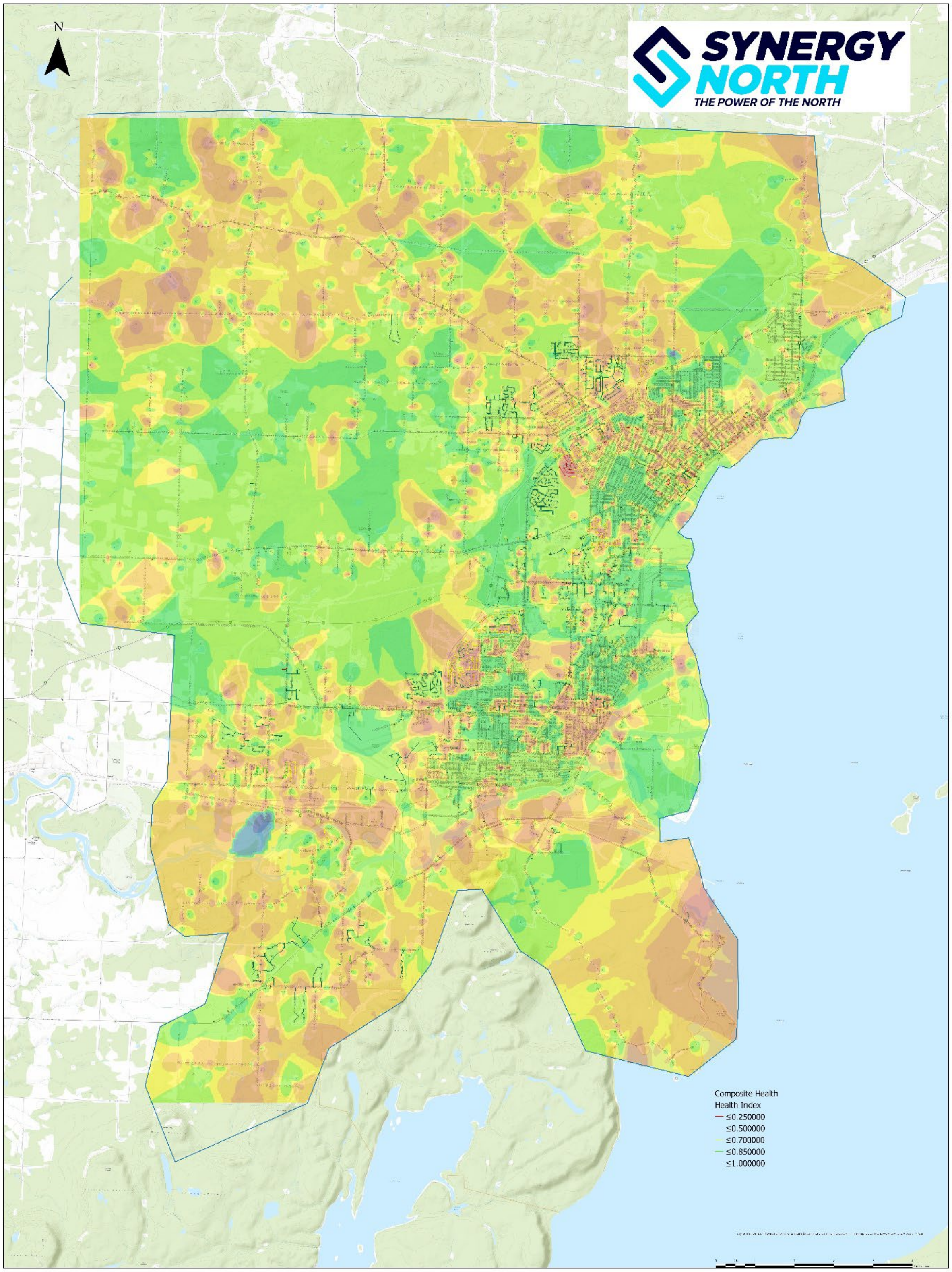


Figure 2-5 Geospatial Asset Health Analysis

3. Investment Justification

Demonstrated Utility Practice

To ensure that SNC can deliver safe, reliable, and efficient service, it is fundamental that SNC has the necessary foundations in place. SNC is a member of the Utilities Standards Forum ("USF") and uses USF standards, supplemented by standards developed internally. The use of USF standards ensures that the design and construction of this project will be done according to a set of standards utilized by many other utilities in Ontario.

The Canadian Standards Association provides standards for several sectors. CSA 22.3 applies to utilities, and it sets out specific requirements which look to improve the safety and reliability of the electrical distribution system.

CSA 22.3 No.1 – Overhead Systems

This standard applies to overhead electric supply, communication lines and equipment placed outside of buildings and fenced supply stations. The standard details best practices for the materials, configuration, and strength requirements of poles and accessories. It also includes factors which are required to determine the load bearing characteristics for poles in the system. The standard also sets the requirements of the support systems accessories such as guy wires and braces. The standard includes clause 8.3.4.3 which states that when the strength of a wood pole structure has deteriorated to 60% of its required design capacity the structure shall be reinforced or replaced. This program is designed to comply with this clause.

Ontario Regulation 22/04

This is a set of regulations that was incorporated into the Electricity Act, 1998 and covers various elements of electrical distribution safety. It is designed to address aspects of safety standards, approval of electrical equipment, approval of plans and specifications for installations, inspection and approval of construction, proximity to distribution lines, disconnection of unused lines, reporting serious electrical incidents, and compliance. This regulation informs part of SNC's renewal programs as compliance with this regulation is tracked by SNC and the OEB. SNC has achieved compliance with this regulation annually for the entire historical period. This program will ensure that SNC can continue this trend.

Distribution System Code: Appendix C

Under this code set forth by the OEB, the distributor must maintain is distribution system considering good utility practice and reliability on a short-term and long-term basis. Inspections are performed to comply with the requirements found in the Code. Where defects are discovered, depending on the severity, assets may be replaced immediately or planned for future replacement.

Cost-Benefit Analysis

A cost-benefit analysis was not performed for this program, however SNC carefully considers the following when considering which projects, it executes.

The planned investments in this program will help sustain system reliability as the failure risk of deteriorated poles is reduce. An outage resulting from a failed asset could result in a loss of economic productivity, and a risk to public safety as street lighting and traffic signals could be affected.

Additionally, deteriorated poles pose a significant risk to the public, third party contractors and SNC employees. Poles in this state often fail because they have insufficient strength to support attachments when external forces are applied (e.g., wind, snow, ice, etc.). This program helps to mitigate the risk that a failed pole injures people or property or causes fires as a result of energized conductors contacting the environment.

Balancing the need for reliability against the level of proactive replacement can be challenging. By carefully controlling the volume of replacements based on upon the flagged-for-action plan and targeting assets in poor condition SNC can have more control over the outcome, especially when compared to reactive replacement, which often requires an immediate response drawing resources away from other planned work.

Historical Outcomes

Assets in this category had historically been underserved as SNC focused on its 4kV Conversion program. In it's previous Cost of Service filing[1] SNC committed to creating a more wholistic plan by incorporating renewal of assets operating at voltages other than 4kV. Since then, project areas have been identified through the asset management process (Section 5.3.1 of the DSP) and the results of the replacements shown in Table 3-1 have led to improvements in asset health in these categories (See Appendix I). Additionally, when end-of-life poor condition assets are replaced as part of these projects, it can also result in maintained system reliability. The assets replaced historically as part of this program can be found in the following table.

Table 3-1 Poor Condition Assets Removed Over Historical Period

Category	Historical Period					
	2017	2018	2019	2020	2021	2022
Poles	70	68	88	79	72	266
Transformers	12	8	4	9	32	31

4. Conservation and Demand Management

CDM is not applicable.

[1] *2017 Cost of Service Application*, EB-2016-0105 – Thunder Bay Hydro Electricity Distribution Inc.

MATERIAL INVESTMENT REPORT

Program/Project

Small Pole Replacements

Investment Category

SYSTEM RENEWAL

A. General Information on the Program/Project

1. Overview

This program is comprised of replacement of wood poles determined to be in poor condition that pose a potential risk to public safety and/or customer reliability. The selected poles are either at the end of their useful life or have prematurely degraded beyond what could be expected of poles of similar age. The poles replaced in this project are identified through field inspections and lines safety reports submitted from customers and internal staff and are scheduled for replacement within the year.

These projects are typically larger in scope than 5 poles (i.e., the scope and scale is larger than that of reactive replacements, but less than that of the Overhead Renewal program) and use work instructions or engineered drawings to conform to O. Reg. 22/04 to replace poles that are in poor condition. SNC expects that the estimated number of replacements will be 30 wood poles annually with varying degrees of difficulty.

These replacements are generally planned for the Kenora service territory and as such the quantity should not vary annually. Where applicable, SNC will incorporate these replacements into a larger program.

2. Timing

a. Beginning: January 2024
b. In-Service: Through to December 2028
c. Factors that may impact timing: Factors that may impact timing Project execution may be impacted by unplanned and/or higher priority work arising, resulting in resource constraints.

3. Historical and Forecast Capital Expenditures

Table 3-1 Historical & Forecast Capital Expenditures ($'000)

Category	Historical Period						Bridge Year	Forecast Period				
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	564	314	422	258	128	27	614	767	782	798	814	830
Contributions	-	-	-	-	-	-	-	-	-	-	-	-
Capital (Net)	564	314	422	258	128	27	614	767	782	798	814	830

The drivers that resulted in reduced expenditure in 2022 were 1) deferred renewal in the Kenora service territory until such time as inspections were complete; and 2) increased renewal required in Thunder Bay service territory to account for assets identified for replacement as part of the asset management process. Further information is available in the Material Investment Report – Overhead Renewal.

The increase proposed in this program for the test year and beyond is as a direct result of the inspection program that occurred in 2022 and identified assets in poor condition requiring replacement.

4. Economic Evaluation

Economic evaluation is generally not applicable.

5. Comparative Historical Expenditure

Section 3 of this document identifies the historical Small Pole Replacement costs. Historical values for this program are tracked closely and budget forecasts are based on average replacement costs by asset type. Performance metrics for these projects have been captured for the years 2016 through 2022. Based on this data, each project receives a detailed estimate annually based upon completed designs. SNC incorporates the latest resource metrics for both labour and material and includes several factors which may impact both. These may include:

- Existing overhead framing on pole
- Third party plant location
- Restricted access to proposed construction location
- Type of ground excavation (auger, vacuum excavation, hand dig, rock set)
- ROW locations requiring off-road equipment
- Vegetation encroachment
- Coordination with third party activities
- Utility easements and corridors that contain underground SNC infrastructure and 3rd party infrastructure
- Crew make-up (number of PLT, lead hand)
- Location in which existing pole/anchors is located (e.g., city sidewalk slab / asphalt paved area)

6. Investment Priority

The Small Pole Replacement program is a discretionary investment and ranks 5 out of 9 with a score of 43.7. As these are discretionary expenditures, they are performed after System Access projects and prioritized against other discretionary spending. Health and Safety is the main factor that influences the program ranking.

Health and Safety - Moderate injury requiring first aid or moderate security incident likely (expected to occur in 5yr).

Like other overhead renewal programs, the potential impact for harm is high with regards to this type of infrastructure. Accordingly, SNC must continue to effectively address the assets identified throughout its service territory to prevent these potential injuries from occurring.

Environmental Impact - Addresses one (1) or more of SNC's identified environmental risks and provides risk mitigation to those risks.

The poor condition poles replaced in this program are designed and installed to meet the latest standards and operating requirements, and therefore reduce the risk that climate change will adversely affect their performance.

Regulatory/Legal Compliance - No impact on regulatory compliance.

Customer Preference - Delivers on two of the top 3 priorities of customers (Affordability, Safety for Employees and the Public and Reliability).

This program allows SNC to maintain existing levels of performance with regards to health and reliability, two of the main customer concerns, through the removal of failing assets.

Asset Performance - >50% of assets in fair condition or non-system assets reaching end of manufacturer support.

This program targets only that subset of poles that are in poor condition, as identified through field assessments and testing. See Figure 2-1.

Operational Efficiency – Aligns with 1

This program decreases SNC's liability with regards to known assets in poor condition and removing them from service prior to catastrophic failure.

System Reliability - Sustained interruption of <1.5 MW of distribution load (100-300 residential customers).

The scope of replacements within this program is less than five poles and as such the relative impact to customers is small as compared to other programs.

7. Alternatives Analysis

The projects listed in this category have been identified based on the outcome of the asset condition assessment, flagged for action plan and review by subject matter experts.

Alternatives for small pole replacements are considered and are captured below.

a. Do nothing approach – this results in reactive replacement of poles which would result in potential long outages for those customers affected, and potentially off business hours, resulting in a higher cost for replacement, for these reasons this alternative is not considered.

b. Like-for-Like replacement (Ie. Without engineering design plan): This would shift these poles to the Lines Safety Reports category, and they would not be reviewed and engineered to the most current CSA standards to withstand climate change and storms.

c. Removing line and placing overhead section of line underground which would result in improved reliability but according to SNC metrics, underground construction results in significant cost increases compared to overhead. For this reason, this alternative is not considered.

8. Innovative Nature of the Project

There are no innovative elements within this program.

9. Leave to Construct Approval

Not applicable to this program.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability and Safety

Criteria	Description
Efficiency	This program has minimal effect on system efficiency, however by grouping poles and addressing them at once, SNC avoids having to return to address them as stand-alone poles in the future. Provides economies of scale for deployment of equipment and staff.
Customer Value	The net benefit to customers is to reduce the potential for a risk in failure and to ensure that any safety hazards are eliminated while maintaining reliability.
Reliability	Replacement of these poles will have a positive impact on reliability performance and safety in the following ways; a) Tree trimming due to replacement will improve reliability by reducing the amount of tree contacts b) Installation of new standards will enhance clearance providing for safer working conditions for both SNC and Third party employees Improved reliability by reducing potential failures prior to failure and greatly decreasing restoration times.
Safety	This investment will maintain SNC's safety to the public, as well as worker safety by replacing existing poles and their associated framing with newer standards of framing with allow for improved safe work practices. In areas of these projects where porcelain insulators are discovered these will be replaced with polymer insulators thereby greatly reducing the risk of failure and eliminating a safety hazard to the public.

2. Investment Need

Primary Driver:

Failure risk – This project is driven primarily by the results of the asset condition assessment and detailed inspection program for the Kenora service territory. The pole replacements are prioritized based on assets that are in poor health, and SNC is obligated to ensure that the way it executes its initiatives does not negatively impact the health and safety of the public, customers or SNC's employees. The assets are identified in this program geospatially and in consultation with subject matter experts.

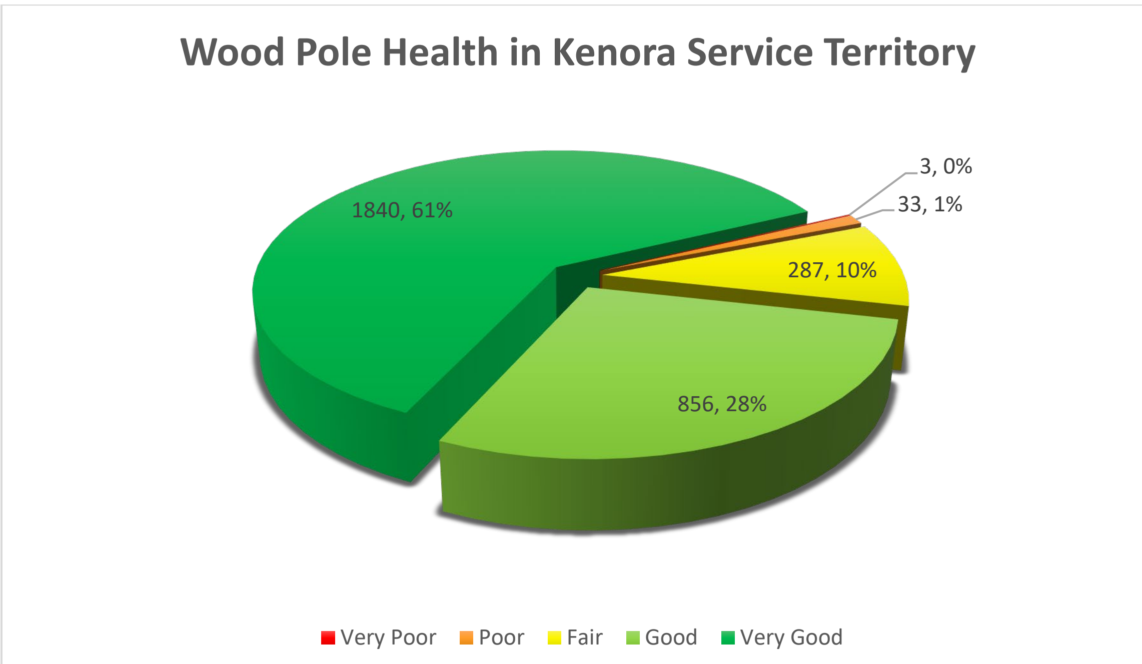


Figure 2-1 - 2022 - Wood Pole Condition Demographics in Kenora

Approximately 10% of the pole population is in fair to poor health in Kenora. SNC expects a number of poles within the fair population will degrade to form part of the poor health population. These are the assets targeted by this program annually.

Secondary Drivers:

Reliability - The secondary driver is Reliability. The risk to the utility and the customer is that the asset will fail and result in an outage that negatively affects reliability and customer satisfaction. Due to the geographic distance between Thunder Bay and Kenora, (approximately 5.5 hours) restoration times could be impacted by response times in the case of large-scale outages. It is expected that SNC maintain the system to the extent possible to prevent this from occurring, and as such considers proactive replacement of poles in fair to poor condition critical to maintaining a reliable supply of electricity in Kenora.

Information Used to Justify the Investment:

The planned replacements of assets identified through this analysis are important to the long-term supply of reliable electricity. SNC identifies wood pools reaching the end of their service life using the output of the asset condition assessment in conjunction with geospatial location. Figure 2-1 displays the geospatial location, by health, of poles within the Kenora service territory. This information assists engineering and operations staff in identifying and planning replacements.

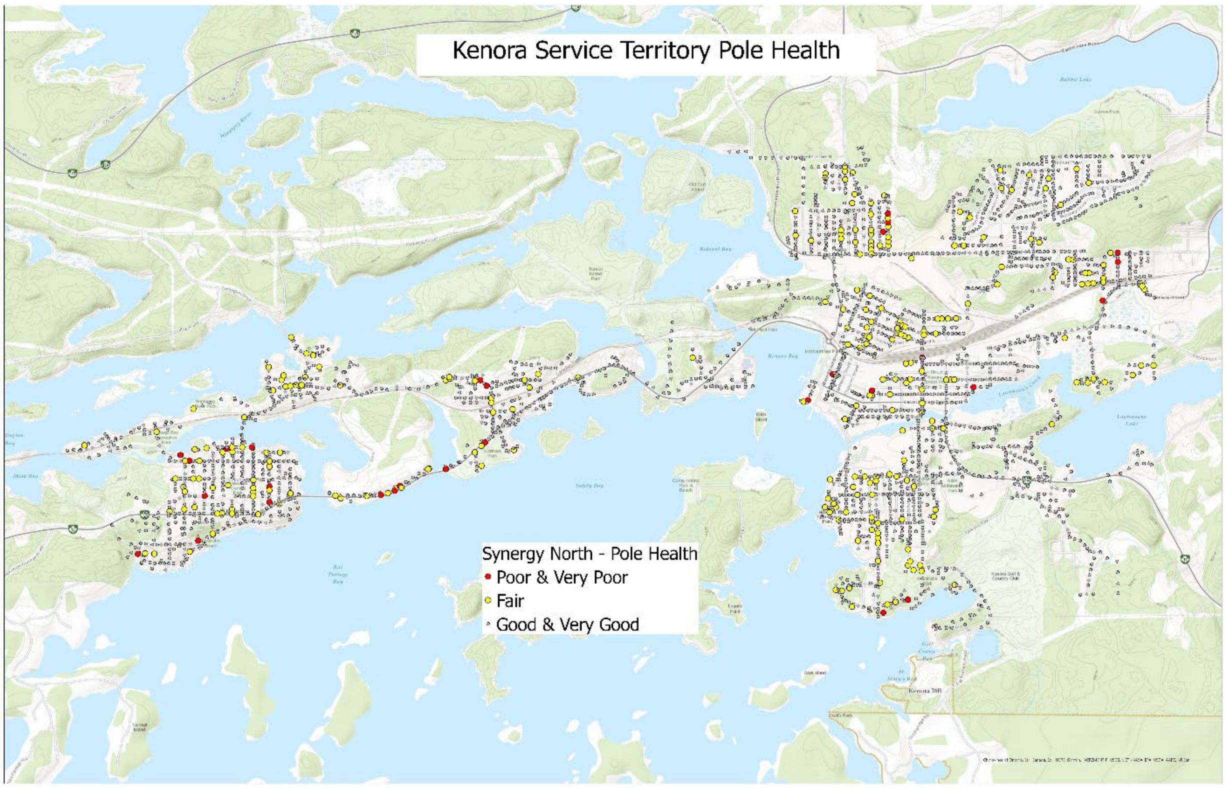


Figure 2-2 Kenora Pole Health Map

Poles serve a critical role in ensuring the distribution system continues to function properly as they are required to physically support other assets such as overhead lines and transformers. They also form the most abundant asset class which means that even one or two percent of the population can have a significant impact on cost and reliability.

3. Investment Justification

Demonstrated Utility Practice

To ensure that SNC can deliver safe, reliable, and efficient service, it is fundamental that SNC has the necessary foundations in place. SNC is a member of the Utilities Standards Forum ("USF") and uses USF standards, supplemented by standards developed internally. The use of USF standards ensures that the design and construction of this project will be done according to a set of standards utilized by many other utilities in Ontario.

The Canadian Standards Association publishes guidelines for various distribution system assets. These standards are reviewed, updated and issues on a regular basis and detail best practices for methods and materials related to poles and accessories. It provides the load factors that must be used when determining the vertical, transverse, and angular load-bearing characteristics of poles in the system. It also specifies the strength requirements of distribution support assets and permits the use of guy wires and braces to meet these requirements. Poles are reviewed as part of this program to ensure they can continue to serve under these requirements.

Ontario Regulation 22/04 is a set of regulatory requirements included in the Electricity Act, 1998, and covers various aspects of Electrical Distribution Safety. It outlines practices for asset ownership, safety standards, approval of electrical equipment (including plans and installations), inspections and approval of construction, deviations from standards, proximity to distribution lines, disconnection of unused lines, condition of approval/reporting of serious electrical incidents, and compliance. SNC has achieved compliance with this regulation and believes that this program will allow SNC to continue to achieve compliance in the future.

Under the Distribution System Code set forth by the OEB, the distributor must maintain its distribution system with consideration to good utility practice quality, and reliability for short term and long-term basis. Inspection activities in Kenora take place following requirements found in the Distribution System Code Appendix C. Where defects are discovered, replacements may be made immediately or planned in connection with other activities such as relocations, joint-use upgrades, etc.

Cost-Benefit Analysis

There is a potential for significant customer impact in the Kenora service territory if there is widespread failure. Its remoteness, as compared to SNC’s main operating territory in Thunder Bay could make for extended restoration times as crews are deployed to assist. Depending on the location of a failure, outage impact and duration will vary depending on the location of the downstream disconnect / isolating device. Each project is reviewed on a case-by-case basis to determine if these risks can be mitigated in other ways, however, there are typically no practical alternatives to pole replacements.

Historical Outcomes

SNC has completed several projects as part of this program historically and has observed many positive outcomes from these projects including but not limited to, improved system efficiency, reduction in losses, and increased standardization requiring less inventory. When end-of-life poor condition assets are replaced as part of these projects, it can also result in maintained or improved system reliability. The table below outlines the quantity of major assets (those assets tracked via the asset condition assessment and asset removal process).

While the focus of the program is to replace poles, assets that are found to be in poor condition are occasionally replaced in conjunction with the pole.

Table 4-1 2019-2022 Historical Replacements by Major Asset Type

Asset	Quantity	Average Age
Insulators	272	1985
Poles	43	1976
Switch	3	1980
Transformer	1	1960

4. Conservation and Demand Management

CDM is not applicable.

MATERIAL INVESTMENT REPORT

Program/Project

Transformer/Switch/Switchgear Replacements

Investment Category

SYSTEM RENEWAL

A. General Information on the Program/Project

1. Overview

This program is comprised of reactive replacement of transformers, switches and switchgear determined to be in poor condition that pose a potential risk to public safety and/or customer reliability. The selected assets are either in poor health or have prematurely degraded beyond what could be expected of assets of similar age. The assets replaced in this project are identified through field inspections and lines safety reports submitted from customers and internal staff and are scheduled for replacement within the year.

These projects are typically replaced on a like-for-like basis to conform to O. Reg. 22/04. Table 1 highlights the estimated number of replacements by asset category. These replacements are generally unplanned in nature and as such the quantity may vary annually. Where applicable, SNC will incorporate these replacements into a larger program.

Table 1-1: Forecast Quantity of Replacements by Type

Category	Forecast Period				
	2024	2025	2026	2027	2028
Pole MountedTransformers	40	40	40	40	40
Pad Mounted Transformers	25	25	25	25	25
Load Break Switch	3	3	3	3	3
In-line Switch	7	7	7	7	7

2. Timing

a. Beginning: January 2024
b. In-Service: Through to December 2028
c. Factors that may impact timing: Assets are in this category pose a risk to the health and safety of staff and public and are completed as high priority, as such, no factors should affect timing.

3. Historical and Forecast Capital Expenditures

Table 3-1 Historical & Forecast Capital Expenditures ($'000)

Category	Historical Period						Bridge Year	Forecast Period				
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	990	672	781	662	598	808	868	932	951	970	989	1,009
Contributions	-	-	-	-	-	-	-	-	-	-	-	-
Capital (Net)	990	672	781	662	598	808	868	932	951	970	989	1,009

4. Economic Evaluation

Economic evaluation is generally not applicable.

5. Comparative Historical Expenditure

Section 3 of this document identifies the historical Transformer/Switch/Switchgear replacement costs. The quantity of replacements is dependent on the field inspections and risk assessments. SNC attempts to limit the subjectivity of inspections by using qualified individuals and it is important to establish sufficient criteria to ensure the data collected is valid. The Engineering department works closely with the Lines department to create standardized testing and inspection procedures, to ensure that imminent replacement quantities are justifiable.

In addition, there is a risk that required replacements will exceed the expected quantities and planned expenditures. For this reason, all replacements are reviewed by the Lines Maintenance Supervisor and the expenditures in this account are tracked by the Project Engineer and reported on a bi-monthly basis. This program is similar to that of Line Safety Reports, as the assets identified pose an increased risk of failure and could be detrimental to the safety and reliability of the system. This program will be completed within the year, and projects with a lower level of prioritization in the System Renewal category are deferred if increases in asset replacements are identified for replacement.

6. Investment Priority

The timing of these projects is affected by the urgency of resolving the potential risk of failure, however as much of this program concerns pad-mounted equipment the risk is slightly lower as compared to overhead infrastructure. This program ranks 4 out of 9 with a score of 48.4. If an asset is identified as more urgent, it will be prioritized, rather than completing replacements based on the timing of their identification. For more information on the prioritization process see Section 5.4.2 of the DSP.

Health and Safety - Moderate injury requiring first aid or moderate security incident likely (expected to occur in 5yr).

In most cases, the assets removed as part of this program have failed to meet the criteria to remain in service as (e.g., pad mounted transformer found to be leaking oil, switch fails to operate), however do not typically fail catastrophically and are removed from service to reduce the risk of injury.

Environmental Impact - Addresses one (1) or more of SNC's identified environmental risks and provides risk mitigation to those risks.

The poor condition transformers replaced as part of this program are often of a vintage that contain some amount of PCB however, less than 50PPM as prescribed[1]. Replacing these prevents PCB release into the environment.

Regulatory/Legal Compliance - Addresses an issue that may become nonconformant with best practices if no action is taken.

While not a primary driver of this program, the removal of transformers containing PCB's is encompassed in this program. If further, more stringent regulations were to be introduced during the planning period (e.g., transformers containing <50PPM PCB's), SNC would be well positioned to address several of these assets within this program.

Customer Preference - Delivers on two of the top 3 priorities of customers (Affordability, Safety for Employees and the Public and Reliability)

This program ensures that two of the main customer concerns, safety for employees and the public, as well as reliability are addressed through the removal of failing assets.

Asset Performance - >50% of assets in poor condition or non-system assets operating within extended manufacturer support.

This program targets only those transformers and switches that are in poor condition, as identified through field assessments and testing.

Operational Efficiency – Aligns with 1

Although not a primary driver, this program aims at reducing SNC's liability with regards to discharging PCB's into the environment in the case of an unexpected oil leak.

System Reliability - Sustained interruption of <1.5 MW of distribution load (100-300 residential customers).

SNC is unable to predict when and where the replacement of the infrastructure in this program will occur. However, as they are generally only a singular replacement the customer impact is typically low.

7. Alternatives Analysis

The projects listed in this category have been identified based on the outcome of the asset condition assessment, flagged for action plan and review by subject matter experts.

Alternatives for Transformer, Switch and Switchgear replacements are considered and are captured below.

[1] Government of Canada (2008). *PCB Regulations* SOR/2008-273, https://laws-lois.justice.gc.ca/eng/regulations/sor-2008-273/FullText.html

a. Do nothing approach – this results in reactive replacement of these assets which would result in potential long outages for those customers affected, and potentially off business hours, resulting in a higher cost for replacement, for these reasons this alternative is not considered.

b. Removal of the asset – this option is considered for overhead switches based on functionality and operational effectiveness but is not an option for transformers which provide service to customers.

c. Relocation of the asset - this alternative could result in a higher cost, but it is considered in cases where there are access issues or where this results in a more cost-effective option which provides value to the utility or the customer.

d. Decreased or increased sizing for transformers is considered based on an analysis of the loading.

e. Like-for-like replacement with updated standards (such as transformers of the same size but with current limiting fuses) is the typical replacement strategy as it provides the least impact to the customer, the land, and the utility. It is also typically the most cost-effective and efficient option.

8. Innovative Nature of the Project

There are no innovative elements within this program.

9. Leave to Construct Approval

Not applicable to this program.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability and Safety

Criteria	Description
Efficiency	This program has some effect on system efficiency as failure to replace deteriorating assets might result in untimely asset failure and system reliability concerns. This will have a negative impact on operating efficiency at a given time. Additionally, SNC assesses the load on the transformer during replacement and may suitably resize the unit to better align with historical loading characteristics.
Customer Value	The replacement of these assets will positively impact the number and duration of outages attributed to the defective equipment outage code, and ensure that existing levels of reliability are

	maintained, and safety issues are eliminated. Customers appreciate having a scheduled outage outside of peak business hours to proactively replace ageing infrastructure, verses the alternative or unscheduled outage at peak revenue times. These projects also make efficient use of existing infrastructure; all of this will maintain or improve customer satisfaction.
Reliability	Replacement of these assets will have a positive impact on reliability performance and safety in the following ways; a) Installation of new standards will enhance working clearances providing for safer working conditions for both SNC and Third party employees. b) Installation of new standards includes animal protection on transformers which will reduce the number of animal contact related outage, improving reliability. c) Maintenance of reliability by reducing potential failures prior to failure and greatly decreasing restoration times. d) Significant improvement in safety by removing defective equipment from the system as soon as possible
Safety	Proactive replacement of assets identified in this project will ensure that the devices are operable when required to do so to either restore or isolate sections of the distribution system. This will ensure the system continues to operate efficiently and effectively.

2. Investment Need

Primary Driver:

Failure Risk – The transformer/switch/and switchgear program is a renewal program meant to replace aging/deteriorating assets that fall under these categories such as padmounted transformers, vault transformers and padmounted switchgear. SNC is obligated to ensure that the way it executes its initiatives does not negatively impact the health and safety of the public, customers or SNC's employees. From the most recent asset condition assessment for padmounted transformers, 7% (167) are in poor health with an additional 8% (199) in very poor condition. Additionally, 42% (119) of vault transformers are in considered to be in poor/very poor condition.

Switches are in generally good condition overall, with no padmounted switchgear in poor/very poor condition. These assets are relatively few and new as compared to other assets in the distribution system, limiting their overall impact to this program. 2% (16) switches are considered in very poor condition, with 2% (21) being described as in poor condition.

The following figures describe the condition of the assets that are targeted through this program. The condition is determined through field data collection of the condition parameters that have been determined to have the greatest impact to the health of these assets. The condition is grouped into 5 categories: very good, good, fair, poor, and very poor.

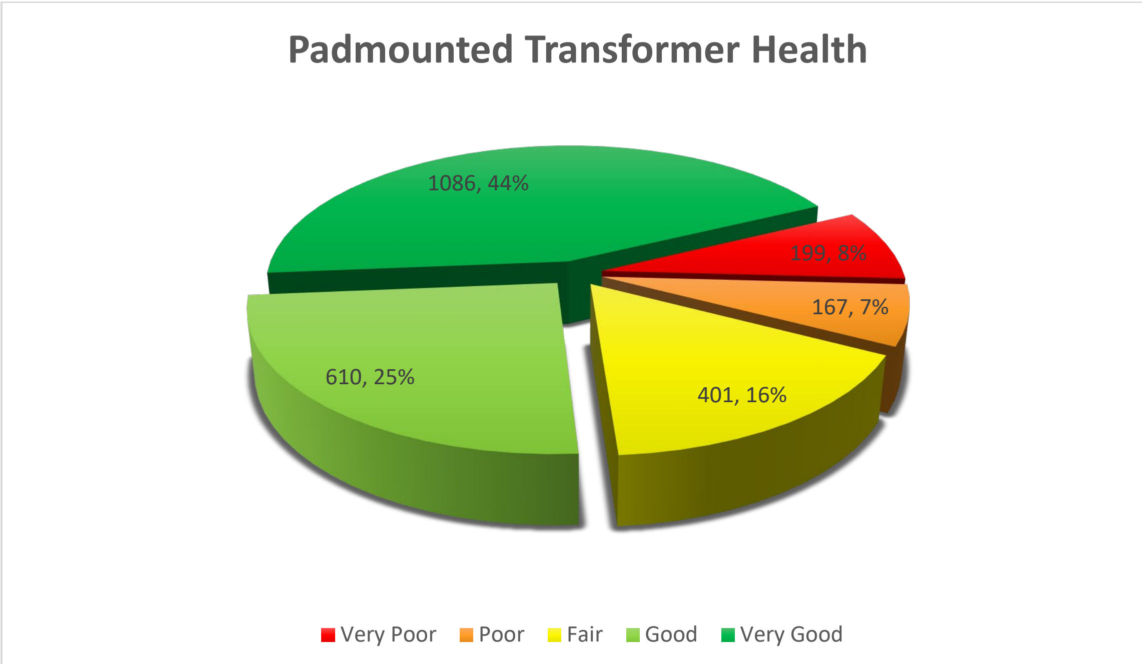


Figure 2-1 2022-Padmounted Transformer Condition Demographics

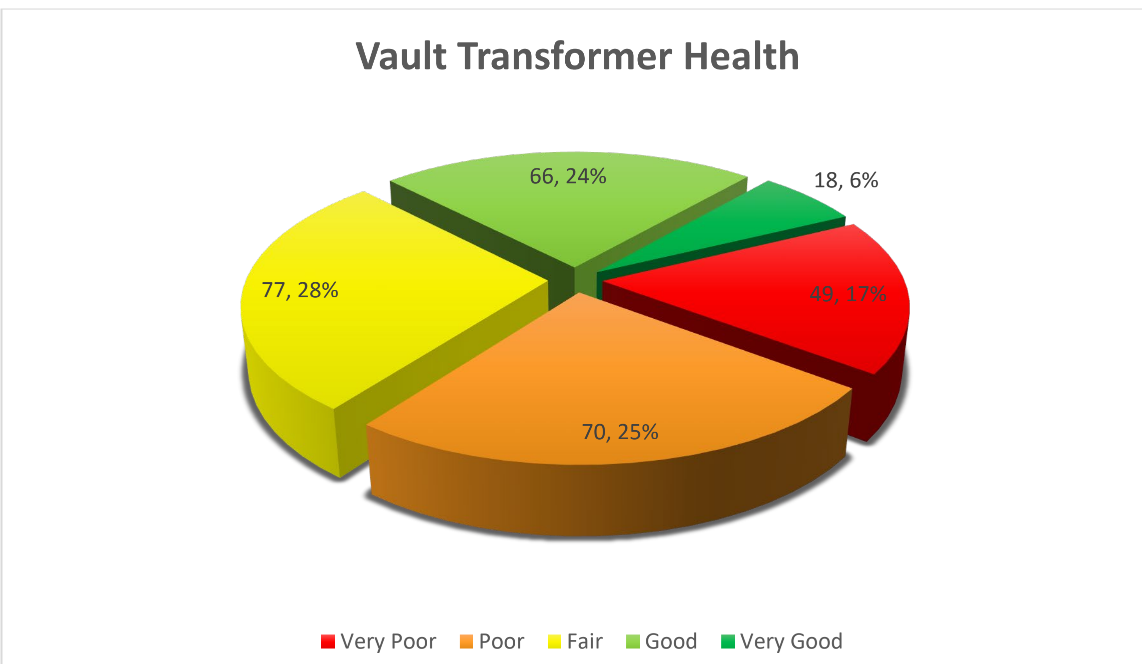


Figure 2-2 2022-Vault Transformer Condition Demographics

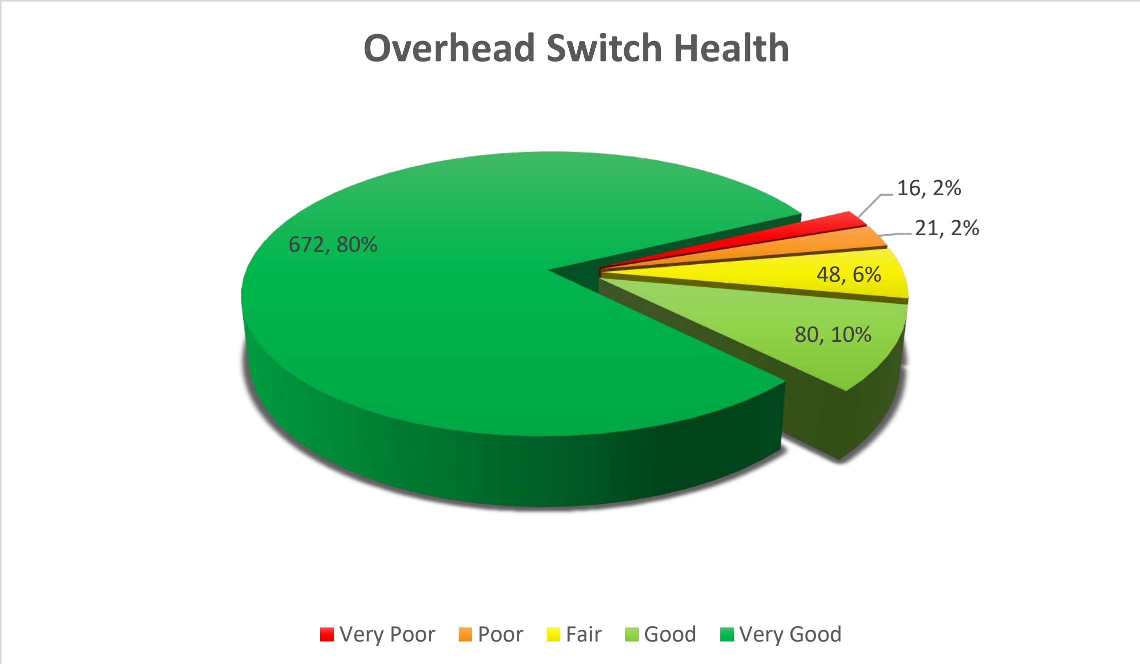


Figure 2-3 2022-Overhead Switch Condition Demographics

SNC anticipates that several of the assets identified as in poor/very poor condition will fail unexpectedly or fail to meet the criteria to remain in service during an inspection. For padmounted equipment and vault transformers this can include severe deterioration of the enclosure, significant oil leakage and electrical failure. For overhead switches, this may include failure to operate, mechanical failure or an electrical fault.

Secondary Drivers:
Reliability - The secondary driver is Reliability. The risk to the utility and the customer is that the asset will fail and result in an outage that negatively affects reliability and therefore customer satisfaction.

Information Used to Justify the Investment:

This information is derived directly from the output of the asset management process (Section 5.3.1 of the DSP) and the asset lifecycle optimization practices (Section 5.3.3). The assets replaced in this program are the result of unanticipated failure and pose an imminent risk and safety concern to the public. SNC attempts to quantify the number of failures by tracking the reason-for-removal for these assets, combined with inspection data. The following figures and tables summarize the findings.

Table 2-1 Asset Failure Coding

FAILURE CODE	DESCRIPTION	DEFINITION	CAUSE/TACTICAL ASPECTS
C	CAPACITY	VOLUME OF DEMAND EXCEEDS DESIGN CAPACTIY	GROWTH, SYSTEM EXPANSION
LOS	LEVELS OF SERVICE	FUNCTIONAL REQUIRMENTS EXCEEDS DESIGN CAPACITY	CODES & LEGISLATION, SAFETY, SERVICE REQUIREMENTS, NOISE ETC.
M	MORTALITY	CONSUMPTION OF ASSET REDUCES PERFORMANCE BELOW ACCEPTABLE LEVEL	PHYSICAL DETERIORATION DUE TO AGE/USAGE (INCLUDING OPERATING ERROR), ACTS OF NATURE

Padmounted Transformers

Transformers that have deteriorated to the point they have begun to leak oil, or the enclosure is rusted/damaged beyond repair are considered to have failed and are removed from service. Assets that fail electrically are also replaced as part of this program.

Table 2-2 Transformer Removal Codes

REMOVAL CODE	DESCRIPTION	FAILURE CODE
CONV	Conversion Related Replacement	C
SVUP	Service Upgrade	C
RELO	Relocation	LOS
PCBR	PCB Related Replacement	LOS
ELEC	Electrical Failure	M
MVAR	Motor Vehicle Accident Related	M
LEAK	Oil Leak/Other Leak	M
RUST	Excessive Rust	M
SYSH	System Health Improvements	M

Figure 2-4 details the reason-for-removal statistics for padmounted transformers. Approximately 70% of the replaced equipment has been due to failure from a mortality code. This program is designed to address the assets that fail because of this.

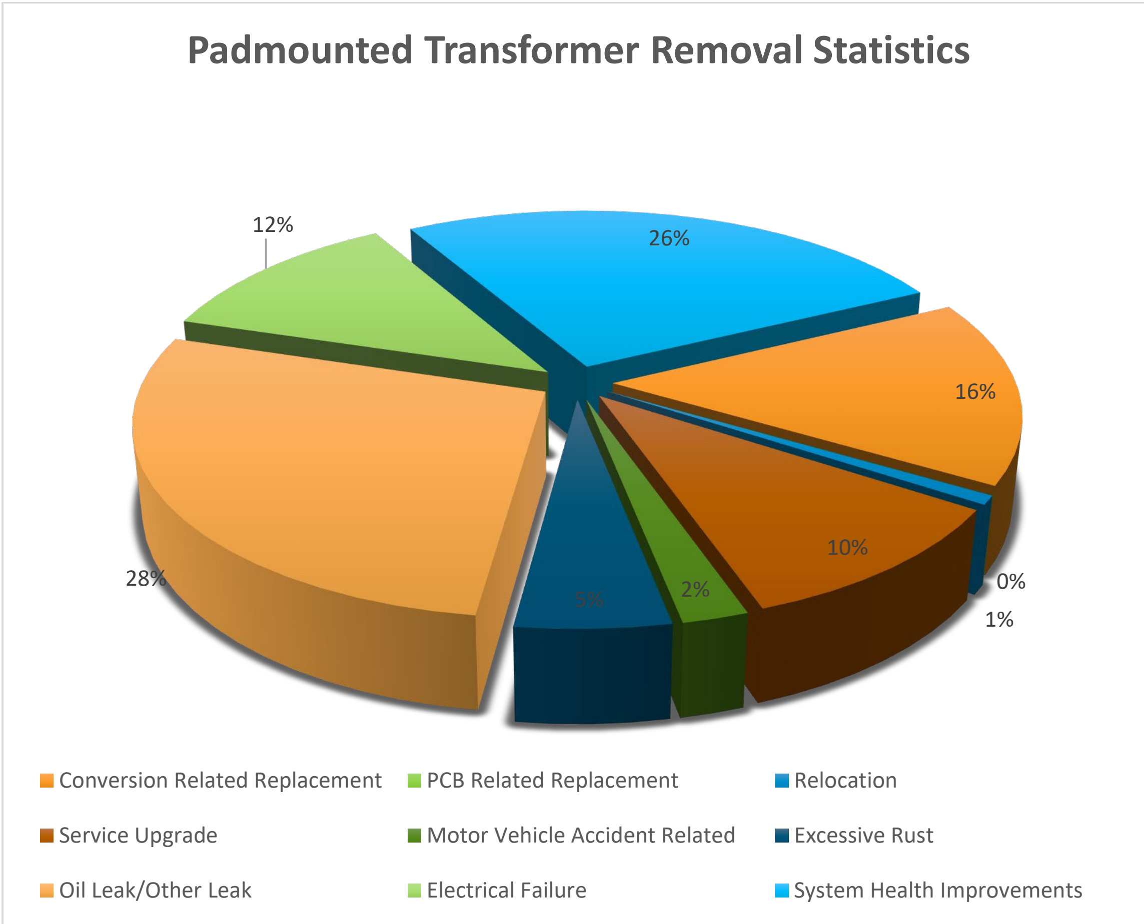


Figure 2-4 Padmounted Transformer Removal Statistics 2019-2022

Failed assets identified through the inspection process (1/3 of the system annually) are scheduled for replacement within the calendar year. The remainder of the data informs the asset condition assessment and the flagged for action plan which forms the basis for planned replacements. The inspection parameters and their relative weights are shown in Table 2-3.

Table 2-3 Padmounted Transformer Condition Parameters

CONDITION PARAMETER	WEIGHT
Oil Leak	40%
Overall	23%
Age	17%
Enclosure Damage	10%
Paint Condition	4%
Base Condition	4%
Access Restricted	2%

Overhead Switches

Overhead switches can often serve a critical role in the successful operation of a distribution system. They are often required for transferring load to reduce the impact of an outage to as small an area as possible. They are also routinely required for the isolation of services and equipment. If a switch fails electrically during its operation or fails to operate at all it is removed from service. Switch location is reviewed at the time of replacement to determine the optimal alternative (i.e., like-for-like replacement, relocation, or removal). Figure

Table 2-4 Overhead Switch Failure Codes

REMOVAL CODE	DESCRIPTION	FAILURE CODE
CONV	Conversion Related Replacement	C
RTNG	Ratings Exceeded	LOS
RELO	Relocation	LOS
ELEC	Electrical Failure	M
FAOP	False or Failed Operation	M
MVAR	Motor Vehicle Accident Related	M
MCHF	Mechanical Failure (of component)	M
SYSH	System Health Improvements	M

Figure 2-5 displays the reason-for-removal for overhead switches. Between 2019 and 2022 approximately 65% of switches were replaced for mortality related failure codes.

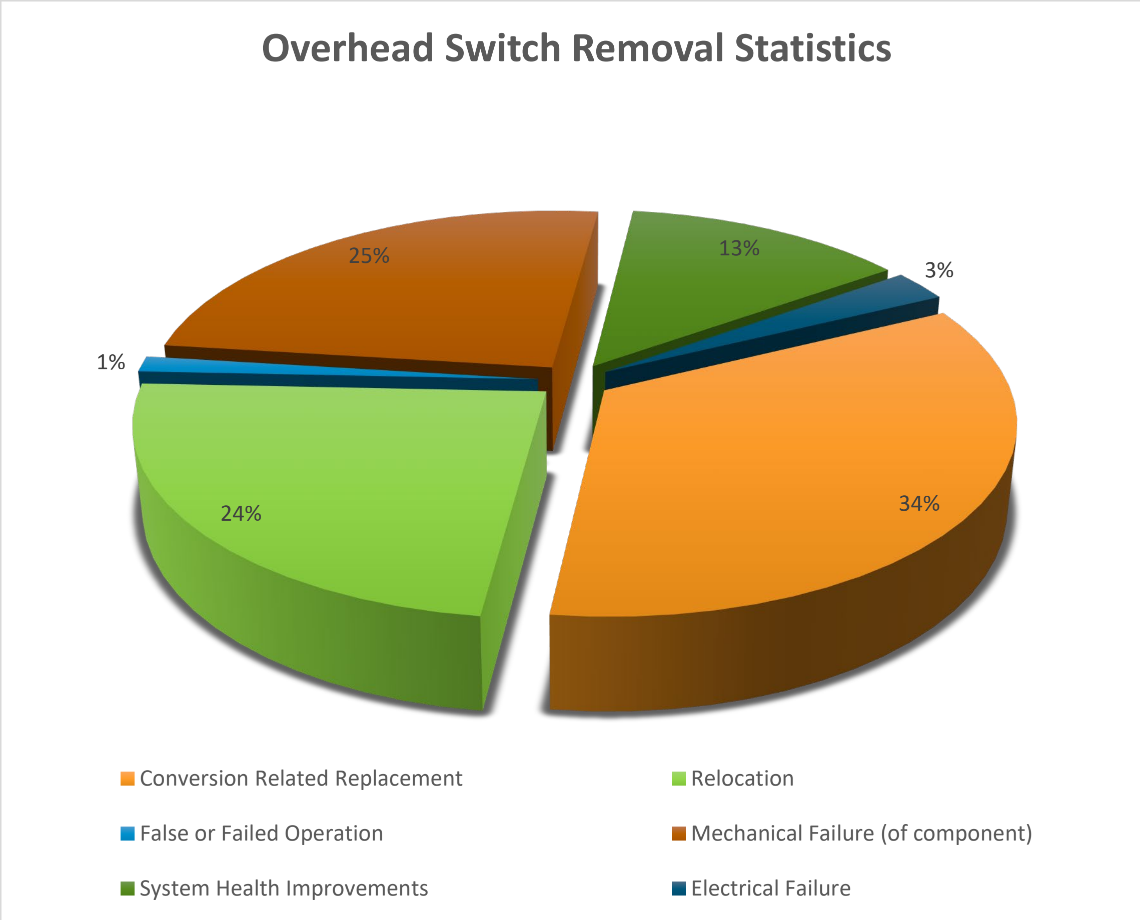


Figure 2-5 Overhead Switch Removal Statistics 2019-2022

Overhead switches are inspected as a stand-alone program following the requirements of the distribution system code. Switches are occasionally repaired when there is a minor defect noted (e.g., blade misaligned). If a switch is significantly deteriorated, it is reviewed for its suitability to remain in service. If it fails to meet the criteria, (e.g., inoperable, no longer required) it may be replaced or alternatively, removed from service. Table 2-5 details the condition parameters for overhead switches.

Table 2-5 Overhead Switch Condition Parameters

CONDITION PARAMETER	WEIGHT
Oil Leak	40%
Overall	23%
Age	17%
Enclosure Damage	10%
Paint Condition	4%

Base Condition	4%
Access Restricted	2%

3. Investment Justification

Demonstrated Utility Practice

To ensure that SNC can deliver safe, reliable, and efficient service, it is fundamental that SNC has the necessary foundations in place. SNC is a member of the Utilities Standards Forum ("USF") and uses USF standards, supplemented by standards developed internally. The use of USF standards ensures that the design and construction of this project will be done according to a set of standards utilized by many other utilities in Ontario.

CSA 22.3 No.1 – Overhead Systems

This standard applies to overhead electric supply, communication lines and equipment placed outside of buildings and fenced supply stations. The standard details best practices for the materials, configuration, and strength requirements of poles and accessories. It also includes factors which are required to determine the load bearing characteristics for poles in the system. The standard also sets the requirements of the support systems accessories such as guy wires and braces. This program is designed to comply with this clause.

CSA 22.3 No. 7 Underground Systems

CSA 22.3 No. 7 is a standard that applies to the lines and equipment related to underground electric supply and communication systems placed outside of buildings and fenced supply chains. Section 10 of the standard includes clauses related to above-ground equipment, such as pad-mounted transformers. Clause 10.1 states that live parts must be inaccessible. Live parts of pad-mounted transformers being accessible makes it prone to rust, which would then require the transformer to be replaced or treated. Clause 10.2 states that there must be adequate working space around the pad-mounted transformer.

Ontario Regulation 22/04

This is a set of regulations that was incorporated into the Electricity Act, 1998 and covers various elements of electrical distribution safety. Section 4 discusses safety standards, specifically, 4.(5).1 all underground distribution lines and operating equipment shall be maintained and in proper operating condition. This regulation informs part of SNC’s renewal programs as compliance with this regulation is tracked by SNC and the OEB. SNC has achieved compliance with this regulation annually for the entire historical period. This program will ensure that SNC can continue this trend.

Distribution System Code: Appendix C

SNC performs it inspections to comply with the requirements found in the Code. Where defects are discovered, depending on the severity, assets may be replaced immediately or planned for future replacement.

Cost-Benefit Analysis

This program does not substantially exceed materiality, however SNC does consider the following:

Asset replacement is reviewed on a case-by-case basis to determine if these risks can be mitigated in other ways, however, there are typically no practical alternatives to replacements.

When adding or replacing transformers, SNC ensures that correct asset is installed according to the future demands and current efficiency standards. A newly installed asset meeting today's installation methods leaves the asset at risk of failure only due to manufacturing defects or external factors (e.g., struck by motor vehicle), as opposed to failure as a result of degradation.

Additionally, damaged and failing transformers are at risk of leaking oil which can have negative environmental impacts. This too is mitigated through replacement.

Historical Outcomes

SNC tracks the average historical costs to develop the budget for the forecast period. However, as these are unplanned replacements, the cost can vary widely due a variety of factors such as location (backyard easement requiring a crane), size (large transformer failure), timing of replacement (overtime requirements), and time of year (frozen ground). For these reasons it is difficult to create a precise forecast. These replacements have minimal impact to other SNC programs. This program targets transformers and switches that are in poor condition, however other connected assets (e.g., poles, cables, etc.), may also be replaced when found to be in poor condition.

Table 3-1 2019-2022 Historical Replacements by Major Asset Type

Asset	Quantity	Average Age
Cable (m)	2235	1973
Insulators	66	1967
Poles	8	1968
Switch	27	1982
Transformer	115	1979

4. Conservation and Demand Management

CDM is not applicable.

MATERIAL INVESTMENT REPORT

Program/Project

Underground Renewal

Investment Category

SYSTEM RENEWAL

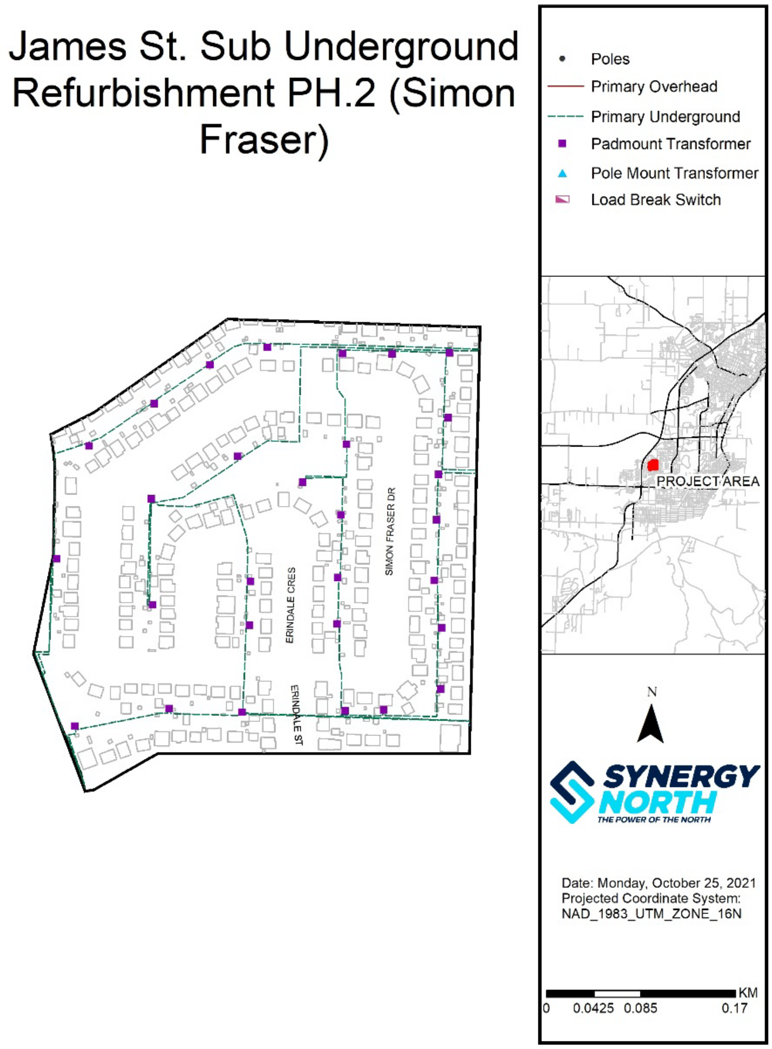
A. General Information on the Program/Project

1. Overview

SNC has several subdivisions where the assets are in backyard easements. These are legacy assets (live front transformers, direct buried cables) that are in poor health and past their typical useful life (TUL). The assets in these areas were originally installed in the 1970's and SNC has undertaken field inspections of the transformers and performed cable testing of the direct buried cables. The location of these assets makes unscheduled replacement difficult and increases the cost of replacement substantially. This has resulted in SNC taking a proactive approach to replacement to reduce the risk of untimely failures by replacing the live-front transformers with modern dead-front transformers and performing cable injection to rejuvenate the cables.

The Underground Program achieves several asset management objectives but focuses on Asset Performance and Customer Preference.

For the 2024 Test Year, the following activities are planned:



Major Assets Impacted:

Assets identified below are shown by asset quantity. The quantity of assets have been identified as those requiring replacement or refurbishment as part of this project as determined by the project type and project scope. These assets directly or indirectly impact the total expenditure required to complete this project.

Street Front Poles	0	1 Phase Pad Transformers	25
Easement Poles	0	3 Phase Pad Transformers	0
Reframe Poles	0	Vault Transformers	0
Reclosers	0	Pole Mount Transformers	0
UG Primary	2,700	Bored Duct	0

Figure 1-1: James St. Subdivision Ph.2

2. Timing

a. Beginning: January 2024
b. In-Service: Through to December 2028

c. Factors that may impact timing: Project execution may be impacted by unplanned and/or higher priority work arising, resulting in resource internal constraints. Additionally, material and contractor availability may also impact the timing.

3. Historical and Forecast Capital Expenditures

Table 3-1 Historical & Forecast Capital Expenditures ($'000)

Category	Historical Period						Bridge Year	Forecast Period				
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	4	427	811	19	1,044	1,067	500	646	659	1,529	2,538	2,589
Contributions	-	-	-	-	-	-	-	-	-	-	-	-
Capital (Net)	4	427	811	19	1,044	1,067	500	646	659	1,529	2,538	2,589

Increases in 2026 through 2028 are not reflective on a significant increase in the overall capital expenditure plan. They are due to the planned end of the 4kV conversion program and SNC's effort to rebalance and continue to renew underground cables outside of the 4kV areas. SNC's intent is to harmonize the asset renewal volumes to align with the flagged-for-action plan as part of the asset condition assessment.

4. Economic Evaluation

Economic evaluation is generally not applicable, however SNC completed an evaluation of traditional excavation and replacement as compared to cable rejuvenation. These details are discussed in section B.3.

5. Comparative Historical Expenditure

Section 3 of this document identifies the historical Underground Renewal costs. SNC has information on executing projects of this nature and based on this data, each project receives a detailed estimate annually based upon completed designs. SNC incorporates the latest resource metrics for both labour and material and includes several factors which may impact both. These may include:

- Third party plant location
- Restricted access to proposed construction location
- Vegetation encroachment
- Coordination with third party activities
- Utility easements and corridors that contain underground SNC infrastructure and 3rd party infrastructure
- Location in which existing transformers and cable is located (e.g., city sidewalk slab / asphalt paved area)
- Crane access

6. Investment Priority

The Underground Renewal program is a discretionary investment and ranks 6 overall out of 9 with a score of 41.9. As these are discretionary expenditures, they are performed after System Access projects and prioritized against other discretionary spending. Asset Performance and Customer Preference are the main factors that influences the project ranking.

Health and Safety – Minor injury or security incident is likely (expected to occur in 5yr).

The assets targeted for renewal as part of this program are in poor overall condition and have a high likelihood of failure, however as underground infrastructure fails is it less likely to have a severe impact on customers and SNC employees.

Environmental Impact - Addresses two (2) or more of SNC's identified environmental risks and provides risk mitigation to those risks.

PCB containing transformers are replaced as part of this program when they coincide with the cable rejuvenation efforts. Sunken and substandard transformer installations are also addressed, reducing the risk that flooding will cause unnecessary outages.

Regulatory/Legal Compliance - No impact on regulatory compliance.

Customer Preference - Delivers on two of the top 3 priorities of customers (Affordability, Safety for Employees and the Public and Reliability).

Cable rejuvenation can be performed on cables in-situ requiring minimal disturbance to existing installations and for a fraction of the cost of traditional replacement, directly impacting the affordability of this program (which customers have indicated as their top concern). Additionally, these assets targeted in this program are difficult to access making untimely failures difficult and costly to replace, impacting reliability.

Asset Performance - >50% of assets in poor condition or non-system assets operating within extended manufacturer support.

The infrastructure in this program is in poor condition and comprises some of the oldest underground installations in SNC's service territory, exceeding the typical service life of 40 years by a decade in many instances.

Operational Efficiency - Aligns with 2

Many of the cables in this program are connected to transformers of similar vintage, most of which are live front installations. Replacement parts are becoming increasingly difficult to source and unexpected failures during normal operations can lead to full replacements. These deficient units are addressed during the execution of this program. By replacing these units, SNC also addresses the liability associated with oil containing infrastructure in customers back yards (i.e., transformers may be in such poor condition as to potentially leak oil).

System Reliability - Sustained interruption of <1.5 MW of distribution load (100-300 residential customers).

This program is focused on rejuvenating cables in residential areas, with loops containing approximately 15 transformers total, impacting approximately 100 customers.

7. Alternatives Analysis

The projects listed in this category have been identified based on the outcome of the asset condition assessment, flagged for action plan and review by subject matter experts.

Alternatives for Underground Renewal are considered and are captured below.

a. Do Nothing - this option will result in the perpetuation of operational issues, increased risk of failure, and further deterioration resulting in decrease in reliability, and is therefore not considered appropriate.

b. Replace the underground feeder a cable with an overhead line – this option was considered however, as the location is in a residential area, the use of an overhead system is not conducive to the design and aesthetics of the existing site. For this reason, replacement with an overhead system is considered ineffective.

c. Defer replacement until a later date – this project has been prioritized against other proposed projects, and to delay the replacement to a later date puts SNC and customers on these feeders at too great a risk of failure for delay.

d. Replace the cable in a like-for-like fashion – this alternative is the not cost effective as there is little access for conventional excavation and directional drilling costs are at a significant premium.

8. Innovative Nature of the Project

While cable rejuvenation is not new, it is new to SNC. SNC conducted a pilot project to determine the suitability and cost of this program. SNC found that rejuvenation presents significant costs savings over traditional replacements. Additionally, SNC is working with a manufacturer of fibreglass bases to create a base that is adjustable. Allowing the base to be manually adjusted in situ based on the ground conditions prevents premature failure of the transformer and connections and will ensure that SNC sees the TUL of their assets.

9. Leave to Construct Approval

Not applicable to this program.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability and Safety

Criteria	Description
Efficiency	The proactive replacement of underground cables transformers that have reached their end of life will greatly decrease the probability of a failure in this project area. Because these assets are in extremely difficult to access locations, the completion of replacing these transformers and rejuvenating the cables on a planned basis is the safest, most efficient and cost-effective option.
Customer Value	The renewal of this infrastructure will have the following benefits: reduction of the potential risk of failure and number and duration of outages, avoidance of an emergency repair resulting in a potential loss of functionality which in turn impacts customers ability to effectively live out their day-to-day lives.
Reliability	These investments will not have a significant impact on reliability performance in the short term. However, due to the inaccessible nature of these areas, delays in proceeding could lead to cascading failures throughout the system and could lead to significant outages and therefore could have an impact on the reliability in the long-term. By addressing these issues, access to equipment would improve and therefore restoration would typically be easier and quicker.
Safety	These projects are not intended to address any existing safety concerns, but all new facilities will be designed and constructed to current safety standards. This program will have no adverse impact on health and safety, or protection and performance.

2. Investment Need

Primary Driver:

Failure risk - The focus of this program consists of projects aimed at replacing or rejuvenating assets on underground lines to improve their condition, reliability, and safety. The efforts include targeted areas in SNC distribution territory where sudden failures due to asset deterioration makes reactive replacements difficult and costly. SNC seeks to prioritize project selection based on assets that are in poor health, and the assets identified in this project have a high probability of failure which is a result of the condition of the assets.

The latest asset condition assessment for the equipment impacted by this program is displayed in the following figures.

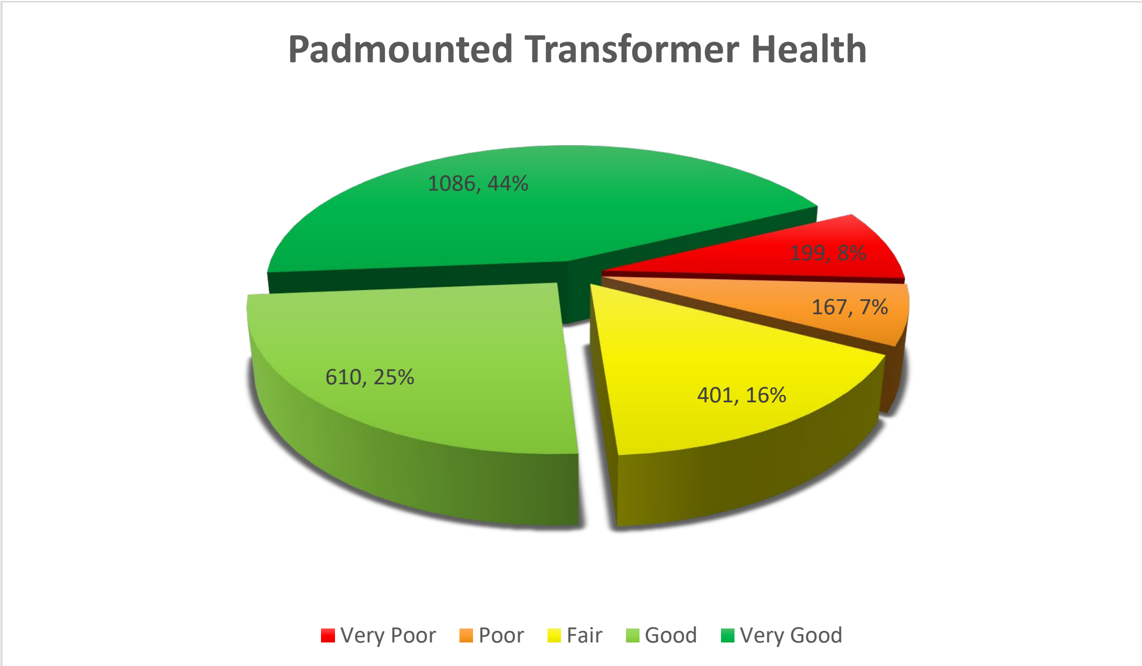


Figure 2-1 2022-Padmounted Transformer Condition Demographics

It is evident from Figure 2-1 that approximately 15% of padmount transformers are in poor health. This program is designed to identify and replace assets in poor/very poor condition that are not captured as part of other programs. Typically, these are standalone units that cannot be scheduled for replacement as part of a larger program which generally have larger scale and scope and allow for improved economies.

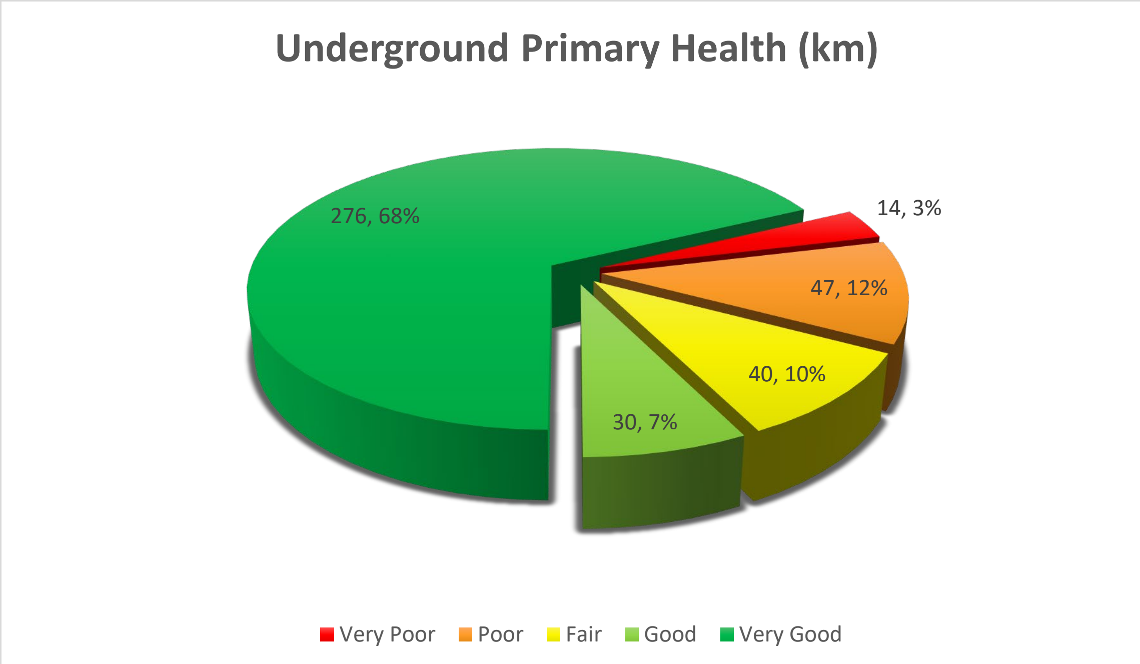


Figure 2-2 2022-Underground Primary Health Demographics

Figure 2-2 details the health demographics for underground primary cables. Much of the cable is unjacketed (causing neutral corrosion) and was installed in residential subdivisions in the 1970's. Many of the installations are in customers rear yards making access for both the cables and the transformers difficult.

Secondary Drivers:

Reliability – While there is likely no near-term risk to the reliability of the system, long-term risk to the utility and the customer is that a series of assets will fail and result in an outage that negatively affects reliability and customer satisfaction.

Information Used to Justify the Investment:

SNC's asset management process (Section 5.3.1 of the DSP) and asset lifecycle optimization practices (Section 5.3.3 of the DSP) inform the execution of the Underground Renewal program. The planned replacements in this program (approximately 20 transformers, and rejuvenation of 3500m of cable) ensures that SNC continues to mitigate the risk of unplanned outages and provides a safe electrical system by controlling hazards.

The latest ACA yields the flagged-for-action plan and suggested replacement levels for the assets targeted as part of this program. Targeted renewal of these assets will ensure SNC can maintain a reliable supply of electricity to the customers served by them.

Table 2-1 Flagged-for-Action Volume

ASSET	FLAGGED FOR ACTION BY YEAR				
	2024	2025	2026	2027	2028
UNDERGROUND PRIMARY (km)	6	5	5	5	5
PADMOUNTED TRANSFORMERS	80	80	80	80	64

Underground Primary

Several years ago, SNC (formerly Thunder Bay Hydro) undertook a program to shorten the loops in many of its residential subdivision to limit the risk of widespread outages due to unexpected failure. This program was completed with success, however most of the assets continued to deteriorate. Decline in cable health is the most difficult element to establish since there are no physical elements to inspect, the result of this being that cables have been managed on a reactionary basis. Diagnostic testing can eliminate these challenges, but until recently was used with little success. With the advent of new non-destructive cable testing technology, SNC has been able to better understand the condition of these underground cables to optimize its capital programs to meet customer and regulator demands.

This technology is being used to test the condition of non-tree resistant, cross-linked polyethylene cables, which was widely used in the utility sector until the early 1990's. Water-treeing is one of the most prevalent aging mechanisms of medium voltage cables. A water tree begins due to the ingress of moisture and impurities within the cable insulation. As the water tree progresses in size, voltage stress can cause an electrical tree to form and once this occurs, failure is a near certainty. The cumulative results of cable testing between 2020 and 2022 can be found in Figure 2-3.

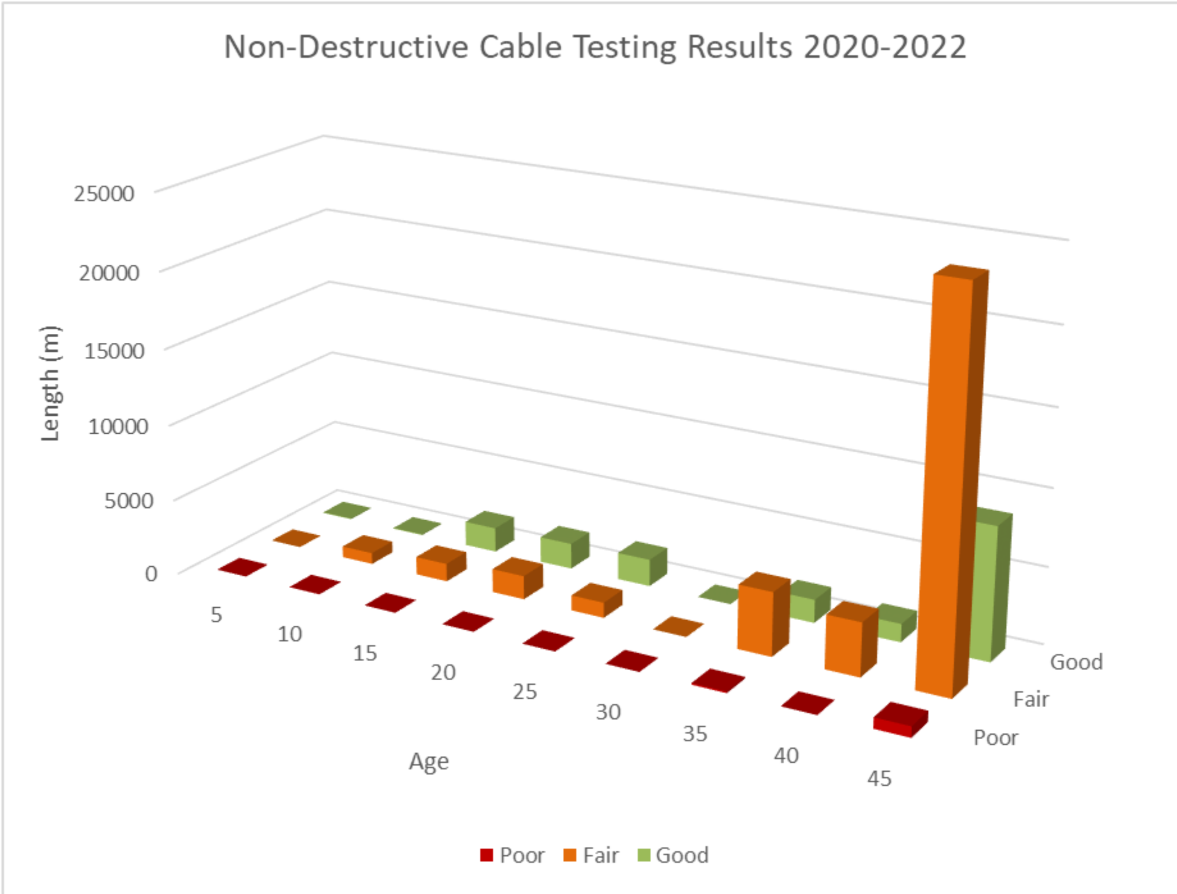


Figure 2-3 Non-Destructive Cable Testing Results

The figure illustrates that there is a significant portion of the cables in fair condition. SNC uses this data as the key element for its asset condition assessment. As part of the inspection and testing program, SNC collects this information annually from the subset of cables to perform the assessment. The condition parameters for underground primary can be found in Table 2-13.

Table 2-2 Underground Primary Condition Parameters

CONDITION PARAMETER	WEIGHT
Cable Testing	50%
Age	40%
Neutral Condition	5%
Splice(s) Present	5%

In SNC's past filing[1] the data availability indicator (DAI) for cables was a key area of improvement identified as part of the asset condition assessment. SNC proceed to strategically test cables to both better understand the condition of these assets and improve the quality of the assessment. As a result, the DAI for these cables has gone from 47% to 69%. SNC intends to cable test all the cables that fall within this program scope to ensure that there is quantitative data to support the decision-making processes.

Additionally, SNC undertook a pilot program in 2021 to test the viability of cable rejuvenation and the potential cost implications/savings associated with this technology. Cable rejuvenation is a process that allows for the restoration of cable insulation without disturbing the cable itself. It is performed by injecting technical fluid into the cable at high pressure, forcing water and impurities out of the water-treed areas. The cables can be returned to service immediately following the injection process, where, over time, the insulating properties are restored as the fluid cures. The project involved rejuvenating approximately 3500m of primary, direct buried cable. SNC determined that this process is approximately one-third the cost of replacing the cable in directionally bored duct.

Padmount Transformers

The padmount transformers that form part of this program pose significant challenges when it comes to replacement, with accessibility being the main issue. These units are installed in customers' back yards and are often surrounded by customer owned infrastructure (e.g., fences, sheds, decks, and gardens) and prior to project execution, customers may be required to move/remove their installations. The replacement method involves disconnecting the old unit, removing it by crane, craning in the new unit, and reconnecting it. Due to the legacy installation methods and significant deterioration, substantial remediation may be required to remove the units and existing concrete bases. SNC has completed detailed surveys of these installations to determine whether existing installation locations can be repurposed. Figure 2-4 illustrates the current health demographics for padmount transformers and Figure 2-5 is a photo of a typical installation found in the areas targeted by this program.

[1] Thunder Bay Hydro Electricity Distribution EB-2016-0105

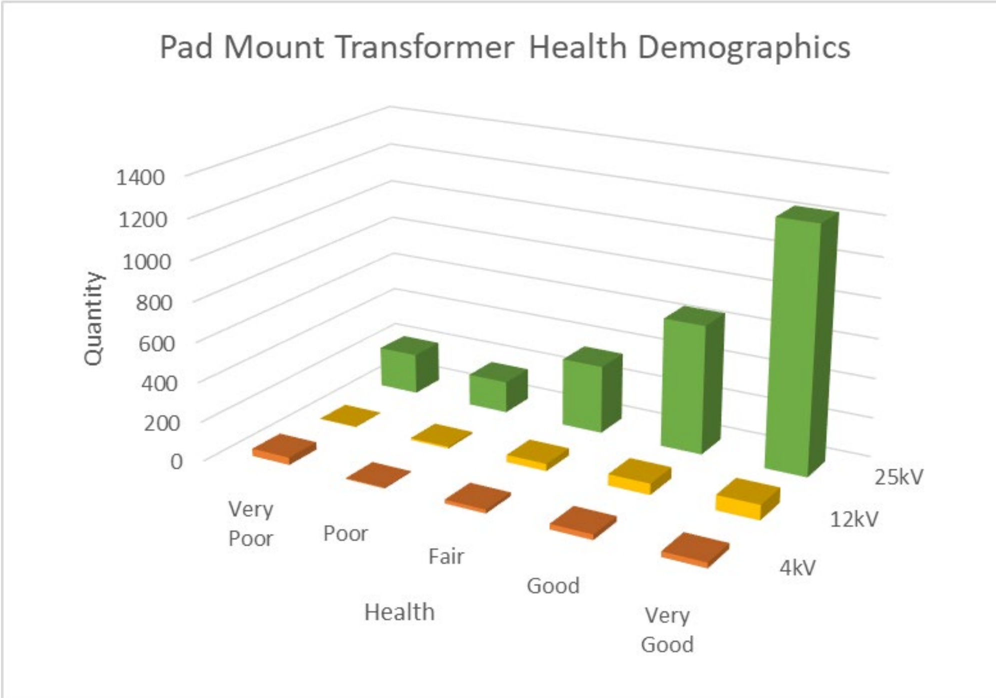


Figure 2-4 2022 - Padmount Transformer Health Demographics

Figure 2-5 Backyard Padmount Installation

Pad mounted transformers are inspected based on a 3-year inspection cycle following the requirement of Appendix C of the Distribution System Code. Because they are in contact with the ground, they often experience a harsher environment as compared to pole mounted transformers.

Table 2-3 Pad Mounted Transformer Condition Parameters

CONDITION PARAMETER	WEIGHT
Oil Leak	40%
Overall	23%
Age	17%
Enclosure Damage	10%
Paint Condition	4%
Base Condition	4%
Access Restricted	2%

3. Investment Justification

Demonstrated Utility Practice

The Canadian Standards Association (CSA) publishes guidelines for various distribution system assets that detail best practices for the materials, configuration and requirement for pad mounted transformers and underground cables. Clause 10.2 of CSA 22.3 No.7 states that their must be adequate working space around the equipment. Section 4.5.4 discusses unstable soils causing damaging stresses on underground plant. In several areas targeted by this program the infrastructure is at risk due to sinking/floating civil infrastructure.

Ontario Regulation 22/04

This is a set of regulations that was incorporated into the Electricity Act, 1998 and covers various elements of electrical distribution safety. This regulation addresses safety standards, approval of electrical equipment, approval of plans and specifications for installations, inspection and approval of construction, proximity to distribution lines, disconnection of unused lines, reporting serious electrical incidents, and compliance that inform part of SNC's renewal programs as compliance with this regulation is tracked by SNC and the OEB. SNC has achieved compliance with this regulation annually for the entire historical period. This program will ensure that SNC can continue this trend.

Distribution System Code: Appendix C

Under this code set forth by the OEB, the distributor must maintain is distribution system considering good utility practice and reliability on a short-term and long-term basis.

Inspections are performed to comply with the requirements found in the Code. Where defects are discovered, depending on the severity, assets may be replaced immediately or planned for future replacement.

Cost-Benefit Analysis

A typical cost/benefit analysis was not performed for this program however SNC considers proactive replacement of these assets a benefit to customers, as the utility has control over factors such as timing of the outage, length of the outage, and informing customers well in advance of the project.

Failures that occur outside regular operating hours can have negative consequences in terms of outage duration and cost, both of which impact the overall quality of SNC's service. By carefully considering the scale and scope of proactive replacements, SNC can mitigate some of these impacts and maintain its quality of service.

Historical Outcomes

SNC has completed several Underground Renewal projects historically and has observed many positive outcomes from these projects including but not limited to, improved access to pad mounted equipment, cost avoidance with regards cable rejuvenation, and mitigation of large-scale outages due the proactive replacement of clusters of assets in poor condition. The information follows compares the cost of directionally drilling against cable rejuvenation as well as some of the advantages of the process. For more information on this process, refer to Section 5.3 of the DSP.

Cable Rejuvenation – Advantages? Why are we doing it?

<u>Rejuvenation - Advantages</u>

- cables are left mostly undisturbed and are injected with compounds that restore the cables dielectric strength
- You get the value of a new cable, without the added cost
- With sustained pressure rejuvenation (SPR), cables are restored to full dielectric strength in several days, and injection can be completed in a single day

<u>Why are we doing it?</u>

- Direct buried underground installations
- Several failures have caused reactive installation of new primary
- Reactive replacement will make for costly maintenance when unexpected failures occur
- Over the last decade rejuvenation has surpassed replacement as the most utilized method of rehabilitation.

Table 3-1 Cable Rejuvenation vs Cable Replacement

Project	Total Cost	Length of Cable (m)	Cost/m
Cable Rejuvenation	$186,720	2,526	$73
Cable Replacement (Duct and New Cable)	$469,897	1,532	$307

4. Conservation and Demand Management

CDM is not applicable.

MATERIAL INVESTMENT REPORT

Program/Project

Voltage Conversion

Investment Category

SYSTEM RENEWAL

A. General Information on the Program/Project

1. Overview

SNC began the voltage conversion program (formerly as Thunder Bay Hydro) approximately 20 years ago to upgrade the distribution system from 4kV to 25kV. As the 4kV substations and associated distribution assets reach their end of service life, rather than replace with equipment in a like-for-like manner (i.e., at the same operating voltage) the distribution assets are replaced to operate at 25kV, and the station assets are decommissioned. This program originally began with 15 stations in service along with 24 station transformers and 68 feeder circuits. Currently 8 substations have been decommissioned along with 12 station transformers. Additionally, 55 feeder circuits have been converted to 25kV.

SNC has 7 stations remaining to decommission along with 12 station transformers and 13 feeder circuits comprising 63km of overhead primary. Most of the remaining infrastructure operating at 4kV is at the end (or well past) is service life and in poor health. Maintaining a distribution system with two operating voltages results in duplication of lines and economic inefficiencies due to losses.

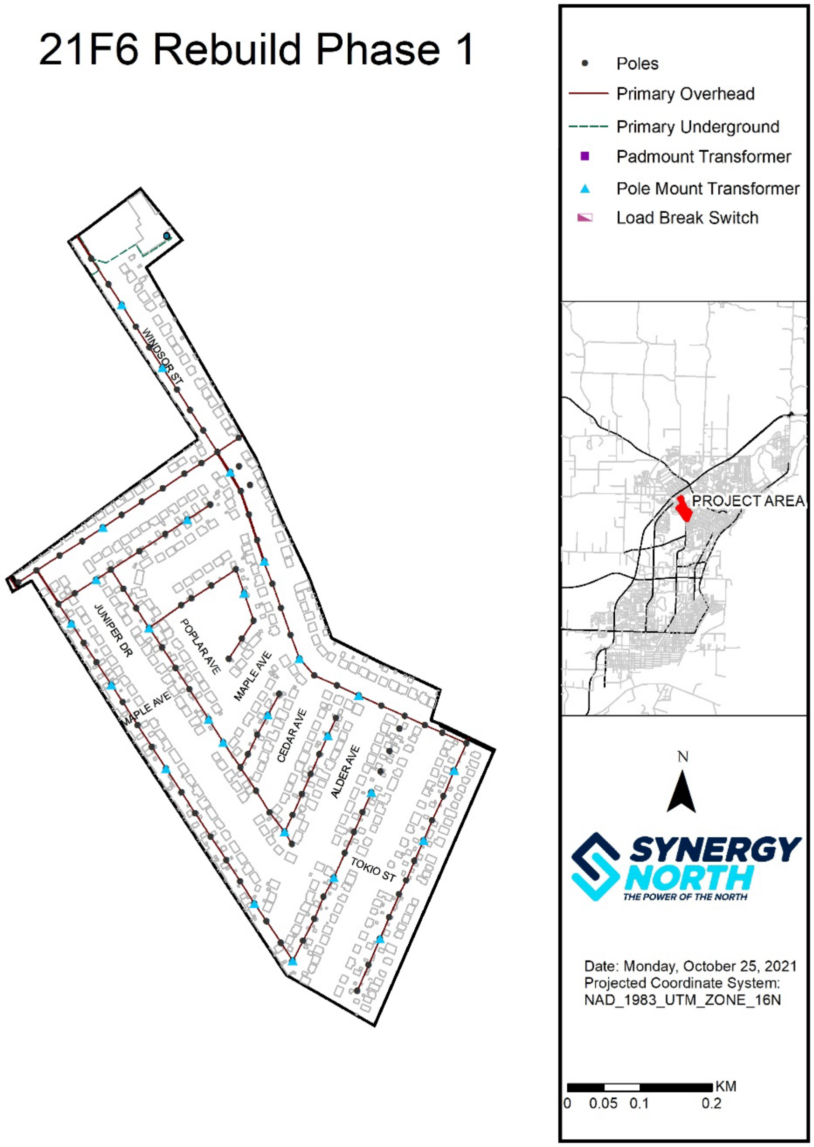
As part of this Voltage Conversion program, SNC is proposing to complete this initiative by converting the remaining 13 feeder circuits to 25kV and decommissioning the substation assets.

Completion of voltage conversion program during this filling period is expected to bring benefits in several ways. The remaining circuits once converted, will further support SNC's ability to connect DER's as the new 25kV feeders include the necessary protection systems to enable their connection. Additionally, the elimination of multi-circuit distribution lines along many streets leads to a less complex system and improved performance during severe weather conditions. Also, it will eliminate the need to stock 4kV equipment reducing overall inventory requirements.

Finally, removal of the remaining 4kV distribution lines and subsequent substation decommissioning should result in the reduction in electrical losses with the move to a higher operating voltage and is expected to bring advantages from an environmental perspective.

This longstanding program continues to deliver on several of SNC's asset management objectives (see Section 5.3 of the DSP for further explanation). The objectives, and how they are addressed by this program are outlined in detail in section A.6 of this document.

For the 2024 Test Year, the following activities are planned:

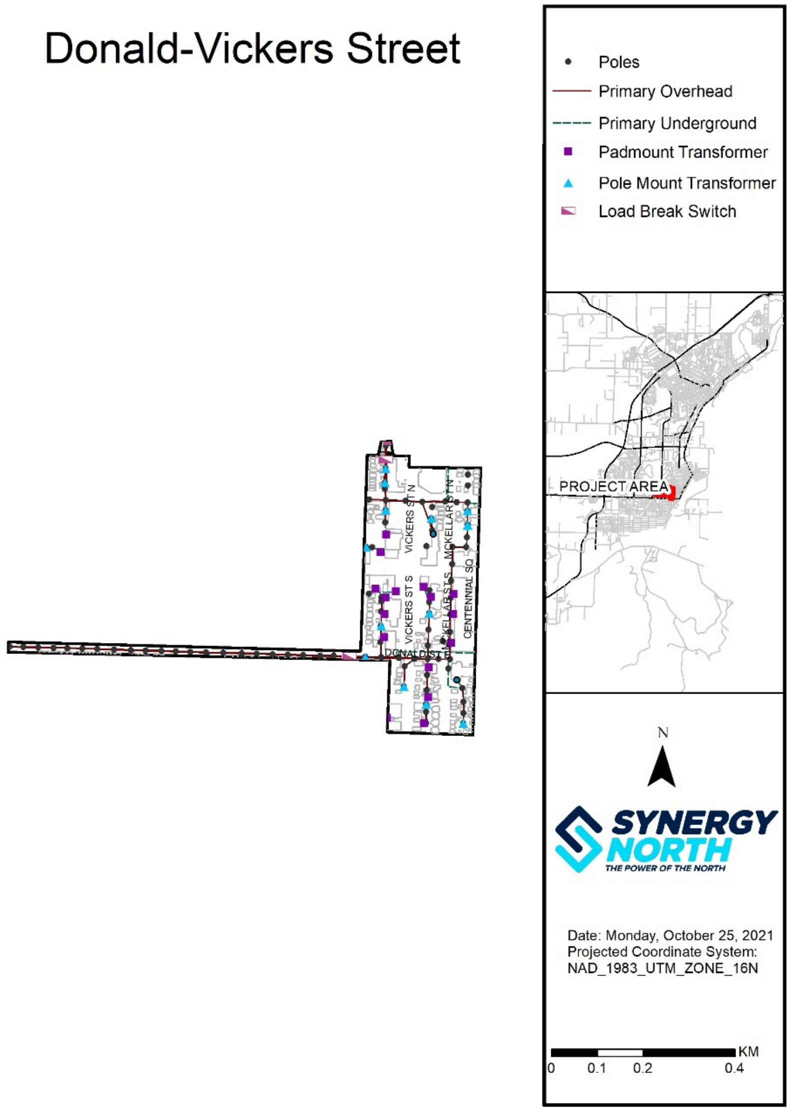


Major Assets Impacted:

Assets identified below are shown by asset quantity. The quantity of assets have been identified as those requiring replcement or refurbishment as part of this project as determined by the project type and project scope. These assets directly or indirectly impact the total expenditure required to complete this project.

Street Front Poles	45	1 Phase Pad Transformers	4
Easement Poles	73	3 Phase Pad Transformers	1
Reframe Poles	2	Vault Transformers	0
Reclosers	1	Pole Mount Transformers	36
UG Primary	0	Bored Duct	0

Figure 1-1: 21F6 Voltage Conversion Ph.1 – Framing and Stringing

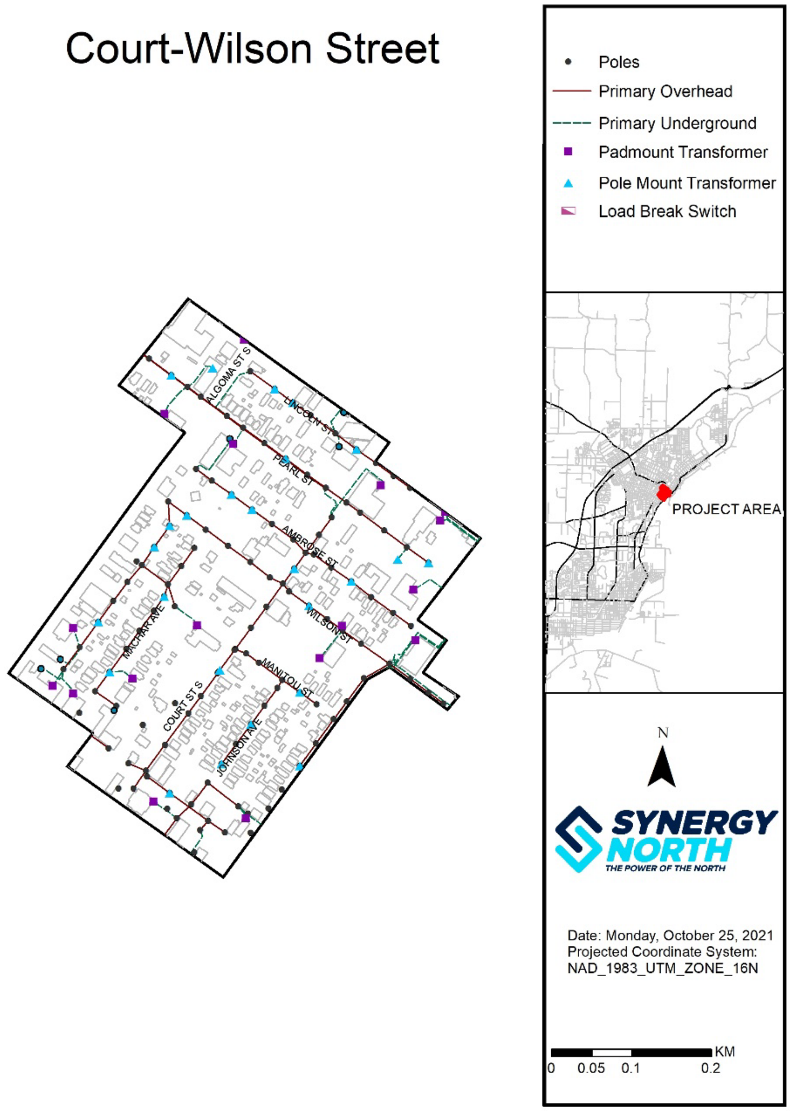


Major Assets Impacted:

Assets identified below are shown by asset quantity. The quantity of assets have been identified as those requiring replcement or refurbishment as part of this project as determined by the project type and project scope. These assets directly or indirectly impact the total expenditure required to complete this project.

Street Front Poles	73	1 Phase Pad Transformers	0
Easement Poles	0	3 Phase Pad Transformers	10
Reframe Poles	6	Vault Transformers	2
Reclosers	1	Pole Mount Transformers	7
UG Primary	900	Bored Duct	900

Figure 1-2: Donald/Vickers Voltage Conversion – Framing and Stringing

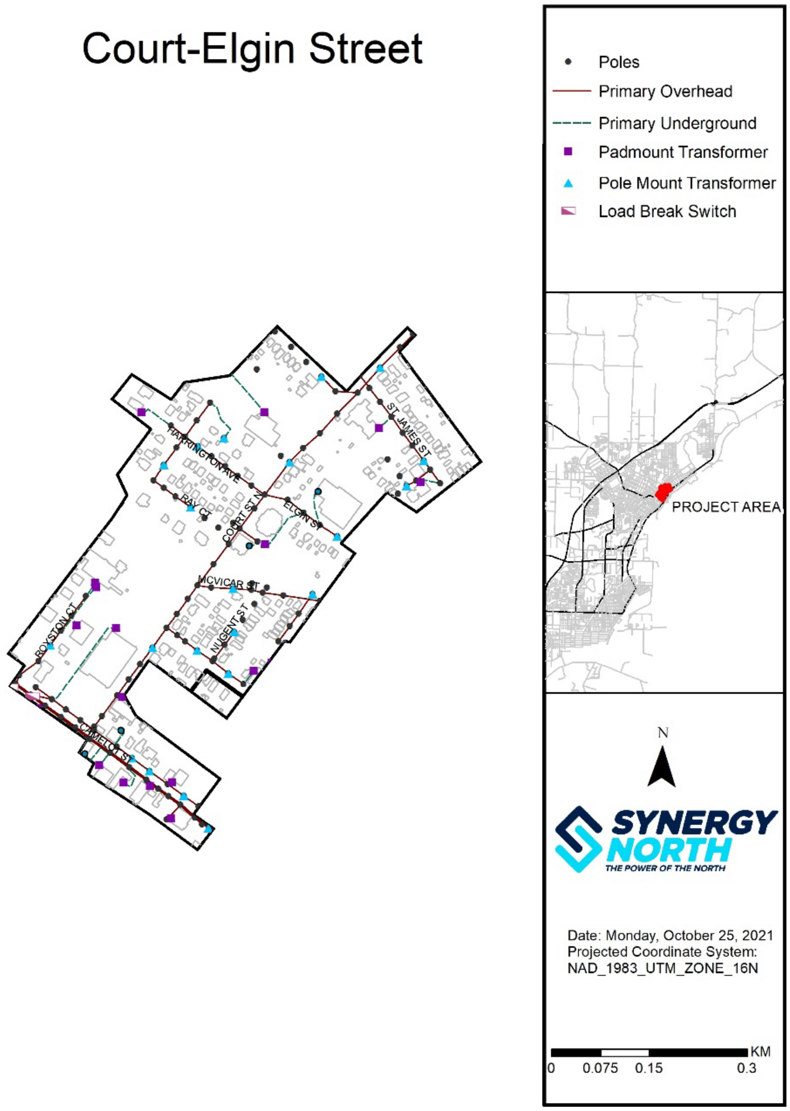


Major Assets Impacted:

Assets identified below are shown by asset quantity. The quantity of assets have been identified as those requiring replcement or refurbishment as part of this project as determined by the project type and project scope. These assets directly or indirectly impact the total expenditure required to complete this project.

Street Front Poles	101	1 Phase Pad Transformers	7
Easement Poles	0	3 Phase Pad Transformers	7
Reframe Poles	13	Vault Transformers	3
Reclosers	1	Pole Mount Transformers	23
UG Primary	1,600	Bored Duct	0

Figure 1-3: Court/Wilson Voltage Conversion – Framing and Stringing

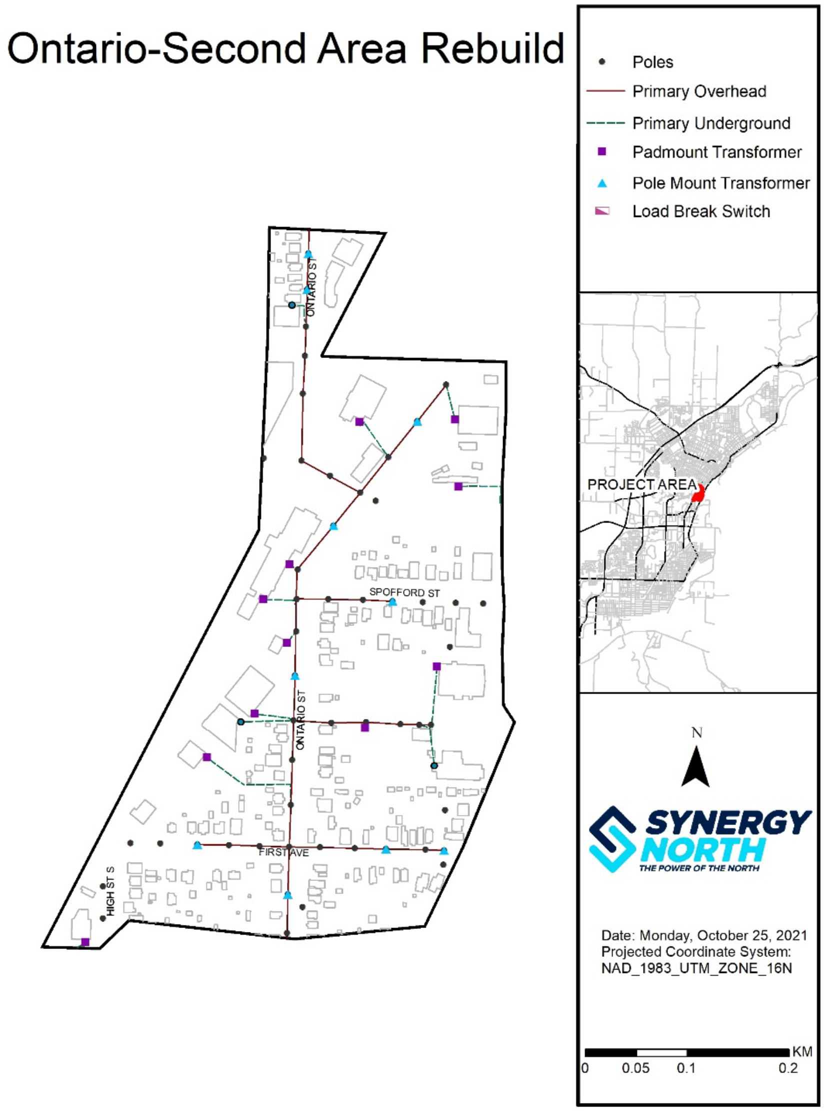


Major Assets Impacted:

Assets identified below are shown by asset quantity. The quantity of assets have been identified as those requiring replcement or refurbishment as part of this project as determined by the project type and project scope. These assets directly or indirectly impact the total expenditure required to complete this project.

Street Front Poles	111		1 Phase Pad Transformers	4
Easement Poles	2		3 Phase Pad Transformers	8
Reframe Poles	16		Vault Transformers	2
Reclosers	1		Pole Mount Transformers	20
UG Primary	0		Bored Duct	700

Figure 1-4: Court/Elgin Voltage Conversion – Pole Setting

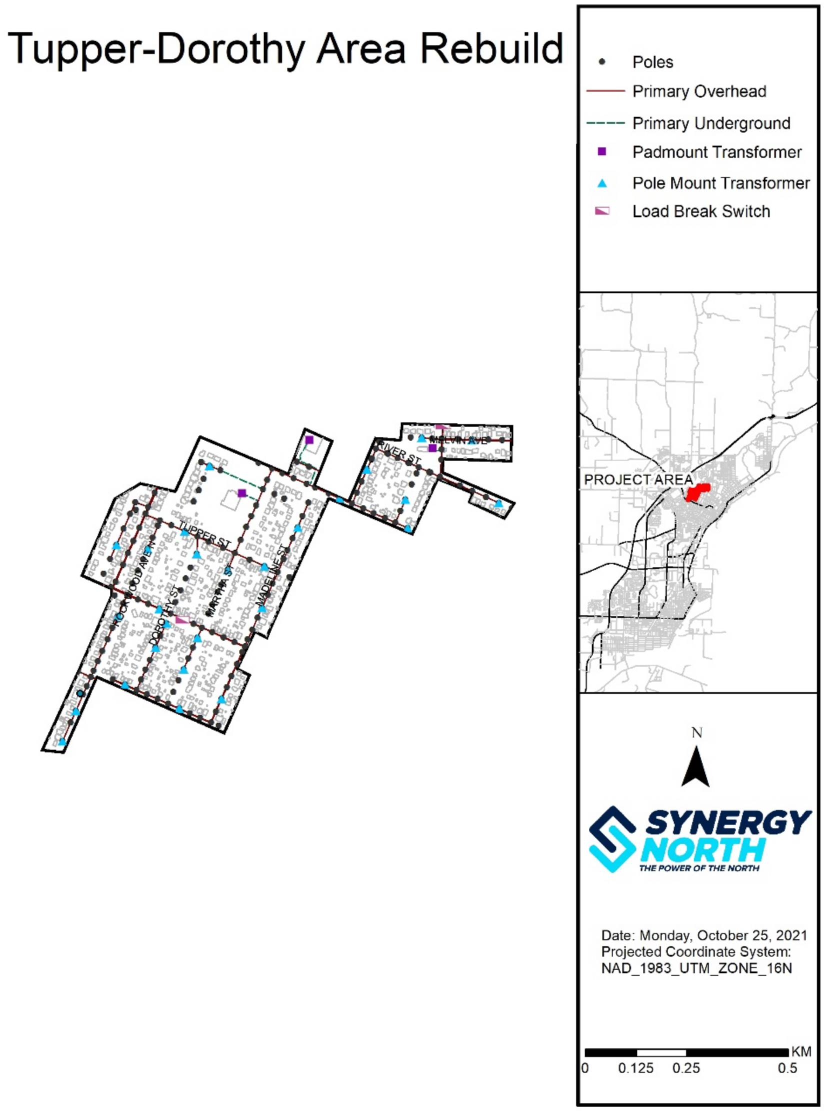


Major Assets Impacted:

Assets identified below are shown by asset quantity. The quantity of assets have been identified as those requiring replcement or refurbishment as part of this project as determined by the project type and project scope. These assets directly or indirectly impact the total expenditure required to complete this project.

Street Front Poles	62	1 Phase Pad Transformers	4
Easement Poles	0	3 Phase Pad Transformers	7
Reframe Poles	35	Vault Transformers	1
Reclosers	1	Pole Mount Transformers	12
UG Primary	0	Bored Duct	0

Figure 1-5: Ontario/Second Voltage Conversion – Pole Setting



Major Assets Impacted:

Assets identified below are shown by asset quantity. The quantity of assets have been identified as those requiring replacement or refurbishment as part of this project as determined by the project type and project scope. These assets directly or indirectly impact the total expenditure required to complete this project.

Street Front Poles	131	1 Phase Pad Transformers	2
Easement Poles	0	3 Phase Pad Transformers	1
Reframe Poles	36	Vault Transformers	0
Reclosers	1	Pole Mount Transformers	26
UG Primary	0	Bored Duct	0

Figure 1-6: Tupper/Dorothy Voltage Conversion – Pole Setting

2. Timing

a. Beginning: January 2024
b. In-Service: Through to December 2027
c. Factors that may impact timing: Project execution may be impacted by unplanned and/or higher priority work arising, resulting in resource constraints.

3. Historical and Forecast Capital Expenditures

Table 3-1 Historical & Forecast Capital Expenditures ($'000)

Category	Historical Period						Bridge Year	Forecast Period				
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	5,973	4,873	3,612	4,949	5,632	3,008	5,028	7,219	8,351	6,903	4,401	-
Contributions	-	-	-	-	-	-	-	-	-	-	-	-
Capital (Net)	5,973	4,873	3,612	4,949	5,632	3,008	5,028	7,219	8,351	6,903	4,401	-

The 4kV conversion program has been an ongoing renewal program for several years, and the renewal work in 2024 is no exception. The 4kV conversion projects that have been targeted for renewal through the asset management process (Court-Wilson, Donald-Vickers, Court-Elgin, and 21F6 Phase 1) all pose significant challenges due to the nature of the customer make-up (i.e., sizable portion of the area contains commercial customers requiring SNC to minimize outage impacts increasing after hours work) or the location of the assets (i.e., poles and transformers in easements requiring crane to install). For example, in the 4kV conversion program in 2017, only 10% of poles (45) were installed in easements, and 4% of customers (45) in these projects were commercial. In 2024, in the 4kV conversion program, SNC is projecting to install 20% of poles (73) in easements, and 14% of customers (129) are commercial. The scope of work in the test year is similar in size and scale to the historical years, however, these elements, along with a significant rise in material and labour costs, are primary factors that impact project estimates and are directly attributable to the increases noted over the forecast period.

4. Economic Evaluation

An economic evaluation was performed for this program in the 2013 Cost of Service application submitted by Thunder Bay Hydro Electricity Distribution Inc. It has been validated during the 2017 Cost of Service application and then again prior to this application. This evaluation indicates that the present value of future costs of rebuilding 4kV substations is $33M and not of economic value to SNC. Refer to section 5.2.1.2.2 in the DSP for further details.

5. Comparative Historical Expenditure

Section 3 of this document identifies the historical 4kV conversion costs. SNC has extensive information on executing projects of this nature. Metrics for these projects have been captured for and based on this data, each project receives a detailed estimate annually based upon completed designs. SNC incorporates the latest resource metrics for both labour and material and includes several factors which may impact both. These may include:

- Existing overhead framing on pole
- Third party plant location
- Restricted access to proposed construction location
- Type of ground excavation (auger, vacuum excavation, hand dig, rock set)
- ROW locations requiring off-road equipment
- Vegetation encroachment
- Coordination with third party activities
- Utility easements and corridors that contain underground SNC infrastructure and 3rd party infrastructure
- Crew make-up (number of PLT, lead hand)
- Location in which existing pole/anchors is located (e.g., city sidewalk slab / asphalt paved area)

SNC evaluates project estimates, based on project type, against historical cost per pole figures to ensure that present estimates align with past project performance.

6. Investment Priority

The 4kV conversion program is a discretionary investment and ranks number 2 out of 9, with a score of 67.0. As these are discretionary expenditures, they are performed after System Access projects and prioritized against other discretionary spending. The asset management objectives listed below, along with project interdependence are the main factors that influence the program ranking. This means that projects must be completed in a systematic manner and not completing this program will negatively influence the ability to complete future work. It is important that SNC complete the conversion program to simplify, standardize and improve the overall performance and efficiency of the distribution system.

Health and Safety - Moderate injury requiring first aid or moderate security incident likely (expected to occur in 5yr).

The assets that comprise this program are some of the oldest in the system, and as a result have some of the highest likelihoods of failure. What this means is that assets are statistically likely to fail within the planning window. Additionally, this program mainly addresses overhead distribution assets which have a greater potential to cause injury to both the public and SNC employees.

Environmental Impact - Addresses three (3) or more of SNC's identified environmental risks and provides risk mitigation to those risks.

The conversion program addresses several factors that impact the environment. All installations are designed to the latest standards which include elements of climate change adaptation and system hardening. Additionally, vegetation contacts are mitigated as trees are trimmed to accommodate renewed infrastructure. The transformers replaced during this program may contain PCBs since many of them were installed prior to the ban on the substance. Finally, issues surrounding flooding of vault mounted equipment are attended to, if substandard installations are found (e.g., replaced with pad mounted equipment).

Regulatory/Legal Compliance - Addresses an issue that may become nonconformant with best practices if no action is taken.

While not a primary driver of this program, the removal of transformers containing PCB's is encompassed in this program. If further, more stringent regulations were to be introduced during the planning period (e.g., transformers containing <50PPM PCB's), SNC would be well positioned to address several of these assets within this program.

Customer Preference - Delivers on two of the top 3 priorities of customers (Affordability, Safety for Employees and the Public and Reliability)

Customers have ranked Affordability, Safety, and Reliability as their top three concerns during our latest round of engagement for this Filing (see Section 5.2.2.1 of the DSP). This program enables SNC to address safety concerns be proactively renewing legacy equipment while at the same time, maintaining system reliability.

Asset Performance - Asset deficiency impacting substation reliability or critical non-system assets operating outside manufacturer support.

The conversion program is specifically centered on removing instead of renewing 4kV substations, thus having a direct impact on substation reliability (i.e., reducing the complexity of the system).

Operational Efficiency – Aligns with 4

This program aligns with all criteria in this category:

Reduces operating expenses – costs associated with station maintenance are removed with decommission.

Avoids Future Capital – stations are decommissioned instead of being rebuilt at significant capital cost.

Coordinates with Other Projects – this program coordinates with Grid Modernization by reducing potential constraints imposed by lower operating voltages allowing for further enablement of DER.

Decreases Liability – By addressing assets in poor condition and with the greatest likelihood of failure, SNC can reduce the potential for injury to its staff and the public.

System Reliability - Sustained interruption of 4.5-12.5 MW of distribution load (900-2,500 residential customers).

The conversion program in the test year has the potential to impact approximately 1900 customers.

7. Alternatives Analysis

The projects listed in this category have been identified based on a voltage conversion plan which considers the condition of the substation transformers, as well as the geographic location of the substation, the loads it feeds, and the age of infrastructure on the associated feeder.

Alternatives for voltage conversion are considered and are captured below.

Table 7-1 Alternatives Analysis

Scenario	A. Base Case	B. Do Nothing	C. Increased Pace	D. Decreased Pace
Description	Proceed with voltage conversions as planned.	Continue to operate with existing assets.	Invest $1M more into this program.	Decrease investment into this program by $1M.
Scope	Planned conversions take place as outlined in this document and the DSP with all areas being converted by the end of this filing period.	SNC continues to operate the existing 4kV network, and only replaces assets as they fail.	Renewal takes place at a quicker pace to complete conversions by mid filing.	SNC invests less into this program, extending the conversions past the filing period.
Test Year CAPEX	$7,953M	$0.00M	$8,953M	$6,953M
Program Benefits	All assets will be installed to meet the latest standards, incorporating aspects of system hardening. Defective	Near-term cost savings to all customer classes.	Reduced operating expenses as substations come out of service more quickly. Potential improvement to reliability statistics and opportunity to support increased	Allows for increased renewal of assets in other discretionary programs.

	equipment is the top contributor to SAIFI and SAIDI annually (averaging 22%, 2019-2022). Reduction in inventory. Reduction in costs to operate and maintain stations.		EV/DER adoption rates.	
Program Savings	Base scenario, all others are measured against this.	Program savings for this scenario were not calculated as End-of-service life assets remaining in service creates elevated risk to health and safety and SNC has a long-term plan to convert legacy voltages.	No net savings to customers as a result this alternative.	Residential customers would experience an increase of approximately $0.39 (see note 1 below).
Program Risks	Base scenario, all others are measured against this.	Increased risk of outages due to large number of assets not being renewed. Potential significant impact to reliability and safety. Significant reduction in opportunity to support increased EV/DER	Increased pace reduces the available capital in other discretionary programs resulting in a less wholistic renewal program and potential increase in failures at other operating voltages.	Reduced pace extends substation decommissioning beyond this DSP filing period resulting in increase operating and maintenance costs and may require additional contingencies in the event of station failure. Reduced opportunity to support EV/DER expansion.

		adoption rates.		Maintain 4kV inventory.
Customer Feedback	In our recent survey, 83% of customers (451 respondents) have said that SNC should replace aging infrastructure before it fails to prevent outages and keep costs predictable. 58% (310 respondents) also support maintaining or increasing SNC's current investment plan.			
Other Factors	This program is constrained by the needs of mandatory system investments.	SNC has had a longstanding 4kV conversion program. Proceeding with this option would not remove the operational constraints that remain with the legacy voltage in service.	Resource and material constraints may reduce SNC's ability to proceed with this option. Does not align with assets identified through the asset condition assessment.	Does not align with assets identified through the asset condition assessment.

Note 1:

SNC undertook a financial review of the most realistic alternative, reduced spending on DSP projects by roughly $1M per year. To provide a more realistic impact on customers, the analysis was extended through the next cost of service period (2029-2033) and included the impact of expected OM&A and Rate Base requirements. The present value of the total amount collected from customers was calculated back to 2024 to determine the actual impact. This analysis assumes that all remaining capital spending will remain the same and that the cost of capital parameters will remain the same for the 2029 COS proceeding. It also anticipates a 2% increase for all IRM periods (2025-2028) and (2030-2033)

The total required funding under the DSP plan is $13.03M over the next ten years. The total funding needed under Alternative D in Table 7-1, the $1M dollar reduction plan, is $13.39M. This results in savings to customers of $360,000, of which approximately $200,000 would be allocated to residential customers, a savings of $.39 per residential customer.

8. Innovative Nature of the Project

This project is integral to enabling future technological functionality and to addressing future operational requirements to meet the changing needs of customers, industry, and regulators. Once the remaining 4kV circuits are converted SNC will be able to further support the connection of DER's into the distribution system as the new 25kV network has the protections systems necessary to enable their connection.

9. Leave to Construct Approval

Not applicable to this program.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability and Safety

Criteria	Description
Efficiency	Upgrading 4kV rated equipment to 25kV equipment will result in greater operating efficiency, reduced power losses, and standardized equipment allowing for purchasing efficiencies. It will also eliminate the last of many complex multi-circuit distribution lines and the need to stock multiple types of equipment.
Customer Value	With the conversion from 4kV to 25kV construction SNC anticipates the following benefits to customers. • Eliminate older, end of life 4kV distribution assets. • Allow for the deployment of modernized grid technologies and all their related benefits to customers which allow the ability to manage, and remotely control and troubleshoot the system. • Standardize construction practices across the different systems, which helps to control construction and operating costs. • Reduce system losses through the elimination of substations. • Allow for the connection of larger loads and generators without major system rebuilds. • Conform to the standard voltage across the province making it easier to source material and expertise. • Eliminate the use of outdated, difficult to operate and maintain equipment. • Eliminate the need for 4kV substations and simplify the operation of the distribution system.
Reliability	The conversion projects will improve reliability performance as these projects are typically in older areas of the city where legacy construction practices were used. These areas will be constructed with modern standards and equipment, which will improve system operation efficiency using new technologies to protect and control the system. These modern systems will

	provide more cost-effective options to limit outage areas and restore outage areas, providing improved reliability while eliminating safety hazards to the public.
Safety	This investment will improve safety to the public, as well as worker safety by replacing existing poles and their associated framing with newer standards which will allow for improved safe work practices.

2. Investment Need

Primary Driver:

Failure Risk - The main driver for this project is aimed at addressing failure risk. SNC seeks to prioritize project selection based on assets that are in the worst health. The assets identified in this program for replacement are being supplied by multiple 4kV substation transformers and breakers which are at end of life and have a high probability of failure which is a result of the age and the condition of the assets.

The following figures illustrate the current state of the assets operating at 4kV. The asset health and condition assessment were performed for each asset using predetermined condition parameters which are part of the asset management process. Each parameter is weighted depending on its overall importance in determining asset health. Assets are field inspected by subject matter experts and scored based on the severity of a given defect. The score of each condition parameter combined with its respective weight determines the overall health. The health of the assets is grouped into 5 categories: very good, good, fair, poor, and very poor.

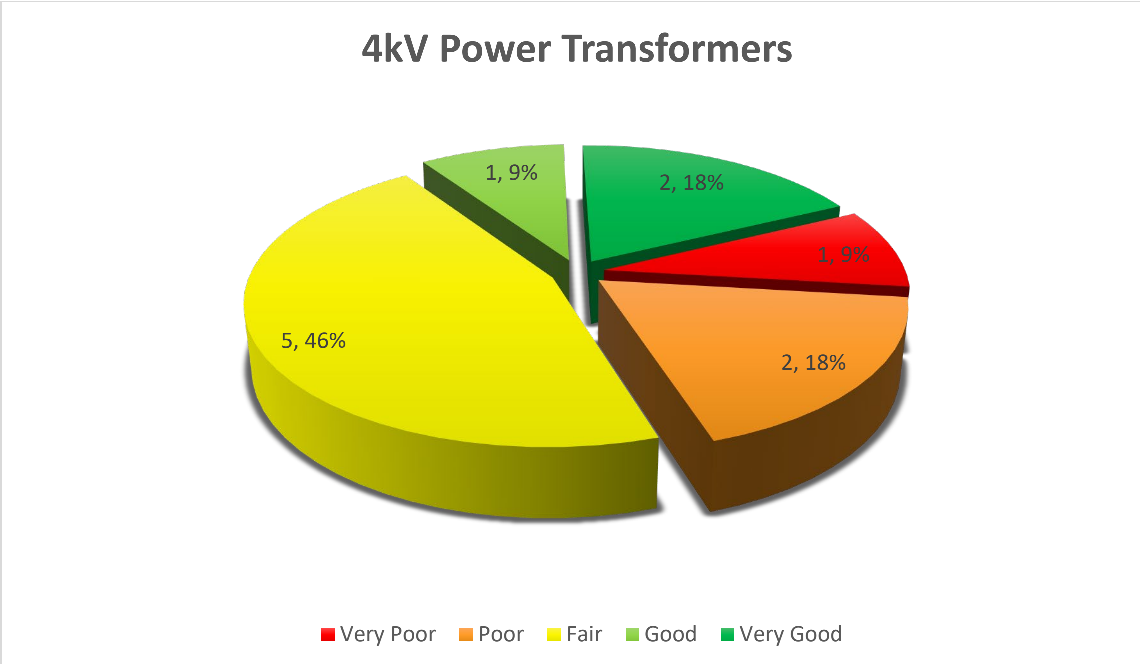


Figure 2-1 2022 - 4kV Power Transformer Condition

Table 2-1 2022 - 4kV Transformer Demographics

STATION	AGE	HI	TYPICAL USEFUL LIFE
STN#16 MACDONNEL	69	10.0%	45
STN 21 WINDEMERE	67	25.4%	
STN 5 DONALD	65	44.2%	
STN#16 MACDONNEL	64	53.3%	
STN 21 WINDEMERE	64	53.3%	
STN #4 VICKER	64	53.3%	
STN#14 ALGOMA	64	53.3%	
STN 11 HIGH ST	63	61.5%	
STN 5 DONALD	60	80.0%	
STN#12 CAMELOT	54	95.4%	
STN#12 CAMELOT	54	95.4%	

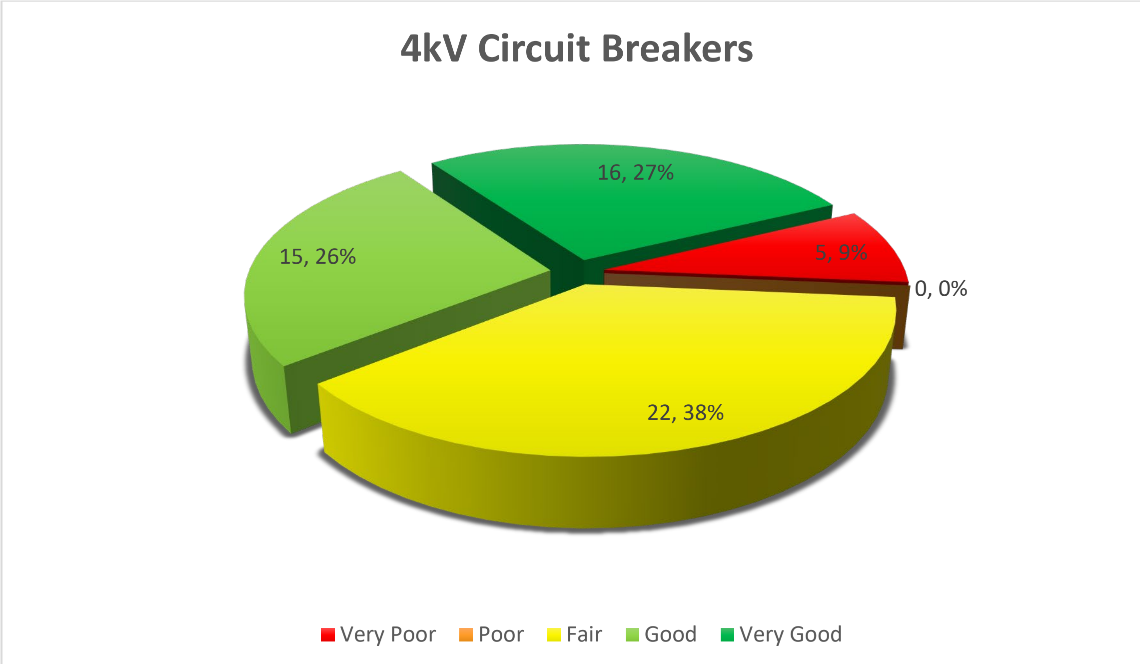


Figure 2-2 2022 - 4kV Circuit Breaker Condition

Table 2-2 2022 - 4kV Circuit Breaker Demographics

BREAKER ID	AGE	HI	TYPICAL USEFUL LIFE
34912	74	10.0%	45
34913	74	10.0%	
34914	74	10.0%	
34915	74	10.0%	
34916	74	10.0%	
2-0444-1	69	53.3%	
2-0444-2	69	53.3%	
2-0444-3	69	53.3%	
2-0444-4	69	53.3%	
38923	69	53.3%	
38924	69	53.3%	
38925	69	53.3%	

38926	69	53.3%	
38927	69	53.3%	
52775	69	53.3%	
52776	69	53.3%	
52777	69	53.3%	
52781	69	53.3%	
201097	67	68.7%	
201131	67	68.7%	
201133	67	68.7%	
231986	67	68.7%	
231987	67	68.7%	
52778	67	68.7%	
52782	67	68.7%	
52784	67	68.7%	
52785	67	68.7%	
51854	65	80.0%	
51853	65	80.0%	
51855	65	80.0%	
51856	65	80.0%	
51857	65	80.0%	
55979	65	80.0%	
55980	65	80.0%	
55981	65	80.0%	
55982	65	80.0%	
55983	65	80.0%	
52774	64	84.2%	
52779	64	84.2%	
52780	64	84.2%	
52783	64	84.2%	
52786	64	84.2%	
55560	61	92.4%	
55565	61	91.1%	
55561	61	91.2%	
55563	61	91.2%	
55570	61	91.2%	
55559	61	91.2%	
55562	61	92.4%	
55564	61	91.2%	
55566	61	92.4%	
55567 (SPARE)	61	92.4%	
55569	61	92.4%	
1742876	19	97.3%	
1742877	19	94.5%	

1742875	19	91.8%	
1742878	19	91.8%	
1742879	19	94.5%	

Table 2-3 Average Age and HI% for 4kV Assets

ASSET	AVERAGE AGE	AVERAGE HI	POPULATION	TYPICAL USEFUL LIFE
WOOD POLES	44	71.0%	1381	45
POLE MOUNTED TRANSFORMERS	44	54.0%	315	40
PAD MOUNTED TRANSFORMERS	42	55.0%	116	30
VAULT TRANSFORMERS	44	52.0%	26	40
OVERHEAD SWITCHES	32	75.0%	66	45
UG PRIMARY	45	48.0%	28km	40

The following table illustrates the percentage of the population of assets in poor and very poor health by operating voltage. SNC generally targets these assets for renewal. The table demonstrates that there is a greater need to renew assets operating at 4kV relative to the assets operating at higher voltages.

Table 2-4 2022 - Assets in Poor/Very Poor Health by Voltage

ASSET	% OF POPULATION IN POOR/VERY POOR HEALTH		
	4kV	12kV	25kV
WOOD POLES	10%	6%	8%
POLE MOUNTED TRANSFORMERS	47%	15%	4%
PAD MOUNTED TRANSFORMERS	37%	6%	14%
VAULT TRANSFORMERS	54%	-	41%
OVERHEAD SWITCHES	18%	19%	16%

Secondary Drivers:

Operational Efficiency - The secondary drivers are Operational Efficiency and Modernization of Systems. SNC seeks to maximize factors that positively affect operational efficiency through consideration of equipment types and the analysis of constraints on the system. The modernization of assets to the 25kV voltage system results in the retirement of distribution transformer stations in need of otherwise expensive upgrades. Over time, uprating the operating voltage during renewal projects from 4kV to 25kV eliminates the need to operate, maintain, and upgrade stations required for providing electrical connectivity between the 25kV and the 4kV systems. While capacity is not a driving factor for any projects under this DSP, uprating of 4kV distribution system to higher more efficient operating voltage will also improve line losses as well as ability to accept more load and/or generation customers.

The average age of the 4kV power transformers and circuit breakers is 63 years respectively, well above the typical useful life of 45 years. The average health index of the power transformers is 57% and 70% for the circuit breakers. The projects identified in this document will assist in renewing the assets connected to the 4kV network with higher operating voltage equipment and new service life. When each of the feeders associated with these transformers is converted, the subsequent station will be decommissioned. This results in both deferred capital expenditure associated with renewing the station and removes the operating and maintenance (O&M) costs associated with servicing the station buildings, structures, and equipment. Table 2-6 details the O&M spending associated with operating the 4kV stations.

Table 2-5 Historical Station O&M Costs

STATION	YEAR			
	2019	**2020**	**2021**	**2022**
DONALD	$46,279	$15,003	$17,156	$47,844
HIGH	$26,879	$51,226	$31,362	$24,199
VICKERS	$16,645	$23,109	$32,469	$18,723
WINDEMERE	$14,557	$36,570	$16,481	$35,195
MACDONNEL	$23,490	$48,528	$21,259	$18,022
CAMELOT	$22,791	$38,660	$21,533	$49,515
ALGOMA	$20,097	$24,632	$21,183	$20,216
Total:	**$170,739**	**$237,727**	**$161,442**	**$213,713**

SNC performs a visual inspection of all substations monthly and a detailed inspection of all substations every three years. This regime includes regular inspection and maintenance of the following facilities as their conditions require;

- Substation enclosure and fencing;
- Breakers and switchgear;
- Power transformers; and,
- Auxiliary station equipment (AC and DC systems, protective relaying, SCADA equipment, remote terminal units, metering, instrument transformers, lightning arrestors, insulators, bus connections, steel structures, foundations, oil containment, ducts / conduits etc.).

The substation maintenance program also includes event related maintenance due to faults or component failure, for the purposes of this section the costs for these activities are distributed across the 4kV substation population.

SNC's annual costs associated with the scheduled and emergency maintenance of the 4kV substation population is estimated to be $27,986 per station, per year ($195,905 on average total per year).

Additionally, there are increased system losses associated with operating the 4kV network. The conductors that are utilized in the distribution network contain a resistive component which dissipates power in the form of heat when supporting electrical loads. Heat dissipated by conductors is a component of electrical loss and represents a monetary loss to the LDC.

Typically, conductors are sized such that they can economically perform the function for which they are designed while limiting the amount of energy lost through heating. Designers must strike a balance whereby losses are minimized and yet the conductor remains economical and practical from a construction perspective.

The power lost to the heating of a conductor is proportional to the square of the current and the resistance of the conductor. Further, the current demanded by an electrical load is proportional to the voltage multiplied by the current. As such, a load connected directly to the 25kv network will have a current demand equivalent to $1/6^{th}$ that of an equivalent 4kV load. The figure below shows the exponential growth in line losses for varying loads serviced 1km from the source using the same conductor. Note this is intended as an example only, not representative of actual losses experienced by SNC's system.

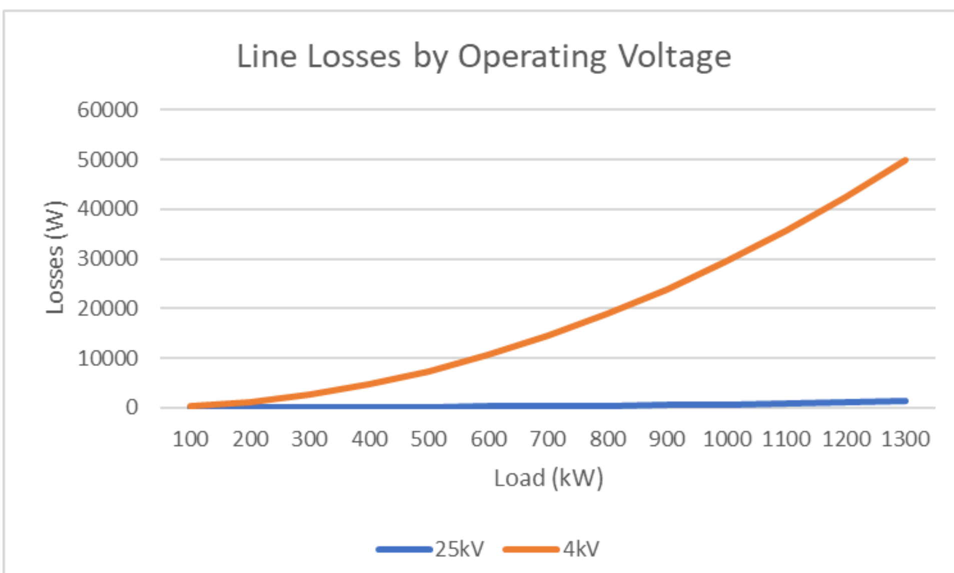


Figure 2-3 Line Losses by Voltage

Information Used to Justify the Investment:

SNC's asset management process (Section 5.3.1 of the DSP) and asset lifecycle optimization practices (Section 5.3.3 of the DSP) inform the execution of the long standing 4kV conversion program. The average health of these assets is 63% and the average age is 62 years. The substation assets and associated distribution infrastructure are generally in poor health and well past their typical service life. By allowing poor condition and end-of-life equipment to be replaced, this investment prevents the power supply reliability from degrading below SNC's targets. The planned replacement and conversion projects are essential in maintaining a reliable distribution system for customers.

The flagged for action plan is a direct out put of the 2022 asset condition assessment and incorporates a forward looking analysis of the potential failures from the test year, 2024 through to 2028. The following table shows the recommended replacement schedule.

Table 2-6 Flagged for Action Volume

ASSET	YEAR				
	2024	2025	2026	2027	2028
WOOD POLES	420	341	335	336	336
POLE MOUNTED TRANSFORMERS	141	141	141	141	141
PAD MOUNTED TRANSFORMERS	80	80	80	80	64
VAULT TRANSFORMERS	23	23	23	23	23
OVERHEAD SWITCHES	13	10	10	10	11

The following figures detail the demographics of the major assets within the distrbuiton system. The information is a direct output of the latest asset management process.

Wood Poles

Poles form the largest group of assets and are expected to form the largest portion of the voltage converstion program annually (as noted in Table 2-7). Most poles within a conversion area must be changed due to the clearances required to operate at a higher voltage. However, poles that have been recently replaced due to failure are generally replaced at the height required to conform to standards. These poles then only require reframing to support the new 25kV infrastrucutre.

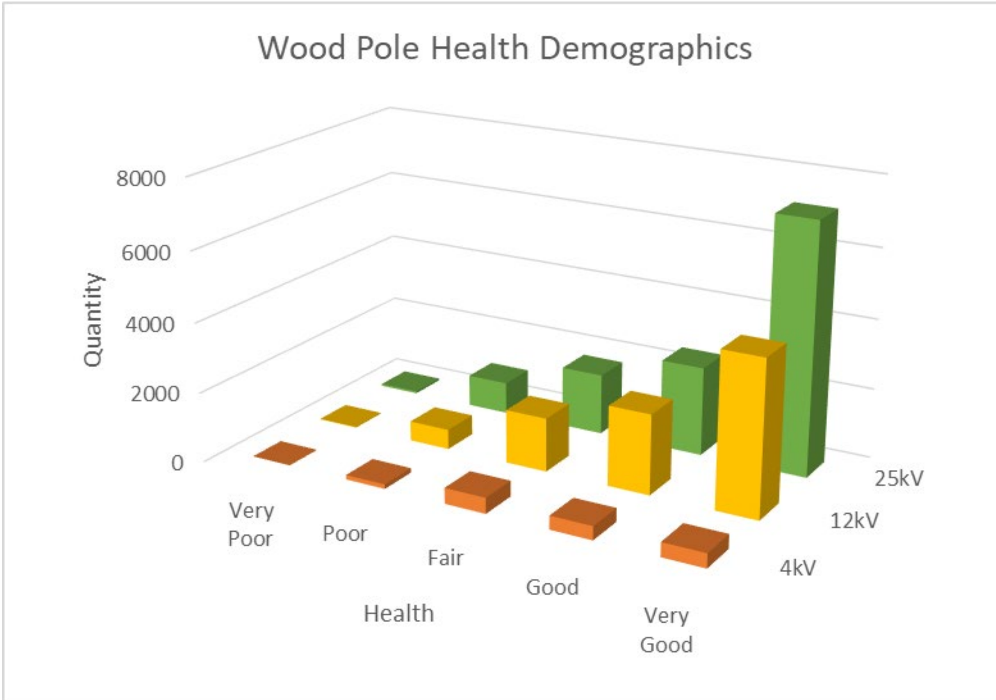


Figure 2-4 2022 - Wood Pole Health Demographics

SNC inspects visually inspects wood poles every 3 years and tests the remaining strength at the groundline of a subset of poles annually. SNC replaces poles based on the inspection and testing results using the forward looking, flagged for action plan as a basis for the volume of poles and the health to identify specific assets. The inspection parameters are found in Table 2-9.

Table 2-7 Wood Pole Condition Parameters

CONDITION PARAMETER	WEIGHT
Pole Remaining Strength	38%
Overall Condition	19%
Ground Line Rot	6%
Mechanical Damage	6%
Age	5%
Shell Rot	3%
Split	3%
Woodpecker Hole	3%
Insect Damage	3%
Leaning	3%
Feathering	3%
Crossarm	3%
Guy Wire & Anchor	2%
Foundation	2%
Riser	1%

Pole Mounted Transformers

Pole mounted transformers are the second largest asset group expected to impact the 4kV conversion program. All 4kV pole mounted transformers within a conversion area are replaced due to the change in operating voltage.

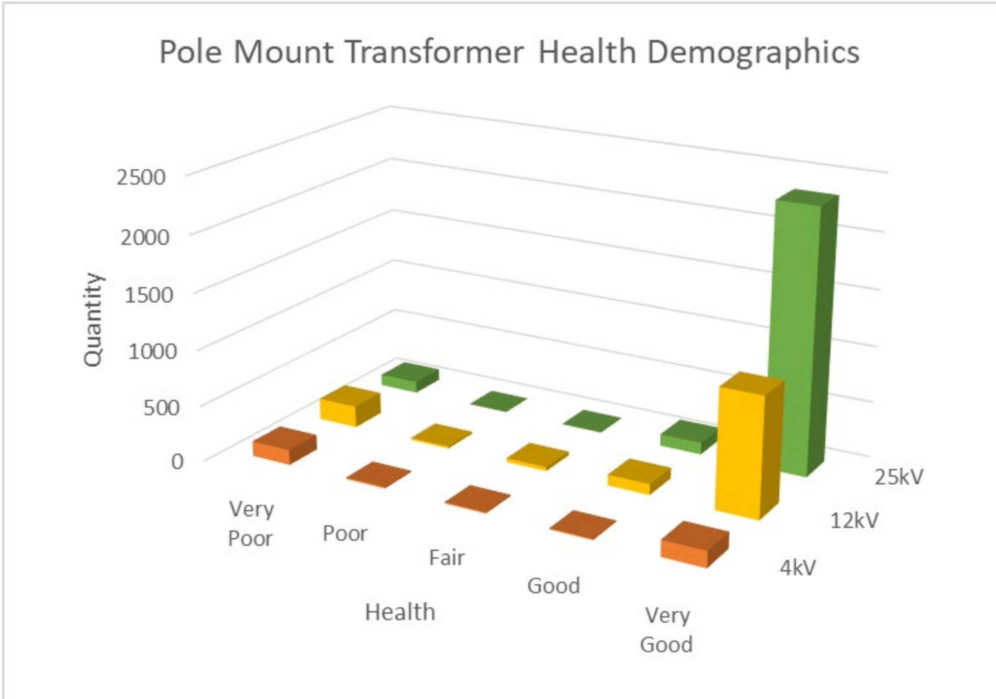


Figure 2-5 2022 - Pole Mounted Transformer Health Demographics

Pole mounted transformers are inspected in conjunction with the pole inspections. Overall condition is assessed visually. Pole mounted transformers operating at 12/25kV are replaced reactively as generally the assets are in good/very good health. The condition parameters for pole mounted transformers are found in Table 2-10 below.

Table 2-8 Pole Mounted Transformer Condition Parameters

CONDITION PARAMETER	WEIGHT
Overall Condition	75%
Age	25%

Pad Mounted Transformers

Pad mounted transformers form the next largest group of assets that are expected to impact the 4kV conversions. Like pole top transformers, all 4kV units must be replaced to accommodate the higher operating voltage.

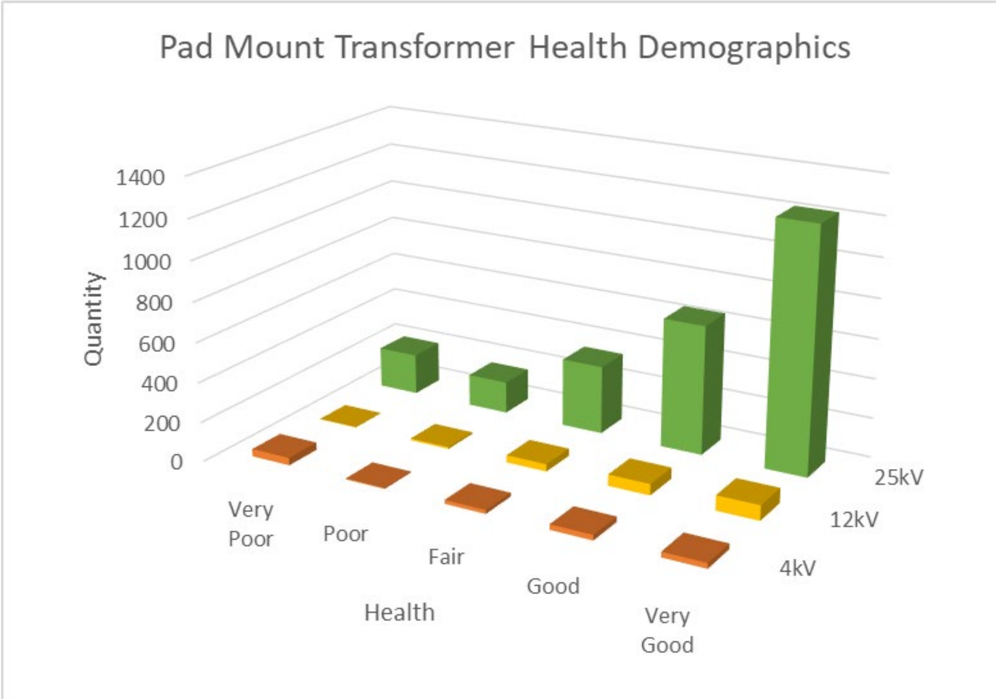


Figure 2-6 2022 - Pad Mount Transformer Health Demographics

Pad mounted transformers are inspected based on a 3-year inspection cycle. Pad mounted equipment experience a harsher environment as compared to pole mounted transformers and have more inspection points as a result. In many cases pad mounted transformers are proactively replaced where an inspection shows significant deterioration of the tank, otherwise pad mounted transformers are reactively replaced.

Table 2-9 Pad Mounted Transformer Condition Parameters

CONDITION PARAMETER	WEIGHT
Oil Leak	40%
Overall	23%
Age	17%
Enclosure Damage	10%
Paint Condition	4%
Base Condition	4%
Access Restricted	2%

Vault Transformers

Vault transformers are anticipated to be the next largest contributor expected to impact the 4kV conversion program. These assets must be replaced to accommodate the change in operating voltage. Vault transformers are found inside customer owned structures, which often makes inspections, maintenance, and replacement difficult. Through this program careful consideration is given to replacing these assets with pad mounted infrastructure to facilitate repair and replacement in the future.

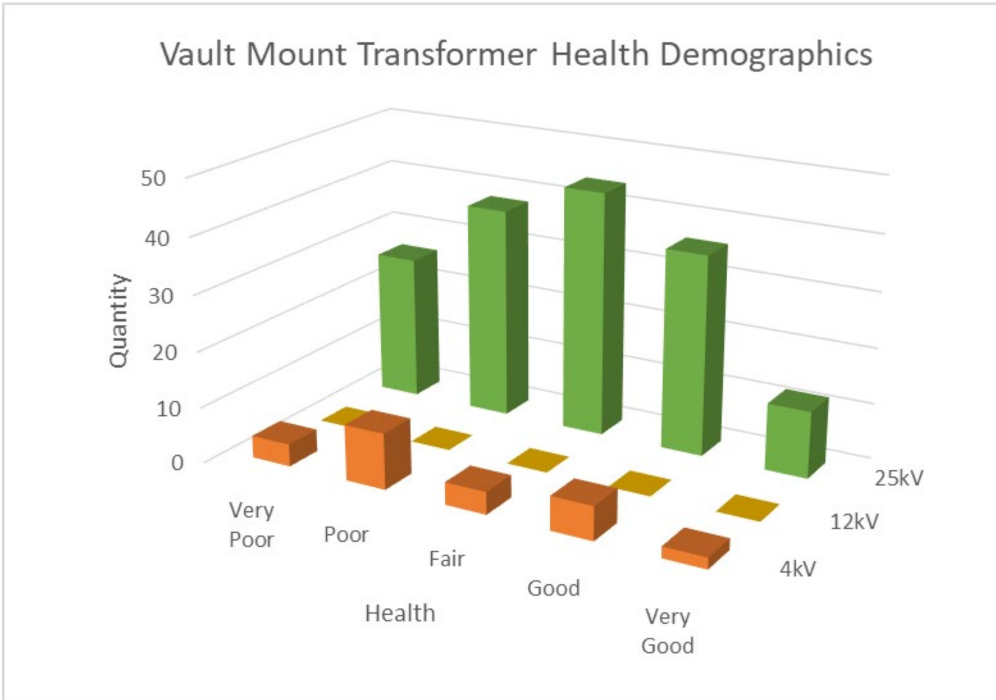


Figure 2-7 2022 - Vault Transformer Health Demographics

Vault transformers are inspected based on a 3-year inspection cycle. Vault transformers are installed in customer owned structures and are relatively protected from the environment, often this has the benefit of a long service life. In most cases vault transformers must be replaced proactively in coordination with the customer as many are difficult to access and have unplanned outages have the potential to impact many residential customers (in the case of large housing complexes) or business and industrial customers for an extended period during their replacement. The condition parameters for vault transformers are found in Table 2-11

Table 2-10 Vault Transformer Condition Parameters

CONDITION PARAMETER	WEIGHT
Age	50%
Capable of Live Switching	17%
Oil Leak Present	14%
Pressure Relief Valve	10%
Disconnects Present	5%
Fusing Present	5%

Overhead Switches

Overhead switches are expected to have the least impact to the 4kV conversion program. In many cases, switches are removed from service rather than replaced as the switching point is no longer necessary to the ongoing operation of the distribution system.

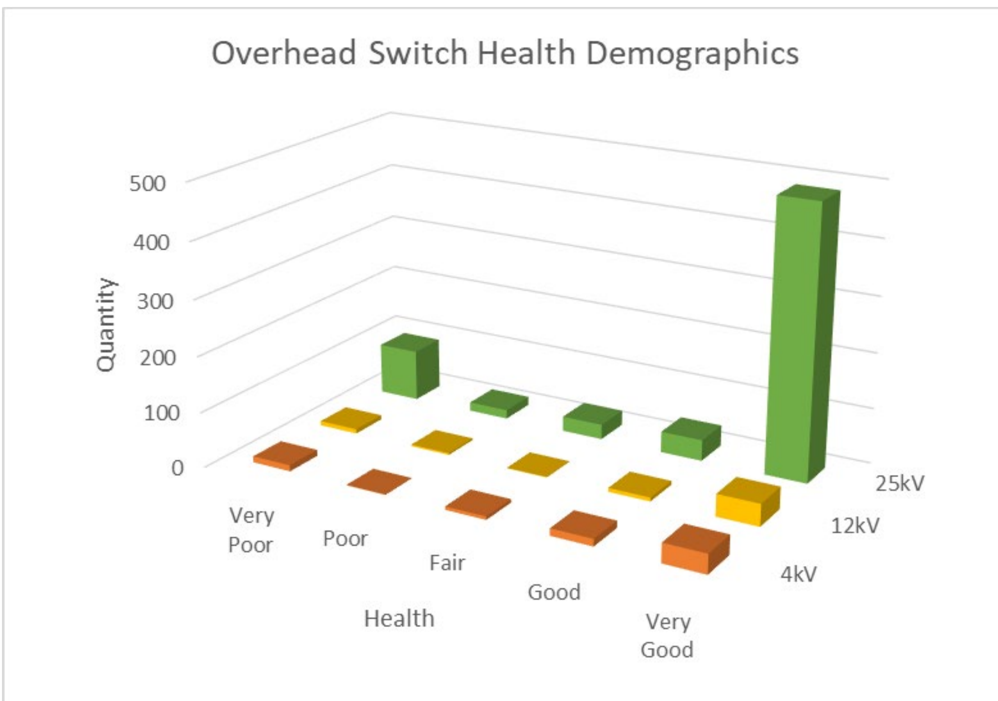


Figure 2-8 2022 - Overhead Switch Health Demographics

Overhead switches are inspected visually inspected every three years. Additionally, infrared scanning is performed on a subset of critical switches as well. All overhead switches are replaced reactively. SNC reviews each switch installation with subject matter experts prior to returning it to service to determine whether that switching point is still required for the system to operated effectively.

Table 2-11 Overhead Switch Condition Parameters

CONDITION PARAMETER	WEIGHT
Age	34%
Blade Condition	18%
Switch Insulator Condition	16%
Strain Insulator Condition	16%
Arc Suppression	16%

Primary Underground

Primary underground is expected to have a moderate impact on the 4kV conversion program. The underground cable must be replaced with cable rated for 25kV. Depending on the extent of underground cable within a given project, the cost associated with installing new cable and duct can significantly impact the project.

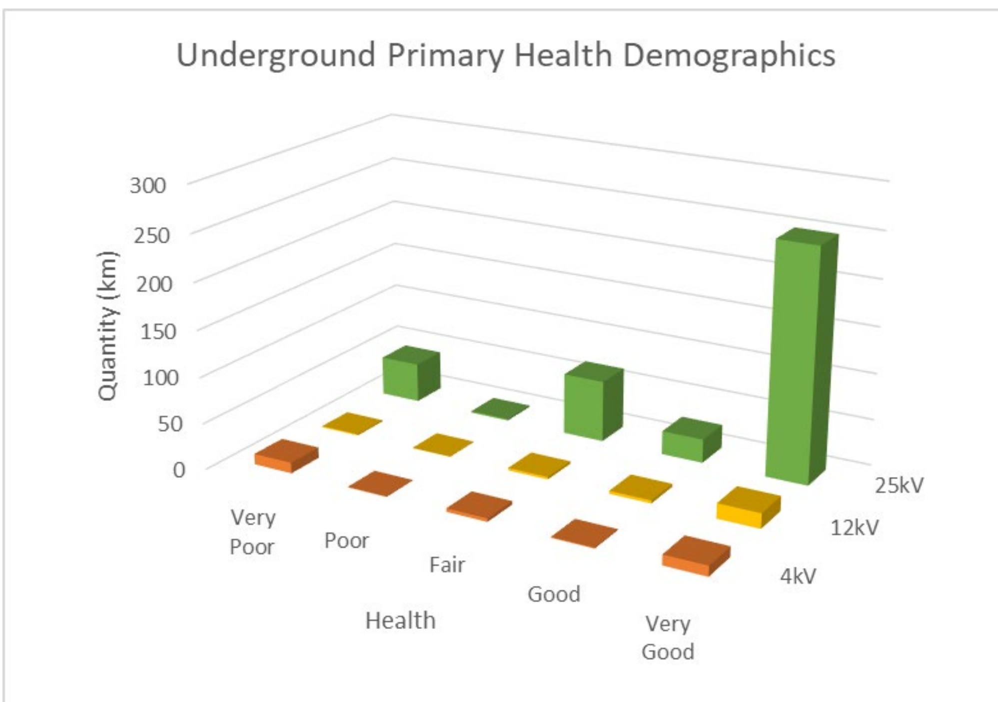


Figure 2-9 2022 - Underground Primary Health Demographics

SNC currently bases most of its cable health on age, as aside from non-destructive testing it is difficult to determine any other health parameters. SNC is in the process of testing the direct buried cables that can be found in several subdivision areas throughout Thunder Bay. The condition parameters for underground primary can be found in Table 2-13.

Table 2-12 Underground Primary Condition Parameters

CONDITION PARAMETER	WEIGHT
Cable Testing	50%
Age	40%
Neutral Condition	5%
Splice(s) Present	5%

3. Investment Justification

Demonstrated Utility Practice

To ensure that SNC can deliver safe, reliable, and efficient service, it is fundamental that SNC has the necessary foundations in place. SNC is a member of the Utilities Standards Forum ("USF") and uses USF standards, supplemented by standards developed internally. The use of USF standards ensures that the design and construction of this project will be done according to a set of standards utilized by many other utilities in Ontario.

The Canadian Standards Association provides standards for several sectors. CSA 22.3 applies to utilities, and it sets out specific requirements which look to improve the safety and reliability of the electrical distribution system.

CSA 22.3 No.1 – Overhead Systems

This standard applies to overhead electric supply, communication lines and equipment placed outside of buildings and fenced supply stations. The standard includes clause 5.3.1.1 which states that there is a minimum vertical clearance above ground that is dependent on the operating voltage. This program is designed to comply with this clause.

CSA 22.3 No.7 – Underground Systems

This standard applies to lines and equipment related to underground electric supply and communication systems placed outside of buildings and fenced supply stations. Section 10 relates to the location of above-ground facilities such as pad mounted transformers. Section 10.1 states that live parts must be inaccessible. Clause 10.2 states that there must be adequate working space around the equipment. Clause 10.5 states the equipment must be protected from potential vehicular damage (e.g., snowplows). Clause 2.1.3 states that underground cable must be buried at a minimum depth depending on the voltage of the cable as well as what the cable will be buried under. Substandard installations identified by these clauses will be addressed through this program.

Ontario Regulation 22/04

This is a set of regulations that was incorporated into the Electricity Act, 1998 and covers various elements of electrical distribution safety. It is designed to address aspects of safety standards, approval of electrical equipment, approval of plans and specifications for installations, inspection and approval of construction, proximity to distribution lines, disconnection of unused lines, reporting serious electrical incidents, and compliance. This regulation informs part of SNC's renewal programs as compliance with this regulation is tracked by SNC and the OEB. SNC has achieved compliance with this regulation annually for the entire historical period. This program will ensure that SNC can continue this trend.

Distribution System Code: Appendix C

Under this code set forth by the OEB, the distributor must maintain is distribution system considering good utility practice and reliability on a short-term and long-term basis. Inspections are performed to comply with the requirements found in the Code. Where defects are discovered, depending on the severity, assets may be replaced immediately or planned for future replacement.

Cost-Benefit Analysis

As this program substantially exceeds materiality, SNC performed the alternatives analysis in Table 7-1. The table details that there are no other practical and cost-effective alternatives for projects under this investment that provide the same level of benefits to customers.

Historical Outcomes

SNC has completed several voltage conversion projects historically and has observed many positive outcomes from these projects including but not limited to, improved system efficiency, reduction in losses, and increased standardization requiring less inventory. When end-of-life poor condition assets are replaced as part of these voltage conversion projects, this also results in maintained system reliability.

The following chart illustrates the historical progression of the 4kV Conversion program since its inception in 2007 to its current state. As mentioned, this long-standing initiative was undertaken when approximately 1/3 of the then, Thunder Bay Hydro customers were serviced at 4kV. Since that time, steady progress has been made to where less than 10% of SNC's customers are connected to the 4kV network.

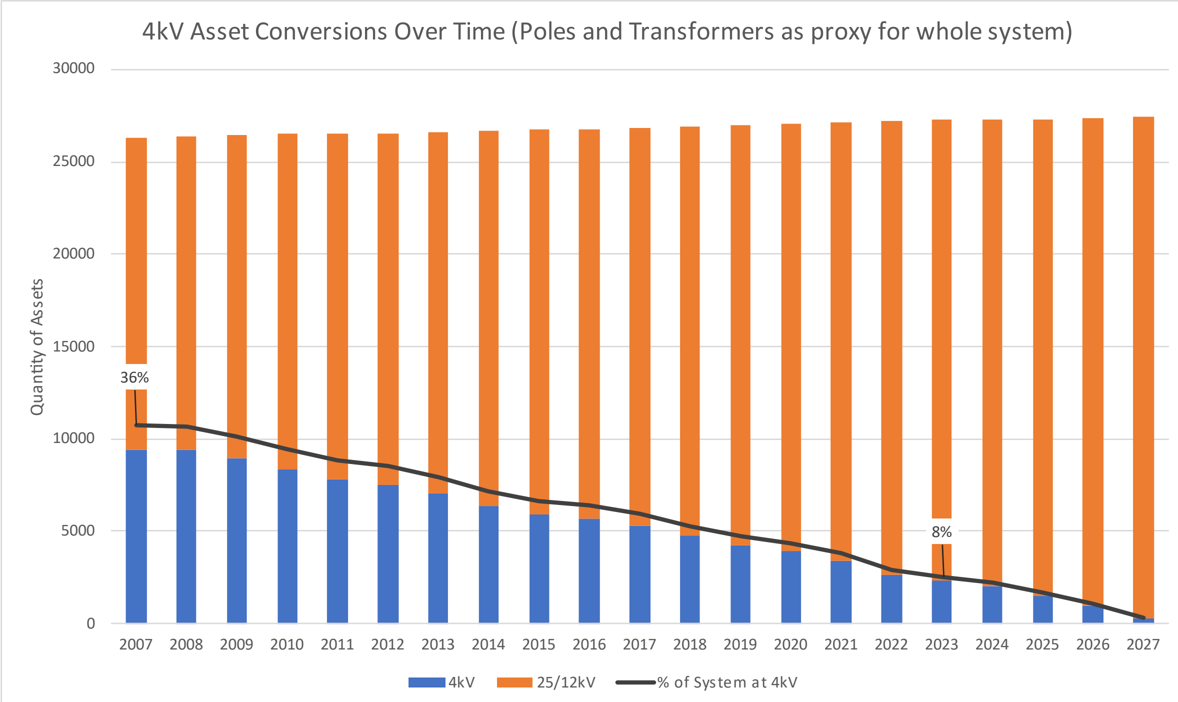


Figure 3-1 4kV Asset Replacements

4. Conservation and Demand Management

CDM is not applicable.

MATERIAL INVESTMENT REPORT

Program/Project

Grid Modernization

Investment Category

SYSTEM SERVICE

A. General Information on the Program/Project

1. Overview

SNC covers a large service territory and has several remotely monitored or controlled devices in its system. Grid modernization enhancements are aimed at reducing outages and providing improved service to customers when an outage does occur. This could be in form of; improved communication, including how quickly customers are notified, how frequently they are notified, and improved quality of information. It could also mean a reduction in the duration of outages because of improved ability to remotely control regions of load.

This program category consists of design, installation, and commissioning of remotely controlled reclosers and distributed automation enhancements to the SCADA system. This program consists of 15 remotely monitored and controlled devices, distribution automation modules and continued enhancements of the SCADA system being deployed in the next 5 years. In 2024 the expenditures include costs to install four reclosers with all the associated hardware, telemetry, and labour. The recloser locations are chosen based on the worst performing feeder analysis from 2022 as well as the 25 kV reliability analyses.

SNC worked extensively over the historical period to achieve a fully functional Outage Management System (OMS). Understanding that this has been an extensive undertaking and a burden, both financially and on internal resources required for implementation SNC was able to pace SCADA integration with several operational pieces: Geographic Information System (GIS); Advanced Meter Infrastructure (AMI); and Customer Information Systems (AMI) In 2024, expenditures will focus on further integration of the GIS system with the SCADA system.

The technological additions to the system are intended to enhance asset management objectives related to Customer Preference and System Reliability.

2. Timing

a. Beginning: January 2024
b. In-Service: Through to December 2028
c. Factors that may impact timing: annual variation in the number of customers connected will impact the volume of work performed in this program each year. The timing of execution depends on when the customer initiates the request.

3. Historical and Forecast Capital Expenditures

Table 1 Historical & Forecast Capital Expenditures ($'000)

Category	Historical Period						Bridge Year	Forecast Period				
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	151	289	432	87	242	142	277	323	330	336	343	350
Contributions	-	-	-	-	-	-	-	-	-	-	-	-
Capital (Net)	151	289	432	87	242	142	277	323	330	336	343	350

4. Economic Evaluation

Economic evaluation is generally not applicable.

5. Comparative Historical Expenditure

Section 3 of this document identifies the historical grid modernization costs. The quantity and scope of varies year-to-year, however SNC forecasts based on the best available data considering inflation, supply chain and material cost factors for these installations.

As part of this program SNC has installed a completed Outage Management System (OMS), five automated reclosers complete with remote sensing equipment, two vista switchgear automation systems as well as several upgrades to the Supervisory Control and Data Acquisition (SCADA) system.

6. Investment Priority

Grid modernization projects are discretionary investments driven by the identification of potential system enhancements that improve reliability and outage response time. As these are discretionary expenditures, they are performed after System Access projects and prioritized against other discretionary spending. This project ranks as last overall, which is 9 of 9 with a score of 8.5. This program is primarily driven by system reliability improvements.

Health and Safety - No impact to health and safety.

Environmental Impact - Does not address any environmental risks or provide risk mitigation.

Regulatory/Legal Compliance - No impact on regulatory compliance.

Customer Preference - Delivers on one of the top 3 priorities of customers (Affordability, Safety for Employees and the Public and Reliability).

This program is designed to deliver on improved reliability to the benefit of SNC customers.

Asset Performance - No impact asset performance or health.

Operational Efficiency – Aligns with None

System Reliability - Sustained interruption of > 12.5 MW of distribution load (>2,500 residential customers).

This program is designed to address poor performing feeders and targets high impact areas (i.e., greatest number of customers) and includes technological improvements aimed at enhancing visibility into the grid, operability of the grid and has the potential to impact large groups of customers.

7. Alternatives Analysis

The projects identified under system service category have been initiated because of customer preferences and feedback and the continued improvements required operating a distribution system in a cost-effective manner. To address these issues, SNC considered the following alternatives:

a. Do Nothing - this option could result in degradation of service quality as well as significant (and potentially very public) customer dissatisfaction. Over time, customers have become accustomed to receiving timely information. By doing nothing, the ability to both operate the network and provide timely information is put at risk. For these reasons, this option is not considered appropriate.

b. Integrate more manual switching points into the system - this option is always considered as one of the alternatives for reliability enhancement. It has the characteristics of being quick and relatively inexpensive to implement. However, it does not significantly improve the duration of outages. If additional switching points form the complete or part of the final solution, installing automated switches rather than manually operated ones is preferred as the increased upfront investment will have an enhanced long term return on system wide operational benefits.

c. Installation of more line sensing and fault indicating devices. These will improve operations' ability to determine the fault location, and likely improve efficiency in isolation, but they cannot automatically transfer load, thus eliminating outages for many customers. In some situations, these devices may be utilized for information purposes, but a more robust system that provides all the benefits of isolation and operability is preferred.

d. Invest more heavily in renewal activities, to reduce the potential failure points. This option consists of a greater investment than is proposed in the system renewal justifications of pole, transformer, and line replacements. These replacements may enhance system reliability; however, the unpredictability of storms, lighting, and animals will continue to produce some level of outages regardless of the health of the system.

e. Combination of Alternatives b) thru d) - it is unlikely that a sole alternative provides an adequate and complete technical solution to address reliability. Most often, the adequate technical solution requires the use of a combination of the above identified options, depending on the issues being experienced. It involves identifying various line sections where multiple drivers or benefits can be realized and forming a solution comprised of various steps. This may result in minimizing overall and future costs, avoiding the possibility of renewing pole lines that are not approaching end of life, and minimizes the risk of stranded assets on a long-term basis.

8. Innovative Nature of the Project

This project is integral to enabling future technological functionality and to addressing future operational requirements to meet the changing needs of customers, industry and regulators. A modernized grid is one that facilitates the use of automated and self-healing devices to distribute electricity more effectively, economically, and securely. Although SNC has been purposefully renewing its grid by converting voltages from 4kV to 25kV and installing telemetry-based switching points for the last 5 years, a true modernization of the grid will allow for the deliberate incorporation of intelligent devices that will provide better visibility and operational flexibility to minimize outage impacts and identify areas to achieve better grid performance.

There are two main approaches to distributed automation in the industry: centralized and localized. Both require intelligent devices and a communication system. In the localized mode, the intelligent devices communicate directly to their peers to determine where the system disturbance might be and how best to restore the power to as many people as possible. This system works very well in locations where feeder routes are fixed and not subject to reconfiguration. In the centralized mode, the intelligent devices communicate to a centralized location, and the centralized system determines origin of disturbance and follow up actions.

9. Leave to Construct Approval

Not applicable to this program.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability and Safety

Criteria	Description
Efficiency	SNC seeks to maximize factors that positively affect operational efficiency through consideration of equipment types and the analysis of constraints on the system.
Customer Value	The addition of these devices has numerous benefits to both the customer and the LDC, some of these include: a) Enhanced visibility and control over the distribution system; b) More timely and accurate information regarding outages

	including anticipated restoration time; c) Reduced outage duration; and, d) Improved planning for commercial and residential customers regarding energy usage and outage response.
Reliability	The objective of this program is to continue to maintain the system reliability targets of SAIDI and SAIFI, specifically feeders with the largest concentration of small commercial and large users. SNC's commitment to continuous improvement seeks to positively impact these metrics through these enhancements to its system.
Safety	The installation of automatic reclosing devices helps to improve equipment protection and reduce arc-flash energy. This may lead to improved worker safety as settings can be adjusted to instantly respond to abnormal conditions, deenergizing the downstream connection.

2. Investment Need

Primary Driver:

Operational Efficiency - The effect of these investments is a potential improvement in operation efficiency and cost-effectiveness by eliminating or reducing the need for manual switching; automated restoration vs. patrolling and manual restoration; and improved access to information to system operators.

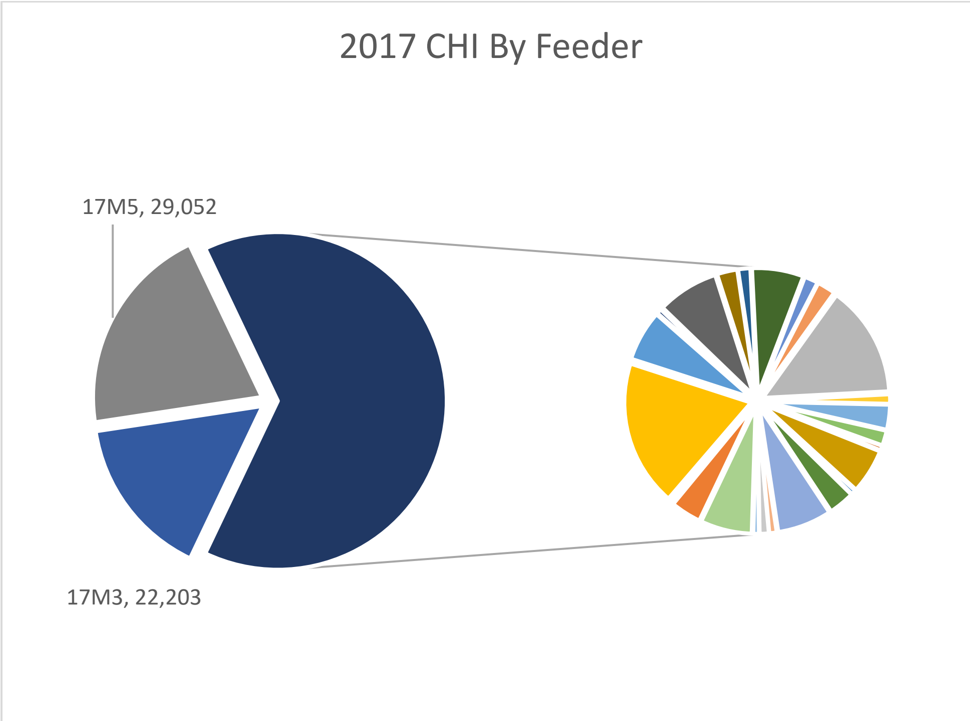
Secondary Drivers:

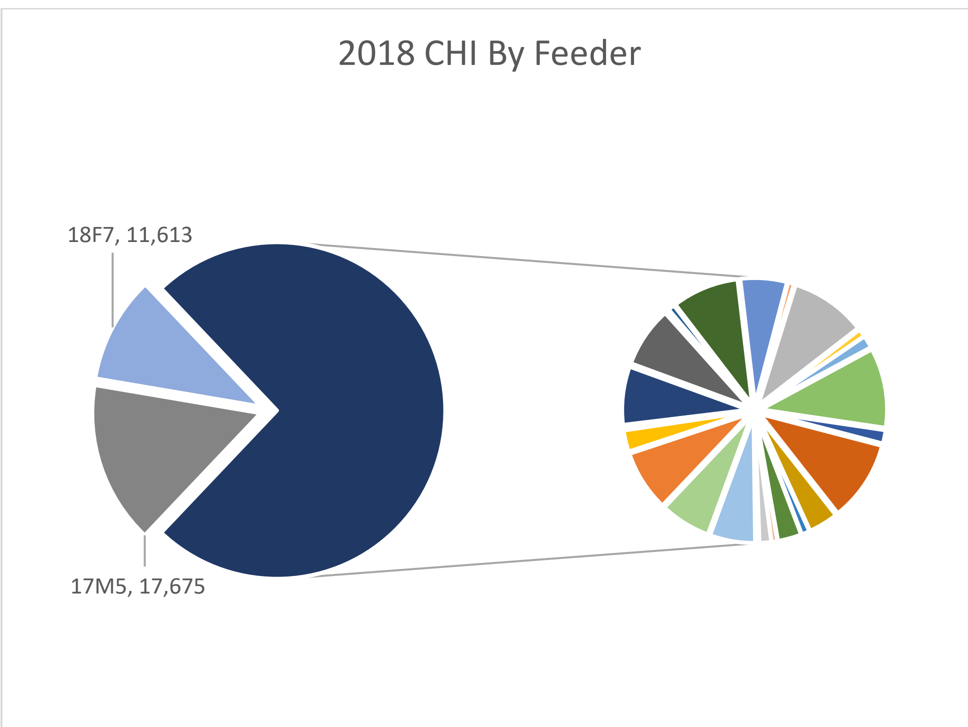
Customer Focus - At its core, SNC exists to provide safe, reliable electricity supply to its customers. Meeting this obligation requires an understanding of our customers' needs and expectations and a commitment to delivering a high level of service. SNC continuously monitors its performance in the form of OEB and corporate metrics and customer satisfaction surveys.

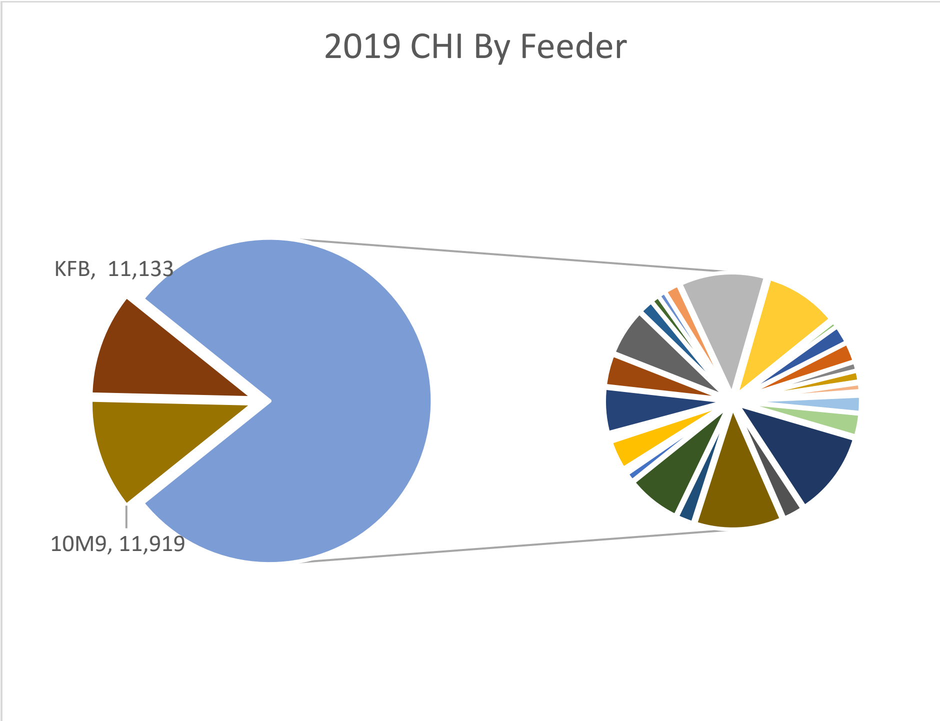
Information Used to Justify the Investment:

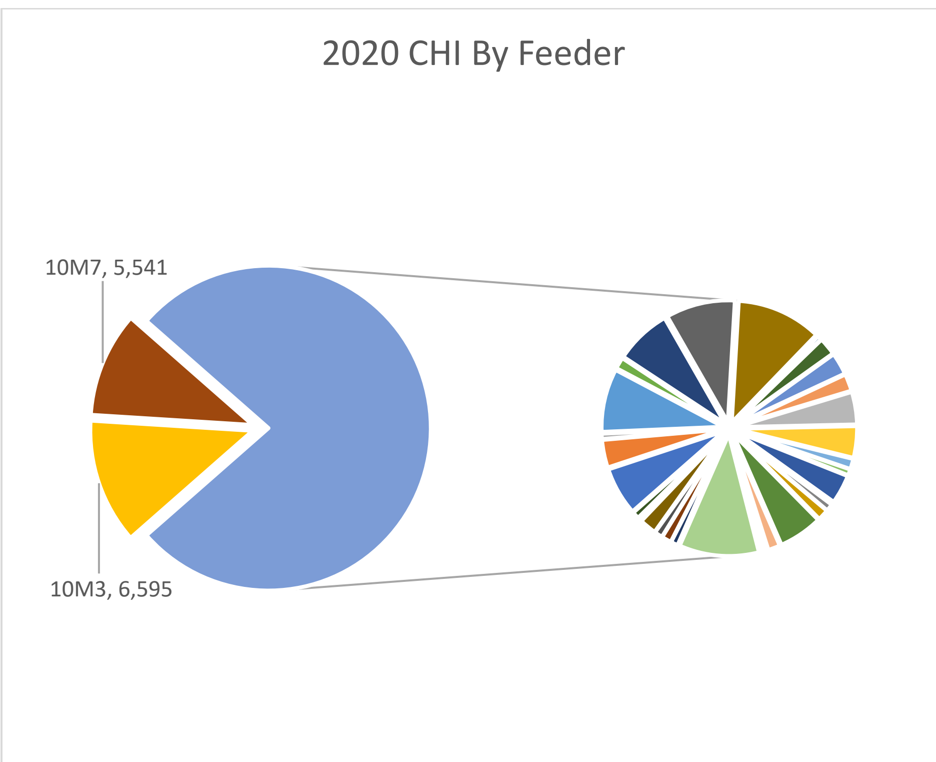
SNC uses a combination of reliability-based data (SAIDI, SAIFI) in conjunction with historical worst performing feeder data and installation costs to determine both; if there is a problem that can be addressed using grid modernizing devices and, the potential impact to budget forecasts for these devices. Additional information on SNC's reliability statistics can be found in Section 5.2.3.2 of the DSP.

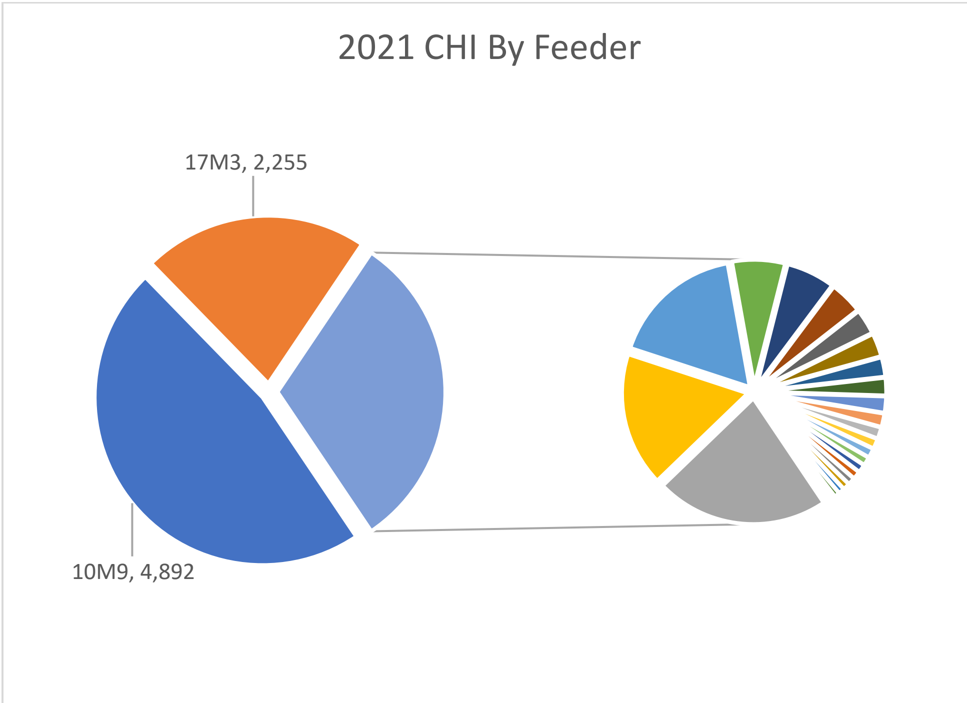
The following figures show the Customer Hours of Interruptions (CHI) by feeder (for all outage codes), with the two worst performing highlighted. This information assists in directing activities in this program.

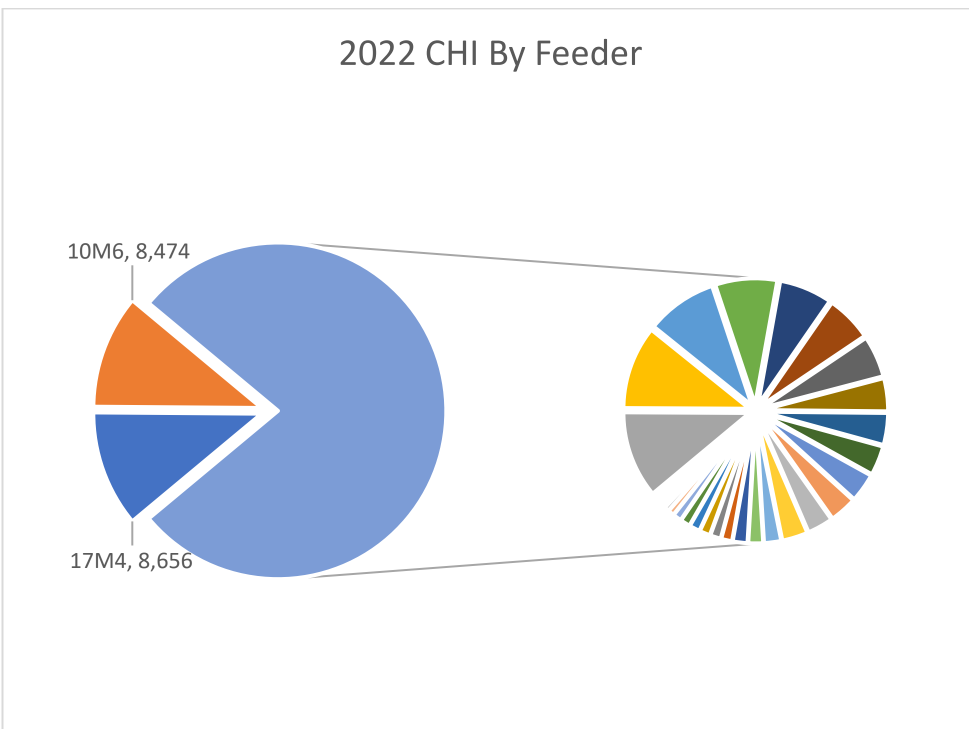

2017 CHI By Feeder
17M5, 29,052
17M3, 22,203


2018 CHI By Feeder
18F7, 11,613
17M5, 17,675


2019 CHI By Feeder
KFB, 11,133
10M9, 11,919


2020 CHI By Feeder
10M7, 5,541
10M3, 6,595


2021 CHI By Feeder
17M3, 2,255
10M9, 4,892


2022 CHI By Feeder
10M6, 8,474
17M4, 8,656

3. Investment Justification

Demonstrated Utility Practice

The electricity sector is experiencing a set of changes driven by some key trends like the decentralization of energy and adoption of distributed energy resources (DERs), both of which are supported by the digital transformation. Customers remain concerned about affordability, but interest is mounting around the consumers ability to choose how they receive their energy. Uncertainty in the pace aside, these trends are shaping the future of the energy landscape bolstered by the electrification of heating and transportation.

To ensure that SNC can deliver safe, reliable, and efficient service, it is fundamental that SNC has the necessary foundations in place. For any utility it is accepted practice that to continue to operate effectively into the future the system must be both remotely operable and have good data visibility for system operators.

SNC has carefully reviewed and planned its investments considering these trends and how changing priorities over the next five years will influence expenditures.

Cost-Benefit Analysis

Each grid modernization activity is reviewed on a case-by-case basis to identify optimal locations for intervention. The long-term benefits of this program include improved grid resiliency and operability which can mitigate the duration of outages customers experience annually. SNC's system operators will be afforded further remote management of the grid thereby increasing the efficiency with which load can be transferred and restoring customers more quickly than in the past. Including automated reclosing devices, smart software along other advancements in technology, SNC will be in position to further integrate DERs and electric vehicles into its network.

Historical Outcomes

Historical costs for this program are indicated in Section 3 of part A of this document. Investments in this program have allowed SNC to progress to a fully functional OMS and in doing so allows SNC to keep customers better informed of outages. Additionally, this program in conjunction with other SNC programs has resulted in a net positive effect on reliability (see Section 5.2.3.2 of the DSP).

4. Conservation and Demand Management

There are no current investments planned for CDM program delivery. However, the IESO will consider Kenora MTS as a potential focus area for the Local Initiatives Program under the 2021-2024 Conservation and Demand Management Framework. The IESO will collaborate with Synergy North as further details for the next round of the Local Initiatives Program becomes available.

MATERIAL INVESTMENT REPORT

Program/Project

Fleet

Investment Category

GENERAL PLANT

A. General Information on the Program/Project

1. Overview

SNC covers a large service territory and requires a fleet of specialized vehicles to complete its daily activities. Vehicles and other mobile assets form an essential component of the quick restoration of power during outages, the efficient construction and maintenance of a distribution system, and the safety of employees and the public.

To effectively manage Fleet assets, SNC has adopted the following objectives:

- Provision of safe, reliable, and efficient vehicles and equipment to meet operational requirements;
- Compliance with legislation and regulations;
- Optimization of size of fleet;
- Cost effectiveness and alignment with corporate funding objectives; and
- Environmental considerations including fuel economy, emissions, electrification.

To achieve these goals, SNC maintains a multi-year capital plan. This plan is essential in both short- and long-term forecasting and includes the following criteria when establishing replacement of individual vehicles:

- Vehicle age;
- Mileage;
- Engine and PTO hours;
- Annual maintenance/inspection results;
- 3 year rolling repair history;
- Use case requirements; and
- Changing regulations.

As each Fleet asset is assessed for optimal replacement. What this may mean is vehicles could be retained longer due to better-than-average condition, while others may be replaced earlier due to poorer condition. Additionally, vehicles may not be replaced in-kind. Prior to replacement, an assessment of current and future needs occurs to determine if an alternative vehicle type would be beneficial. Table 1 details the current fleet complement, while Table 2 outlines the proposed replacements over the forecast period 2024-2028. SNC plans to reduce its fleet complement by from 91 down to 75 (approximately 17.6%) during this period. The forecasted replacements are intended to achieve the minimum critical fleet complement level, minimizing redundancy.

Table 1-1: Fleet Complement

Category	2023 Quantity	2028 Quantity
Light Duty Vehicles	20	16
Heavy Duty Vehicles	20	17
Aerial Devices	22	19
Excavators	2	2
Trailers	20	15
Stringing Machines	4	4
Other	3	2
TOTAL	91	75

Table 1-2: Forecast Fleet Additions

Category	Forecast Period				
	2024	2025	2026	2027	2028
Light Duty Vehicles	4	2	2	2	3
Heavy Duty Vehicles	-	1	-	-	2
Aerial Devices	-	1	1	1	-
Excavators	-	-	-	-	-
Trailers	-	-	-	-	-
Stringing Machines	-	-	-	-	-
Other	3	1	2	-	4
Total	7	5	5	3	9

2. Timing

a. Beginning: January 2024
b. In-Service: Through to December 2028
c. Factors that may impact timing: Factors that may impact timing include supply chain constraints, availability of rental equipment and unexpected failures.

3. Historical and Forecast Capital Expenditures

Table 3-1 Historical & Forecast Capital Expenditures ($'000)

Category	Historical Period						Bridge Year	Forecast Period				
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	427	622	440	492	690	788	325	600	715	715	800	850
Contributions	-	-	-	-	-	-	-	-	-	-	-	-
Capital (Net)	427	622	440	492	690	788	325	600	715	715	800	850

4. Economic Evaluation

Economic evaluation is generally not applicable.

5. Comparative Historical Expenditure

Section 3 of this document identifies the historical fleet costs. The quantity and scope of replacements year-to-year is based on the best available data considering inflation, supply chain and material cost factors for these assets.

Additionally, SNC gathers vehicle age, mileage, engine and PTO hours, annual maintenance, and inspection history, along with use case and regulatory requirements are among factors considered when contemplating replacement, however vehicle age and overall condition are primary factors in determining when a replacement will be initiated.

6. Investment Priority

Maintaining an adequate complement of specialized vehicles is required to operate and maintain a safe and effective distribution system. While this project ranks 7 of 9 overall with a score of 41.5, when compared to other programs, there is a requirement to closely monitor the program on an annual basis to ensure that critical vehicle categories are not neglected. Specialized vehicles includes aerial devices, where prolonged downtime due to poor performance may lead to a reduction in restoration capabilities and reduced efficiencies.

Health and Safety - Moderate injury requiring first aid or moderate security incident likely (expected to occur in 5yr).

Having fleet vehicles in good working order is essential to the safety of SNC's personnel and the public. The working conditions in Thunder Bay and Kenora can wreak havoc on vehicles (e.g., cold, ice and snow, sand, and salt) and despite best efforts these assets deteriorate beyond repair. It is critical that SNC replace these assets when they are no longer safe to continue operating.

Environmental Impact - Addresses one (1) or more of SNC's identified environmental risks and provides risk mitigation to those risks.

As vehicle replacements occur, SNC reviews the possibility of replacing internal combustion engine (ICE) vehicles with greener alternatives. For the test year SNC is proposing to purchase one light duty fully electric vehicle (EV) to in an attempt to offset some of its carbon emissions.

Regulatory/Legal Compliance - Addresses an issue that may become nonconformant with best practices if no action is taken.

As with environmental impacts, the best practice regarding the purchase and use of EV's is ever changing. SNC plans to purchase an EV in attempt to better understand the use costs and use cases and position the utility to remain current and competitive with these practices.

Customer Preference - Delivers on one of the top 5 priorities of customers (Accommodating Renewable Connections and EV support).

Customers have indicated that supporting EV's is one of their top five priorities. SNC hopes that by adding and EV to its fleet will provide insight into the benefits and challenges associated with owning and operating this type of vehicle in northern climates.

Asset Performance - >50% of assets in fair condition or non-system assets reaching end of manufacturer support.

Only those assets that are in poor condition and fit the criteria for removal from service are targeted for replacement as part of this program.

Operational Efficiency – Aligns with 1

This program decreases SNC's liability with regards to known assets in poor condition and removing them from service prior to catastrophic failure.

System Reliability - No impact on reliability of distribution.

7. Alternatives Analysis

The alternatives for fleet replacements are the following;

a. Do Nothing (continue to use and repair as needed) – as the vehicles age, the required maintenance and downtime will likely increase thus resulting in lost productivity by SNC personnel and increased operational costs. This is not a feasible option as it deviates from the utility's commitment to customer satisfaction, is fiscally irresponsible and severely impacts the construction schedules and cost of other capital projects.

b. Replace with a lower specified vehicle – this would result in a loss of functionality for the truck, work activities on energized powerline apparatus would be limited / restricted as well as putting an increased demand on the remaining fleet vehicles which would result in scheduling conflicts and a resulting loss in effectiveness and productivity. This is not a feasible option.

c. Purchase Used – this alternative was not considered for these investments but has been selected in the past. The issues associated with a used purchase are that there is a considerable risk on the dependability of the vehicle; as well the option for competitive bidding and warranty are not available. SNC's experience with this alternative due to the longevity and price are not worth the sacrifice to purchase used.

8. Innovative Nature of the Project

Although not strictly innovative, where it is economically feasible and responsible to do so SNC will acquire and trial fossil fuel alternative vehicles.

9. Leave to Construct Approval

Not applicable to this program.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability and Safety

Criteria	Description
Efficiency	The objective of this program is to ensure prudent Return on Investment (ROI) for any vehicle and equipment assets and to ensure customer commitments are not compromised or delayed because of vehicle or equipment gaps. The forecast expenditures enable crews to work on energized powerline apparatus while meeting legislated and company safety requirements.
Customer Value	Benefit to customers includes enabling SNC to carryout critical maintenance and capital work as well as preserving response time to outages and consequently system reliability statistics.
Reliability	The reliability of fleet vehicles can impact work on the 25kV system including voltage conversion, 25kV pole replacements and maintenance work. Equipment availability directly impacts construction schedules as well as emergency response times, crew efficiencies and productivity and/or work effectiveness.
Safety	Employee and public safety will be improved by ensuring that SNC's fleet assets are managed according to all codes, standards and regulations as prescribed from time to time. A capable fleet will enable the delivery of electricity services to the customers which SNC serves.

2. Investment Need

Primary Driver:

Business Operations Efficiency - The main drivers for the fleet replacements are Failure Risk and Operational Efficiency. SNC seeks to maximize factors that positively affect operational efficiency through consideration of equipment types. The vehicle types that currently make up the fleet have specific functions and limitations and are required to fulfill or enhance worker safety, ergonomics and operational activities and the fleet size is currently matched with our field staff compliment.

Secondary Drivers:

A well maintained and current fleet is required to support critical maintenance activities and capital work programs and assists in addressing system failure risks.

Information Used to Justify the Investment:

Forecast investments are generated using informal vendor quotes for purchase price (see Table 2-1 for summary of pricing and figures 2-1 to 2-4 for vendor quotes for the same) and lead times. Lead times for large aerial vehicles has increased dramatically, as noted in Figure 2-4, a purchase made in 2023 is expected to be received in the second quarter of 2025 (104-week lead time). Prior to purchase, SNC enters its formal procurement process. This involves seeking multiple quotations through a request for proposal process. All formal quotations are reviewed prior to purchase to ensure the best value is obtained.

Table 2-1 Typical Purchase Price Historical vs Current

Category	2016 Price	2023 Price	Difference in Cost	% Difference
Light Truck	$ 39,009	$ 67,390	$ 28,381	73%
SUV	$ 31,771	$ 38,244	$ 6,473	20%
F-350	$ 42,085	$ 80,265	$ 38,180	91%
Single Bucket	$ 326,000	$ 510,000	$ 184,000	56%

2023 F-150 4x4 SuperCrew Cab 6.5' box 157" WB XLT (W1E)
Quote ID: 2023-W1E

As Configured Vehicle (cont'd)

Code	Description	MSRP
153	Front License Plate Bracket *Standard in provinces where required.*	Included
Fleet Options		
85H	Backup Alarm System Requires valid FIN code.	$160.00
91P	8-Way Power Driver's Seat w/Power Lumbar (Fleet) Requires valid FIN code.	$670.00
Exterior Colour		
YZ_01	Oxford White	N/C
Interior Colour		
MS_01	Black w/Medium Dark Slate w/Cloth 40/20/40 Front Seat	N/C
SUBTOTAL		$65,095.00
Destination Charge		$2,295.00
TOTAL	[redacted]	$67,390.00

Figure 2-1 Light Truck Quote

2023 Escape 4dr AWD Active (U9G)
Quote ID: 2023-U9G

As Configured Vehicle (cont'd)

Code	Description	MSRP
Interior Colour		
CB_05	Ebony w/Unique Cloth Front Bucket Seats	N/C
SUBTOTAL		$36,149.00
Destination Charge		$2,095.00
TOTAL		$38,244.00

Figure 2-2 SUV Quote

2023 F-350 4x4 SD Crew Cab 8' box 176" WB SRW XLT (W3B)
Quote ID: 2023-01

Pricing Summary - Single Vehicle

	MSRP
Vehicle Pricing	
Base Vehicle Price	$76,395.00
Options	$1,575.00
Colours	$0.00
Upfitting	$0.00
Fleet Discount	$0.00
Fuel Charge	$0.00
Destination Charge	$2,295.00
Subtotal	$80,265.00

Figure 2-3 Heavy Duty Vehicle Quote

SYNERGY NORTH
37 FRONT STREET
THUNDER BAY ONTARIO
P7A 8B2

JULY 4TH 2023

ATTENTION: GARRETT MOULAND

We at Posi-Plus wish to thank you for your interest in our product. In reference to your request for quotation we wish to submit the following quotation for your consideration. We look forward to the opportunity to work with you on this project. If you should have any questions regarding any of the enclosed information please do not hesitate to call

BEST REGARDS

MIKE RUSSELL

ONE ONLY FREIGHTLINER SINGLE AXLE CAB AND CHASSIS AS PER ATTACHED SPECIFICATION	$ 140,000.00
ONE ONLY POSI-PLUS MODEL 400-46 C/W PROTEK FIBERGLASS UTILITY LINE BODY AND AS PER ATTACHED SPECIFICATION.	$ 370,000.00
TOTAL	$ 510,000.00

TERMS :
CAB AND CHASSIS NET UPON RECIEPT OUR YARD
CAB AND CHASSIS PRICE SUBJECT TO CHANGE BASED ON
MODEL YEAR CHANGE
SURCHARGES
EXCHANGE RATE
ALL APPLICABLE TAXES EXTRA
NET 30 DAYS
DELIVERY 2ND QUARTER 2025
FOB THUNDER BAY
NOTE DELIVERY SUBJECT TO CHANGE BASED ON CHASSIS DELIVERY

Figure 2-4 Single Bucket Truck Quote

Vehicle replacements are generated using the extensive historical vehicle maintenance and repair data combined with detailed inspection and expert judgement. The vehicles proposed for replacement in the test year are detailed in the following fleet profile documents and images

SYNERGY NORTH
THE POWER OF THE NORTH

Unit Number	**55**			
Year	**2009**		**In Service Date:**	**2009-09-02**
Make	**Chevrolet**			
Model	**LT 2500**			
Work Order	**636795**			
Assigned to Department/Work Group:	**Operations - Fleet**			
Unit required by department	■ Yes □ No	Notes: fleet service truck required for mobile repairs		
Local Rental Options available	□ Yes ■ No	Notes:		
Year	**2019**	**2020**	**2021**	**2022**
Maintenance Costs (parts and labour)	$ 2,047.47	$ 1,478.07	$ 3,881.54	$ 457.10
Diesel/Gasoline Costs	$ 1,234.46	$ 747.45	$ 1,011.74	$ 1,391.69
Total Operating Costs (Maintenance and Diesel/Gasoline)	**$ 3,281.93**	**$ 2,225.52**	**$ 4,893.28**	**$ 1,848.79**
Total Annual Life-to Date Operating Costs				
Average Annual Life-to-Date Operating Costs				
Year	**2019**	**2020**	**2021**	**2022**
Total Mileage (kms)	4261	2119	5201	2320
Accumulated Annual Mileage (kms)	61481	63600	68801	71121
Engine Idle/PTO operating hours	na	na	na	na
Downtime/Availability % (Based on 1,992 available hours)	1%	2%	2%	1%
Utilization (Based on 1,992 available hours)	n/a	n/a	n/a	

Annual Mechanical /Structural Inspection Summary:

Rust and Corrosion over top rear wheel wells. Temporary repairs done on the rocker panels. Fleet required to perform out of town work in Kenora area. This truck is no longer suitable for the changing scope of work since the merger.

Recommended Replacement of this unit: ■ Yes □ No **Notes:**

Reason for replacement: □ Maintenance Costs ■ Age ■ Major Defects □ Downtime Reliability □ High Mileage ■ Change in Road Safety Regulations

Year of Expected Replacement: 2024

Type: □ Diesel ■ Gas □ Electric (EV) □ Plug In Hybrid Electric Vehicles (PHEV)

Figure 2-5 Unit 55 Fleet Profile

Figure 2-6 Unit 55 Photo 1

Figure 2-7 Unit 55 Photo 2

Figure 2-8 Unit 55 Photo 3

Unit Number	59			
Year	2009	In Service Date:	2009-09-02	
Make	Toyota			
Model	Highlander SUV			
Work Order	636798			
Assigned to Department/Work Group:	AM&E - Locates			
Unit required by department	■ Yes ☐ No	Notes:		
Local Rental Options available	☐ Yes ■ No	Notes:		
Year	**2019**	**2020**	**2021**	**2022**
Maintenance Costs (parts and labour)	$ 2,875.60	$ 4,089.01	$ 13,835.01	$ 1,615.25
Diesel/Gasoline Costs	$ 2,961.85	$ 2,336.84	$ 2,498.60	$ 6,399.63
Total Operating Costs (Maintenance and Diesel/Gasoline)	**$ 5,837.45**	**$ 6,425.85**	**$ 16,333.61**	**$ 8,014.88**
Total Annual Life-to Date Operating Costs				
Average Annual Life-to-Date Operating Costs				
Year	**2019**	**2020**	**2021**	**2022**
Total Mileage (kms)	9092	7912	9521	11004
Accumulated Annual Mileage (kms)	191380	199292	208813	219817
Engine Idle/PTO operating hours	na	na	na	na
Downtime/Availability % (Based on 1,992 available hours)	4%	5%	14%	4%
Utilization (Based on 1,992 available hours)	n/a	n/a	n/a	

Annual Mechanical /Structural Inspection Summary:

Rust over the windsheild and strut tower and undercarriage. Oil leaks, timing chain, ABS issues, High mileage. High idle time. AC work due to corrosion. Tire replacement required.

Recommended Replacement of this unit: ■ Yes ☐ No **Notes:**

Reason for replacement: ■ Maintenance Costs ☐ Age ■ Major Defects ☐ Downtime Reliability ■ High Mileage ☐ Change in Road Safety Regulations

Year of Expected Replacement: 2024

Type: ☐ Diesel ■ Gas ☐ Electric (EV) ☐ Plug In Hybrid Electric Vehicles (PHEV)

Figure 2-9 Unit 59 Fleet Profile

Figure 2-10 Unit 59 Photo 1

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Figure 2-11 Unit 59 Photo 2

Figure 2-12 Unit 59 Photo 3

SYNERGY NORTH
THE POWER OF THE NORTH

Unit Number	69			
Year	2012		In Service Date:	2012-04-11
Make	Dodge			
Model	Ram 1500			
Work Order	636804			
Assigned to Department/Work Group:	AM&E			
Unit required by department	■ Yes ☐ No	Notes:		
Local Rental Options available	☐ Yes ■ No	Notes:		
Year	**2019**	**2020**	**2021**	**2022**
Maintenance Costs (parts and labour)	$ 4,465.06	$ 2,017.42	$ 2,800.32	$ 780.23
Diesel/Gasoline Costs	$ 2,011.09	$ 917.70	$ 2,127.84	$ 3,233.11
Total Operating Costs (Maintenance and Diesel/Gasoline)	**$ 6,476.15**	**$ 2,935.12**	**$ 4,928.16**	**$ 4,013.34**
Total Annual Life-to Date Operating Costs				
Average Annual Life-to-Date Operating Costs				
Year	**2019**	**2020**	**2021**	**2022**
Total Mileage (kms)	6465	4876	8296	4944
Accumulated Annual Mileage (kms)	53461	58337	66633	71577
Engine Idle/PTO operating hours	na	na	na	na
Downtime/Availability % (Based on 1,992 available hours)	2%	4%	2%	6%
Utilization (Based on 1,992 available hours)	n/a	n/a	n/a	

Annual Mechanical /Structural Inspection Summary:

Severely rusted over the wheel wells, rocker panel, cab corner. Due to holes in the body, will not pass safety in 2024.

Recommended Replacement of this unit: ■ Yes ☐ No **Notes:**

Reason for replacement: ☐ Maintenance Costs ☐ Age ■ Major Defects ☐ Downtime Reliability ☐ High Mileage ☐ Change in Road Safety Regulations

Year of Expected Replacement: 2024

Type: ☐ Diesel ■ Gas ☐ Electric (EV) ☐ Plug In Hybrid Electric Vehicles (PHEV)

Figure 2-13 Unit 69 Fleet Profile

Figure 2-14 Unit 69 Photo 1

Figure 2-15 Unit 69 Photo 2

Figure 2-16 Unit 69 Photo 3

Unit Number	**84**			
Year	**2012**		**In Service Date:**	**2012-04-11**
Make	**Nissan**			
Model	**4X4 Titan Crew Cab**			
Work Order	**636805**			
Assigned to Department/Work Group:	**Lines**			
Unit required by department	■ Yes ◻ No	Notes:		
Local Rental Options available	◻ Yes ■ No	Notes: cost of using a rental is not feasible		
Year	**2019**	**2020**	**2021**	**2022**
Maintenance Costs (parts and labour)	$ 6,357.80	$ 5,079.97	$ 5,885.34	$ 1,020.18
Diesel/Gasoline Costs	$ 4,297.79	$ 2,340.92	$ 2,663.21	$ 5,362.57
Total Operating Costs (Maintenance and Diesel/Gasoline)	**$ 10,655.59**	**$ 7,420.89**	**$ 8,548.55**	**$ 6,382.75**
Total Annual Life-to Date Operating Costs				
Average Annual Life-to-Date Operating Costs				
Year	**2019**	**2020**	**2021**	**2022**
Total Mileage (kms)	19556	9912	11713	8943
Accumulated Annual Mileage (kms)	127768	137680	149393	158336
Engine Idle/PTO operating hours	na	na	na	na
Downtime/Availability % (Based on 1,992 available hours)	1%	2%	4%	13%
Utilization (Based on 1,992 available hours)	91%	91%	91%	

Annual Mechanical /Structural Inspection Summary:

Severly rusted under carriage, all brake lines need to be replaced. Body is starting to rust as well on areas that have already been repaired and replaced. Floor boards and rockers are compromised and will not pass safety in 2024. High mileage, high idle time.

Recommended Replacement of this unit: ■ Yes ◻ No **Notes:**

Reason for replacement: ■ Maintenance Costs ■ Age ■ Major Defects ◻ Downtime Reliability ■ High Mileage ◻ Change in Road Safety Regulations

Year of Expected Replacement: 2024

Type: ◻ Diesel ■ Gas ◻ Electric (EV) ◻ Plug In Hybrid Electric Vehicles (PHEV)

Figure 2-17 Unit 84 Fleet Profile

Figure 2-18 Unit 84 Photo 1

3. Investment Justification

Demonstrated Utility Practice

To ensure that SNC can deliver safe, reliable, and efficient service, it is fundamental that SNC has the necessary foundations in place. For any utility it is accepted practice that to continue to operate effectively into the future the utility must have a fleet of vehicles in good operating condition. Key scorecard metrics (e.g., SAIDI, appointments met on time) are influenced by a properly operating fleet. SAIDI could increase as vehicles used to respond to outages are unavailable or break down while responding to a call. Additionally, there various forms of legislation requiring specific timelines to be met when responding to customer requests. The DSC[1] specifies minimum timelines for connecting new customers and the OUINSA[2] prescribes the response time regarding underground locate requests.

The Highway Traffic Act[3] sets out rules and requirements regarding the weight (Part VIII, S.121), equipment load and dimensions (Part VII, S.109) and safety standards (Part VI, S.100) of vehicles. New vehicles purchased must comply with this act, and regular maintenance must be performed on existing vehicles to ensure compliance with the regulations.

Furthermore, with regards to aerial devices and boom trucks, Rule 123.5 of EUSA[4] relates to the mechanical, structural, and hydraulic operational fitness for duty. SNC ensures that all aerial devices and boom trucks in operation meet the standards to perform the work necessary to serve customers and ensure the safety of the public and personnel.

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[1] Ontario Energy Board, Distribution System Code, 2000, - Section 7.2 – *Connection of New Services*

[2] Ontario Underground Infrastructure Notification System Act, 2012, S.O. 2012, c. 4 – Section 6(3) – *Time limit for response, standard locate request.*

[3] Highway Traffic Act, 1990, R.S.O 1990 c. H.8

[4] Infrastructure Health and Safety Association, *Electrical Utility Safety Rules*, RB-ELEC

SNC has carefully reviewed and planned what is required to be carried out to ensure it can still operate and deliver safe, reliable, and efficient service to its customers.

Cost-Benefit Analysis

Each fleet replacement is reviewed on a case-by-case basis to identify optimal replacement schedule based on the factors previously discussed. This includes an alternatives analysis that may include renting equipment, repairing equipment, and/or replacing with a different vehicle type.

The proposed expenditures for the test year have been assessed with replacement being the only viable option due in some cases to significant structural deterioration and rusting.

Historical Outcomes

Historical costs for this program are indicated in Section 3 of part A of this document. Investments in this program have allowed SNC to successfully operate and maintain its distribution system in a safe and efficient manner.

4. Conservation and Demand Management

This is not applicable.

MATERIAL INVESTMENT REPORT

Program/Project

Information Systems

Investment Category

GENERAL PLANT

A. General Information on the Program/Project

1. Overview

SNC relies on a complex technology infrastructure to support its business goals, operational processes, and regulatory requirements. To ensure that these critical needs are effectively addressed and that both the infrastructure and data processes remain secure and resilient, ongoing expenditures are required. These IT expenditures encompass a wide range of critical components needed to maintain operations of the infrastructure.

Given the constantly evolving nature of IT technology and cybersecurity threats, equipment replacement and technology upgrades are required on an annual basis. The capital forecasts include not only routine replacements but also the introduction of new initiatives and technologies to support the goals of the organization. The overall focus reflected in the capital expenditures is on ensuring the security and integrity of the data and infrastructure while also enhancing business efficiencies and automations.

SNC persistently faces the challenge of delivering secure, apt, timely, and technologically advanced solutions within an increasingly intricate IT landscape. The introduction of new third-party interactions, sophisticated methods for safeguarding IT business assets and data integrity, and elaborate business processes collectively test existing resources. As we look towards the future, IT-based business functionality and adaptability will hinge on the efficiencies and controls enabled by the harmonious integration of multiple systems, a complex yet indispensable process.

This program targets SNC's asset management objectives of reducing risk to Health and Safety (cyber security incident) and Asset Performance by replacing end of service life assets.

SNC plans to undertake the following for the forecast period 2024 thru 2028 (additional details are contained in Appendix G – Information Systems Strategy):

2024 – an augmentation to existing SAN solution will be required to meet data backup and retention requirements; an Intrusion Prevention System to continuously analyze network traffic and help minimize incidents; Phone System; network traffic load balancers.

2025 – the older of the IBM series I servers will be replaced due to end of hardware support. New network switches will be deployed to replace ageing equipment where the software is end of support.

2026 – a pair of SANs will be replaced as they will reach the end of their product support; new specialized server hardware will be deployed to support expected increased requirements for functions including the electronic document management processes, along with updated server hardware hosting the fleet / radio services.

2027 – an augmentation to the remote access solution will be required, and specialized log servers will need to be replaced. A pair of uninterruptable power supplies (UPS's) for servers will have reached their end-of-life expectancy requiring replacement. A group of network switches will be replaced along with some of the enterprise firewalls.

2028 – an IBM i server will reach it's end of support and will be replaced. The wireless point-to-point network equipment will be replaced, along with a few network switches. Another pair of uninterruptable power supplies (UPS's) for the servers will have reached their end-of-life expectancy requiring replacement. The firewall infrastructure throughout Synergy North will be due for replacement.

2. Timing

a. Beginning: January 2024
b. In-Service: Through to December 2028
c. Factors that may impact timing: Factors that may impact timing include supply chain constraints and unexpected failures.

3. Historical and Forecast Capital Expenditures

Table 1 Historical & Forecast Capital Expenditures ($'000)

Category	Historical Period						Bridge Year	Forecast Period				
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	144	114	463	191	452	478	420	305	380	366	416	443
Contributions	-	-	-	-	-	-	-	-	-	-	-	-
Capital (Net)	144	114	463	191	452	478	420	305	380	366	416	443

4. Economic Evaluation

Economic evaluation is generally not applicable.

5. Comparative Historical Expenditure

Section 3 of this document identifies the Information Systems costs. The quantity and scope of replacements varies year-to-year, however SNC forecasts based on the best available data considering inflation, supply chain and material cost factors for these assets.

The capital purchases are influenced by ongoing business requirements, supporting new and evolving software applications, ensuring network and data security, and managing risk. To ensure that the IT infrastructure remains secure, available, and reliable, proper monitoring and control mechanisms are needed. Security patch availability for hardware, firmware, and software is a major factor in the hardware and software lifecycle.

6. Investment Priority

Synergy North's ongoing strategy has been to ensure that its technology is both current and adaptive, which leads to a stable, reliable, and secure environment. This program ranks eighth out of nine with a score of 31.1 when compared to other programs, there is a requirement to closely monitor the program on an annual basis to ensure that critical categories are not neglected. These include assets related to cyber security as prolonged downtime due to poor performance may lead to critical systems being unavailable.

Health and Safety - Moderate injury requiring first aid or moderate security incident likely (expected to occur in 5yr).

SNC is implementing an intrusion prevention system to actively monitor network traffic and help minimize the risk of a security incident occurring.

Environmental Impact - Does not address any environmental risks or provide risk mitigation.

Regulatory/Legal Compliance - Addresses an issue that may become nonconformant with best practices if no action is taken.

SNC will be well positioned to address any practice and/or legislative/regulatory changes that may occur over the planning period requiring more stringent forms of cyber security controls.

Customer Preference - Does not deliver on any priorities of customers.

Asset Performance - Asset deficiency impacting substation reliability or critical non-system assets operating outside manufacturer support.

SNC has servers that are currently operating outside of manufacturer support and will require replacement.

Operational Efficiency – Aligns with 1

This program decreases SNC's liability with regards to the potential impact of a cyber security incident.

System Reliability - No impact on reliability of distribution.

7. Alternatives Analysis

The following alternatives have been considered:

a. Do Nothing (continue to use and repair as needed) – as the assets age, the required maintenance and downtime will likely increase thus resulting in lost productivity by SNC personnel and increased operational costs. This is not a feasible option as it deviates from the utility's commitment to customer satisfaction, is fiscally irresponsible and severely impacts the construction schedules and cost of other capital projects.

b. Replace with reduced specifications – this would result in a loss of functionality for the devices, work activities throughout the organization may be limited / restricted as well as putting an increased demand on the remaining devices which would result in loss of effectiveness and productivity. This is not a feasible option.

8. Innovative Nature of the Project

SNC is not proposing any innovative expenditures for the forecast period.

9. Leave to Construct Approval

Not applicable to this program.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability and Safety

Criteria	Description
Efficiency	Synergy North's ongoing strategy has been to ensure that its technology is both current and adaptive, which leads to a stable, reliable, and secure environment. The planning and capital expenditures for hardware, software, and other capital resources have enabled Synergy North to meet its critical goals, including effective and efficient business processes, integrated and reliable enterprise solutions, secure data interchanges with regulatory bodies and third parties, business continuity and disaster recovery processes, and the implementation a secure and managed network infrastructure.
Customer Value	At Synergy North, our dedication lies in delivering cost-efficient, secure, and modern processes and services to cater to the needs of both our internal and external clientele. We ensure that our technological implementations and solutions are integrated with business objectives and adhere to regulatory mandates. Emphasizing our adaptability to changes in the business or technological landscapes is vital to maintaining a robust and agile IT infrastructure.
Reliability	The reliability of network devices and SCADA is critical to the ongoing safe and efficient supply of electricity to SNC's customers.
Safety	Employee and public safety will be improved by ensuring that SNC's IT assets are managed according to all codes, standards and regulations as prescribed from time to time. A capable information network will enable the delivery of electricity services to the customers which SNC serves.

2. Investment Need

Primary Driver:

Operational Efficiency - The main drivers for the Information System replacements are Asset Retirement and Operational Efficiency. SNC seeks to maximize factors that positively affect operational efficiency through consideration of hardware types. The hardware that currently make up the information systems network have specific functions and limitations and are required to fulfill or enhance worker productivity and operational activities.

Information Used to Justify the Investment:

Forecast investments are generated using informal vendor quotes for purchase price and lead times. Asset replacements are generated using the extensive historical vehicle maintenance and repair data combined with detailed inspection and expert judgement. Prior to purchase, SNC enters its formal procurement process. This involves seeking multiple quotations through a request for proposal process. All formal quotations are reviewed prior to purchase to ensure the best value is obtained.

3. Investment Justification

Demonstrated Utility Practice

To ensure that SNC can deliver safe, reliable, and efficient service, it is fundamental that SNC has the necessary foundations in place. For any utility it is accepted practice that to continue to operate effectively into the future the utility must have a fleet of vehicles in good operating condition. SNC has carefully reviewed and planned what is required to be carried out to ensure it can still operate and deliver safe, reliable, and efficient service to its customers.

Cost-Benefit Analysis

Each replacement is reviewed on a case-by-case basis to identify optimal replacement schedule based on the factors previously discussed. This includes an alternatives analysis that may include renting equipment, repairing equipment, and/or replacing with a different vehicle type.

Historical Outcomes

Historical costs for this program are indicated in Section 3 of part A of this document. Investments in this program have allowed SNC to successfully operate and maintain its distribution system in a safe and efficient manner.

4. Conservation and Demand Management

This is not applicable.

APPENDIX G: INFORMATION SYSTEMS STRATEGY

Overview of Information Systems Strategy and Capital Projects

DSP 2024-2028

v.03

This document provides an overview of the capital needs for IS projects aimed at supporting the business requirements of Synergy North. The capital expenditures for these initiatives are projected over a 5-year period from 2024 through 2028.

Given the constantly evolving nature of IT technology and cybersecurity threats, equipment replacement and technology upgrades are required on an annual basis. The capital forecasts include not only routine replacements but also the introduction of new initiatives and technologies to support the goals of the organization. The overall focus reflected in the capital expenditures is on ensuring the security and integrity of the data and infrastructure while also enhancing business efficiencies and automations.

Synergy North relies on a complex technology infrastructure to support its business goals, operational processes, and regulatory requirements. To ensure that these critical needs are effectively addressed and that both the infrastructure and data processes remain secure and resilient, ongoing expenditures are required. These IT expenditures encompass a wide range of critical components needed to maintain operations of the infrastructure.

Synergy North's ongoing strategy has been to ensure that its technology is both current and adaptive, which leads to a stable, reliable, and secure environment. The planning and capital expenditures for hardware, software, and other capital resources have enabled Synergy North to meet its critical goals, including effective and efficient business processes, integrated and reliable enterprise solutions, secure data interchanges with regulatory bodies and third parties, business continuity and disaster recovery processes, and the implementation a secure and managed network infrastructure.

Synergy North persistently faces the challenge of delivering secure, apt, timely, and technologically advanced solutions within an increasingly intricate IT landscape. The introduction of new third-party interactions, sophisticated methods for safeguarding IT business assets and data integrity, and elaborate business processes collectively test existing resources. As we look towards the future, IT-based business functionality and adaptability will hinge on the efficiencies and controls enabled by the harmonious integration of multiple systems, a complex yet indispensable process.

The capital purchases are influenced by ongoing business requirements, supporting new and evolving software applications, ensuring network and data security, and managing risk. To ensure that the IT infrastructure remains secure, available, and reliable, proper monitoring and control mechanisms are needed. Security patch availability for hardware, firmware, and software is a major factor in the hardware and software lifecycle.

Key components within Synergy North's infrastructure include:

- 500+ network points of contact
- 30+ physical servers

- 85+ virtual servers
- 25+ firewall appliances
- 50+ network switches
- 4 storage area network (SAN) appliances
- 220+ user workstations including desktops, laptops, tablets, and virtual
- 1000+ distinct software applications installed

The Capital Projects is divided into hardware and software components. Hardware is further categorized into five groups: Office Equipment, Computers and Tablets, Printers, Corporate Installed Hardware, and SCADA Installed Hardware; software is categorized into two groups: HTE (Naviline) Software, and Computer Software.

Office Equipment

No capital expenditures for IS office equipment are planned during this period.

	2024	2025	2026	2027	2028
Office Equipment	0	0	0	0	0

Computers and Tablets

Computer equipment used by staff is replaced on a five-year cycle. Laptops and desktops have a steady rate of replacement, however tablets do not and will have the majority replaced in 2027 followed by a smaller batch due to be replaced in 2028.

	2024	2025	2026	2027	2028
Computers and Tablets	72500	88000	88000	130000	100000

Printers

Printers are not replaced on a regular cycle and generally only replaced when hardware fails. Given the current average age of the printers deployed, it is expected that some will fail and need replacement.

	2024	2025	2026	2027	2028
Printers	7500	15000	7500	15000	7500

Corporate Installed Hardware

The hypervisor host servers, which host the virtual servers, are replaced on a six-year cycle with a flat rate of replacement each year.

In 2024 an augmentation to existing SAN solution will be required to meet data backup and retention requirements; an Intrusion Prevention System to continuously analyze network traffic and help minimize incidents; Phone System; network traffic load balancers.

In 2025 the older of the IBM i servers will be replaced due to end of hardware support. New network switches will be deployed to replace ageing equipment where the software is end of support.

In 2026 a pair of SANs will be replaced as they will reach the end of their product support; new specialized server hardware will be deployed to support expected increased requirements for functions including the electronic document management processes, along with updated server hardware hosting the fleet / radio services.

In 2027 an augmentation to the remote access solution will be required, and specialized log servers will need to be replaced. A pair of uninterruptable power supplies (UPS's) for servers will have reached their end-of-life expectancy requiring replacement. A group of network switches will be replaced along with some of the enterprise firewalls.

In 2028 an IBM i server will reach it's end of support and will be replaced. The wireless point-to-point network equipment will be replaced, along with a few network switches. Another pair of uninterruptable power supplies (UPS's) for the servers will have reached their end-of-life expectancy requiring replacement. The firewall infrastructure throughout Synergy North will be due for replacement.

Corporate Installed Hardware	**2024**	**2025**	**2026**	**2027**	**2028**
SAN Storage	30000		150000		
Secure Remote Access Augmentation				10000	
IBM i Server		150000			150000
Log Servers				25000	0
Host Servers	50000	50000	50000	50000	50000
Document Server			20000		
Cheque Validators				6000	
Fleet GPS Radio Server			5000		
Wireless PtP Network					15000
Network Switches		10000		15000	5000
Firewalls				25000	70000
UPS				20000	20000
Intrusion Prevention System	50000				
Phone System	20000				
Load Balancers	10000				
Total:	160000	210000	225000	151000	310000

SCADA Installed Hardware

In 2025 additional hardware will be added to the SCADA test / development environment to better support planned software upgrades before they are deployed to the production environment.

In 2027 the hypervisor host servers will reach their hardware life expectancy, along with the three physical host servers running the SCADA ADMS software.

	2024	2025	2026	2027	2028
SCADA Installed Hardware	0	12000	0	75000	0

HTE (Naviline) Software

Significant enhancements to HTE (Naviline) are undertaken annually, with an increase spend forecasted in 2025 to support additional business projects.

	2024	2025	2026	2027	2028
HTE (Naviline) Software	5000	10000	5000	5000	5000

Computer Software

Annual spend on security tools is projected to be evenly spent across all years.

In 2024 additional IBM i server software will be acquired, along with a solution for data classification and data loss prevention.

In 2025 additional automation software will be deployed. Server operating systems will be upgraded to a current version to maintain security updates.

In 2026 a network access control system to manage access to Synergy North networks is planned.

In 2027 server licensing will be required for Windows server operating systems that will be end of support.

Computer Software	2024	2025	2026	2027	2028
IBM i Software	30000				
Network Access Control (NAC)			20000		
Automation Software		15000			
Server Licensing		10000		20000	
Security Tools	20000	20000	20000	20000	20000
Data classification and DLP	10000				
Total:	60000	45000	40000	40000	20000

Cost Summary

At Synergy North, our dedication lies in delivering cost-efficient, secure, and modern processes and services to cater to the needs of both our internal and external clientele. We ensure that our technological implementations and solutions are integrated with business objectives and adhere to regulatory mandates. Emphasizing our adaptability to changes in the business or technological landscapes is vital to maintaining a robust and agile IT infrastructure.

	2024	**2025**	**2026**	**2027**	**2028**
Office Equipment	0	0	0	0	0
Computers and Tablets	72500	88000	88000	130000	100000
HTE Software	5000	10000	5000	5000	5000
Printers	7500	15000	7500	15000	7500
Capital Purchases / SCADA	0	12000	0	75000	0
Corp Installed Hardware	160000	210000	225000	151000	310000
Computer Software	60000	45000	40000	40000	20000
Total:	**305000**	**380000**	**365500**	**416000**	**442500**

APPENDIX I: ACA UPDATE SUMMARY

Synergy North Corporation

2022 Asset Condition Assessment Updates

Data and Analysis as of May 9, 2023

1 Data Assessment Results

SNC continues to progress towards a data availability indicator (DAI) for each asset category of 100% i.e. Data for all condition parameters used in the HI formulas collected for all assets. Data gaps are identified for each asset category, prioritized in the order of importance, and gathered in prioritized manner. Data may be gathered from inspections or corrective maintenance records and additional sources of data would come from testing (e.g. pole strength testing or cable testing).

DAI is measurement that is relative to the information that SNC currently collects, whereas data gaps are information that SNC does not collect. As such, even if an asset group has a high DAI, this does not mean information for this asset group is complete. i.e. if there are numerous data gaps, the degree of confidence that the Health Index reflects true condition may still be low. The Data Gap column indicates the extent of the data gap (i.e. “high” indicates that a significant amount of condition information can be collected for future assessments). Overall assessments for each asset category are summarized below.

However, collecting this quantitative data and incorporating it into the ACA immediately decreases the DAI of those assets for which the data was collected (this is due to a small portion of the population now having an extra condition parameter relative to the remaining population). SNC has significantly improved the assessment confidence in the asset classes that form the largest part of this DSP by reducing the data gaps from high to low.

Due to rounding in the health index distribution (Very Poor, Poor, Fair, good, Very Good), the total distribution may not add to exactly 100% in each asset category.

1.1 Station Transformers

Age, loading, oil quality and dissolved gas analysis tests were available for all Substation Transformers. Since the last data assessment inspection records have been complied for Kenora and the 12kV transformers.

Changes in Station Transformers since 2015

- Removed 6 units @ 4kV - Hardisty (3T1 and 3T2), Balsam (18T3), Grenville (15T1), Mountdale (9T1) and Northwood Plaza due to 4kV conversion programs.
- Added 3 units @ 12kV when merged with Kenora Hydro
- Health Index reduced from 88% to 75% due to the aging of remaining 11 units of 4kV station transformers. The asset management strategy for the 4kV station transformers is to remove them from service rather than replace them.

1.2 Circuit breakers

Age and maintenance reports that had information on the following: internal, closing, trip mechanisms; tolerance; close and trip timing; contacts; arc chute (Air Blast), heater and tank leak (oil); Insulation. SNC has decided not to put resources into obtaining operation counts, fault interruption counts, and fault level interrupted as the population of breakers, as they will be removed from service and the cost of obtaining data will not inform an asset management strategy.

Changes in Breakers since 2015

- Removed 19 units @ 4kV due to stations decommissioning.
- Went from 56 to 62 average age, as the population is aging and not being replaced.

1.3 Wood Poles

Age and overall risk ratings based on inspection records were available for wood poles. SNC began quantitative pole strength testing using the Polux wood pole strength system with its partner UTS in 2019. This testing has been completed on approximately 4,800 poles. There are approximately 1,200 poles tested annually depending on the area that is scheduled for inspection activities. It is expected that a complete data set for pole population is needed for all poles to achieve 100% DAI.

Changes in Wood Poles since 2015

- Increased population of 12kV poles by 2,590 due to Kenora merger in 2019.
- Improvement in health index overall of poles from 75% to 83% due to pole replacement program (4kV and 25kV)
- Improvement in data gap by gathering quantitative testing, but DAI reduced due to entire population not complete.

1.4 Distribution Transformers

Age, PCB content, and inspection records that provide information on transformer base, enclosure, leaks, and overall hazard condition were available for pad-mounted transformers. Inspection information regarding the base and enclosure condition has been added to the annual inspections of the pad mounted transformers.

Age and PCB content were available for pole-mounted and vault transformers. SNC has begun collecting transformer condition, but not any corrective or maintenance information, as there are no maintenance functions for pole-mounts.

Changes in Distribution Transformers since 2015

- Increased population of transformer by 284 pad mounted, 757 pole mounted due to merger with Kenora Hydro
- Vault population decreasing as 4kV replacement program removes and replaces with either a pad or pole mounted unit
- Improvement in DAI from 85% to 91% on pad mounted transformers as SNC is gathering more inspection and condition data
- Loading information is being monitored quarterly as part of the FINO strategy to manage loading due to increased electrification.

1.5 OH and UG Switches

Age was the only information available for overhead and underground switches in 2015, which resulted in a low DAI. SNC began collecting inspection and maintenance records (e.g. condition related to switch, operating mechanism, insulation, arc extinguishing mechanism).

Changes in OH Switches since 2015

- Sample size of data improved, this is an improvement in data gathering processes, which resulted in a health index improvement from 76% to 92%.
- Obtained condition data on Overhead switches – Age data is unavailable on 75 manual and 72 in-line switches due to no physical nameplates.

Changes in UG Switches since 2015

- Sample size of data improved, this is an improvement in data gathering processes, which resulted in a health index improvement of 81% to 99%

1.6 Underground Cables

This asset category had only age information for fewer than half the population in 2015. SNC began quantitative diagnostic testing using DC Polarization/Depolarization to detect insulation condition with its partner Cable Q in 2020.

Changes in Underground Cables since 2015

- Quantitative cable testing has been completed on 800 segments of cables in the distribution territory. Testing is needed to enhance DAI of cables and continuing with the program of 200 segments tested annually this results in an approximate 4% increase of DAI per year.

2 Data Availability and Data Gap Comparison 2015 and 2022

Asset Category		Average DAI 2015	Average DAI 2022	Average DAI Trend	Data Gap 2015	Data Gap 2022
Station Transformers	All	93%	94%	+	Low-Medium	Low-Medium
	4 kV	92%	94%	+		
	12 kV	93%	93%	N/C		
	115 kV	0%	93%	+		
Breakers	Breakers	61%	61%	N/C	Low-Medium	Low-Medium
Wood Poles	All	100%	77%	-	Medium-High	Low
	4 kV	100%	78%	-		
	12 and 25 kV	100%	77%	-		
Distribution Transformers	Pad Mounted Transformers	85%	91%	+	Low-Medium	Low-Medium
	Pole Mounted Transformers	100%	100%	N/C	Medium-High	Medium-High
	Vault Transformers	100%	98%	-	Medium-High	Low
OH Switches	All	42%	65%	+	High	Low-Medium
	4 kV In-Line	46%	72%	+		
	12 and 25 kV In-Line	37%	69%	+		
	12 and 25 kV Air / Load Break	35%	55%	+		
	115kV Air Break	0%	33%	+		
Underground Switches	25 kV Underground Load Break Switches	38%	67%	+	High	High
Underground Cables (km)	All	48%	62%	+	High	Low-Medium
	4 kV	35%	79%	+		
	12 and 25 kV	47%	69%	+		

3 Health Index Distribution Tables

3.1 Health Index Results Summary 2022

2022 Asset Category		Population	Sample Size	Average Health Index	Health Index Distribution					Average Age
					Very Poor (< 25%)	Poor (25 - <50%)	Fair (50 - <70%)	Good (70 - <85%)	Very Good (>= 85%)	
Station Transformers	All	20	20	75%	5%	5%	35%	15%	40%	53
	4 kV	11	11	63%	10%	10%	50%	10%	20%	63
	12 kV	9	9	89%	0%	0%	10%	20%	70%	40
Breakers	Breakers	58	58	70%	9%	0%	37%	26%	28%	62
Wood Poles	All	22362	22362	83%	0%	7%	17%	23%	52%	29
	4 kV	1381	1381	74%	0%	9%	33%	28%	30%	41
	25 and 12kV	20981	20981	82%	0%	7%	16%	23%	54%	25
Distribution Transformers	Pad Mounted Transformers	2490	2463	76%	8%	7%	16%	25%	44%	29
	Pole Mounted Transformers	4900	4900	87%	11%	1%	1%	6%	81%	27
	Vault Transformers	280	280	54%	18%	25%	27%	24%	6%	39
OH Switches	All	990	837	92%	2%	3%	6%	10%	80%	20
	4kV In-Line	82	76	89%	1%	3%	11%	17%	68%	24
	12 and 25kV In-Line	609	537	96%	1%	1%	3%	8%	97%	16
	12 and 25kV Air / Load Break	296	221	84%	5%	7%	10%	10%	68%	26
	115kV	3	3	61%	0%	0%	100%	0%	0%	47
Underground Switches	25kV Underground Load Break	88	80	99%	0%	0%	0%	0%	100%	17
Underground Cables	All	445	407	80%	3%	12%	10%	7%	68%	30
	4kV	25	25	48%	42%	17%	7%	5%	29%	45
	12 and 25kV	420	382	83%	1%	11%	10%	8%	70%	28

3.2 Health Index Results Summary 2015

2015 Asset Category		Population	Sample Size	Average Health Index	Health Index Distribution					Average Age
					Very Poor (< 25%)	Poor (25 - <50%)	Fair (50 - <70%)	Good (70 - <85%)	Very Good (>= 85%)	
Station Transformers	All	23	23	88%	0%	4%	9%	4%	83%	52
	4 kV	17	17	86%	0%	6%	6%	12%	76%	54
	12 kV	6	6	94%	0%	0%	0%	0%	100%	47
Breakers	Breakers	77	77	72%	0%	18%	23%	12%	47%	56
Wood Poles	All	19813	19813	75%	1%	9%	34%	21%	34%	28
	4 kV	3862	3862	63%	4%	22%	39%	21%	15%	36
	25 kV	15951	15951	77%	< 1%	6%	33%	21%	39%	27
Distribution Transformers	Pad Mounted Transformers	2206	2206	87%	9%	1%	2%	12%	75%	25
	Pole Mounted Transformers	4143	4141	81%	19%	1%	1%	1%	77%	29
	Vault Transformers	285	285	78%	8%	3%	15%	26%	49%	33
OH Switches	All	729	305	76%	14%	5%	10%	12%	60%	32
	4kV In-Line	101	46	71%	26%	0%	9%	11%	54%	32
	4kV Manual Air Break	7	2	70%	0%	50%	0%	0%	50%	32
	12 and 25kV In-Line	399	148	80%	11%	7%	5%	8%	70%	31
	12 and 25kV Manual Air Break	183	74	78%	14%	4%	7%	9%	66%	33
	25kV Motorized Load Break	39	10	67%	10%	20%	20%	10%	40%	39
Underground Switches	25kV Underground Load Break Switches	80	30	81%	0%	13%	17%	3%	67%	31
Underground Cables	All	432	374	80%	3%	3%	31%	4%	60%	29
	4kV	44	29	44%	34%	14%	21%	0%	31%	43
	12 and 25kV	387	344	84%	< 1%	2%	32%	4%	63%	28

APPENDIX J: REGIONAL INFRASTRUCTURE PLAN

REGIONAL INFRASTRUCTURE PLAN REPORT

Northwest Ontario

Regional Infrastructure Plan Report

[Northwest Ontario]

[Date: August 4, 2023]

Lead Transmitter:

Hydro One Networks Inc.

Prepared by:

Northwest Ontario Technical working group

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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 any additional needs identified based on new and/or updated information provided by the RIP Technical Working Group (TWG).

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

The TWG participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") shall not, under any circumstances whatsoever, be liable to each other, to any third party for whom the Regional Infrastructure Plan Report was prepared ("the Intended Third Parties") or to any other third party reading or receiving the Regional Infrastructure Plan Report ("the Other Third Parties"). The Authors, Intended Third Parties and Other Third Parties acknowledge and agree that: (a) the Authors make no representations or warranties (express, implied, statutory or otherwise) as to this document or its contents, including, without limitation, the accuracy or completeness of the information therein; (b) the Authors, Intended Third Parties and Other Third Parties and their respective employees, directors and agents (the "Representatives") shall be responsible for their respective use of the document and any conclusions derived from its contents; (c) and the Authors will not be liable for any damages resulting from or in any way related to the reliance on, acceptance or use of the document or its contents by the Authors, Intended Third Parties or Other Third Parties or their respective Representatives.

Executive Summary

REGION	Northwest Ontario Region (the "Region")
LEAD	Hydro One Networks Inc. ("HONI")

START DATE: February 9, 2023 **END DATE:** August 4, 2023

1. INTRODUCTION

The Regional Infrastructure Plan (RIP) is the final step of Regional Planning Process for the Northwest Region, preceded by, the publication of Needs Assessment (NA) report in July 2020 by Hydro One, followed by the Scoping Assessment (SA) in January 2021 & Integrated Regional Resource Plan (IRRP) in January 2023 published by the IESO respectively.

Hydro One as the lead transmitter undertakes the development of a RIP with input from the TWG for the region and publishes a RIP report. The RIP report includes a common discussion of all the options and recommended plans and preferred wire infrastructure investments identified in earlier phases to address the near- and medium-term needs.

2. OBJECTIVES AND SCOPE

Objectives:

- Provide a comprehensive summary of needs and wires plans to address the needs for the Northwest Ontario 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.

Scope:

- A consolidated summary of needs and recommended plans for the region over a study period of 2023-2043 based on available information.
- A consolidated report of the needs and relevant wires plans to address near and medium-term needs identified in previous planning phases (i.e., Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan).
- Identification of any new needs and wires plans in the near and medium-term to address these needs based on new and/or updated information.

- Consideration of long-term needs identified in the Northwest Ontario IRRP, Bulk system studies or as identified by the TWG.

3. REGIONAL PLANNING PROCESS & RIP METHODOLOGY

This section provides a detailed overview of the various steps followed during different phases of Regional Planning Process and their outcomes starting with the Needs Assessment, Scoping Assessment, Local Plan, Integrated Regional Resource Plan and finally details the Regional Infrastructure plan Methodology.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

This section provides a general overview of the Geographical boundaries, Circuit connections and Stations located in the Northwest Ontario region though a regional planning area map and a single line diagram. The Northwest region includes the area roughly bounded by Lake Superior to the south, the Marathon area to the east, and the Manitoba border to the west. It includes the districts of Kenora, Rainy River, and Thunder Bay. The region is comprised of 230kV circuits from the Manitoba interties in the west to Marathon TS in the east and 115kV sub-systems in between.

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

This section provides a summary and brief description of all the projects completed in the past ten years or are currently underway.

I. Following Major projects were completed during the last ten years:

1. **Manitouwadge TS (2016)** – The 115/44kV, 5/7MVA T1 transformer was replaced with new 115/44kV 25/33/41.7 MVA unit.
2. **Dryden TS (2018)** – Five 115kV breakers and two 115/44kV, 11/15MVA transformers were replaced with new 115/44 kV 25/33/42MVA units.
3. **Lakehead TS (2017)** – Two 230/115kV autotransformers were replaced with new 230/115kV 150/200/250MVA units.
4. **Birch TS (2015)** – One 115/25kV transformer was replaced with a new 115/25kV 25/33/42MVA unit.
5. **Ear Falls TS (2022)** – Four 115kV breakers and one 115/13.2kV transformer was replaced with a new 115/13.2 kV 7.5/10/12.5MVA unit.
6. **East West Tie (2022)** – A 450 km, double-circuit, 230kV transmission line from Wawa TS to Lakehead TS was built with a connection approximately mid-way at Marathon TS.
7. **Wataynikaneyap Power Project Phase 1 (2022)** – A 300 km, single circuit, 230kV transmission line from Dinorwic to Pickle Lake, Ontario was built with a 230/115kV autotransformer, related switching facilities and necessary voltage control devices.

II. Following Major projects are underway:

1. **Rabbit Lake SS (2024-2027)** – Replace 115kV circuit breakers and associated equipment.
2. **Whitedog Falls SS (2025-2028)** – Replace 115kV circuit breakers and associated equipment.

3. **Mackenzie TS (2026-2029)** – Replace 230kV circuit breakers and associated equipment.
4. **Wawa TS (2026-2029)** – Replace two existing 230/115kV autotransformers with two new units; replace four 230kV and four 115kV circuit breakers.
5. **Wataynikaneyap Power Project Phase 2 (2022-2024 and beyond)** – Construct approximately 1438 km of 115kV, 44kV and 25kV transmission lines and twenty substations to connect 16 First Nations in two transmission subsystems.

Note: The planned in-service year for the above projects is tentative and is subject to change.

6. LOAD FORECAST AND STUDY ASSUMPTIONS

During the study period, the load in the Northwest Ontario Region is expected to grow at an average annual rate of approximately 2% in winter from 2023 to 2033. The Region is winter peaking so this assessment is based on winter peak loads.

The following other assumptions are made in this report.

- The study period for the RIP assessments covers near and medium-term. However, a longer term forecast up to 2043 is provided to identify long-term needs and align with the Northwest Ontario region IRRPs.
- LDCs reconfirmed load forecasts up to 2033. A longer term forecast up to 2040 is adopted with IRRP load forecast. The additional three 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.
- 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); or winter 10-day LTR if undergoing a winter season analysis.
- Bulk transmission line and auto-transformation 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.

7. SYSTEM ADEQUACY AND REGIONAL NEEDS

This section reviews the adequacy of the existing Transmission Systems and Transformer Station facilities supplying the Northwest Ontario Region and lists the facilities requiring reinforcement over the near and midterm period. The adequacy assessment assumes that all the projects that are currently underway are completed.

I. Needs identified in the region

a. Asset Renewal for Major HV Transmission Equipment (Replace equipment identified in deterioration and technical obsolescence)

- Rabbit Lake SS
- Whitedog Falls SS
- Mackenzie TS
- Wawa TS
- Marathon TS
- Lakehead TS
- Lakehead TS C8 Condenser
- Fort Frances TS
- Kenora TS

b. Station Capacity

- Margach DS
- Crilly DS
- White Dog DS
- White River DS
- Kenora MTS

c. Transmission Line Capacity

- E2R and E4D
- M2W

d. System Reliability, Operation and Load restoration

- Fort France MTS - Planned outages considering station single supply configuration
- E1C - Operation and High Voltage under a Normally-open configuration

8. REGIONAL PLANS

This section discusses the regional electric supply needs and presents all the wires alternatives considered to address these needs and identifies the best and preferred wires solutions for the Northwest Ontario region. The needs include those previously identified in the NA and IRRP for the Northwest Ontario region as well as any new needs identified during the RIP phase.

9. CONCLUSION AND RECOMMENDATIONS

The major infrastructure investments recommended by the TWG in the Northwest Ontario region is given below:

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Cost ($M)
Asset Renewal Needs				
Rabbit Lake SS	Replacement of the 115kV switchyard and its associated equipment	Hydro One Transmission	2024-2027	35.2
Whitedog Falls SS	Replacement of three 115kV breakers, DC station services and associated equipment	Hydro One Transmission	2025-2028	8.5
Mackenzie TS	Replacement of one 230/115kV autotransformer, five 230kV breakers, four switches, the AC station services and associated equipment	Hydro One Transmission	2025-2028	54.6
Wawa TS	Replacement of two 230/115kV autotransformer, associated breakers and equipment and station services	Hydro One Transmission	2026-2029	43.8
Marathon TS	Replacement of 230kV and 115kV breakers and associated equipment	Hydro One Transmission	2026-2029	14.6
Lakehead TS	Replacement of 230kV and 115kV breakers, the station services and associated equipment	Hydro One Transmission	2028-2031	41.5
Lakehead TS Condenser C8 Replacement	Replacement of the condenser C8 with a +60/- 40 MVAR STATCOM	Hydro One Transmission	2027	40.6
Fort Frances TS	Replacement of the 230kV breakers, associated equipment, and the station services	Hydro One Transmission	2029-2032	20.3
Kenora TS	Replacement of 230kV breakers, associated equipment, and the station services	Hydro One Transmission	2030-2033	17
Station Capacity Needs				
Margach DS	To be monitored and implemented in investment plan in 2025	Hydro One Distribution	2025	1

Crilly DS	To further assess the Alternative 1 and Alternative 2 from this RIP	Hydro One Distribution	NA	NA
White Dog DS	To be monitored and reviewed in next planning cycle	Hydro One Distribution	NA	NA
White River DS	To be monitored and reviewed in the next planning cycle	Hydro One Distribution	NA	NA
Kenora MTS	To further assess the alternatives from this RIP; To be monitored and reviewed in next planning cycle	Synergy North	NA	NA
Transmission Line Capacity Needs				
E2R and E4D	To further evaluate the four alternatives based on mining customers' requests	Hydro One Transmission and Proponent	TBD	125-375
M2W	To further evaluate the two alternatives based on mining customers' requests	Hydro One Transmission and Proponent	TBD	TBD
System Reliability, Operation and Load restoration Needs				
Fort Frances MTS	Installation of a second breaker and switch in Fort Frances MTS to create a second supply to the MTS	Fort Frances Power	2026-2027	0.85
E1C Operation	To open E1C end at Ear Falls TS and installation of a 10 – 15 MVAR shunt reactor at Pickle Lake SS	Hydro One Transmission	2026-2027	20
Other Planning Considerations				
Fort Williams TS Shunt Capacitor Banks Replacement	Replacement of temporary capacitor banks with permanent units	Hydro One Transmission	2026-2027	6
Greenstone-Marathon Area System Needs	Further evaluation of the alternatives presented in the past IRRPs and RIP upon customers' requests	Hydro One Transmission and Proponent	TBD	TBD
Supply to the Ring of Fire	IESO to update Supply to the Ring of Fire study	IESO	TBD	TBD

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1. INTRODUCTION

The Regional Infrastructure Plan (RIP) is the final step of Regional Planning Process where, Hydro One as the lead transmitter undertakes the development of a RIP with input from the TWG for the region and publishes a RIP report. The second cycle of the Regional Planning process for the Northwest Ontario Region was initiated with the publication of Needs Assessment (NA) report in July 2020 by Hydro One, followed by the Scoping Assessment (SA) & Integrated Regional Resource Plan (IRRP) in January 2021 and in January 2023 published by the IESO respectively.

The RIP report includes a common discussion of all the options and recommended plans and preferred wire infrastructure investments identified in earlier phases to address the near- and medium-term needs.

This report was prepared by the Northwest Ontario Technical Working Group ("TWG"), led by Hydro One Networks Inc. (Transmission). The report presents the results of the assessment based on information provided by the Hydro One, the Local Distribution Companies ("LDC"), the Municipalities, the transmitters, and the Independent Electricity System Operator ("IESO"). Participants of the TWG are listed below in Table 1.

Table 1: Northwest Ontario Region TWG Participants

Sr. no.	Name of TWG Participants
1	Hydro One Networks Inc. (Distribution)
2	Independent Electricity System Operator ("IESO")
3	Atikokan Hydro Inc.
4	Fort Frances Power Corporation
5	Sioux Lookout Hydro Inc.
6	Synergy North
7	Wataynikaneyap Power LP
8	NextBridge Infrastructure LP
9	Hydro One Networks Inc. (Transmission)

2. OBJECTIVES AND SCOPE OF REGIONAL INFRASTRUCTURE PLAN

This RIP report examines the needs in the Northwest Ontario Region. Its objectives are to:

- Provide a comprehensive summary of needs and wires plans to address the needs for the Northwest Ontario 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") forecasts, renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant wires plans to address near and medium-term needs identified in previous planning phases (i.e., Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan).
- Identification of any new needs and wires plans in the near and medium-term to address these needs based on new and/or updated information.
- Consideration of long-term needs identified in the Northwest Ontario IRRP, Bulk system studies or as identified by the TWG.

3. REGIONAL PLANNING PROCESS & RIP METHODOLOGY

3.1 Overview

Bulk System Planning, Regional Planning and Distribution Planning are the three levels of planning for the electricity system in Ontario. Bulk system planning typically looks at issues that impact the system on a provincial level and requires longer lead time and larger investments. Comparatively, planning at the regional and distribution levels look at issues on a more regional or localized level. Typically, the most essential and effective regional planning horizon is the near- to medium-term (1- 10 years), whereas long-term (10-20 years) regional planning mostly provides a future outlook with little details about investments because the needs and other factors may vary over time. On the other hand, Bulk System plans are developed for the long term because of the larger magnitude of the investments.

The regional planning process begins with a Needs Assessment (NA) which is led by the transmitter to identify, assess, and document which of the needs

a) can be addressed directly between the customer and transmitter along with a recommended plan, and;
b) that require further regional coordination and identification of Local Distribution Companies (LDCs) to be involved in further regional planning activities for the region.

At the end of the NA, a decision is made by the Technical Working Group (TWG) as to whether further regional coordination is necessary to address some or all the regional needs. If no further regional coordination is required, recommendations to implement the recommended option and any necessary investments are planned directly by the LDCs (or customers) and the transmitter. The Region's TWG can also recommend to the transmitter and LDCs to undertake a local planning process for further assessment when needs

a) are local in nature,
b) require limited investments in wires (transmission or distribution) solutions, and;
c) do not require upstream transmission investments.

If coordination at the regional or sub-regional levels is required for identified regional needs, then the Independent Electricity System Operator (IESO) initiates the Scoping Assessment (SA) phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires or resource alternatives, e.g., Conservation and Demand Management (CDM), Distributed Generation (DG), etc., in order to make a decision on the most appropriate regional planning approach including Local Plan (LP), Integrated Regional Resource Plan (IRRP) and/or Regional Infrastructure Plan (RIP).

The primary purpose of the IRRP is to identify and assess both resource and wires options at a higher or macro level, but sufficient to permit a comparison of resource options vs. wire infrastructure to address the needs. Worth noting, the LDCs' CDM targets as well as contracted DG plans provided by IESO and LDCs are reviewed and considered at each step in the regional planning process.

If and when an IRRP identifies that resource and/or wires options may be most appropriate to meet a need, resource/wires planning can be initiated in parallel with the IRRP or in the RIP phase to undertake a more detailed assessment, develop specific resource/wires alternatives, and recommend a preferred wires solution.

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.

The various phases of Regional Planning Process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome are shown below in figure 1.

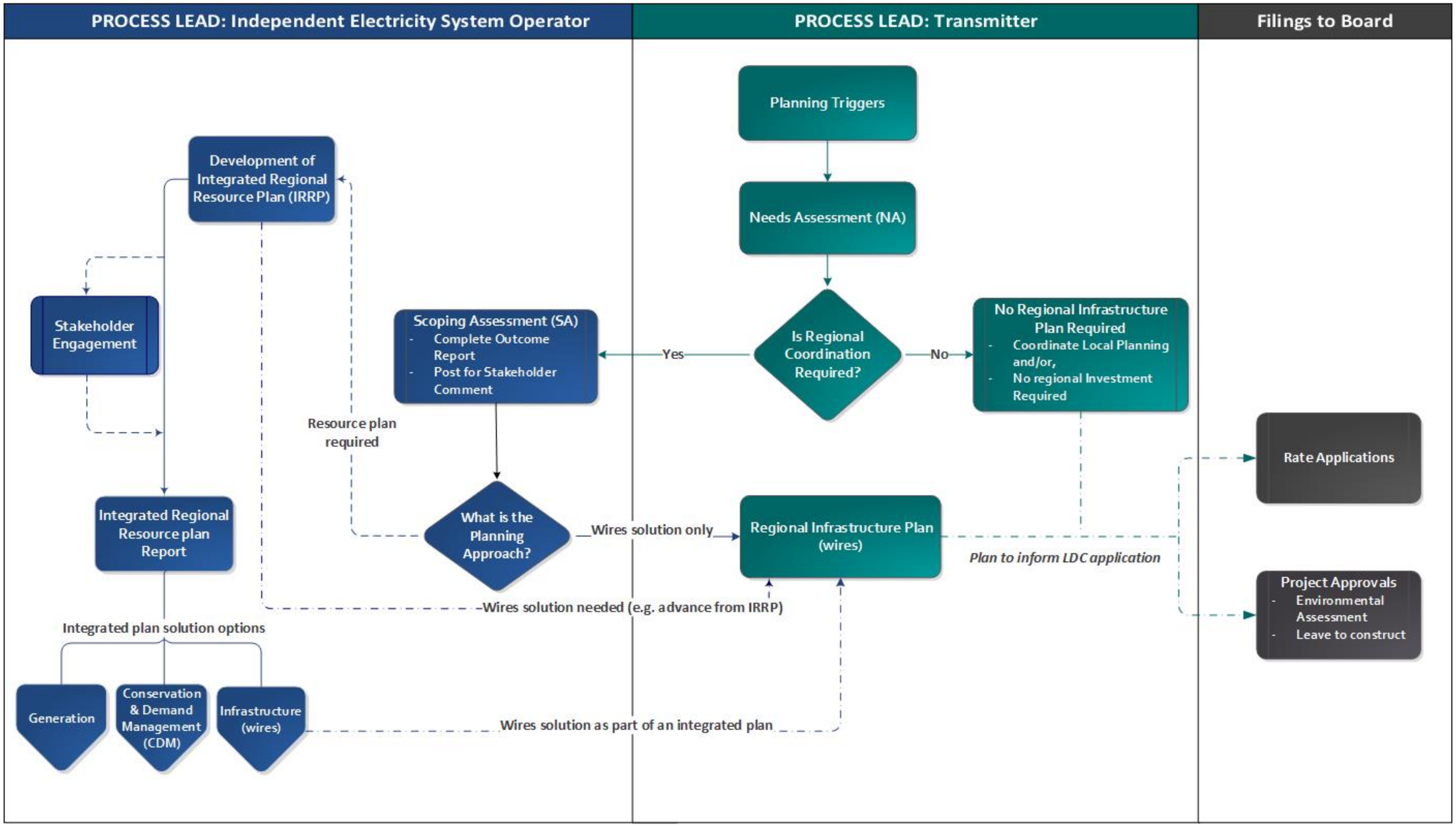

Figure 1: Regional Planning Process Flowchart

3.2 Regional Infrastructure Plan Methodology

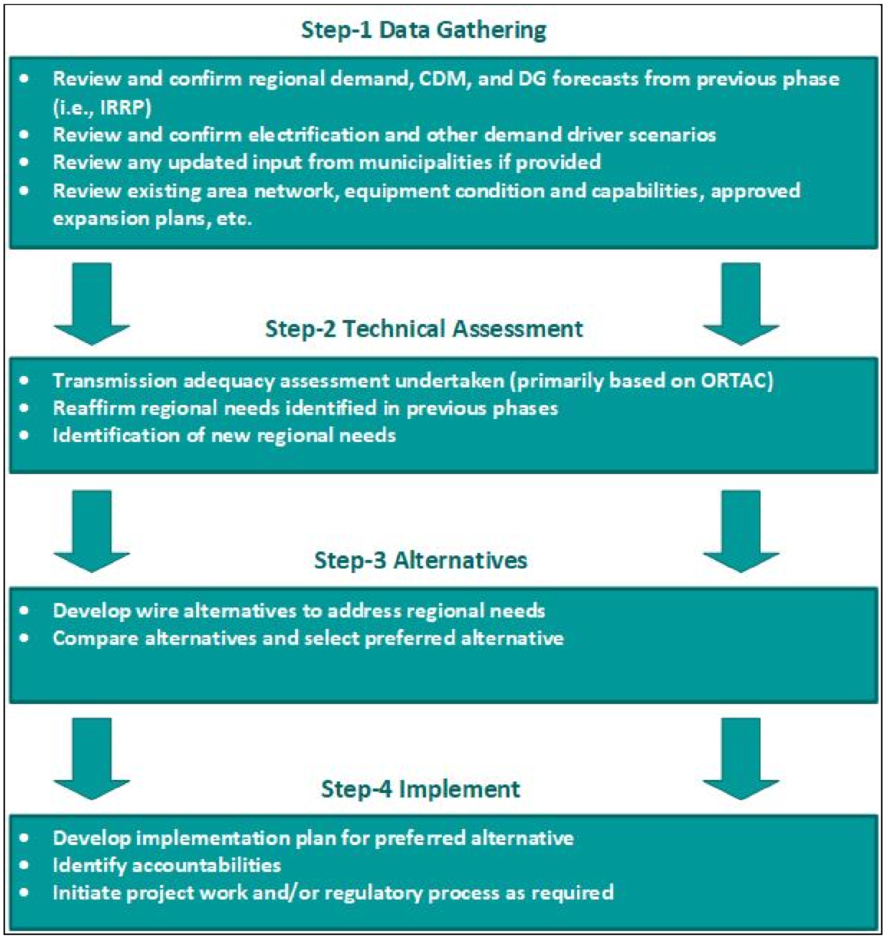

Figure 2: Regional Infrastructure Plan Methodology

Figure 2 above represents the four-step process of the Regional Infrastructure Plan which are described below:

3.2.1. 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.

- Review and confirm electrification and other growth scenarios which effects the projects recommended in in previous stages and also update the inputs provided by the Municipalities.
- 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.

3.2.2. 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.

3.2.3. 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.

3.2.4. Implementation Plan:

The fourth and last step is the development of the implementation plan for the preferred alternative, identifying accountabilities and initiate project work or obtain permissions from Regulatory Commission if any.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

Northwest Ontario Region is roughly boarded by west of Hudson Bay and James Bay, North and West of the Lake Superior, and East of the Canadian province of Manitoba. The region consists of the districts of Thunder Bay, Kenora and Rainy River. Almost 54 percent of Region's entire population lives in Thunder Bay. The region accounts for approximately 60 percent of land area of the province and about two percent of Ontario's total population.

The geographical boundaries of the Northwest Ontario region are shown in Figure 3 below.

Figure 3: Map of Northwest Ontario Regional Planning Area

Bulk electrical supply to the Northwest Ontario region is provided through a combination of local generation stations connected to the 230kV and 115kV network, the East-West Tie transmission corridor and future Waasigan transmission line.

The Local Distribution Companies ("LDCs") that serve the electricity demands for the Northwest Ontario are Hydro One Networks Inc. (Distribution), Atikokan Hydro Inc., Synergy North, Sioux Lookout Hydro Inc., and Fort Frances Power Corporation. The LDCs receive power at the step-down transformer stations and distribute it to the end users – industrial, commercial and residential customers.

In the first cycle of regional planning, the region was divided into four sub-regions, each with its own IRRP. The January 2015 Integrated Regional Integrated Regional Resource Plan ("IRRP") report for North of Dryden Sub-Region, the June 2016 IRRP report for Greenstone-Marathon Sub-Region, the July 2016 IRRP report for West of Thunder Bay Sub-Region, and the December 2016 IRRP report for Thunder Bay Sub-Region focused on northern, eastern, western, and central parts, respectively, of the Region. All IRRP reports were prepared by the IESO in conjunction with Hydro One and the LDCs. The January 2021 Northwest Region second cycle SA report prepared by IESO recommended a single IRRP covering the entire Northwest region. Subsequently, the January 2023 Northwest Ontario Region IRRP prepared by IESO considered the region as a whole.

4.1 North of Dryden Sub-Region

A radial single-circuit 115kV transmission line (“E4D”) and a new 230kV transmission line ("W54W”) supply electricity to the customers in the North of Dryden sub-region. The major supply stations for this sub-region are Dryden TS and Pickle Lake CTS, where the voltage is stepped down from the 230kV to 115kV at both stations, to serve local and industrial customers. Two of Wataynikaneyap Power’s 115kV transmission lines (WBC and WPQ) will supply two remote subsystems, north of Pickle Lake and Red Lake. Electricity demand in the North of Dryden sub-region is generally supplied by local hydroelectric generation.

The circuits and stations of the area are summarized in the Table 2 below:

Table 2: Transmission Station and Circuits in the North of Dryden Sub-Region

115kV circuits	230kV circuits	Transformation Stations	Generation Stations
• E4D • E2R • E1C • M1M • M3E • C3W • C2M • WBC** • WPQ**	• W54W	• Red Lake TS • Cat Lake MTS • Pickle Lake CTS* • Slate Falls DS • Perrault Falls DS • Crow River DS • Pickle Lake SS • Ear Falls TS • CTS1 • CTS2 • CTS3*	• Ear Falls GS (18.6MW) • Manitou Falls GS (72MW) • Lac Seul GS (12.5MW)

***Stations with Autotransformers installed**

** Multiple Wataynikaneyap Power circuits and transformer stations are supplied radially from WBC (which connects to Pickle Lake CTS) and WPQ (which connects to E2R). See Appendices B & C for details.

4.2 Greenstone-Marathon Sub-Region

Electrical supply to the customers in the Greenstone-Marathon Sub-Region comprises of Marathon TS and Alexander Switching Station (“SS”). Located in the town of Marathon, Marathon TS connects the Northwest electrical system to the East Lake Superior electrical system at Wawa TS, with four 230kV lines - W21M, W22M, W35M and W36M. Marathon TS steps down 230kV to 115kV and supplies customers in the Town of Marathon, White River and Manitouwadge through a 115kV single circuit - M2W. Three circuits A5A, A1B, and T1M - in series connect Marathon TS to Alexander SS in Thunder Bay Sub-Region.

The circuits and stations of the area are summarized in the Table 3 below:

Table 3: Transmission Station and Circuits in the Greenstone-Marathon Sub-Region

115kV circuits	230kV circuits	Transformation Stations	Generation Stations
• A1B • A5A • A4L • T1M • M2W	• W21M • W22M • W35M • W36M • M23L • M24L • M37L • M38L	• Marathon TS* • Longlac TS • Manitouwadge TS • Beardmore DS #2 • Jellicoe DS #3 • Manitouwadge DS #1 • Marathon DS • Pic DS • Schreiber Winnipeg DS • White River DS • CTS1 • CTS2 • CTS3 • CTS4 • CTS5	• CGS1 • CGS2 • CGS3 • CGS4 • CGS5 • CGS6

*Stations with Autotransformers installed

4.3 West of Thunder Bay Sub-Region

Supply to this Sub-Region is provided from a 230kV transmission system consisting of Kenora TS, Fort Frances TS, Dryden TS, and Mackenzie TS. Kenora TS steps down 230kV to 115kV and supplies customers in the City of Kenora and surrounding areas. In addition, it also connects Ontario to Manitoba's electrical system through two 230kV transmission lines, K21W and K22W. Fort Frances TS steps down 230kV to 115kV and supplies customers in the City of Fort Frances and surrounding areas. It also connects Ontario to Minnesota's electrical system through a 115kV transmission line, F3M. Dryden TS steps down 230kV to 115kV and supplies customers in the City of Dryden and surrounding areas. It also connects West of Thunder Bay to North of Dryden Sub-Region. Mackenzie TS steps down 230kV to 115kV and supplies customers in Atikokan and surrounding areas. It also connects West of Thunder Bay to the Thunder Bay Sub-Region. The West of Thunder Bay Sub-Region is also supplied by many local hydroelectric generation facilities.

The circuits and stations of the area are summarized in the Table 4 below:

Table 4:Transmission Station and Circuits in the West of Thunder Bay Sub-Region

115kV circuits	230kV circuits	Transformation Stations	Generation Stations

• A3M • M1S • B6M • M2D • 29M1 • D5D • K3D • 15M1 • K6F • K7K • F2B • F3M • F1B • K4W • K5W • SK1 • K2M • W3C	• A21L • A22L • K22W • K21W • K23D • K24F • W54W • D26A • F25A • N93A	• Kenora TS* • Fort Frances TS* • Dryden TS* • Mackenzie TS* • Moose Lake TS • Barwick TS • Fort Frances MTS • Kenora MTS • Agimak DS • Burleigh DS • Clearwater Bay DS • Eton DS • Keewatin DS • Margach DS • Minaki DS • Nestor Falls DS • Sam Lake DS • Sapawe DS • Shabaqua DS • Sioux Narrows DS • Valora DS • Vermilion Bay DS • CTS1 • CTS2 • CTS3 • CTS4 • CTS5 • CTS6 • CTS7	• Atikokan GS (227MW) • Whitedog Falls GS (64.8MW) • Caribou Falls GS (70MW) • CGS1 • CGS2 • CGS3 • CGS4 • CGS5 • CGS6

*Stations with Autotransformers installed

4.4 Thunder Bay Sub-Region

Thunder Bay Sub-Region consists of the Lakehead TS as the 230kV step-down transformation facility which steps down 230kV to 115kV and supplies customers in the City of Thunder Bay and surrounding areas. The area is served primarily at 115kV by three step-down transformer stations – Birch TS, Fort William TS, and

Port Arthur TS #1. Two parallel circuits A7L and A8L connect Lakehead TS to Alexander SS, which then interconnect Alexander Generating Station ("GS"), Cameron Falls GS, and Pine Portage GS together.

The circuits and stations of the area are summarized in the Table 5 below:

Table 5: Transmission Station and Circuits in the Thunder Bay Sub-Region

115kV circuits	230kV circuits	Hydro One Transformer Stations	Generation Stations
• B5 • B9 • B14 • B15 • R2LB • R1LB • P7B • P3B • S1C • P5M • L3P • A6P • L4P • A7L • A8L	• A21L • A22L • M23L • M24L • M37L • M38L	• Lakehead TS* • Port Arthur TS #1 • Birch TS • Fort Williams TS • Murillo DS • Nipigon DS • Red Rock DS • CTS1 • CTS2 • CTS3	• Silver Falls GS (45MW) • Alexander GS (65.1MW) • Cameron Falls GS (70MW) • Pine Portage GS (143.9MW)

*Stations with Autotransformers installed

The single line diagram of the Transmission Network of Northwest Ontario region is shown in Figure 4 below.

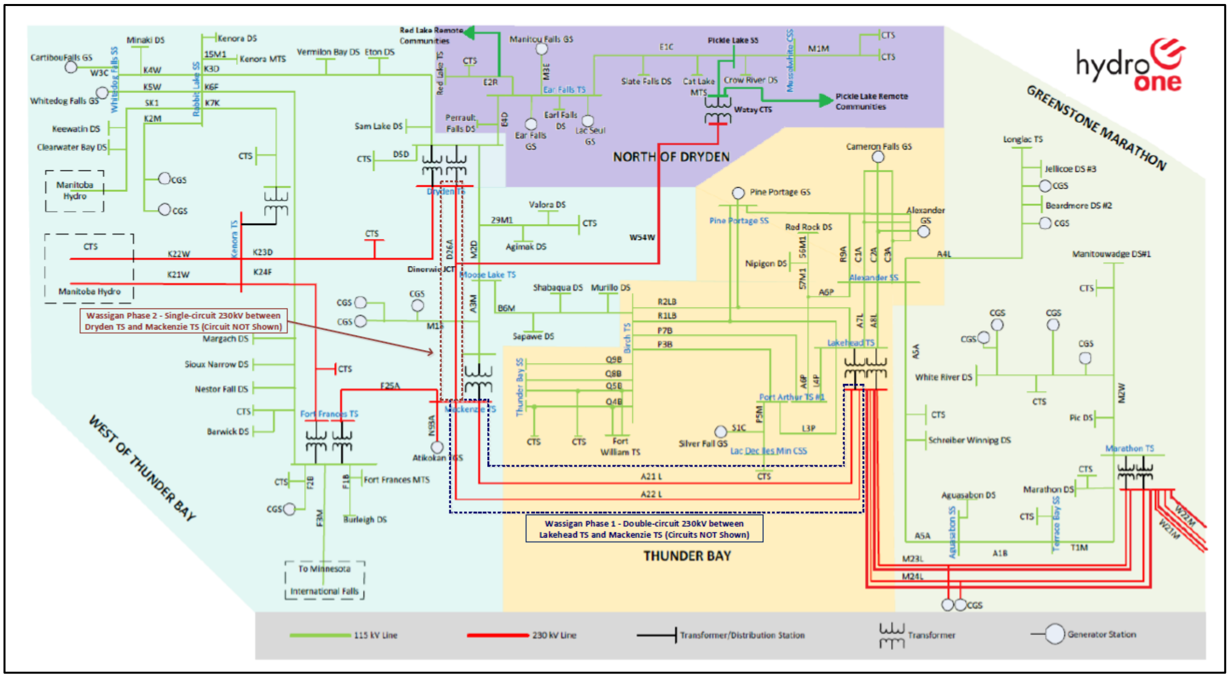

Figure 4: Northwest Ontario Transmission Single Line Diagram

4.5 New/Ongoing Transmission Line Projects Connect Sub-Regions

Below three recent/ongoing transmission projects in the Northwest regions reinforce the transmission corridors of the four sub-regions:

- East-West Tie Reinforcement
  - New double circuit 230kV line from Wawa TS to Lakehead TS in the Municipality of Shuniah, near Thunder Bay, Ontario, with a connection approximately mid-way at the Marathon TS.
- Waasigan Transmission Line Project
  - Phase 1 – New double circuit 230kV line from Lakehead TS to Mackenzie TS;
  - Phase 2 – New single circuit 230kV line from Mackenzie TS to Dryden TS.
- Wataynikaneyap Transmission Project
  - New single circuit 230kV line from Dinorwic Junction near Dryden to Pickle Lake CTS near Pickle Lake;
  - 115kV Remote connection subsystems north of Pickle Lake and Red Lake.

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

In this section, all projects that have been completed in the past ten years or currently are underway is provided and their scope of work is briefly discussed. As a part of this or previous Regional Planning Cycle(s), several "Major HV Transmission Projects" were recommended in the Northwest Region to improve the supply capability and reliability.
Hydro One, Next Bridge Infrastructure and Wataynikaneyap Power, three Transmission Asset Owners (TAO) in the region have undertaken execution of the projects recommended in the past ten years. A summary and brief description of all the projects completed or are currently underway is given below:

I. Following Major projects were completed during the last ten years:

- **Manitouwadge TS (2016)** – The 115/44kV, 5/7 MVA T1 transformer was replaced with new 115/44kV 25/33/41.7 MVA unit.
- **Dryden TS (2018)** –Two 115/44kV, 11/15 MVA transformers were replaced with new 25/33/42 MVA units in addition to replacement of five 115kV breakers.
- **Lakehead TS (2017)** – Two 230/115kV autotransformers were replaced with new 230/115kV 150/200/250MVA units.
- **Birch TS (2015)** – One 115/25kV transformer was replaced with a new 115/25kV 25/33/42MVA unit.
- **Ear Falls TS (2022)** – One 115/13.2 kV transformer was replaced with a new 115/13.2 kV 7.5/10/12.5MVA unit in addition to replacement of four 115kV breakers.
- **East West Tie Reinforcement (2022)** – A 450 km, double-circuit, 230kV transmission line from Wawa TS to Lakehead TS was built with a connection approximately mid-way at Marathon TS.
- **Wataynikaneyap Power Project Phase 1 (2022)** – A 300 km, single circuit, 230kV transmission line from Dinorwic to Pickle Lake, Ontario was built with a 230/115kV autotransformer, related switching facilities and the necessary voltage control devices.

II. Following Major projects are underway:

- **Rabbit Lake SS (2024-2027)** –This investment will replace the station equipment identified as in poor condition and at high risk of failure. Hydro One will replace identified 115kV circuit breakers, associated disconnect switches, instrument transformers and equipment protections. The scope of work also involves installing new AC station service, DC battery and PCT building.
- **Whitedog Falls SS (2025-2028)** – This investment will replace the station equipment identified as in poor condition and at high risk of failure. Hydro One will replace identified 115kV circuit

breakers and associated switches. The scope of work also involves replacing and upgrading DC station supply system.

- **Mackenzie TS (2025-2028)** – This investment will replace the station equipment identified as in poor condition and at high risk of failure. Hydro One will replace 230kV circuit breakers, select protections, and AC/DC station service systems. A new 115/44kV load facility at Mackenzie TS to replace the one at Moose Lake TS.

- **Wawa TS (2026-2029)** – This investment will replace the station equipment identified as in poor condition and at high risk of failure. Hydro One will replace two autotransformers rated 75/100/125MVA, 230/115kV, four 230kV circuit breakers, and four 115kV circuit breakers. The scope of work also includes replacing associated disconnect switches, protection equipment and the station service system.

- **Wataynikaneyap Power Project Phase 2 (2022-2024 and beyond)** – This investment, led by Wataynikaneyap Power, will construct approximately 1438 km of overhead 115kV, 44kV and 25 kV transmission lines and twenty substations to connect 16 First Nations in two transmission subsystems by 2024 (10 north of Pickle Lake and 6 north of Red Lake). The Red Lake subsystem is designed to connect a seventh First Nation beyond 2024.

Note: The planned in-service year for the above projects is tentative and is subject to change.

6. LOAD FORECAST AND STUDY ASSUMPTIONS

6.1. Load Forecast

After verification from the TWG participants, and as no material changes were identified, the Northwest Region IRRP Load Forecasts were used in development of this Report. TWG participants, including representatives from LDC's, Wataynikaneyap Power, IESO and Hydro One, provided information and input for the IRRP Load forecast, which also includes the inputs from the Municipal Energy Plans (MEP) and/or Community Energy Plans (CEP).

During the study period, the load in the Northwest Ontario Region is expected to grow at an average annual rate of approximately 2% in winter from 2023-2033. The Region is winter peaking, so this assessment is based on winter peak loads.

Figure 5 shows the Northwest Region median winter weather net non-coincident load forecast from 2023-2033. Note that the non-coincident forecast is typically 10-15% higher than the coincident forecast in the Northwest region. This assessment is based on non-coincident forecast. In the event that non-coincident load forecast identifies network element needs, a sensitivity study will be performed utilizing coincident load forecast. The load forecasts from the Northwest Ontario Region 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.

The main factor contributing to the deviation between the load forecasts in the IRRP and the RIP is the mining sector forecast. In the IRRP, the mining forecast was considered final as of the end of 2021. However, after the completion of IRRP, IESO has provided an updated reference scenario for the mining forecast, accounting for potential future mining projects. As a result, this updated mining forecast contributes to the variation between the load forecasts in the IRRP and RIP beyond 2026.

Non-coincident forecast for the individual stations in the region is available in Appendix A and is used to determine any need for station capacity relief in the region.

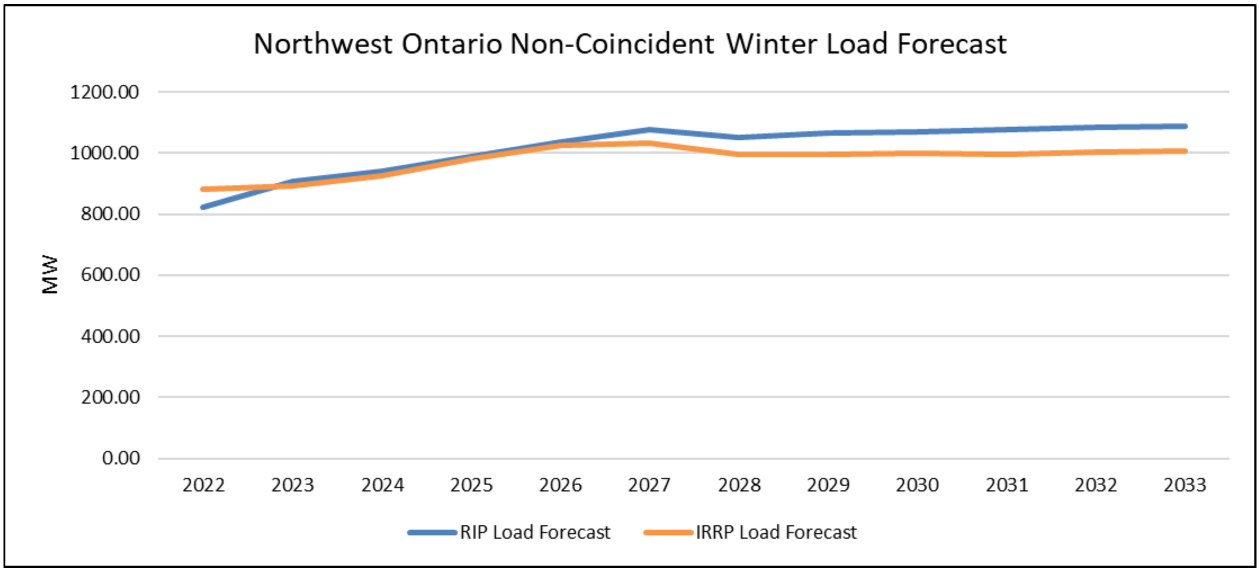

Figure 5: Northwest Ontario Region Winter Non-Coincident Net Peak Load Forecast

6.2. Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2023-2033. However, a longer term forecast up to 2040 is provided to identify long-term needs and align with the Northwest region IRRPs.

- LDCs reconfirmed load forecasts up to 2033. A longer term forecast up to 2040 is adopted with IRRP load forecast. The additional three 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.
- This region is winter peaking, so this assessment is based on winter peak loads. However, since summer transmission line ratings are more constrained, Section 7.3 Transmission Line Capacity Needs is based on potential summer peak load demands.
- 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) or by using the winter 10-day LTR if performing a winter season assessment.
- Bulk transmission line and auto-transformation 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.

7. SYSTEM ADEQUACY AND REGIONAL NEEDS

This section reviews the adequacy of the existing Transmission Systems and Transformer Station facilities supplying the Northwest Region and lists the facilities requiring reinforcement over the near and midterm period. The adequacy assessment assumes that all the projects that are currently underway, listed in **"Section 5"** are completed.

In current regional planning cycle, the following regional assessments were completed, and their findings were used as inputs to this RIP report:

- Northwest Region Second Cycle Needs Assessment Report completed in July 2020 by Hydro One
- Northwest Region Second Cycle Scoping Assessment Report completed in January 2021 by the IESO
- Northwest Region Second Cycle Integrated Regional Resource Plan Report completed in January 2023 by the IESO

The Technical Working Group identified several regional needs based on the forecasted load demand over the near to mid-term period in the reports mentioned above. The results of the Adequacy Assessment to define the needs are discussed in sub-sections "7.1 to 7.4" and a detailed description and status of plans to meet these needs are given in **"Section 8"** of this report.

7.1. Asset Renewal Needs for Major HV Transmission Equipment

In addition to the asset renewal needs identified in previous regional planning cycle, Hydro One and TWG has also identified new asset renewal needs for major high voltage transmission equipment that are expected to be replaced over the next 10 years in the Northwest Region. The complete list of major HV transmission equipment requiring replacement in the Northwest Region is provided in table 6 in this sub-section. Hydro One, Next Bridge Infrastructure and Wataynikaneyap Power are the Transmission Asset Owners (TAO) in the Region.

Asset Replacement needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as:

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

The major high voltage equipment information shared and discussed as part of this process is listed below:

- 230/115kV autotransformers
- 230 and 115kV load serving step down transformers
- 230 and 115kV breakers where:
  replacement of six breakers or more than 50% of station breakers, the lesser of the two
- 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
- 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

Table 6: Major HV Transmission Asset assessed for Replacement in the region

Station/Circuit	Need Description	Planned ISD
Rabbit Lake SS	Replace equipment identified in deterioration and technical obsolescence	2024-2027
Whitedog Falls SS	Replace equipment identified in deterioration, technical obsolescence and lack of spare parts availability and no manufacturer support	2025-2028
Mackenzie TS	Replace equipment identified in deterioration and technical obsolescence	2025-2028
Wawa TS	Replace Equipment deterioration due to aging infrastructure	2026-2029
Marathon TS	Replace equipment identified in deterioration and technical obsolescence	2026-2029

Lakehead TS	Replace equipment identified in deterioration and technical obsolescence	2028-2031
Lakehead TS	Replace Condenser C8 identified in deterioration and technical obsolescence	2027
Fort Frances TS	Replace equipment identified in deterioration and technical obsolescence	2029-2032
Kenora TS	Replace equipment identified in deterioration, technical obsolescence and lack of spare parts availability and no manufacturer support	2030-2033

Note: The planned in-service year for the above projects is tentative and is subject to change.

7.2. Station Capacity Needs

Over the study period 2023-2033 RIP reviewed the capacity of all the 230kV, 115kV Transforming stations and 115kV step down Distribution stations within the Northwest Ontario Region. The NA and IRRP studies had previously indicated that the following stations require capacity relief within the study period. This RIP has further confirmed those needs and based on the load forecast, the stations which require capacity relief during the study period are shown in Table 7 below. The need timeframe defines the time when the peak load forecast exceeds the most limiting seasonal (winter) Limited Time ratings.

Table 7: Northwest Ontario Region Station Capacity Needs in the study period

Sr.no.	Station Name	Capacity (MVA)	2023 Historical Loading (MW)	Station 10-day LTR (MW)	Need Date
1	Margach DS	11.60	10.07	10.44	2023
2	Crilly DS	2.40	2.28	2.16	2027
3	White Dog DS	3.20	2.37	2.88	2027
4	White River DS	15.60	12.02	14.04	2029
5	Sam Lake DS	24.00	23.34	21.06	Now
6	Kenora MTS	26.00	19.13	23.40	2030

The options and preferred solutions to address these needs are discussed further in Section 8 of the report.

7.3. Transmission Line Capacity Needs

Over the study period 2023-2033 RIP reviewed the capacity of all the 230kV and 115kV Transmission lines within the Northwest Region. The NA and IRRP studies had previously indicated that the following Transmission lines potentially require capacity relief within the study period. This RIP has further confirmed those needs and based on the load forecast and following contingencies, the Transmission lines which require capacity relief during the study period are shown in Table 8 below. The mining sector load materialization timing drives the need timeframe. It defines when the peak load forecast exceeds the most limiting seasonal (summer) Limited Time ratings.

Table 8: Northwest Ontario Region Transmission Line Capacity Needs in the study period

Sr.no.	Name of Circuit	Name of Section	Contingency	LTE Line Rating (Amps)	Need Date
1	E2R	Ear Falls TS – Red Lake TS	NA	421	TBD
2	E4D	Dryden TS – Ear Falls TS	NA	410	TBD
3	M2W	Pic JCT – Manitouwadge JCT	NA	290	TBD

The options and preferred solutions to address these needs are discussed further in Section 8 of the report.

7.4. System Reliability, Operational and Load restoration Needs

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 loss of 2 transmission elements.

Furthermore, loads are to be restored in the restoration times[1] 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 interrupted in excess of 250 MW must be restored within 30 minutes.

The IRRP studies had previously indicated that the following stations and transmission line require actions on system reliability and operational improvement. The RIP further confirms those needs with regards to System Reliability and Operation requirements.

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

Table 9: Northwest Ontario Region System Reliability and Operational Needs in the study period

Station/Circuit	Need Description
Fort France MTS	Planned outages considering station single supply configuration
E1C	Operation and high voltage under a normally open configuration

The options and preferred solutions to address these needs are discussed further in Section 8 of the report.

8. REGIONAL PLANS

This section discusses the regional electric supply needs and presents all the wires alternatives considered to address these needs and identifies the best and preferred wires solutions for the Northwest Ontario region. These needs include those previously identified in the NA and IRRP for the Northwest Ontario as well as any new needs identified during the RIP phase. All references to costs included in the alternative analysis are considered as planning allowances[2] and are used for comparative purposes only and may vary. The Needs in the region are summarized below in Table 10 below:

Table 10: Near/Mid-term Needs Identified in the region

Station/Circuit Name	Description of Need	Need Date	RIP Report Section
Asset Renewal Needs			
Rabbit Lake SS	Replace equipment identified in deterioration and technical obsolescence	2024-2027	8.1.1
Whitedog Falls SS	Replace equipment identified in deterioration, technical obsolescence and lack of spare parts availability and no manufacturer support	2025-2028	8.1.2
Mackenzie TS	Replace equipment identified in deterioration and technical obsolescence	2025-2028	8.1.3
Wawa TS	Replace Equipment deterioration due to aging infrastructure	2026-2029	8.1.4

[2] Allowances do not include real estate costs, environmental impacts and other costs not directly associated with the electrical infrastructure.

Marathon TS	Replace equipment identified in deterioration and technical obsolescence	2026-2029	8.1.5
Lakehead TS	Replace equipment identified in deterioration and technical obsolescence	2028-2031	8.1.6
Lakehead TS	Replace Condenser C8 identified in deterioration and technical obsolescence	2027	8.1.6
Fort Frances TS	Replace equipment identified in deterioration and technical obsolescence	2029-2032	8.1.7
Kenora TS	Replace equipment identified in deterioration, technical obsolescence and lack of spare parts availability and no manufacturer support	2030-2033	8.1.8
Station Capacity Needs			
Margach DS	Station Capacity Needs	2023	8.2.1
Crilly DS	Station Capacity Needs	2027	8.2.2
White Dog DS	Station Capacity Needs	2027	8.2.3
White River DS	Station Capacity Needs	2029	8.2.4
Sam Lake DS	Station Capacity Needs	Now	8.2.5
Kenora MTS	Station Capacity Needs	2030	8.2.6
Transmission Line Capacity Needs			
E2R	Capacity Needs of Section Ear Falls TS – Red Lake TS	TBD	8.3.1
E4D	Capacity Needs of Section Dryden TS – Ear Falls TS	TBD	8.3.1
M2W	Capacity Needs of Section Pic JCT – Manitouwadge JCT	TBD	8.3.2
System Reliability, Operational and Load restoration Needs			
Fort France MTS	The planned transmission outage caused customer interruptions due to the station's single supply configuration.	2023	8.4.1
E1C Operation and High Voltage	Supply capacity limitations with E1C operated normally closed; high voltage issues with E1C operated normally open	2023	8.4.2

Other Planning Considerations			
Fort William TS Shunt Capacitor Banks Replacement	Temporary capacitor banks to be replaced with permanent units	2026-2027	8.5.1

8.1 Asset Renewal Needs for Major HV Transmission Equipment

The Asset renewal assessment considers the following options for "right sizing" the equipment:

- Maintaining the status quo
- Replacing equipment with similar equipment with *lower* ratings and built to current standards
- Replacing equipment with similar equipment with *lower* ratings and built to current standards by transferring some load to other existing facilities
- Eliminating equipment by transferring all the load to other existing facilities
- Replacing equipment with similar equipment and built to current standards (i.e., "like-for-like" replacement)
- Replacing equipment with higher ratings and built to current standards

From Hydro One's perspective as a facility owner and operator of its transmission equipment, do nothing is generally not an option for major HV equipment due to safety and reliability risk of equipment failure. This also results in increased maintenance cost and longer duration of customer outages.

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

8.1.1. Rabbit Lake SS

Rabbit Lake SS, a North American Electric Reliability Corporation (NERC) Bulk Electrical System station, was originally built in 1956 and is located within the city limits of Kenora, Ontario. The switching station has six 115kV transmission lines connecting to three customer generating stations (CGSs) as well as Whitedog Falls SS, Kenora TS, Fort Frances TS, Dryden TS, and the interconnection with Manitoba Hydro. There are six 115kV oil circuit breakers and two 115kV SF6 circuit breakers in the yard.

Hydro One has plans to replace equipment identified in deterioration due to aging infrastructure and technical obsolescence due to outdated design. The scope of work involves replacing 115kV circuit breakers, associated disconnect switches, instrument transformers and equipment protections. A New AC station service, DC battery and PCT building will also be installed.

This investment will help maintain the reliability of supply to area customers and reduce the risk of interruptions caused by station equipment failure. The project is currently planned to be completed in 2024-2027.

8.1.2. Whitedog Falls SS

Whitedog Falls Switching Station (SS) located approximately 80 km northwest of the City of Kenora, containing three 115kV circuits that terminate at the station with four circuit breakers, connecting to Rabbit Lake SS, Caribou Falls GS, and Whitedog Falls GS.

Hydro One has plans to replace equipment identified in deterioration due to aging infrastructure and technical obsolescence with little or no spare parts and manufacturer support. The scope of work involves replacing 115kV circuit breakers and associated disconnect switches. Replacement and upgrades of the DC station supply system will also be part of this investment,

This investment will help maintain the reliability of supply to area customers and reduce the risk of interruptions caused by station equipment failure. The project is currently planned to be completed in 2025-2028.

8.1.3. Mackenzie TS

Mackenzie TS is a 230/115kV station is located approximately 200 km west of Thunder Bay, Ontario. Mackenzie TS has six 230kV breakers which are about 46 years old. The station is a major station for Waasigan transmission line reinforcement project.

Hydro One has plans to replace station equipment identified in deterioration due to aging infrastructure and technical obsolescence with minimal spare parts and manufacturer support. The scope of work involves replacing the existing 230/115kV 75/125 MVA autotransformer with new 230/115kV 75/100/125 MVA. The project will also replace 230kV circuit breakers, select protections, and AC/DC station service systems. Hydro One has also planned to install a new 115/44 kV load facility at the station to replace the one at Moose Lake TS, optimizing the area supply configuration.

This investment will help maintain the reliability of supply to Atikokan Hydro customers and reduce the risk of interruptions caused by station equipment failure. This project is currently planned to be completed in 2025-2028.

8.1.4. Wawa TS

Wawa TS is a 230/115kV transformer station, located southeast of the township of Wawa in northern Ontario. It was put in-service in 1969. The station is a major hub for connecting the Northeast, Northwest and Hydro One Sault Ste. Marie transmission systems. The existing autotransformers, oil circuit breakers, disconnect switches, protection and control, station service, and other ancillary facilities are in poor condition and in deterioration that require replacement to maintain the operability and reliability of the station.

Hydro One has plans to replace all deteriorated equipment at the station. The scope of work involves replacing two 239-121/13.9kV 75/100/125 MVA autotransformers, four 230kV circuit breakers, and four 115kV circuit breakers. In addition, the scope of work also includes replacing associated disconnect switches, protection equipment and station service system.

This investment will improve transmission system reliability and reduce the risk of interruptions caused by station equipment failure. This project is currently planned to be completed in 2026-2029.

8.1.5. Marathon TS

Marathon TS is a 230/115kV transformer station, located in the City of Marathon in northern Ontario. It was put in-service in 1970. The station is critical to the transmission system of the Northwest and a major hub for East-West power transfer. All four 115kV oil circuit breakers at the station are about 40 years old, and three 230kV circuit breaker at the station are about 48 years old.

Hydro One has plans to replace station equipment identified in deterioration due to aging infrastructure to ensure the reliability of the transmission system and supply to customers. The scope of work involves replacing three 230kV circuit breakers with new SF6 breakers, and four 115kV circuit breakers with new SF6 breakers. The replacement of disconnect switches, protection equipment, and AC station service system will also be part of this investment.

In addition to component replacement. this project will separate and re-terminate two branches of 115kV circuit M2W. M2W is a radial transmission line consisting of two independent branches that merge into 1 switching position at the entry point of Marathon TS. To unbundle, Hydro One will install one additional 115kV circuit breaker with associated protections in order to create a new switching position at Marathon TS 115kV bus.

This investment at Marathon TS will improve transmission system reliability performance and reduce the risk of interruptions caused by station equipment failure. This project is currently planned to be completed in 2026-2029.

8.1.6. Lakehead TS

Lakehead TS is a 230/115kV transformer station which was put in-service in 1955, located northeast of the city of Thunder Bay in norther Ontario. The station is critical to the transmission system of the Northwest, a major hub for East-West power transfer, and a major station for Waasigan transmission line reinforcement project. The station is classified as Bulk Electric System (BES) under NERC standards.

8.1.6.1 HV Component Replacement

Hydro One has plans to replace all station equipment identified in deterioration due to aging infrastructure to ensure the reliability of the transmission system and supply to the customers. The scope of work involves replacing high voltage circuit breakers with new SF6 breakers, replacing eight 115kV circuit breakers with new SF6 breakers, replacing protection equipment associated with 115kV facilities and the synchronous condenser, replacing select switches, and replacing/upgrading AC station service system.

This investment will improve transmission system reliability and reduce the risk of interruptions caused by station equipment failure. This project is currently planned to be completed in 2028-2031.

8.1.6.1 Condenser C8 Replacement

The transformers T7 and T8 at Lakehead TS are 239/121/13.9 kV 250 MVA autotransformers with primary and secondary windings connecting to the 230kV and 115kV systems, respectively. The tertiary windings of T7 and T8 are rated at 60MVA. In 2009, a -40/+60Mvar SVC replaced a poor condition condenser connected at T7 tertiary bus. The SVC consists of a 100Mvar TCR and a 60Mvar filter. A recent condition assessment has highlighted the poor condition and high risk of failure associated with C8, a synchronous condenser connected to T8's tertiary bus. To address this issue, Hydro One consulted with IESO to explore the options of maintaining the status quo, removing the condenser, or replacing it with appropriately sized equipment. The consideration of the need for condenser inertia was also part of the assessment.

Following discussions between IESO and Hydro One, it has been recognized that replacing C8 with a static synchronous compensator (STATCOM) is the preferred solution. To ensure optimal controller coordination, the recommended replacement strategy involves sourcing the STATCOM from the same vendor as the existing SVC. By installing a STATCOM with the same capacity and connecting it to the 13.8kV tertiary winding of transformer T8, effective voltage control of the 230kV bus at Lakehead can be achieved in coordination with the existing SVC at T7. This asset and infrastructure replacement will effectively mitigate the risks associated with equipment failure and enhance the overall reliability of the system. It's important to note that IESO is currently conducting further studies to assess the reactive power needs in northern Ontario.

8.1.7. Fort Frances TS

Fort Frances TS is in the Town of Fort Frances and was put in-service in 1947. Hydro One has plans to replace equipment identified in deterioration due to aging infrastructure and technical obsolescence. The scope of work involves replacing high voltage circuit breakers, replacing/upgrading AC/DC station service systems and protection equipment.

This investment will improve transmission system reliability and reduce the risk of interruptions caused by station equipment failure. This project is currently planned to be completed in 2029-2032.

8.1.8. Kenora TS

Kenora TS is a 230/115kV station in-service since 1972 and located in east side of Kenora City, Ontario. The station is critical to supply of the city of Kenora and the interconnection with the province of Manitoba.

Hydro One has plans to replace station equipment identified in deterioration due to aging infrastructure and technical obsolescence with minimal spare parts and manufacturer support. The scope of work involves replacing high voltage circuit breakers, protection equipment and replacing/upgrading AC/DC station service systems.

This investment will improve transmission system reliability and reduce the risk of interruptions caused by station equipment failure. This project is currently planned to be completed in 2030-2033.

8.2 Station Capacity Needs

A Station Capacity assessment was performed over the study period 2023-2033 for the 230kV ,115kV Transformer stations and 115kV step down Distribution stations in the Northwest Ontario Region using either the summer or winter peak load forecasts that were provided by the study team. Based on the results, the following Station capacity needs have been identified in the during the study period:

8.2.1 Margach DS– 115kV – Distribution Station Step-Down Transformer Capacity Needs (2023)

Margach DS is approximately 10 km east of Kenora. Margach DS presently has two 115/ 26.5kV 7.5MVA transformers (T1/T2) with a winter LTR of 10.4MW. The historical demand at Margach DS has remained stable, consistently just below 10 MW. The station will exceed its normal supply capacity in 2023.

Table 11: Margach DS Load Forecast

Station	LTR	Load Forecast (MW)										
	(MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Margach DS	10.4	10.50	10.48	10.47	10.48	10.51	10.53	10.53	10.53	10.55	10.55	10.58

The following alternatives were considered to address Margach DS capacity need.

Alternative 1: Install Transformer Fan Monitoring.

Installing transformer fan monitoring is a relatively inexpensive solution to increase the station LTR by enabling the use of higher thermal ratings on the existing transformers.

Alternative 2: Maintain Status Quo

Considering that the peak loading in 2022 was 9.96 MW and there is only anticipated natural residential load growth, maintaining the status quo is also considered a viable solution.

The LDC- Hydro One Distribution recommends alternative 2 as the preferred solution at the time of this RIP. Regarding alternative 1, the LDC has incorporated it into its investment plan with an anticipated implementation date in 2025. Given the gradual growth in station loading and the existing plan in place, the LDC will closely monitor the station's load and take necessary actions if required before 2025, ensuring a smooth transition to Alternative 1.

8.2.2 Crilly DS– 115kV – Distribution Station Step-Down Transformer Capacity Needs (2027)

Crilly DS is a small (~2.2 MW LTR) station supplied from 115kV transmission circuit M1S and has a 6.6 kV bus shared with Sturgeon Falls CGS, a small hydroelectric plant located approximately 50 km west of Atikokan. This legacy non-standard supply arrangement results in annual outages at Crilly DS during maintenance periods of the generator. Backup power from diesel generation is utilized when Sturgeon Falls is offline. Moreover, the station equipment is approaching its end-of-life, and limited space constraints limit refurbishment options on-site.

Crilly DS is expected to exceed its capacity in 2027 due to incremental growth in the community.

Table 12: Crilly DS Load Forecast

Station	LTR (MW)	Load Forecast (MW)										
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Crilly DS	2.16	2.14	2.14	2.15	2.16	2.18	2.19	2.20	2.21	2.23	2.24	2.25

To address this capacity issue, the TWG has identified the following alternatives for consideration:

Alternative 1: Refurbish Crilly DS at the current location

This alternative is likely the least costly solution, but Crilly DS will still rely on backup power from diesel generation during outages at Sturgeon Falls CGS.

Alternative 2: Rebuild Crilly DS at a different location as a 115/25 kV HVDS

This alternative entails rebuilding Crilly DS at a different location, operating as a 115/25 kV HVDS station. The new site would be situated closer to the existing station and supplied by the 115kV transmission circuit M1S.

Alternative 3: Rebuild Crilly DS at a different location as a 230/25 kV TS (connected to F25A closer to the community served by Crilly DS)

This alternative will rebuild the station and operate it as a 230/25kV Transformer Station (TS).

Alternative 4: Replace Crilly DS with 115:25kV padmount transformer (transformer enclosed in a grounded cabinet that can be accommodated outside the existing station fence)

This alternative requires further investigations on the feasibility of configuring the station with a padmount transformer.

Hydro One Distribution are considering all 4 alternatives. Due to the radial supply nature of M1S, reliability concerns can only be partially addressed by upgrading station assets at Crilly DS. Considering the timeline and the need for further assessment, the LDC has indicated that additional studies and investigations are required to evaluate the cost and benefits of all four alternatives before determining the preferred solution to address the station capacity needs projected for 2027. In the interim, the LDC will closely monitor the loading of Crilly DS and take appropriate actions if the load grows faster than forecasted. This proactive approach will ensure that any capacity challenges are promptly addressed. By conducting thorough analyses and closely managing the station's loading, the LDC aims to make informed decisions and select the most suitable alternative to meet the future capacity requirements of Crilly DS.

8.2.3 Whitedog DS – 115kV - Distribution Station Step Down Transformer Capacity Need (2027)

Whitedog DS is a distribution station that receives its supply from the OPG Whitedog GS 13.8kV bus. The station is comprised of three 0.667MVA single-phase transformers, with an additional single-phase transformer serving as a spare. All the single-phase transformers in the station are 75 years old. Currently, Whitedog DS is connected to a single feeder (12.48kV) that supplies the Whitedog First Nation community.

Whitedog DS is expected to exceed its capacity in 2027 due to incremental growth in the community. Recently, the Whitedog First Nation also expressed plans for growth and expansion within their community and it is at the preliminary stage of development. To support this potential load growth, the capacity of the Whitedog DS station would need to be increased. In addition, OPG is planning system renewal work on this 13.8 kV bus and needs to coordinate scope and cost with the LDC if the connection is to be maintained.

Table 13: Whitedog DS Load Forecast

Station	LTR (MW)	Load Forecast (MW)										
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Whitedog DS	2.88	2.80	2.82	2.85	2.87	2.92	2.95	2.99	3.01	3.05	3.07	3.11

To address this capacity issue, the TWG has identified the following tentative alternatives for consideration:

Alternative 1: Replace the existing transformers with a larger size

This alternative will allow Whitedog DS to remain connected to the OPG bus. But it involves expanding the existing site to accommodate larger-size transformers, which need OPG's approval since OPG owns the land. Additionally, OPG is in the process of refurbishing the Whitedog GS switchgear; if the DS is to remain connected to OPG, the scope of work is subject to coordination with OPG.

Alternative 2: Relocate Whitedog DS as a 115/12.48 kV DS

This alternative will relocate Whitedog DS with a larger size transformer to the Hydro One Whitedog Switching Station, connecting it to the transmission 115kV bus. This solution may require a small site expansion, which would necessitate approval from OPG.

Alternative 3: Maintain Status Quo

This alternative will not take action at this point and continue monitoring if the forecasted load growth materializes. This alternative requires the LDC to work with the generator to land on an amicable solution for the generator's system renewal work.

The LDC – Hydro One Distribution recommends alternative 3 maintaining the status quo for now. While the Whitedog First Nation has expressed plans for future growth, they are currently in the preliminary stage, indicating that the load demand increase might not materialize in the immediate future. Maintaining the status quo allows the LDC to closely monitor the actual load growth and assess its sustainability before committing to significant infrastructure changes. If the projected increase materializes, appropriate corrective actions will be taken. This approach ensures that the LDC can respond effectively to the evolving needs of the Whitedog First Nation while maintaining a reliable power supply to the community.

8.2.4 White River DS – 115kV - Distribution Station Step Down Transformer Capacity Need (2029)

White River DS is a 115/26.8 kV step down distribution station supplying the Town of White River. The station has two 7.5/10MVA transformers both in service serving the load with a LTR of 14.04MW. However, the station is lacking the provision of a spare transformer as a backup in the event of a failure. Currently, if one of the transformers fails, the load can be transferred to the remaining operational unit. With the projected load growth, White River DS's contingency capacity to fully restore the load following a contingency will be compromised, specifically, in the event of one transformer failure, the failed transformer's load cannot be offloaded to the other transformer at the station due to overloading as the load grows in the area. Hence, the station is expected to exceed the contingency capacity in 2029.

Table 14: White River DS Load Forecast

Station	LTR (MW)	Load Forecast (MW)										
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
White River DS	14.04	13.42	13.51	13.69	13.80	13.91	14.00	14.09	14.18	14.27	14.35	14.44

To address this capacity issue, the TWG has identified the following tentative alternatives for consideration:

Alternative 1: Maintain Status Quo

This alternative will not take action at this point and continue monitoring if the forecasted load growth materializes.

Alternative 2: Install a MUS Facility

There is a tentative plan for the LDC to look into installing a MUS facility at the station; in such case, the station contingency capacity can be increased with the additional MUS facility. It is also recognized as the most cost-effective solution to address the need.

The LDC – Hydro One Distribution recommends alternative 1 to maintain the status quo as the preferred solution. Based on the load forecasts, White River DS will exceed contingency capacity in 2029. The next cycle of regional planning will commence in 2025. It will allow the working group to reevaluate this need and confirm if the capacity needs at White River DS still holds in 2028. Should this be the case, the study group at that moment will decide the best course of action to fill this need.

8.2.5 Sam Lake DS – 115kV -Distribution Station Step Down Transformer Capacity Need (Now)

Sam Lake DS is a Hydro One Distribution owned 115/25kV High Voltage Distribution Station (HVDS) supplied from 115kV circuit K3D. The station is the sole supply for Sioux Lookout Hydro LDC. It contains two 115kV/25kV 15/20/25MVA transformers (T1 and T2) and only one of the transformers is in-service at any given time. The station is projected to exceed its normal supply capacity this year. A Local planning study[3]was conducted and was published in January 2023 with a TWG[4] recommended solution to address the need.

Station	LTR (MW)	Load Forecast (MW)										
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Sam Lake DS	21.6	28.22	28.47	28.67	28.70	28.72	28.74	28.74	28.74	28.78	28.81	28.87

The following alternatives were considered by the TWG in the Local Planning study:

Alternative 1 – T1 and T2 Transformer both in service at Sam Lake DS

Currently, only one of the transformers is on load, while the other is a hot spare in case of a transformer contingency. Therefore, the additional capacity can be made available if both T1 and T2 are in service.

Alternative 2 – Install fan monitoring on T1 and T2 at Sam Lake DS

As discussed in section 2, T1 and T2 transformers at Sam Lake DS are currently equipped with unmonitored fans, and it is not reliable to load the transformers at the maximum fan-cooled rating without a fan monitoring system. Therefore, installing fan monitoring can increase the station capacity at Sam Lake DS.

Alternative 3 – Install an additional (3rd) transformer at Sam Lake DS

An additional transformer at Sam Lake DS can also increase the capacity at Sam Lake DS.

Alternative 4 – Construct a new 115kV/25kV station supplied from Hydro One's K3D Circuit

A new High Voltage Distribution Station (HVDS) can be built to increase the capacity of the area.

Alternative 5 – Construct a new 230kV/25kV station supplied from Wataynikaneyap transmission system

[3] Local Planning – Report (Sam Lake DS)

[4] Local Planning Technical Working Group Members: Hydro One Inc. (Transmission), Hydro One Inc. (Distribution) and Sioux Lookout Hydro.

A new station can be built and supplied from the new Wataynikaneyap 230kV system, which would bring in a new transmission supply and significantly improve the load supply diversity at the Sam Lake DS area in case of a K3D outage.

The TWG have conducted a coordinated review and evaluation of all the alternatives to address the local capacity need. The TWG recommended Alternative 2 – Install fan monitoring on T1 and T2 at Sam Lake DS. This alternative allows Hydro One Distribution and Sioux Lookout Hydro to address the capacity need in the timeframe required (based on the winter conservative load forecast) and maintain supply reliability to the Sam Lake area customers. This alternative is the lowest cost option and achieves the best balance between cost versus local system benefits.

8.2.6 Kenora MTS – 115kV - Transmission Station Capacity Need (2030)

Kenora MTS is currently equipped with 115/12.5 KV transformers T1, T2 and T4. T1 and T4 have a rating of 9/12 MVA, while T2 has a rating of 10/13/14 MVA. The station's total planning winter LTR is 23.4MW. Therefore, this station will exceed its normal supply capacity in 2030.

Table 15: Kenora MTS Load Forecast

Station	LTR (MW)	Load Forecast (MW)										
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Kenora MTS	23.4	21.4	21.7	21.9	22.1	22.5	22.9	23.2	23.5	23.8	24.1	24.4

Synergy North has received inquiries from potential customers seeking new connections, but formal agreements still need to be finalized. Although these new connection loads have not been incorporated into the forecast, an annual growth rate of 1.25% has been applied to account for the significant level of development interest. The following wires and non-wires alternative solutions are considered:

Alternative 1: Expand Kenora MTS with an Additional Transformer

Install an additional transformer and associated protections, control, and structures with an expansion of the existing station.

Alternative 2: Construct a new substation across the city from the existing station

The proposed new substation will be located on the city's west side. In addition to increasing the supply capacity, this solution will provide substantial distribution system benefits by reducing the feeder length required to reach the customers and improving the distribution system performance.

Alternative 3: Non-Wires Solutions

IRRP recommends three non-wire alternatives. A 4MW gas generation facility, a 6-hour 4MW (24MWh) battery, or a combination of energy efficiency measures and demand response are feasible options. This alternative will provide potential distribution benefits to the end customers.

Alternative 4: Maintain Status Quo

This alternative is considered based on the long-term horizon of the need. Kenora MTS will exceed station capacity in 2030 based on the load forecasts provided by the LDC. The next cycle of regional planning will commence in 2025 and will allow the working group to reevaluate this need and confirm if the station capacity need still holds true in 2028. Should this be the case, the TWG at that moment will decide the best course of actions to address this need.

The TWG recommends Alternative 4 as the preferred solution at this RIP. Considering the long-term outlook of the need, the LDC intends to move forward by retaining the services of a consultant to assist in understanding the pricing of each of the proposed alternatives. Prior to determining the preferred alternative an investigation of the total costs and benefits of each solution will be completed. The LDC does not intend to engage in any material investments prior to 2028 to mitigate the challenge of Kenora MTS reaching its thermal capacity, instead continued study and monitoring of load growth and customer connections is anticipated to trigger investment. To fully understand the preferred alternative and investment benefits, the LDC intends to incorporate and quantify the benefits of grid scale and behind-the-meter (BTM) energy storage solutions that may allow for access to many different services reducing the cost of reliable service to the City of Kenora.

Furthermore, the LDC recognizes that non-wires alternative could be developed in stages to reduce cost and align with the load growth as compared to a traditional wires investment (e.g., new substation.) This offers enhanced reliability for radially supplied customers that would otherwise not have effective options to improve their reliability, particularly for momentary outages.

The roadmap below has been prepared to ensure that the LDC remains well positioned to address the challenge with sufficient time for deployment and with the most cost-effective solution for its customers.

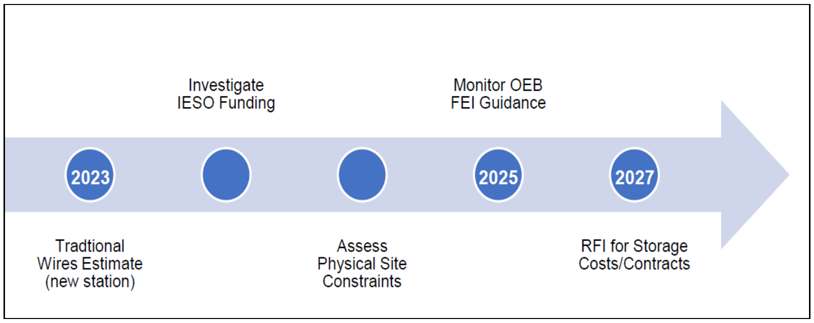

Figure 6: Kenora MTS Strategy Roadmap

8.3 Transmission Lines Capacity Needs

All line and equipment loads shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings. A Transmission

Lines Capacity Assessment was performed over the study period 2023-2033 for the 230kV and 115kV Transmission line circuits in the Northwest Region by assessing thermal limits of the circuit and the voltage range as per ORTAC to cater this need. Based on the results, the Northwest region currently does not have a firm supply capacity need. But it is important to consider the potential impact of large mining and industrial developments that can quickly consume the remaining supply capacity with minimal lead time. After engaging with development proponents and stakeholders during the IRRP phase, the Technical Working Group (TWG) identified three potential transmission circuits, E4D, M2W and E2R, that may require additional supply capacity if all proposed projects materialize.

8.3.1 E4D and E2R – 115kV – Capacity Needs under Mining Sector Development

The E4D circuit supplies the Ear Falls and Red Lake area, while the E2R circuit serves the Red Lake area north of Dryden. The E4D circuit has a continuous summer rating of 410 A, equivalent to approximately 72 MW. Additionally, there is a combined 18 MW of dependable hydro generation output from three hydroelectric power stations. Considering the thermal capability and hydro generation, the load capability of the E4D circuit is approximately 90 MW during the summer. It is worth noting that the winter load meeting capability is expected to be higher due to the circuit's higher thermal rating and increased hydro generation output.

As for the E2R circuit, it has a continuous summer rating of 421 A, translating to a load meeting capability of approximately 74 MW. The E2R circuit's continuous winter rating is 528 A, resulting in a load meeting capability of approximately 93 MW due to pre-contingency thermal and voltage limitations, meaning a load of 93 MW also causes pre-contingency voltage declines at Red Lake TS.

The IRRP forecasts the summer peak demand of the E4D circuit to reach 67 MW in 2032, and the summer peak demand of the E2R circuit to reach 61 MW in the same year.

The system area map is shown below in Figure 7:

Figure 7: Dryden - Ear Falls - Red Lake Map

Considering the potential combined area load growth from mining and Wataynikaneyap Power customer connections, which could increase by 50-115 MW by 2028, a few mining and industrial customers are actively engaging with IESO and Hydro One Transmission to explore potential options to accommodate this load increase. As shown on Figures 8-11, four transmission alternatives have been proposed to address the capacity needs in the area. These options also require the installation of appropriately sized voltage devices to mitigate voltage performance criteria.

- Alternative 1 - Upgrade 115kV Circuit E4D and E2R:

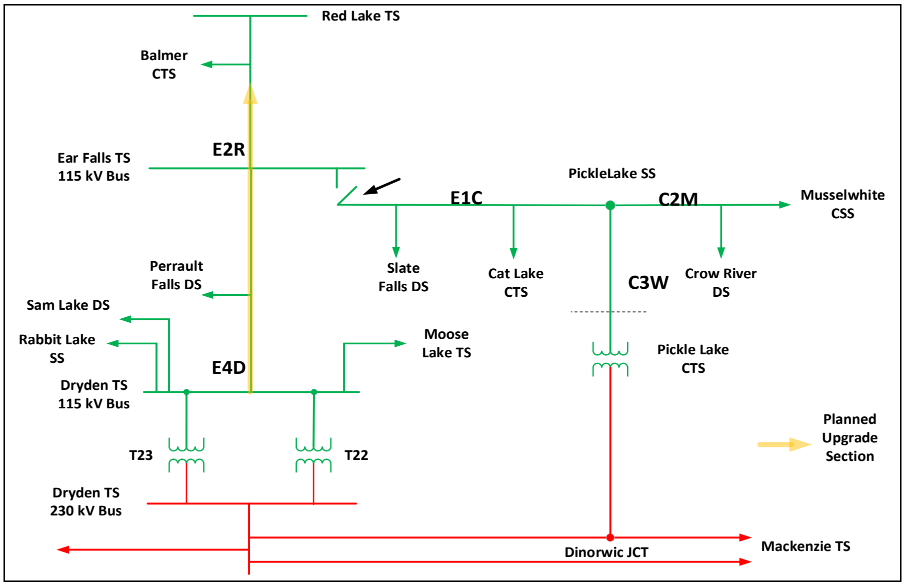

Figure 8: Alternative 1 Single Line Diagram - Upgrades on Existing Infrastructure

- Alternative 2 – Building a new 115kV Single Transmission Line from Dryden TS to Red Lake TS:

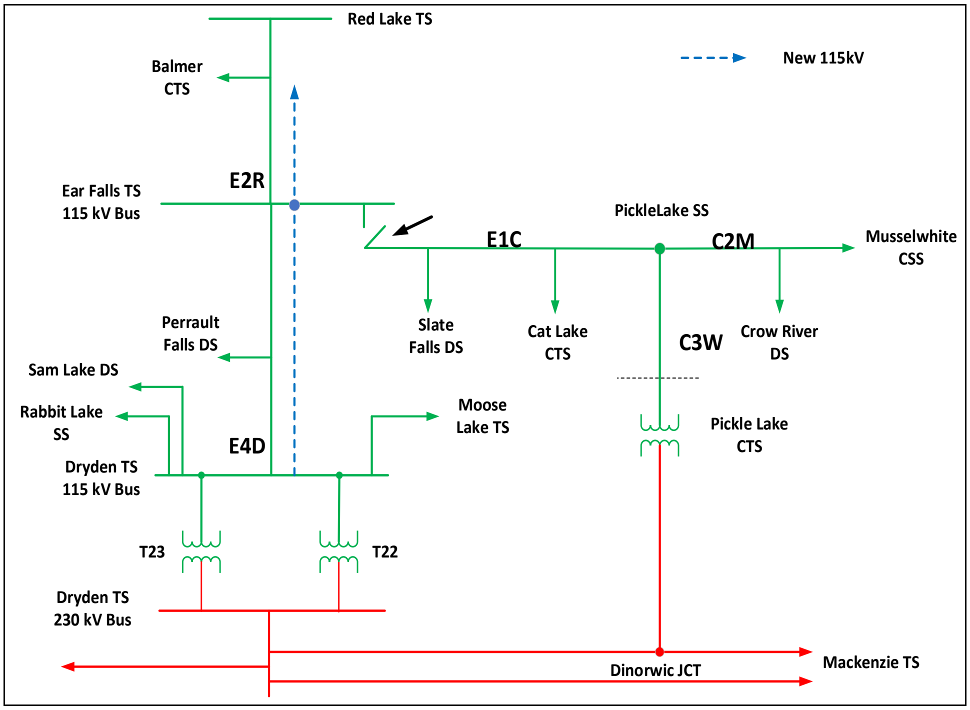

Figure 9: Alternative 2 Single Line Diagram – Building New 115kV Infrastructure

- Alternative 3 – Building a new 115kV Single Transmission Line from Ear Falls TS to Red Lake TS with E4D Upgrades:

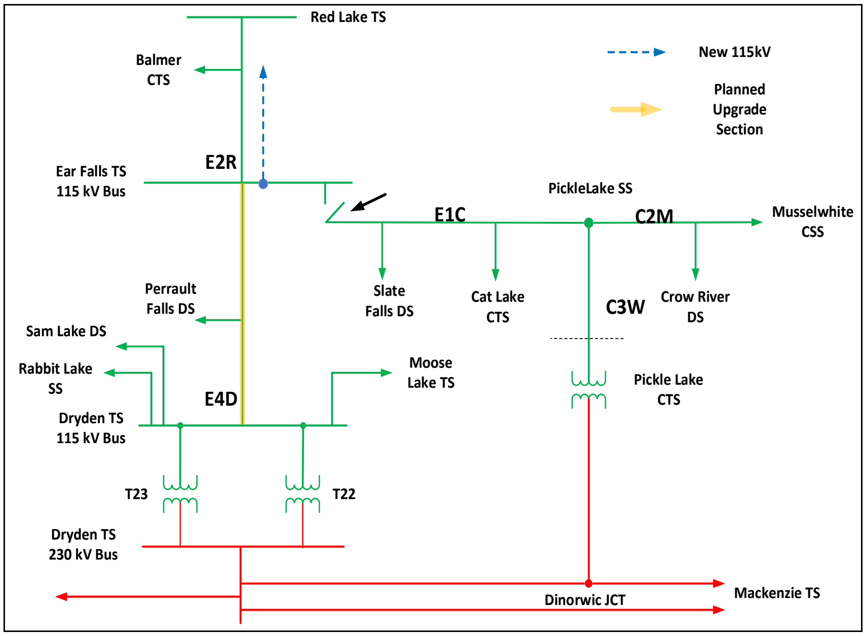

Figure 10: Alternative 3 Single Line Diagram - Building New 115kV Infrastructure and Upgrades on Existing Infrastructure

- Alternative 4 – Building a new 230kV Single Transmission Line from Dryden TS to Red Lake TS:

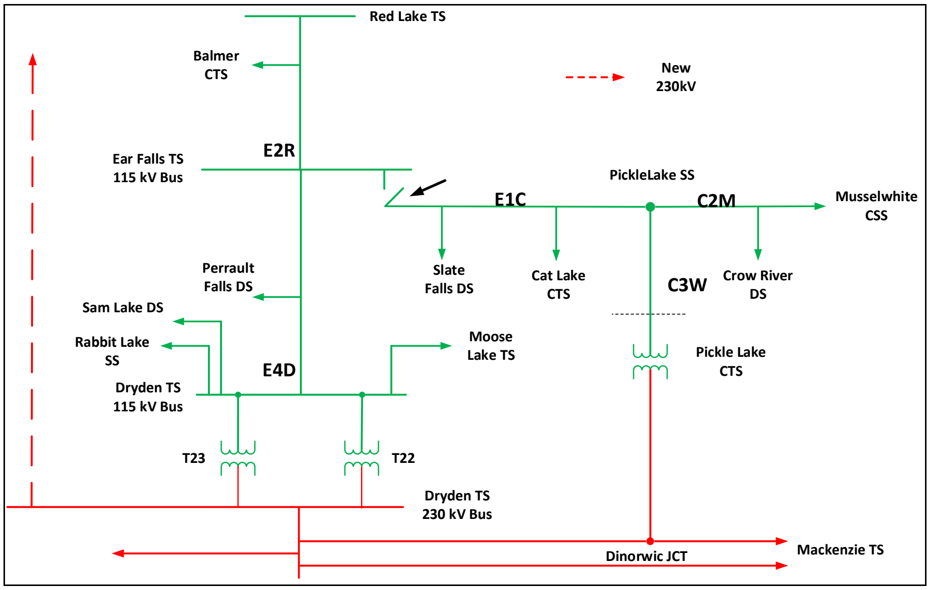

Figure 11: Alternative 4 Single Line Diagram - Building New 230kV Infrastructure

These options require the installation of appropriately sized voltage devices to mitigate pre-contingency voltage limitations. The planning allowance for these alternatives ranges from $125M to $375M, depending on the materialized load and the required infrastructure.

To determine the most cost-effective and beneficial solution to increase the area's load meeting capability, one of the project proponents has taken the lead in initiating a technical feasibility study with IESO and a physical feasibility study with Hydro One. These studies aim to thoroughly investigate the proposed alternatives and assess their economic viability and overall benefits. The goal is to identify the optimal solution that not only meets the area's increasing load demands but also ensures long-term reliability and system stability.

By conducting a detailed analysis and leveraging the expertise of Hydro One and IESO, it is expected to identify the most suitable course of action that maximizes cost-effectiveness and delivers significant value to all stakeholders in the area. The findings of this study will contribute to the decision-making process, enabling the selection of a preferred solution that aligns with the region's future growth plans.

8.3.2 M2W – 115kV – Capacity Needs under Mining Sector Development

The M2W circuit is a radial transmission line supplied from Marathon TS, consisting of two independent branches. One branch extends approximately 70 km in the north-east direction to Manitouwadge DS, while the other branch stretches eastward for about 100 km to White River DS.

There is a possible growing capacity need on the branch that leads towards Manitouwadge DS flagged by a customer connection application after the 2023 Northwest Ontario IRRP The section from Pic JCT to Manitouwadge JCT is the most constrained, with a continuous summer rating of 290 A, equivalent to approximately 57 MW. Recently, there has been significant interest from mining customers, with an anticipated growth of 30-80 MW by 2028. The 2022 summer peak demand on the M2W branch was 6.1 MW. Additionally, an industrial customer is planning a mining project of 50.9 MW by 2025-2026 on this branch. If the mining project proceeds as planned, the branch will start to experience capacity issues.

To address the potential need for additional capacity, the following alternatives are being considered:

- Alternative 1 - Upgrade the conductor and structures on the existing M2W circuit
- Alternative 2 - Building a new parallel 115kV circuit supplied from Marathon TS

Since the anticipated increase in mining sector load has not yet materialized, further assessment of the above alternatives for reinforcing the M2W circuit will be conducted to determine their cost and feasibility. These assessments will be undertaken in the event of a request from customers for additional load and upon reaching an agreement with them.

8.4 System Reliability, Operational and Restoration Needs

The transmission system must be planned to satisfy demand levels up to the extreme weather, median-economic forecast for an extended period with any one transmission element out of service. A study has been performed, considering the net coincident load forecast and the loss of one element over the study period 2023-2033 to cater this need**.** Based on the results, the following system reliability and operation needs have been identified for this Region.

8.4.1 Fort Frances MTS Customer Reliability Need

Fort Frances MTS, a step-down transformer station that supplies LDC loads in Fort Frances, is supplied from the nearby Fort Frances TS via a single circuit 115kV line F1B. Line F1B extends approximately 20 km to the east of Fort Frances to also supply rural Hydro One LDC loads. The single circuit supply configuration results in Fort Frances MTS supply interruptions during certain transmission outages (planned and unplanned). Over the past 10 years, 90% of Fort Frances Power's customer interruptions is a due to transmission supply losses as reported by the Ontario Energy Board (OEB). Fort Frances LDC has indicated a reliability need due to the single circuit supply configuration as planned and unplanned outages causes community-wide power outages. Outage durations ranges from 4 to 8 hours with a total of 16MW load interrupted. Despite meeting the ORTAC criteria, the current supply configuration of the Fort Frances MTS remains highly disruptive for customers. However, considering the close proximity of Fort Frances MTS to Fort Frances TS, there is potential for cost-effective improvement solutions.

The two stations are located across the street from each other. Most of the Fort Frances MTS station equipment has exceeded their manufacture life span and will need to be replaced within the next 10-15 years. The current Fort Frances MTS station configuration also does not allow for any primary 115kV components to be isolated for maintenance purposes; therefore, the entire station must be de-energized to allow for primary components to be serviced or repaired. Considering all above, reconfiguration of the station will improve the supply interruptions for Fort Frances MTS.

The Fort Frances TS 115kV station layout and connection to Fort Frances MTS is shown in Figure 12. Fort Frances TS 115kV side is comprised of a six-breaker ring bus with connections to the station's two autotransformers and circuits K6F, F3M, F2B and F1B. Fort Frances MTS is currently connected to the F1B circuit which connects to L1 bus. Hydro One has proposed reconfiguration options with the goal of reducing Fort Frances MTS' exposure to transmission outages.

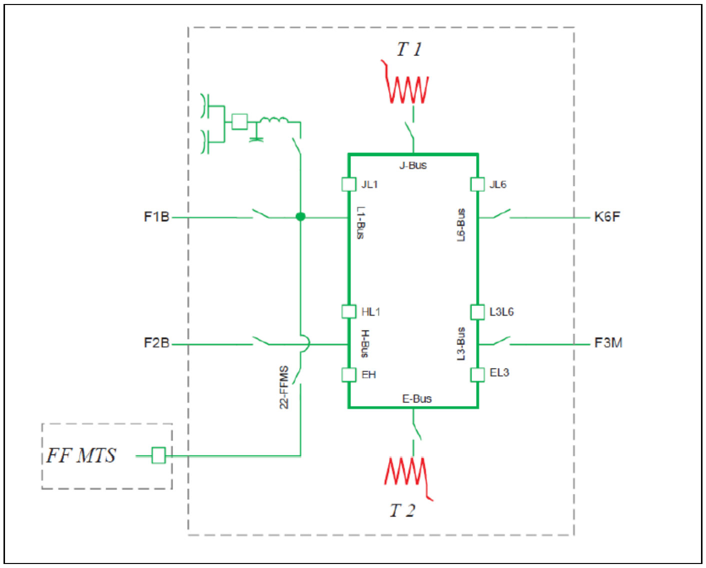

Figure 12: Fort France TS Single Line Diagram

Alternative 1:

Replace the existing 22-FFMS air-break switch with an interrupter switch (still connected to F1B) and install a second interrupter switch to connect Fort Frances MTS to F2B. One of the two switches would be operated normally open, but the switches would allow Fort Frances MTS to be transferred between F1B and F2B to avoid any supply interruptions during planned outages on either of the two circuits or buses.

Alternative 2:

Install a new 115kV breaker on the L1 bus and move the Fort Frances MTS termination between this new breaker and the HL1 breaker. This would form a 7-breaker ring bus and Fort Frances MTS would have its own position separate from any other circuit. This would still have the MTS on a single supply.

Alternative 3:

Install a second breaker at Fort Frances MTS and connect it to the H-bus via a new air-break switch. Since Fort Frances MTS already has two transformers, if both Fort Frances MTS breakers are normally closed, this configuration could provide fully redundant transmission supply. However, the feasibility of having both supply points normally closed is still being reviewed; a normally open point may be required to manage short circuit levels and loop flows. If either the L1-bus or H-bus supply points needs to be operated normally open, this option would be functionally the same as the first option (but more expensive).

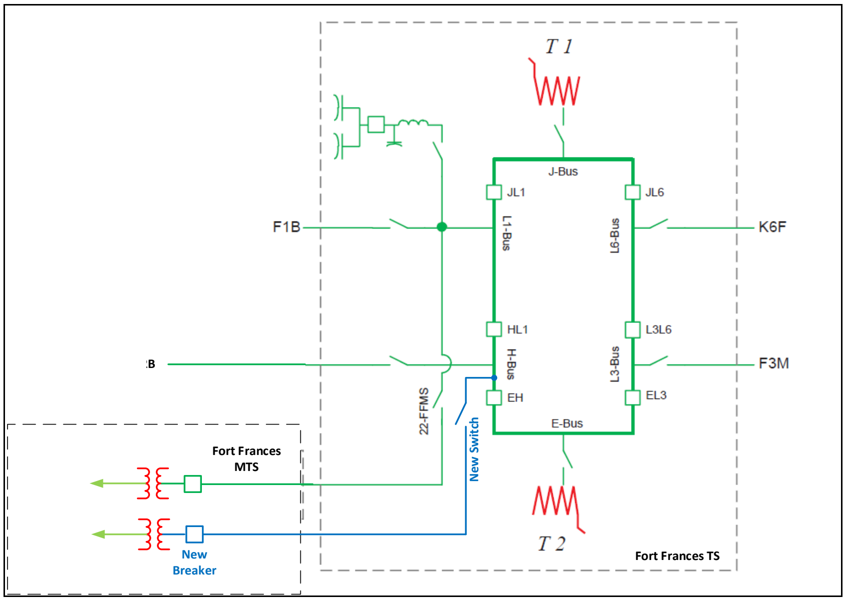

Figure 13: Fort Frances MTS Need Alternative 3

Alternative 4:
Install a second breaker and switch at Fort Frances MTS on the 115kV side, connecting it to 115kV circuit F2B via a drop feed. This creates a second supply for Fort Frances MTS, achieving full redundancy while tapping at a different location comparing to Alternative 3

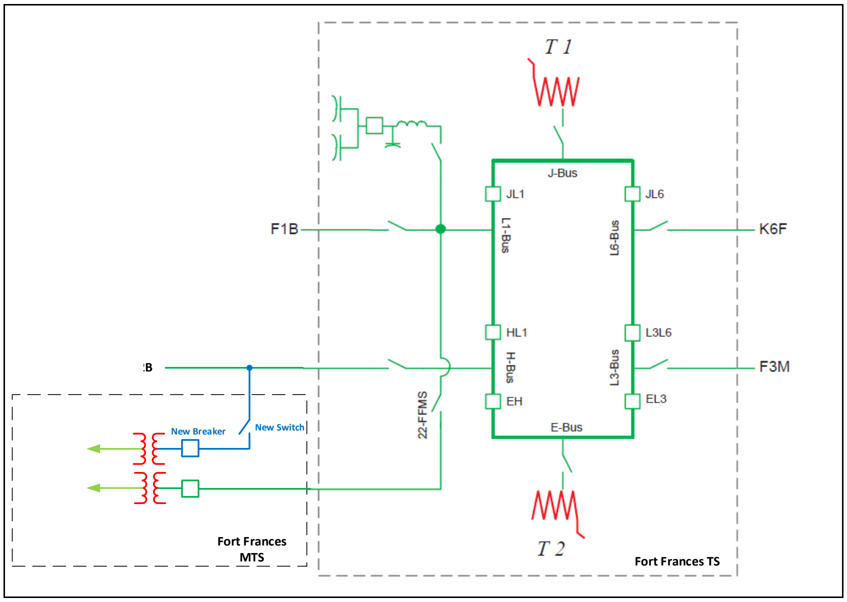

Figure 14: Fort Frances MTS Need Alternative 4

The LDC Fort Frances Power recommends alternative 4 as the optimal alternative for addressing the need. The interruptions caused by planned transmission supply outages can be effectively mitigated with the dual supply. This alternative also provides FFPC with the capability to isolate any primary station components for maintenance purposes without requiring a station-wide outage. Alternative 4 offers a robust station supply configuration that enhances reliability for current customers and accommodates potential significant load growth from industrial customers and electrification of the community. Fort Frances Power has started the preparation of the IESO SIA application package at the time of this RIP, and the project is planned for execution in the year 2026-2027. Additionally, the implementation of Alternative 4 will serve as a building block for the forthcoming Fort Frances MTS End-of-Life replacement project, contributing to its seamless execution.

8.4.2 E1C Operation and High Voltage Need

The Integrated Regional Resource Plan (IRRP), published in January 2023, identified operational challenges concerning the 115kV E1C transmission line. This line plays a critical role in the Pickle Lake area system, and its operational state significantly affects the system's overall performance. Two main challenges have been identified in the E1C operation. Limitations on supply capacity when E1C operates in a normally closed state and high voltage issues when it operates in a normally open state. A single line diagram of the area is presented in Figure 15.

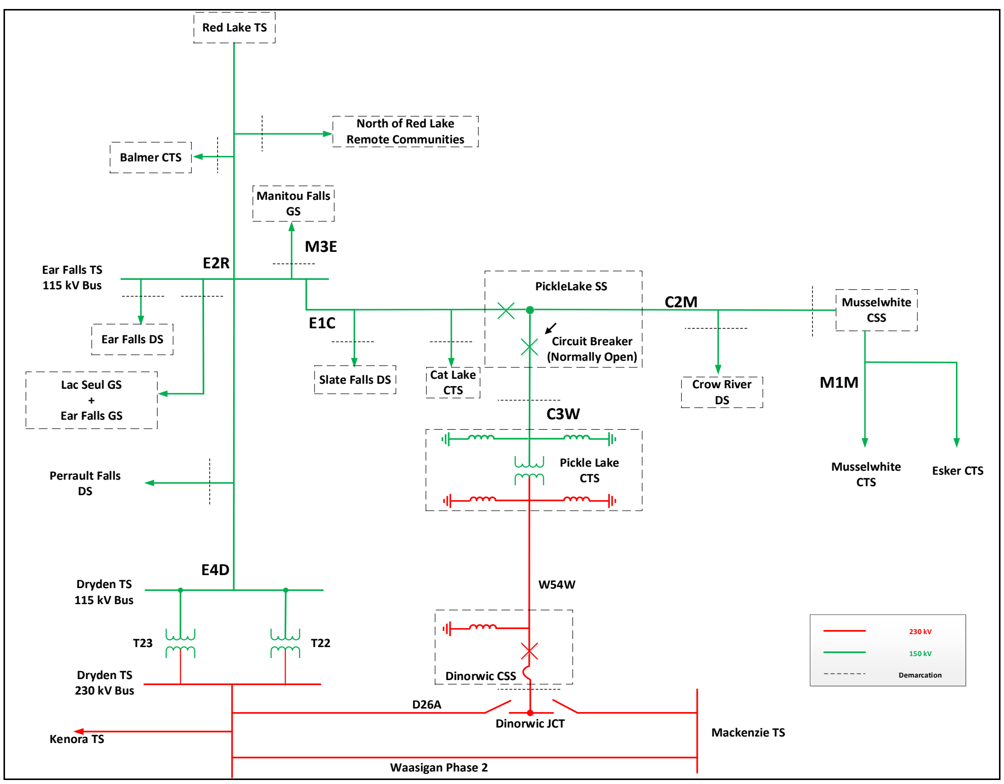

Figure 15: Dryden - Pickle Lake - Ear Falls - Red Lake Area Single Line Diagram

Operating the E1C in a closed state results in a loop configuration that restricts transfer capability through E4D and W54W, thereby limiting the area's overall potential for load increase. This limitation could potentially impact local business expansion. Moreover, if E4D were to fail, the local generations at Ear Falls TS would remain connected, potentially causing transient instability. To maintain system adequacy and meet forecast demand in the Ear Falls, Red Lake, and Pickle Lake areas, it is crucial to introduce a normally open point on the E1C line end. This change would offload E4D and shift the loading on the Pickle Lake area to the newly installed 230kV transmission line W54W. However, operating E1C in an open state would lead to high voltage issues under light load conditions, regardless of the E1C end that is opened. To resolve this problem, the following alternatives are being considered.

Alternative 1: Installation of a Remote-Controlled Switch at a Mid-Point of E1C and Operate E1C Normally Open at the New Switch Location

While opening E1C mid-point reduces most high-voltage issues and provides for more capacity on the E4D by shifting load supply to W54W, it would require an upgraded or newly installed isolation switch capable of being remotely operated from the control center. Closing the switch may be required at times under light load conditions and with unexpected events, involving failure of transmission equipment in the Pickle Lake or Ear Falls areas, could trigger the need to revert to the operating configuration in the Pickle Lake area as illustrated in Figure 15. This involves closing the switch and opening the circuit breaker at Pickle Lake SS. While using an existing switch (with no remote-control capability and no on-load switching capability) will be implemented as an interim solution; this alternative, as a permanent solution, is associated with a planning allowance of approx. $6M and the effectiveness and reliability of communications to this very remote site is low. In addition, sourcing independent and reliable AC and DC supplies for the switch will be challenging and expensive. Therefore, this alternative is considered and rejected as a permanent solution.

Alternative 2: Opening E1C on the Pickle Lake SS Line End with Reactor Installations at Cat Lake MTS or Ear Falls TS

This alternative was discussed with the TWG and was compared with alternative 3.

Opening E1C at the Pickle Lake SS end leads to a voltage as high as 132 kV on the E1C line end near Pickle Lake SS under a light load pre-contingency condition. It also results in multiple post-contingency violations. Consequently, a 10-15 Mvar shunt reactor would need to be installed near Cat Lake MTS or Ear Falls TS to implement this solution. The Ear Falls location would require site expansion. It is unknown at this time the physical feasibility of installing a high voltage shunt reactor at the MTS. As the short circuit level at the MTS is low, at least two reactor installations would be required to comply with the 4% voltage change criteria when switching a reactive device. Planning allowance is approximated to be $20M for an Ear Falls installation.

Alternative 3: Opening E1C on the Ear Falls TS Line End with Reactor Installations at Pickle Lake SS

This alternative mirrors alternative 2 but opens the other end of E1C. High voltage violations are less severe in this configuration, with pre-contingency voltages in the area staying within the ORTAC limit. The most critical contingency is the loss of one of the existing 20 Mvar reactors at Pickle Lake CTS. The TWG has confirmed that installing an additional 10 - 15 Mvar reactor at Pickle Lake SS would address the high voltage violation. Space is available at Pickle Lake SS for a reactor installation and the short circuit levels are sufficient at this station to require 1 reactive device in lieu of two smaller ones. Planning allowance is approximated to be $20M.

The TWG recommends Alternative 3 as the most effective solution. This approach only experiences high voltage violations under post-contingency scenarios, and the addition of a 10 -15 Mvar reactor can effectively mitigate these violations. Once this reactor is installed at Pickle Lake SS, the interim normally open point on E1C (mid-point) will be closed and the new normally open point made to be at Ear Falls TS; refer to Figure 16 for the recommended solution. Once the project is initiated, the TWG will investigate and refine the automatic reactor switching scheme recommended in IRRP.

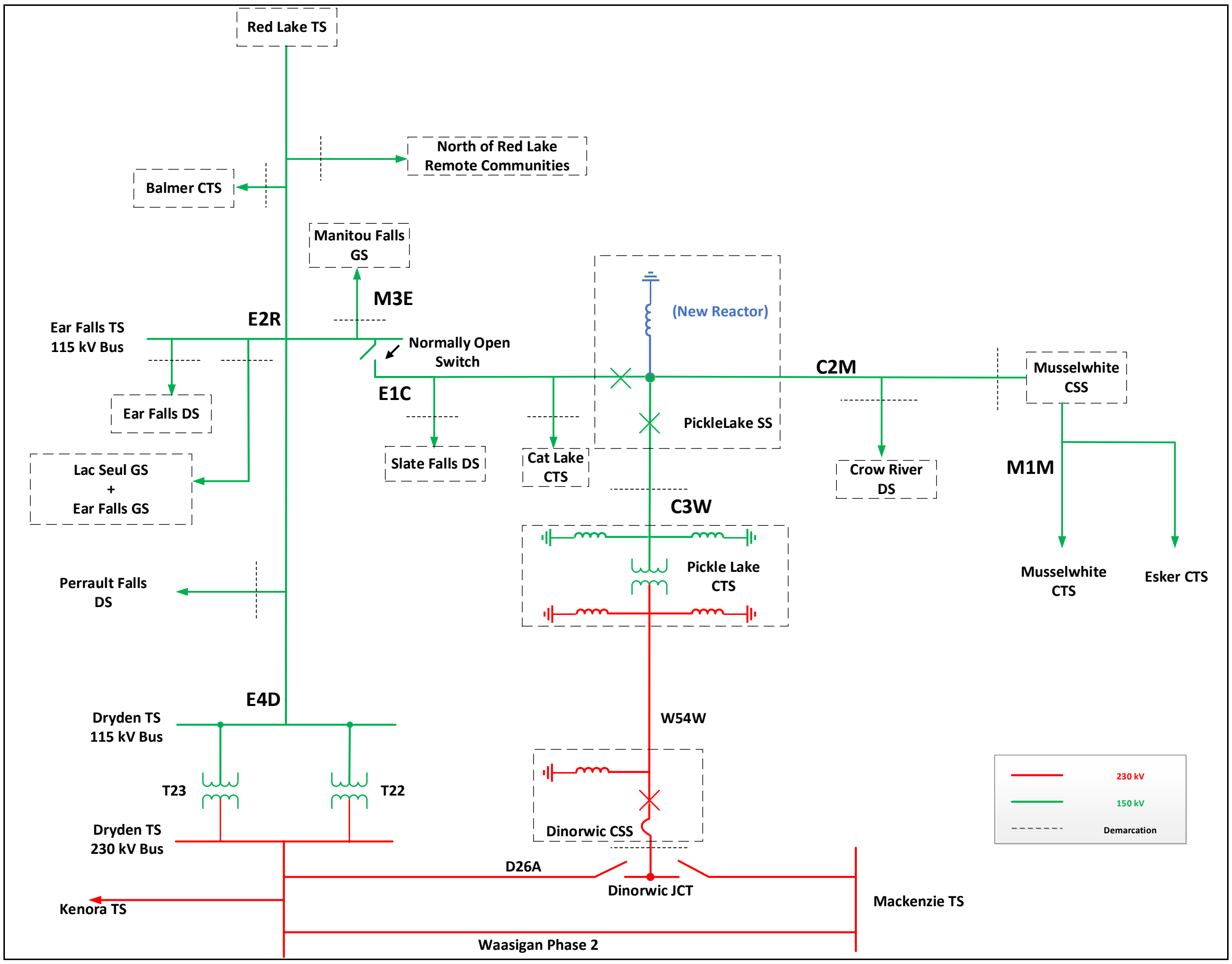

Figure 16: E1C Operation Recommended Solution

8.5 Other Planning Considerations

8.5.1 Fort William TS Shunt Capacitor Banks Replacement

Fort William TS, a step-down station in southeastern Thunder Bay, is supplied by 115kV transmission circuits B5 and B15, providing power to the suburban area. The station comprises of two 115/25 kV transformers with capacities of 50/66.6/83.3 MVA each. Additionally, Fort William TS relies on temporary capacitors on trailers, namely SC1 and SC2, which have been in service for a considerable period. SC1 and SC2 are rated at 14.88 Mvar and 15.77 Mvar respectively, operating at 25 kV. However, both capacitor banks have been assessed in poor conditions and as obsolete.

Presently, SC1 is scheduled for maintenance ensuring that SC1 remains available for service when needed. SC2 is in a significantly deteriorated condition, requiring extensive repairs both in terms of time and costs. It is crucial to address the concerns for supporting local loads and satisfying IESO's contingency planning criteria for both capacitor banks. Therefore, the following alternatives have been considered in this RIP:

Alternative 1: Maintain Status Quo

This alternative was considered and rejected as it does not address the deteriorated condition and the reliance on temporary mobile units, which could reduce supply reliability for customers.

Alternative 2: Refurbish the Existing Units

This alternative was considered and rejected due to the asset condition. SC2 has suffered damage with parts stolen and missing, making refurbishment a significant and non-economic investment with higher future maintenance requirements.

Alternative 3: Replacement for Both Units.

This alternative will provide new permanent shunt capacitors which are appropriately configured to ensure reliable supply to customers and fulfill system contingency planning criteria.

The TWG recommends alternative 3 as the preferred and cost-effective solution. Given the asset condition, refurbishing SC2 is not deemed worthwhile compared to the effort required for replacement. Recognizing the criticality of these units for local system reliability, Hydro One is initiating a project, with a planning allowance of $6M, to replace both units with similar equipment. Simultaneously, SC1 is scheduled for maintenance to ensure its functional operation until replacement.

By implementing alternative 3, Fort William TS will address the significant deteriorated assets issue, meet contingency planning criteria, and maintain a reliable power supply to customers.

8.5.2 Greenstone - Marathon Area System Needs

In Northwest Ontario, there continues to be interest in additional loads and generation connections in the Greenstone-Marathon sub-region. Alternatives presented in the past IRRPs, and RIPs remain valid. Further assessment of those alternatives for reinforcing the area will be conducted to determine their cost and feasibility. These assessments will be undertaken in the event of a request from customers for additional load and upon reaching an agreement with them.

8.5.3 Supply to the Ring of Fire

The Ring of Fire is a remote area approximately 500 km north of Thunder Bay rich in critical minerals but without grid power supply. As per the 2023 Northwest Ontario IRRP, there are a few options to energize the Ring of Fire area. With renewed interest in developing the Ring of Fire from both government and mining companies, the IESO is updating its Supply to the Ring of Fire study to help inform government policy and potential customers seeking connection. Preliminary findings were included in the 2023 Northwest IRRP. The scope and timing of the IESO's ongoing study will evolve with government policy direction.

9. CONCLUSION AND RECOMMENDATION

This section concludes the Regional Infrastructure Plan report for Northwest Ontario region. The Major infrastructure investments recommended by the TWG in the near and mid-term planning horizon 2023-2033 are provided in Table 16 below, along with their planned in-service dates (ISD) and budgetary estimates for planning purposes.

Table 16: Recommended Plans over the next 10 Years

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Cost ($M)
Asset Renewal Needs				
Rabbit Lake SS	Replacement 115kV switchyard and associated equipment	Hydro One Transmission	2024-2027	$35.2M
Whitedog Falls SS	Replacement three 115kV breakers, DC station services and associated equipment	Hydro One Transmission	2025-2028	$8.5M
Mackenzie TS	Replacement of one 230/115kV autotransformer, five 230kV breakers, four switches, AC station services and associated equipment	Hydro One Transmission	2025-2028	$54.6M
Wawa TS	Replacement of one 230/115kV autotransformer, associated breakers and equipment and station services	Hydro One Transmission	2026-2029	$43.8M
Marathon TS	Replacement of 230kV and 115kV breakers and associated equipment	Hydro One Transmission	2026-2029	$14.6M
Lakehead TS	Replacement of 230kV and 115kV breakers, station services and associated equipment	Hydro One Transmission	2028-2031	$41.5M
Lakehead TS Condenser C8 Replacement	Replace Condenser C8 with a +60/-40 Mvar STATCOM	Hydro One Transmission	2027	$40.6M
Fort Frances TS	Replacement of 230kV breakers, associated equipment, and station services	Hydro One Transmission	2029-2032	$20.3M
Kenora TS	Replacement of 230kV breakers, associated equipment, and station services	Hydro One Transmission	2030-2033	$17M

Station Capacity Needs				
Margach DS	Monitor and implement investment plan in 2025	Hydro One Distribution	2025	$1M
Crilly DS	Further assess the Alternative 1 and Alternative 2 from this RIP	Hydro One Distribution	NA	NA
White Dog DS	Monitor and review in next planning cycle	Hydro One Distribution	NA	NA
White River DS	Monitor and review in next planning cycle	Hydro One Distribution	NA	NA
Kenora MTS	Further assess the alternatives from this RIP; monitor and review in next planning cycle	Synergy North	NA	NA
Sam Lake DS	Install fan monitoring – Refer to Local Planning for more detail	Hydro One Distribution and Sioux Lookout Hydro	2023	$1.5M
Transmission Line Capacity Needs				
E2R and E4D	Further evaluation on the four alternatives based on mining customers' requests	Hydro One Transmission and Proponent	TBD	$125M-375M
M2W	Further evaluation on the 2 alternatives based on mining customers' requests	Hydro One Transmission and Proponent	TBD	TBD
System Reliability, Operation and Load restoration Needs				
Fort Frances MTS	Install a second breaker and switch in Fort Frances MTS to create a second supply to the MTS	Fort Frances Power	2026-2027	$0.85M
E1C Operation	Open E1C end at Ear Falls TS and install a 10 – 15 MVAR shunt reactor at Pickle Lake SS	Hydro One Transmission	2026-2027	$20M
Other Planning Considerations				
Fort Williams TS Shunt Capacitor	Temporary capacitors to be replaced with permanent units	Hydro One Transmission	2026-2027	$6M

Banks Replacement				
Greenstone-Marathon Area System Needs	Further evaluation of the alternatives presented in the past IRRPs and RIP upon customers' requests	Hydro One Transmission and Proponent	TBD	TBD
Supply to the Ring of Fire	IESO to update Supply to the Ring of Fire study	IESO	TBD	TBD

Note:

a) The planned in-service dates are tentative and subject to change
b) Costs are based on budgetary planning estimates/allowance and excludes the cost for distribution infrastructure (if required)

10. REFERENCES

[1] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (issue 5.0 August 22, 2007)

[2] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. December 18, 2018)

[3] Ontario Energy Board, Distribution system Code (issue July 14, 2000 rev. October 1, 2022)

[4] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

Appendix A: Extreme Winter Weather Adjusted Net Load Forecast

Table A.1: Northwest Ontario Region – Winter Non-Coincident- Net Load Forecast

Transformer Station Name	DESN ID	LTR (MVA)	LV Cap	LTR (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Agimak DS	T1/T2	12.0	N	10.80	5.14	5.15	5.18	5.24	5.30	5.36	5.43	5.49	5.57	5.64	5.72	5.90	5.95	6.01	6.06	6.12	6.17	6.23	6.32	6.39	6.46
Barwick DS	T1/T2	65.4	Y	62.13	27.61	27.58	27.69	27.86	28.02	28.19	28.35	28.51	28.71	28.79	29.00	23.68	23.88	24.07	24.26	24.45	24.64	24.84	24.12	23.85	23.58
Beardmore DS # 2	T2	12.0	N	10.80	1.67	1.62	1.62	1.64	1.65	1.66	1.75	1.75	1.71	1.72	1.74	1.69	1.70	1.72	1.73	1.74	1.75	1.77	1.77	1.78	1.78
Birch TS	T2/T3/T4	111.6	Y	106.02	74.30	74.25	73.91	73.83	74.12	74.63	74.71	74.79	75.26	75.77	76.10	78.77	79.05	79.46	79.82	80.23	80.68	81.03	81.24	81.72	82.20
Burleigh DS	31T1	11.6	N	10.44	4.70	5.12	5.12	5.13	5.15	5.17	5.18	5.19	5.21	5.22	5.24	5.65	5.68	5.71	5.73	5.76	5.79	5.82	5.91	5.96	6.02
Cat Lake MTS	T1	3.0	N	2.70	1.05	1.05	1.06	1.07	1.09	1.10	1.12	1.13	1.15	1.17	1.18	1.18	1.19	1.21	1.22	1.23	1.25	1.26	1.27	1.29	1.30
Clearwater Bay DS	40T1	10.4	N	9.36	6.37	6.36	6.36	6.37	6.39	6.41	6.41	6.41	6.42	6.43	6.44	7.17	7.21	7.24	7.27	7.30	7.33	7.36	7.43	7.50	7.57
Crilly DS (Sturgeon Falls CGS)	23T1	2.4	N	2.16	2.14	2.14	2.15	2.16	2.18	2.19	2.20	2.21	2.23	2.24	2.25	2.49	2.51	2.53	2.54	2.56	2.58	2.60	2.63	2.66	2.69
Crow River DS	21T1/21T2	11.6	N	10.44	3.32	3.32	3.33	3.35	3.37	3.39	3.42	3.44	3.46	3.49	3.52	3.62	3.64	3.66	3.68	3.71	3.73	3.75	3.78	3.81	3.84
Dryden TS	T4/T5	63.3	N	56.97	20.74	20.82	20.99	21.20	21.47	21.71	21.95	22.17	22.42	22.71	22.81	22.42	22.70	22.97	23.25	23.52	23.80	24.08	24.10	24.29	24.48
Ear Falls DS	T5	11.6	N	10.44	6.01	6.00	6.01	6.05	6.10	6.15	6.22	6.27	6.35	6.41	6.48	6.38	6.41	6.45	6.49	6.52	6.56	6.60	6.66	6.70	6.73
Eton DS	T1	12.0	N	10.80	4.13	4.14	4.15	4.16	4.18	4.20	4.21	4.21	4.22	4.23	4.25	4.72	4.75	4.79	4.82	4.85	4.88	4.91	4.95	5.01	5.06
Fort Frances MTS	T2/T3	26.6	N	23.94	16.23	16.20	16.21	16.27	16.33	16.39	16.46	16.53	16.63	16.72	16.83	17.79	17.88	17.97	18.06	18.15	18.24	18.33	18.48	18.62	18.77
Fort William TS	T5/T6	109.4	N	103.93	79.15	79.30	79.25	79.10	79.50	80.12	80.28	80.44	85.03	85.62	86.11	89.88	90.42	91.04	91.68	92.34	93.00	93.65	95.15	96.19	97.22
Jellico DS # 3	T1	2.4	N	2.16	0.71	0.71	0.71	0.71	0.71	0.72	0.72	0.73	0.73	0.74	0.75	0.75	0.75	0.75	0.76	0.76	0.76	0.77	0.77	0.78	0.78
Keewatin DS	T1	11.6	N	10.44	5.42	5.42	5.43	5.45	5.47	5.50	5.50	5.51	5.52	5.53	5.54	6.21	6.24	6.28	6.32	6.36	6.40	6.43	6.49	6.56	6.63
Kenora DS	T1	12.0	N	10.80	6.79	6.81	6.84	6.88	6.92	6.98	7.01	7.04	7.08	7.11	7.16	7.75	7.81	7.88	7.94	8.00	8.07	8.13	8.20	8.29	8.38
Kenora MTS	-	26.0	N	23.40	21.49	21.76	21.95	22.15	22.52	22.95	23.25	23.56	23.86	24.17	24.45	25.88	26.12	26.53	26.79	27.14	27.55	27.81	28.24	28.64	29.04
Longlac TS	T2	47.6	Y	45.22	21.45	21.39	15.80	15.97	16.15	16.33	16.58	16.80	17.08	17.33	17.59	17.38	17.52	17.67	17.81	17.95	18.09	18.24	17.35	17.32	17.29
Manitouwadge DS	19T1	9.6	N	8.64	1.40	1.39	1.40	1.40	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.60	1.60	1.61	1.62	1.63	1.64	1.64	1.66	1.68	1.69
Manitouwadge TS	T1	41.7	N	37.53	10.34	18.84	18.92	19.11	19.32	19.54	19.82	20.09	20.41	20.69	21.00	19.94	20.09	20.25	20.41	20.56	20.72	20.88	22.04	22.30	22.57
Marathon DS	2375T1	11.6	N	10.44	8.11	8.15	8.19	8.26	8.34	8.41	8.48	8.54	8.61	8.68	8.76	10.49	10.59	10.69	10.80	10.90	11.00	11.10	11.34	11.55	11.76
Margach DS	T2	11.6	N	10.44	10.50	10.48	10.47	10.48	10.51	10.53	10.53	10.53	10.55	10.55	10.61	15.33	15.39	15.45	15.51	15.57	15.63	15.68	16.28	16.68	17.08
Minaki DS	T1	12.0	N	10.80	0.87	1.70	1.69	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.82	1.83	1.83	1.84	1.84	1.85	1.85	1.95	1.98	2.00
Moose Lake TS	T2/T3	12.2	N	10.98	7.78	7.73	7.78	7.77	7.76	7.76	7.76	7.75	7.76	7.77	7.78	7.72	7.72	7.72	7.72	7.72	7.72	7.72	7.72	7.71	7.71
Murillo DS*	T1/T2	13.0	N	11.70	19.55	19.56	19.58	19.63	19.69	19.76	19.76	19.76	19.77	19.78	19.80	21.27	21.34	21.40	21.45	21.50	21.55	21.59	21.78	21.93	22.08
Nestor Falls DS	T1	11.6	N	10.44	3.75	3.75	3.75	3.76	3.77	3.78	3.79	3.79	3.80	3.81	3.83	4.21	4.22	4.24	4.26	4.28	4.30	4.32	4.36	4.40	4.44
Nipigon DS	24T1	11.6	N	10.44	4.07	4.09	4.11	4.14	4.18	4.22	4.26	4.30	4.34	4.38	4.43	4.57	4.61	4.65	4.69	4.73	4.77	4.81	4.86	4.90	4.95
Perrault Falls	36T1	11.6	N	10.44	0.52	0.52	0.53	0.53	0.53	0.54	0.54	0.55	0.55	0.56	0.56	0.59	0.59	0.60	0.60	0.61	0.61	0.62	0.62	0.63	0.64
Pic DS	1504T2	12.0	N	10.80	8.07	13.27	13.28	13.31	13.34	9.13	9.15	9.17	9.20	9.23	9.26	6.80	6.84	6.89	6.93	6.97	7.02	7.06	5.74	5.38	5.02
Port Arthur TS	T1/T2	61.4	N	55.26	36.98	37.10	37.02	37.39	37.73	38.17	38.37	38.61	38.58	39.00	38.91	41.45	41.39	41.86	41.83	42.06	42.55	42.52	43.12	43.50	43.88
Red Lake TS	T3/T4	61.5	Y	58.43	31.04	33.98	34.32	34.69	35.09	35.47	30.75	31.23	31.77	32.23	32.67	31.73	32.14	32.54	32.95	33.36	33.78	34.19	32.82	32.81	32.79
Redrock DS	33TT1	9.6	N	8.64	4.51	4.49	4.49	4.50	4.51	4.53	4.53	4.54	4.55	4.56	4.58	4.12	4.14	4.15	4.16	4.18	4.19	4.21	4.14	4.11	4.08
Sam Lake DS	2501T1/2501T2	24.0	N	21.60	28.22	28.47	28.67	28.70	28.72	28.74	28.74	28.74	28.78	28.81	28.87	30.53	30.64	30.74	30.86	30.97	31.08	31.19	31.33	31.52	31.71
Sapawe DS	11T1/11T2	4.8	N	4.32	4.50	4.51	4.52	4.54	4.57	4.60	4.62	4.64	4.66	4.68	4.71	4.90	4.93	4.97	5.00	5.04	5.07	5.11	5.13	5.17	5.20
Schreiber Winnipeg DS	34T1	9.6	N	8.64	5.80	5.81	5.83	5.87	5.91	5.95	5.98	6.01	6.04	6.08	6.12	6.83	6.88	6.93	6.98	7.03	7.08	7.14	7.23	7.32	7.41
Shabaqua DS	32T1	9.6	N	8.64	3.32	3.32	3.32	3.33	3.35	3.36	3.37	3.39	3.40	3.42	3.44	3.69	3.71	3.73	3.75	3.77	3.78	3.80	3.84	3.87	3.91
Sioux Narrow DS	27T1	12.0	N	10.80	5.01	5.01	5.01	5.03	5.05	5.07	5.08	5.09	5.11	5.12	5.14	5.66	5.69	5.72	5.75	5.78	5.80	5.83	5.89	5.95	6.01
Slate Falls DS	T1	4.7	N	4.23	0.77	0.77	0.77	0.77	0.78	0.78	0.79	0.79	0.80	0.80	0.81	0.84	0.85	0.85	0.86	0.86	0.87	0.88	0.88	0.89	0.90
Valora DS	30T1	4.8	N	4.32	0.96	0.96	0.97	0.99	1.00	1.01	1.03	1.04	1.05	1.07	1.08	1.16	1.17	1.19	1.20	1.22	1.23	1.25	1.26	1.28	1.30
Vermillion Bay DS	31T1	9.6	N	8.64	2.65	2.66	2.68	2.70	2.73	2.75	2.78	2.80	2.83	2.85	2.88	2.85	2.87	2.90	2.93	2.96	2.99	3.01	3.02	3.04	3.06
White Dog DS	-	3.2	N	2.88	2.80	2.82	2.85	2.87	2.92	2.95	2.99	3.01	3.05	3.07	3.11	3.08	3.12	3.16	3.20	3.24	3.28	3.32	3.33	3.36	3.39
Whiteriver DS	36T1	15.6	N	14.04	13.42	13.51	13.69	13.80	13.91	14.00	14.09	14.18	14.27	14.35	14.44	12.15	12.23	12.31	12.39	12.47	12.54	12.62	12.42	12.32	12.22
Pickle Lake Cluster	-	-	-	-	9.57	9.85	10.14	10.43	10.74	11.06	11.39	11.73	12.08	12.44	12.81	13.19	13.59	14.13	14.70	15.29	15.90	16.53	17.20	17.88	18.60
Red Lake Cluster	-	-	-	-	9.93	10.24	10.57	10.90	11.24	11.60	11.97	12.35	12.74	13.15	13.57	14.01	14.46	15.04	15.64	16.26	16.91	17.59	18.29	19.02	19.79

Appendix B: Lists of Step-Down Transformer Stations

Sr.NO	Transformer Station	Voltage (kV)	Supply Circuit
1	EAR FALLS TS	115/44	M3E, E4D, E1C, E2R
2	RED LAKE TS	115/44	E2R
3	CAT LAKE MTS	115/25	E1C
4	CROW RIVER DS	115/25	C2M
5	PERRAULT FALLS DS	115/12.5	E4D
6	SLATE FALLS DS	115/24.9	E1C
7	LONGLAC TS	115/44	A4L
8	MANITOUWADGE TS	115/44	M2W
9	MARATHON TS	230/115	T1M, W21M, M23L, M2W, M24L, W22M
10	BEARDMORE DS #2	115/25	A4L
11	JELLICOE DS #3	115/12.5	A4L
12	MANITOUWADGE DS #1	115/12.5	M2W
13	MARATHON DS	115/25	T1M
14	PIC DS	115/25	M2W
15	SCHREIBER WINNIPEG DS	115/12.5	A5A
16	WHITE RIVER DS	115/25	M2W
17	BARWICK TS	115/44	K6F
18	DRYDEN TS	230/115	K3D, D26A, E4D, D5D, K23D, M2D
19	FORT FRANCES TS	232/115	K24F, F25A, K6F, F1B, F2B, F3M
20	KENORA TS	230/115	K24F, K7K, K21W, K23D, K22W
21	MACKENZIE TS	230/115	D26A, A22L, A3M, F25A, A21L, N93A
22	MOOSE LAKE TS	115/44	A3M, M1S, M2D, B6M
23	FORT FRANCES MTS	115/12.47	F1B
24	KENORA MTS	115/12.5	15M1
25	AGIMAK DS	115/25	29M1
26	BURLEIGH DS	115/12.5	F1B
27	CLEARWATER BAY DS	115/25	SK1
28	ETON DS	115/12.48	K3D

29	KEEWATIN DS	115/12.5	SK1
30	MARGACH DS	115/25	K6F
31	MINAKI DS	115/25	K4W
32	NESTOR FALLS DS	115/12.5	K6F
33	SAM LAKE DS	115/25	K3D
34	SAPAWE DS	115/12.5	B6M
35	SHABAQUA DS	115/12.5	B6M
36	SIOUX NARROWS DS	115/12.5	K6F
37	VALORA DS	115/25	29M1
38	VERMILION BAY DS	115/12.5	K3D
39	BIRCH TS	115/28.4	B9, P7B, B14, B5, R2LB, P3B, B15, R1LB, B6M
40	FORT WILLIAM TS	115/25	B5, B15
41	LAKEHEAD TS	230/115	A22L, M23L, A21L, R2LB, L4P, M24L, A7L, R1LB, A8L, L3P
42	PORT ARTHUR TS #1	115/25	P7B, P1T, A6P, L4P, P3B, P5M, L3P
43	MURILLO DS	115/25	B6M
44	NIPIGON DS	115/12.5	57M1
45	RED ROCK DS	115/12.5	56M1
46	Pickle Lake CTS	230/115	W54W
47	NORTH CARIBOU LAKE TS (D)	115/25	WCD
48	MUSKRAT DAM TS (E)	115/25	WDE
49	BEARSKIN LAKE TS (F)	115/25	WEF
50	SACHIGO LAKE TS (G)	115/25	WEG
51	KINGFISHER LAKE TS (J)	115/44/25	WCJ
52	WUNNUMIN LAKE TS (I)	44/25	WJI
53	WAWAKAPEWIN TS (K)	115/44/25	WJK
54	KASABONIKA LAKE TS (L)	44/25	WKL
55	KI-WAPEKEKA TS (M)	115/25	WKM
56	PIKANGIKUM TS (Q)	115/25	WPQ

57	POPLAR HILL TS (S)	115/25	WRS
58	DEER LAKE TS (U)	115/25	WTU
59	SANDY LAKE TS (W)	115/25	WZW
60	NORTH SPIRIT LAKE TS (V)	115/44/25	WZV
61	KEEWAYWIN TS (Y)	115/25	WVY

Appendix C: Lists of Transmission Circuits

Sr. No.	Connecting Stations	Circuit ID	Voltage (kV)
1	Mackenzie x Dryden	D26A	230
2	Mackenzie x Fort Frances	F25A	230
3	Dryden x TCPL Vermill Bay x Kenora	K23D	230
4	Fort Frances x Kenora	K24F	230
5	Mackenzie x Marmion Lake x Atikokan	N93A	230
6	Kenora x Whiteshell (Manitoba Hydro)	K21W	230
7	Kenora x Whiteshell (Manitoba Hydro)	K22W	230
8	Mackenzie x Lakehead	A21L	230
9	Mackenzie x Lakehead	A22L	230
10	Marathon x Lakehead	M23L	230
11	Marathon x Lakehead	M24L	230
12	Marathon x Lakehead	M37L	230
13	Marathon x Lakehead	M38L	230
14	Wawa x Marathon	W21M	230
15	Wawa x Marathon	W22M	230
16	Wawa x Marathon	W35M	230
17	Wawa x Marathon	W36M	230
18	Dinorwic Jct x Pickle Lake	W54W	230
19	Kenora x Rabbit Lake	15M1	115
20	Ignace x Camp Lake x Valora x Mattabi	29M1	115
21	Mackenzie x Moose Lake	A3M	115
22	Moose Lake x Sapawe x Shabaqua x Stanley x Murillo x Birch	B6M	115
23	Dryden x Domtar Dryden	D5D	115
24	Fort Frances x Burleigh	F1B	115

25	Fort Frances x Internat Fls (Minnesota Power)	F3M	115
26	Kenora x Norman	K2M	115
27	Dryden x Sam Lake x Eton x Vermilion Bay x Rabbit Lake	K3D	115
28	White Dog x Minaki x Rabbit Lake	K4W	115
29	Fort Frances x Ainsworth x Nestor Falls x Sioux Narrows x Rabbit Lake	K6F	115
30	Kenora x Weyerhaeuser Ken x Rabbit Lake	K7K	115
31	Moose Lake x Valerie Falls x Mill Creek	M1S	115
32	Moose Lake x Ignace x Dryden	M2D	115
33	Rabbit Lake x Keewatin x Forgie	SK1	115
34	White Dog x Caribou Falls	W3C	115
35	Nipignon x Red Rock	56M1	115
36	Reserve x Nipignon	57M1	115
37	Alexander x Port Arthur	A6P	115
38	Lakehead x Port Arthur	L3P	115
39	Lakehead x Port Arthur	L4P	115
40	Port Arthur x Birch	P3B	115
41	Port Arthur x Birch	P7B	115
42	Port Arthur x Conmee	P5M	115
43	Thunder Bay x Birch	B9	115
44	Thunder Bay x Birch	B14	115
45	Thunder Bay x Birch	B5	115
46	Thunder Bay x Birch	B15	115
47	Lakehead x Pine Portage x Birch	R1LB	115
48	Lakehead x Pine Portage x Birch	R2LB	115
49	Silver Falls x Lac Des Iles x Conmee	S1C	115
50	Aguasabon x Terrace Bay	A1B	115

51	Alexander x Nipignon x Beardmore x Jellicoe x Roxmark x Longlac	A4L	115
52	Alexander x Minnova x Schreiber x Aguasabon	A5A	115
53	Alexander x Cameron Falls	C1A	115
54	Alexander x Cameron Falls	C2A	115
55	Alexander x Cameron Falls	C3A	115
56	Upper White River x Lower White River	GA1	115
57	Marathon x Black River x Umbata Falls x Hemlo Mine x White River	M2W	115
58	Alexander x Pine Portage	R9A	115
59	Ear Falls x Selco x Slate Falls x Cat Lake x Pickle Lake	E1C	115
60	Pickle Lake x Crow River x Musselwhite	C2M	115
61	Pickle Lake x Wataynikaneyap	C3W	115
62	Ear Falls x Balmer x Red Lake	E2R	115
63	Ear Falls x Scout Lake x Dryden	E4D	115
64	Manitou Falls x Ear Falls	M3E	115
65	Terrace Bay x Marathon	T1M	115
66	Pickle Lake x Ebane/Pipestone	WBC	115
67	Ebane/Pipestone x North Caribou Lake	WCD	115
68	North Caribou Lake x Muskrat Dam	WDE	115
69	Muskrat Dam x Bearskin Lake	WEF	115
70	Muskrat Dam x Sachigo Lake	WEG	115
71	Ebane/Pipestone x Kingfisher Lake	WCJ	115
72	Kingfisher Lake x Wunnumin	WJI	44
73	Kingfisher Lake x Wawakapewin	WJK	115
74	Wawakapewin x Kasabonika Lake	WKL	44
75	Wawakapewin x KI-Wapekeka	WKM	115
76	Red Lake x Pikangikum	WPQ	115

77	Pikangikum x Poplar Hill SS / TS	WQR / WRS	115
78	Poplar Hill SS x Deer Lake SS / TS	WRT / WTU	115
79	Deer Lake SS x Sandy Lake SS	WTZ	115
80	Sandy Lake SS x Sandy Lake TS	WZW	115
81	Sandy Lake SS x North Spirit Lake	WZV	115
82	North Spirit Lake x Keewaywin	WVY	115

Appendix D: List of LDC's

Sr. no.	Name of LDC
1	Atikokan Hydro Inc.
2	Fort Frances Power Corporation
3	Hydro One Networks Inc. (Distribution)
4	Sioux Lookout Hydro Inc.
5	Synergy North

Appendix E: List of Districts[5] in the region

Sr. no.	Name of District
1	Kenora
2	Rainy River
3	Thunder Bay

[5] In Northern Ontario, Districts are in place of Municipalities.

Appendix E: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MEP	Municipal Energy Plan
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor

PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TS	Transformer Station

APPENDIX K: METSCO PROGRAM PRIORTIZATION REPORT

METSCO
MAKING IT POSSIBLE

Synergy North’s Project Prioritization Process

Prepared For: Synergy North

Prepared By: METSCO Energy Solutions Inc.

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IFR	July 14, 2023	Alex Ferguson, Syeda Fatima	Initial draft release.
R1	July 20, 2023	Alex Ferguson, Syeda Fatima	Final Draft Version
R2	August 10th , 2023	Alex Ferguson, Syeda Fatima	Final Version

Table of Contents

Acronyms and Abbreviations

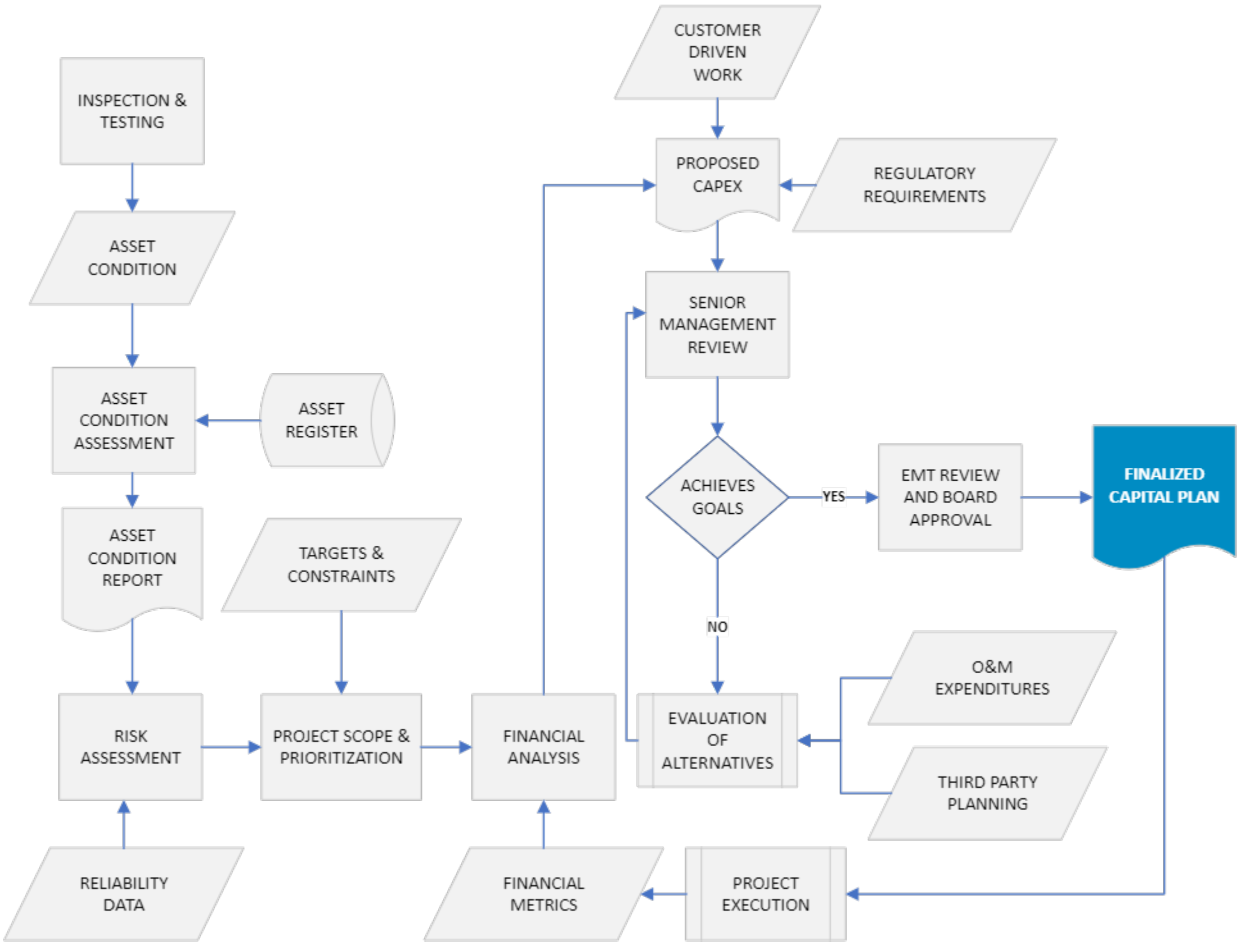
Acronym	Meaning
METSCO	METSCO Energy Solutions Inc.
SNC	Synergy North
DSP	Distribution System Plan
OEB	Ontario Energy Board
AM	Asset Management
O&M	Operations and Maintenance
AHP	Analytical Hierarchy Process
ELT	Executive Leadership Team

1 Overview & Context

METSCO Energy Solutions Inc. (METSCO) has been retained by Synergy North (SNC) to develop in collaboration with SNC a prioritization framework. This framework is used by SNC to help prioritize its proposed capital projects, using a structured, clear and quantifiable methodology. During the process METSCO has collaborated with key SNC staff and used information from its DSP and other documentation to help develop the proposed project prioritization framework. In developing the prioritization framework, METSCO has validated and endorsed the use of the framework by SNC and has ensured it meets the requirements set out in the Chapter 5 filing requirements.

The prioritization process and its role within SNC's overall capital planning process is illustrated in Figure 1 below. The capital planning process begins with the creation of project scope documents, which outline key information such as drivers, costs, benefits, alternatives, and priority. Once the project is scope and finalized the relative priority is established using the prioritization framework to determine a Prioritization Score. The prioritization process is a multi-phase, multi-criteria approach used to rank projects/programs objectively and consistently using quantitative and qualitative methods objectively and consistently. It allows SNC to assess project risk, ensure alignment with corporate goals and customer needs, and optimize capital expenditures. It is a requirement of the Ontario Energy Board's Chapter 5 Filing Requirements for Distribution System Plans. The project prioritization process is conducted annually and adjusted throughout the year as SNC's investment needs evolve. METSCO has not reviewed, endorsed, or validated SNC's DSP and wider Cost of Service application.

Figure 1: Capital Planning Process



Additional details about the prioritization process are provided in the following section. After scope documents have been created, projects are organized into programs, which are summarized through material narratives (business cases). The material narratives are program-level documents which outline key information such as the basis for action, program alternatives, merged operations planning and insights, and the scope documents for the projects within the program. These material narratives are key documents as they are submitted to the OEB along with the Distribution System Plan (DSP) as they provide a justification of capital expenditures.

The proposed capital plan is reviewed by senior management for adherence to any corporate goals, regulated requirements and overall financial fitness. Alternatives are considered at this stage that may impact the timing of certain projects. These considerations can include O&M alternatives and third-party projects. Once finalized, the capital expenditure plan is submitted to the Executive Management Team and Board for review and approval.

The final piece of SNC's capital planning process is related to its corporate goal of continuous improvement. This is achieved by providing feedback from executed projects in the form of lessons learned and financial metrics and utilizing this information to inform future planning processes.

2 Prioritization Process

The prioritization process consists of three steps: filtering out mandatory projects, prioritization assessment scoring, and project ranking – this section outlines each of these steps.

2.1 Filtering

A portion of SNC's capital expenditures is mandatory to comply with Conditions of Service and other obligations of SNC as a licensed distributor in the Province of Ontario, including customer service requests, plant relocations as a result of third-party infrastructure development requirements, and metering. These mandatory expenditures are classified into the OEB-defined System Access investment category which includes investments that allow SNC to fulfill its obligation to provide access to electrical service to customers in its service area via the distribution system. These mandatory capital expenditures are automatically promoted to the appropriate years' investment plan rather than receiving a Priority Score.

2.2 Prioritization Assessment Scoring

The prioritization assessment is the process of calculating prioritization scores (C) for non-mandatory investments in order to prioritize them. The prioritization assessment consists of a two-element formula to score each program (n) in the equation below.

$$\text{Program prioritization score (C)} = \frac{\sum_{i=1}^{n}\left(A_i \times \frac{B_i}{20}\right)}{100}$$

Part (A) consists of the weighted criterion from SNC's asset management objectives. The asset management objectives are a set of goals that are reflective of SNC's corporate values which assist in making strategic decisions that align with the priorities and overarching corporate goals. Each objective is assigned its own weight, using an analytical hierarchy process (AHP)[1], based on its relative importance in achieving SNC's objectives. Each objective has an associated weight which indicates its relative importance in comparison to other objectives and is calculated based on an Analytic Hierarchy Process ("AHP"). The executive leadership team (ELT) participates in this process as each member completes pairwise comparisons between all AM objectives[2]. The participants assign a value between 1 and 9 to represent the relative importance of one objective in comparison to another[3]. A mathematical model is used to determine the weight of each objective based on the inputs provided by all participants[4]. This

[1] Mat/d Modelling, Vol. 9, No. 3-5, pp. 161-176, 1987 – The Analytic Hierarchy Process – What It Is And How It is Used

[2] K. D. Goepel, "Implementing the analytic hierarchy process as a standard method for multi-criteria decision making in corporate enterprises," *Proc. Int. Symp. Analytic Hierarchy Process*, Kuala Lumpur, Malaysia, 2013.

[3] K.D. Goepel, "Comparison of Judgment Scales of the Analytical Hierarchy Process - A New Approach," 20 May 2018. [Online]. Available: https://bpmsg.com/wordpress/wp-content/uploads/2018/05/2018-05-10-AHP-Judgm-Scales-blog.pdf

[4] K. D. Goepel, "New AHP Excel template with multiple inputs," [Online]. Available: https://bpmsg.com/new-ahp-excel-template-with-multiple-inputs/.

approach allows SNC to align the priorities of all business units with its corporate goals and objectives. The proposed methodology has been successfully used as a decision-making tool throughout several industries[5]. The Criterion Weight (A) in the prioritization score equation above is equal to the AM objective weight listed in Table 2 below.

Table 1: SNC's AM Objectives, Description and Weighting

AM Objective	Prioritization Description	Weight (A)
Health & Safety	Risk of safety incidents sustained by SNC's staff, contractor, or the general public, living and working in the vicinity of the utility's equipment.	41.1%
Environmental Impact	Risk of unplanned and uncontrolled release of a hazardous substance (e.g., PCB Spills) or the consequences of climate change, vegetation contact, and flooding.	22.9%
Regulatory/Legal Compliance	Assesses the degree to which a project, service, or product is compliant with regulations and legal obligations.	12.3%
Customer Preference	The primary impact (s) of project, service, or product to address key customer requirements. • Affordability • Safety for employees and public • Reliability • Accommodating Renewable Energy	8.4%
Asset Performance	Project, service, or product replaces substandard equipment or otherwise improves the operations and maintenance practices on the system thereby addressing asset health concerns, premature failures, etc.	6.3%
Operational Efficiency	Project, service, or product that otherwise improves or avoids the following: • Reduces operating expenses; • Avoids future capital costs; • Coordinates with other programs; or • Decreases liability or increases without action.	4.7%
System Reliability	Electrical service continuity: translating it into customer interruption statistics and determining customer base affected.	4.2%

These AM objectives closely align with SNC's corporate values, and therefore by using the AM objectives as its prioritization criteria, SNC is able to link all its investments to how they deliver both its AM objectives, as well as its corporate values. The following table shows how the AM objectives align with the corporate values.

[5] D. Maletič, F. Lasrado, M. Maletič, and B. Gomišček, "Analytic Hierarchy Process Application in Different Organisational Settings," IntechOpen, 31-Aug-2016. [Online]. Available: https://www.intechopen.com/books/applications-and-theory-of-analytic-hierarchy-process-decision-making-for-strategic-decisions/analytic-hierarchy-process-application-in-different-organisational-settings.

Table 2: SNC's AM Objectives Alignment with SNC's Corporate Values

AM Objective	Corporate Values
Health & Safety	**Health & Safety Culture, Human Resources**
Environment	**Environment & Sustainability**
Regulatory/Legal Obligations	**Relationships**
Customer Preference	**Customer Service Focus**
Asset Performance	**Effective Asset Management**
Operational Efficiency	**Sound Financial Framework**
System Reliability	**Supply Electricity & Related Services**

The second element of the formula, Part (B) is the impact score. Each criterion has a predefined scoring model which quantifies the impacts of non-execution. As it can be difficult to apply a singular scoring method to system and non-system investments, some scoring models contain a two-element impact score. For example, in the Asset Performance category, the scoring includes an element defined for distribution system assets (i.e., the identified program impacts substation reliability) and an element for non-system assets (i.e., the asset is operating outside of manufacturer support). This allows for all projects and programs to be assessed using a common framework. Tables 3 – 9 show the impact scores assigned within each criterion, as well as the prioritization score, utilizing the assigned weighting from Table 1.

The following tables contain the scoring framework for each criterion within SNC's project prioritization process.

Table 3: Scoring Methodology for Health and Safety Impacts

Health and Safety	Scoring (B)	Prioritization Score (C)
Permanent disabling injury or fatality is almost certain (occur multiple times in 5yr)	20	41.1%
Serious injury requiring medical attention or serious security incident is very likely (occur more than once in 5yr)	15	30.8%
Moderate injury requiring first aid or moderate security incident likely (expected to occur in 5yr)	10	20.6%
Minor injury or security incident is likely (expected to occur in 5yr)	5	10.3%
No impact to health and safety	0	0.00%

Note:
Certain = occurring multiple times over planning period
Very Likely = occurring more than once over planning period
Likely = expected to happen over planning period

Table 4: Scoring Methodology for Environmental Impacts

Environmental Impact	Scoring (B)	Prioritization Score (C)
Addresses three (3) or more of SNC's identified environmental risks and provides risk mitigation to those risks	20	22.9%
Addresses two (2) or more of SNC's identified environmental risks and provides risk mitigation to those risks	15	17.2%
Addresses one (1) or more of SNC's identified environmental risks and provides risk mitigation to those risks	10	11.5%
Does not address any environmental risks or provide risk mitigation	0	0.00%

Table 5: Scoring Methodology for Regulatory/Legal Impacts

Regulatory/Legal Compliance	Scoring (B)	Prioritization Score (C)
Addresses a currently non-compliant issue to meet regulations or external standards for asset operations.	20	12.3%
Addresses an issue that with become noncompliant with regulations if no action is taken.	15	9.2%
Addresses a currently non-conformant issue with respect to best practices.	10	6.1%
Addresses an issue that may become nonconformant with best practices if no action is taken.	5	3.1%
No impact on regulatory compliance.	0	0.0%

Table 6: Scoring Methodology for Customer Preference Impacts

Customer Preference	Scoring (B)	Prioritization Score (C)
Delivers on all the top 3 priorities of customers (Affordability, Safety for Employees and the Public and Reliability)	20	8.4%
Delivers on two of the top 3 priorities of customers (Affordability, Safety for Employees and the Public and Reliability)	15	6.3%
Delivers on one of the top 3 priorities of customers (Affordability, Safety for Employees and the Public and Reliability)	10	4.2%
Delivers on one of the top 5 priorities of customers (Accommodating Renewable Connections and EV support)	5	2.1%
Does not deliver on any priorities of customers	0	0.0%

Table 7: Scoring Methodology for Asset Performance Impacts

Asset Performance	Scoring (B)	Prioritization Score (C)
Asset deficiency impacting substation reliability or critical non-system assets operating outside manufacturer support	20	6.3%
>50% of assets in poor condition or non-system assets operating within extended manufacturer support	15	4.7%
>50% of assets in fair condition or non-system assets reaching end of manufacturer support	10	3.1%
Minor asset performance issue not impacting levels of service	5	1.6%
No impact asset performance or health	0	0.0%

Table 8: Scoring Methodology for Operational Efficiency Impacts

Operational Efficiency	Scoring (B)	Prioritization Score (C)
Aligns with 4	20	4.7%
Aligns with 3	15	3.5%
Aligns with 2	10	2.3%
Aligns with 1	5	1.2%
Aligns with none	0	0.0%

Note: The criteria for this category are as follows:
Program reduces Operating Expenses
Program avoids future Capital Costs
Program coordinates with Other Projects
Program decreases liability or increases with inaction.

Table 9: Scoring Methodology for System Reliability Impacts

System Reliability	Scoring (B)	Prioritization Score (C)
Sustained interruption of > 12.5 MW of distribution load (>2,500 residential customers)	20	4.2%
Sustained interruption of 4.5-12.5 MW of distribution load (900-2,500 residential customers)	15	3.2%
Sustained interruption of 1.5-4.5 MW of distribution load (300-900 residential customers)	10	2.1%
Sustained interruption of <1.5 MW of distribution load (100-300 residential customers)	5	1.1%
No impact on the reliability of distribution.	0	0.0%

The owner of the business unit is responsible to develop the scope and to select from the tables provided above, the criteria which accurately identify the risks mitigated by that project. SNC's management team provides additional review and check to ensure consistency of scoring across all projects. Once the scorings have been identified, an Excel model is used to calculate the priority score for each project.

The following table shows a sample prioritization scoring for the Overhead Renewal program:

Criteria	Weight (A)	Impact Score (B)	Final Score (C)
Health and Safety	41.1%	10	20.6
Environmental Impact	22.9%	15	17.2
Regulatory/Legal Compliance	12.3%	0	0
Customer Preference	8.4%	20	8.4
Asset Performance	6.3%	15	4.7
Operational Efficiency	4.7%	5	1.2
System Reliability	4.3%	5	1.0
		Final Prioritization Score	53.1

2.3 Project Ranking

Once priority scores have been calculated for all projects within an investment category, they can be prioritized accordingly. This process allows SNC to understand which projects have the greatest risk associated with non-completion and those that will provide the most benefit to its distribution system, operations, and customers.

3 Conclusions & Recommendations

SNC will continue to use the prioritization process annually once the overall proposed projects and programs have been set for the following year. The results of the prioritization process should be referenced whenever budget adjustments need to be made throughout the year (e.g., due to unforeseen investment needs). An investment's priority score indicates how closely it aligns with SNC's asset management and corporate objectives.

SNC's prioritization process should also be periodically reviewed, and the criteria and weighting updated if appropriate. As the industry changes, both customers and therefore SNC's objectives and priorities will change. These changes should be reflected in SNC's corporate and asset management objectives. Therefore, when these do change, the criteria and relative weightings should also be reviewed and updated. At a minimum, it is recommended that this should be reviewed every five years.

EXHIBIT 2

ATTACHMENT 2 - B

SNC DEPRECIATION POLICY

SYNERGY NORTH CORPORATION

Depreciation Policy	Responsible Executive: Vice-President of Finance Responsible Department: Finance Issued: December 2017 Last Reviewed: To be reviewed annually

1.0 PURPOSE

This policy describes the accounting policy used for determining the definition of depreciable assets, the determination of useful lives, and the method of calculating depreciation expenses.

The purpose of recording expenditures as capital assets is to provide for an equitable allocation of costs among existing and future customers. As assets are expected to provide future economic benefits for more than a year, any expenditures incurred for the acquisition, construction or development of assets should be capitalized and allocated over the estimated useful lives of the associated assets in the form of amortization/depreciation. All other expenditures should be expensed in the accounting period incurred.

2.0 OBJECTIVE

The objective of the policy is to ensure proper classification of the Corporation's expenditures in accordance with IFRS, and compliance with applicable regulations.

3.0 BACKGROUND

Effective January 1, 2013, SNC modified its capitalization and depreciation policies to align with IFRS. Effective January 1, 2015, SNC adopted IFRS. SNC engaged Grant Thornton LLP to assist with determining the level of Property, Plant & Equipment ("PP&E") componentization required under IFRS and identifying whether any changes to overhead capitalization were required. As a result of this analysis, and in accordance with the Ontario Energy Board's July 17, 31 2012 letter, SNC revised its capitalization and depreciation policy effective January 1, 2013 to align with guidance under IFRS.

Effective January 1, 2013, SNC revised its estimates of useful lives of certain items of PP&E following a detailed review and analysis supported by third-party evidences (Ontario Energy Board Kinectrics Report). In accordance with the requirements of IFRS, as new information became available SNC reviewed and prospectively updated the service lives of assets for both financial and regulatory reporting purposes.

4.0 POLICY

4.1 Criteria for Capitalization and Depreciation

4.1.1 Capitalization Guidelines

The purpose of capitalizing expenditures is to provide an equitable allocation of costs among current and future customers. Capital assets are expected to provide future economic benefits for more than one year, any expenditure incurred for the acquisition, construction, development or betterment with the intention of being used on a continuing basis, and lastly are not intended for sale in the ordinary course of business. Intangible assets are also considered capital assets and are identified as assets that lack physical substance. These capitalized costs are allocated over the estimated useful life of the assets by amortization.

When parts or components of an item of PP&E have different useful lives, they are accounted for as individual items (major components). Component costs must be significant in relation to the total cost of the item and depreciated separately over the specific component’s useful life. Components with similar useful lives and depreciation methods are grouped in determining the depreciation charge. Parts of the item that are not individually significant are combined and categorized as a single component best suited for the sum of parts.

PP&E include expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes the cost of materials, direct labour and other costs directly attributable to bringing the asset to a working condition for its intended use. Costs also include the initial estimate of the costs of dismantling and removing the item and restoring the site on which it is located.

Major spare parts such as spare transformers and meters are accounted for as capital assets since they form an integral part of the reliability program for a distribution system. They are not depreciable until installed.

Assets with a cost in excess of $1,500 and are expected to provide future economic benefit greater than one year will be capitalized. Expenditures that create a physical betterment or improvement of an asset will be capitalized. Expenditures not meeting the criteria will be expensed in the period incurred.

4.1.2 Depreciable Assets

Depreciable assets refer to fixed assets that deteriorate and lose value over time. The depreciation process takes into account the useful life of a fixed asset, and reports the expense of such an asset over time. All depreciable assets will be classified into the categories determined below in 6.0 Depreciation Method. These items have a cost factor which must be recovered by matching income and expense.

5.0 DETERMINATION OF USEFUL LIFE

IAS 16 requires each part of an item of PP&E with a cost that is significant in relation to the total cost of the item to be depreciated separately. In addition IAS 16 requires entities perform a review of assets’ useful lives, depreciation methods and residual values on an annual basis. The OEB commissioned a depreciation study to assist electricity distributors in their transition to IFRS. SNC reviewed the useful life of its assets with the aid of the Asset Depreciation Study by Kinectrics (Kinectrics Report).

SNC has used the principles in the Kinectrics Report as its basis for determining the estimated service life of assets.

6.0 DEPRECIATION METHOD

Depreciation of an asset begins in the period 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. Depreciation of an asset ceases when the asset is retired from active use, sold or is fully depreciated. The estimated useful lives, residual values and depreciation methods are reviewed at the end of each annual reporting period, with the effect of any changes in estimate being accounted for on a prospective basis.

Depreciation is provided on a straight-line basis over the estimated useful lives at the following annual rates:

Asset Category / Expenditure	Rates %
Buildings	2%
Stations	2% to 7%
OH Conductors	2%-3%
UG Conduit and Conductors	1% to 3%
Poles, towers, fixtures	3%
Transformers	3%
Meters	2% to 7%
Rolling Stock	5% to 8%
Communications	20%
Computer Hardware	20% to 33%
Computer Software	14% to 50%
Equipment and Tools	10%
Other assets	3.3% to 5%

Construction in progress includes assets that are not currently in use and therefore are not depreciated. Land is not depreciated. Spare transformers and meters are not depreciated.

6.0 REFERENCES

SNC has applied its capitalization policies based on the following accounting principles: 2013 - 2014 Canadian Generally Accepted Accounting Principles ("GAAP")

2015 - 2017 International Financial Reporting Standards ("IFRS")

Article 410 Accounting Procedures Handbook for Electricity Distributors, Issued December 2011, Effective January 1, 2012

EXHIBIT 2

ATTACHMENT 2 - C

SERVICE LIFE COMPARISON,
BOARD APPENDIX 2-BB

SYNERGY NORTH CORPORATION

File Number:	EB-2023-0052
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Appendix 2-BB
Service Life Comparison
Table F-1 from Kinetrics Report[1]

Parent*	#	Asset Details: Category| Component | Type			Useful Life: MIN UL	TUL	MAX UL	USoA Account Number	USoA Account Description	Current: Years	Current: Rate	Proposed: Years	Proposed: Rate	Outside Range of Min, Max TUL?: Below Min TUL	Above Max TUL
OH	1	Fully Dressed Wood Poles	Overall		35	45	75	1830	Poles, Towers and Fixtures	40	3%	40	3%	No	No
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	2	Fully Dressed Concrete Poles	Overall		50	60	80								
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	3	Fully Dressed Steel Poles	Overall		60	60	80								
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	4	OH Line Switch			30	45	55	1835	Overhead Conductors and Devices	40	3%	40	3%	No	No
	5	OH Line Switch Motor			15	25	25	1980	System Supervisory Equipment	25	4%	25	4%	No	No
	6	OH Line Switch RTU			15	20	20	1980	System Supervisory Equipment	20	5%	20	5%	No	No
	7	OH Integral Switches			35	45	60	1835	Overhead Conductors and Devices	40	3%	40	3%	No	No
	8	OH Conductors			50	60	75	1835	Overhead Conductors and Devices	60	2%	60	2%	No	No
	9	OH Transformers & Voltage Regulators			30	40	60	1850	Line Transformers	40	3%	40	3%	No	No
	10	OH Shunt Capacitor Banks			25	30	40								
	11	Reclosers			25	40	55	1835	Overhead Conductors and Devices	40	3%	40	3%	No	No
TS & MS	12	Power Transformers	Overall		30	45	60	1820	Distribution Station Equipment <50kV	50	2%	50	2%	No	No
			Bushing		10	20	30	1820	Distribution Station Equipment <50kV	25	4%	25	4%	No	No
			Tap Changer		20	30	60								
	13	Station Service Transformer			30	45	55	1820	Distribution Station Equipment <50kV	45	2%	45	2%	No	No
	14	Station Grounding Transformer			30	40	40								
	15	Station DC System	Overall		10	20	30	1820	Distribution Station Equipment <50kV	20	5%	20	5%	No	No
			Battery Bank		10	15	15	1820	Distribution Station Equipment <50kV	15	7%	15	7%	No	No
			Charger		20	20	30	1820	Distribution Station Equipment <50kV	20	5%	20	5%	No	No
	16	Station Metal Clad Switchgear	Overall		30	40	60	1820	Distribution Station Equipment <50kV	40	3%	40	3%	No	No
			Removable Breaker		25	40	60	1815	Distribution Station Equipment >50kV	40	3%	40	3%	No	No
	17	Station Independent Breakers			35	45	65	1820	Distribution Station Equipment <50kV	50	2%	50	2%	No	No
	18	Station Switch			30	50	60	1820	Distribution Station Equipment <50kV	50	2%	40	3%	No	No
	19	Electromechanical Relays			25	35	50								
	20	Solid State Relays			10	30	45								
	21	Digital & Numeric Relays			15	20	20								
	22	Rigid Busbars			30	55	60								
	23	Steel Structure			35	50	90	1815	Distribution Station Equipment >50kV	38	3%	38.25	3%	No	No
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables			60	65	75								
	25	Primary Ethylene-Propylene Rubber (EPR) Cables			20	25	25								
	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried			20	25	30								
	27	Primary Non-TR XLPE Cables in Duct			20	25	30								
	28	Primary TR XLPE Cables Direct Buried			25	30	35	1845	Underground Conductors and Devices	30		30	3%	No	No
	29	Primary TR XPLE Cables in Duct			35	40	60	1845	Underground Conductors and Devices	40		40	3%	No	No
	30	Secondary PILC Cables			70	75	80								
	31	Secondary Cables Direct Buried			25	35	40	1845	Underground Conductors and Devices	40	3%	40	3%	No	No
	32	Secondary Cables in Duct			35	40	60	1845	Underground Conductors and Devices	40	3%	40	3%	No	No
	33	Network Tranformers	Overall		20	35	50	1845	Underground Conductors and Devices	40	3%	40	3%	No	No
			Protector		20	35	40								
	34	Pad-Mounted Transformers			25	40	45	1850	Lines Transformers	40	3%	40	3%	No	No
	35	Submersible/Vault Transformers			25	35	45								
	36	UG Foundation			35	55	70	1840	Underground Conduit	55	2%	55	2%	No	No
	37	UG Vaults	Overall		40	60	80								
			Roof		20	30	45								
	38	UG Vault Switches			20	35	50								
	39	Pad-Mounted Switchgear			20	30	45	1845	Underground Conductors and Devices	30	3%	30	3%	No	No
	40	Ducts			30	50	85	1840	Underground Conduit	80	1%	80	1%	No	No
	41	Concrete Encased Duct Banks			35	55	80								
	42	Cable Chambers			50	60	80								
S	43	Remote SCADA			15	20	30	1980	System Supervisory Equipment	20	5%	20	5%	No	No

Table F-2 from Kinetrics Report[1]

#	Asset Details: Category| Component | Type		Useful Life Range		USoA Account Number	USoA Account Description	Current: Years	Current: Rate	Proposed: Years	Proposed: Rate	Outside Range of Min, Max TUL?: Below Min Range	Above Max Range
1	Office Equipment		5	15	1915	Office Furniture and Equipment	10	10%	10	10%	No	No
2	Vehicles	Trucks < 3 Tons	5	15	1930	Transportation Equipment	12	8%	12	8%	No	No
		Trucks > 3 Tons	5	15	1930	Transportation Equipment	15	7%	15	7%	No	No
		Trailers	5	20	1930	Transportation Equipment	10	10%	10	10%	No	No
		Vans	5	10	1930	Transportation Equipment	12	8%	12	8%	No	Yes
3	Administrative Buildings		50	75	1808	Buildings and Fixtures	50	2%	50	2%	No	No
4	Leasehold Improvements		Lease dependent		1810	Leasehold Improvements	5	20%	5	20%		
5	Station Buildings	Station Buildings	50	75								
		Parking	25	30								
		Fence	25	60								
		Roof	20	30								
6	Computer Equipment	Hardware	3	5	1920	Computer Equipment-Hardware	3-5	0%	3-5	0%	No	Yes
		Software	2	5	1611	Computer Software	2-7	0%	2-7	0%	No	Yes
7	Equipment	Power Operated	5	10	1950	Power Operated Equipment	10	10%	10	10%	No	No
		Stores	5	10	1935	Stores Equipment	10	10%	10	10%	No	No
		Tools, Shop, Garage Equipment	5	10	1940	Tools, Shop and Garage	10	10%	10	10%	No	No
		Measurement & Testing Equipment	5	10	1945	Measurement and Testing Equipment	10	10%	10	10%	No	No
8	Communication	Towers	60	70	0							
		Wireless	2	10	0							
9	Residential Energy Meters		25	35	0							
10	Industrial/Commercial Energy Meters		25	35	1860	Meters	35	3%	35	3%	No	No
11	Wholesale Energy Meters		15	30	1860	Meters	30	3%	30	3%	No	No
12	Current & Potential Transformer (CT & PT)		35	50	1860	Meters	50	2%	50	2%	No	No
13	Smart Meters		5	15	1860	Meters	15	7%	15	7%	No	No
14	Repeaters - Smart Metering		10	15	1860	Meters	15	7%	15	7%	No	No
15	Data Collectors - Smart Metering		15	20	1860	Meters	15	7%	15	7%	No	No

*** TS & MS = Transformer and Municipal Stations UG = Underground Systems S = Monitoring and Control Systems**

Note 1: Tables F-1 and F-2 above are to be used as a reference in order to complete columns J, K, L and N.
See pages 17-19 of Kinetrics Report

EXHIBIT 2

ATTACHMENT 2 - D

DEPRECIATION AND AMORITIZATION EXPENSE, APPENDIX 2-C

SYNERGY NORTH CORPORATION

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Appendix 2-C
Depreciation and Amortization Expense

General: This appendix is to assess the reasonability of the depreciation expense that is included in rate base via. accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation
This appendix must be completed under MIFRS for each year for the earlier of:

Notes:
1 This should include assets in column A (excel column C) that become fully depreciated.
2 The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to
3 OEB policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.
4 The applicant must provide an explanation of material variances in its evidence.

Year 2017 **TBHEDI**

		Book Values					Service Lives		Expense		
Account	Description	Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Disposals	Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [4]
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1609	Hydro One Gate Station	$ 1,272,321				$ 1,272,321	25.00	4.00%	**$ 50,893**	$ 50,893	**$ -**
1611	Computer Software (Formally known as Account 1925)	$ 1,325,017	$ 1,276,906	$ 2,691		$ 49,457	4.09	24.45%	**$ 12,092**	$ 29,336	**$ 17,244**
1612	Land Rights (Formally known as Account 1906)					$ -		0.00%	**$ -**	$ -	**$ -**
1805	Land	$ 133,038			$ 1,852	$ 131,186		0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ 7,456,455	$ 154,564	$ 100,100		$ 7,351,941	35.57	2.81%	**$ 206,689**	$ 201,134	**-$ 5,555**
1810	Leasehold Improvements	$ 63,262	$ 63,262			$ -		0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV					$ -		0.00%	**$ -**	$ -	**$ -**
1820	Distribution Station Equipment <50 kV	$ 8,319,236	$ 6,507,047	$ 38,000		$ 1,831,189	11.67	8.57%	**$ 156,914**	$ 159,691	**$ 2,777**
1825	Storage Battery Equipment					$ -		0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 44,895,096	$ 10,018,252	$ 4,284,800	$ 619,969	$ 36,399,275	35.57	2.81%	**$ 1,023,314**	$ 1,040,075	**$ 16,761**
1835	Overhead Conductors & Devices	$ 40,698,870	$ 17,192,914	$ 3,477,099	$ 569,980	$ 24,674,526	49.31	2.03%	**$ 500,396**	$ 566,489	**$ 66,093**
1840	Underground Conduit	$ 15,628,647	$ 8,918,677	$ 325,644	$ 12,017	$ 6,860,775	65.02	1.54%	**$ 105,518**	$ 128,883	**$ 23,366**
1845	Underground Conductors & Devices	$ 21,215,363	$ 5,812,508	$ 486,306	$ 43,470	$ 15,602,538	38.26	2.61%	**$ 407,803**	$ 407,400	**-$ 403**
1850	Line Transformers	$ 31,059,571	$ 14,041,095	$ 1,259,945	$ 528,360	$ 17,120,089	31.88	3.14%	**$ 537,017**	$ 625,547	**$ 88,531**
1850	Line Transformers Inventory	$ 2,187,342				$ 2,187,342	-	0.00%	**$ -**		**$ -**
1855	Services (Overhead & Underground)	$ 23,093,575	$ 14,608,760	$ 40,286		$ 8,504,958	38.04	2.63%	**$ 223,579**	$ 256,937	**$ 33,358**
1860	Meters	$ 2,144,072	$ 1,670,672	$ 238,983	$ 90,557	$ 502,334	40.93	2.44%	**$ 12,273**	$ -	**-$ 12,273**
1860	Meters (Smart Meters)	$ 7,551,463	$ 827,941			$ 6,723,522	11.59	8.63%	**$ 580,114**	$ 604,516	**$ 24,402**
1860	Meters Inventory	$ 413,033		$ 119,525	$ 83,938	$ 388,858	-	0.00%	**$ -**		**$ -**
1905	Land					$ -		0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures					$ -		0.00%	**$ -**	$ -	**$ -**
1910	Leasehold Improvements					$ -		0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 1,604,188	$ 1,069,197	$ 65,375		$ 567,679	8.87	11.27%	**$ 64,000**	$ 57,230	**-$ 6,769**
1915	Office Furniture & Equipment (5 years)					$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ 3,311,159	$ 3,011,153	$ 139,695	$ 1,025	$ 368,829	4.18	23.92%	**$ 88,236**	$ 98,565	**$ 10,328**
1920	Computer Equip.-Hardware(Post Mar. 22/04)					$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)					$ -		0.00%	**$ -**	$ -	**$ -**
1930	Transportation Equipment	$ 7,997,105	$ 3,230,534	$ 426,323	$ 610,606	$ 4,369,127	12.93	7.73%	**$ 337,906**	$ 339,299	**$ 1,393**
1935	Stores Equipment	$ 63,417	$ 29,037	$ 34,380		$ 51,570	10.00	10.00%	**$ 5,157**	$ -	**-$ 5,157**
1940	Tools, Shop & Garage Equipment	$ 2,929,380	$ 2,260,539	$ 50,373		$ 694,028	10.00	10.00%	**$ 69,403**	$ 71,778	**$ 2,375**
1945	Measurement & Testing Equipment	$ 374,179	$ 129,616	$ 75,859		$ 282,493	9.85	10.15%	**$ 28,679**	$ 25,710	**-$ 2,970**
1950	Power Operated Equipment	$ 412,564	$ 3,583	$ 13,227		$ 415,595	11.57	8.64%	**$ 35,920**	$ 35,549	**-$ 371**
1955	Communications Equipment	$ 283,980	$ 237,543	$ 2,438		$ 47,656	5.00	20.00%	**$ 9,531**	$ 11,945	**$ 2,414**
1955	Communication Equipment (Smart Meters)					$ -		0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment					$ -		0.00%	**$ -**	$ -	**$ -**
1970	Load Management Controls Customer Premises					$ -		0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises					$ -		0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ 800,438	$ 150,822			$ 649,616	9.09	11.00%	**$ 71,465**	$ 83,392	**$ 11,927**
1985	Miscellaneous Fixed Assets					$ -		0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property					$ -		0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	-$ 18,542,289				-$ 18,542,289	42.90	2.33%	**-$ 432,221**	-$ 432,680	**-$ 459**
2440	Deferred Revenue	-$ 6,859,552		-$ 973,179		-$ 7,346,142	42.00	2.38%	**-$ 174,908**	-$ 173,038	**$ 1,870**
2005	Property Under Finance Lease					$ -		0.00%	**$ -**	$ -	**$ -**
	Total	**$ 199,830,930**	**$ 91,214,622**	**$ 10,207,870**		**$ 109,886,148**	**$ 553**		**$ 3,919,771**	**$ 4,188,650**	**$ 268,880**

$ 81,006,752

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Appendix 2-C
Depreciation and Amortization Expense

General: This appendix is to assess the reasonability of the depreciation expense that is included in rate base via. accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation
This appendix must be completed under MIFRS for each year for the earlier of:

Notes:
1 This should include assets in column A (excel column C) that become fully depreciated.
2 The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to
3 OEB policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.
4 The applicant must provide an explanation of material variances in its evidence.

Year 2017 **KHEC**

		Book Values					Service Lives		Expense		
Account	**Description**	**Opening Book Value of Assets**	**Less Fully Depreciated [1]**	**Current Year Additions**	**Disposals**	**Net Amount of Assets to be Depreciated**	**Remaining Life of Assets Existing [2]**	**Depreciation Rate Assets**	**Depreciation Expense on Assets [3]**	**Depreciation Expense per Appendix 2-BA Fixed Assets, Column J**	**Variance [4]**
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid	$ -		$ -		$ -	-	0.00%	$ -	$ -	$ -
1611	Computer Software (Formally known as Account 1925)	$ 30,009	$ 30,009	$ -		-$ 0	-	0.00%	$ -	$ -	$ -
1612	Land Rights (Formally known as Account 1906)	$ -		$ -		$ -	-	0.00%	$ -	$ -	$ -
1805	Land	$ 2,366		$ -		$ 2,366	-	0.00%	$ -	$ -	$ -
1808	Buildings	$ 33,698		$ -		$ 33,698	22.43	4.46%	**$ 1,502**	$ 1,774	**$ 271**
1810	Leasehold Improvements	$ -		$ -		$ -	-	0.00%	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ 2,778,226		$ 10,691		$ 2,783,572	37.44	2.67%	**$ 74,348**	$ 110,645	**$ 36,298**
1820	Distribution Station Equipment <50 kV	$ -		$ -		$ -	-	0.00%	$ -	$ -	$ -
1825	Storage Battery Equipment	$ -		$ -		$ -	-	0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 2,742,449		$ 316,207		$ 2,900,553	21.21	4.71%	**$ 136,754**	$ 174,101	**$ 37,347**
1835	Overhead Conductors & Devices	$ 970,010		$ 48,973		$ 994,496	38.72	2.58%	**$ 25,684**	$ 36,674	**$ 10,990**
1840	Underground Conduit	$ 130,843		$ 8,302		$ 134,994	35.00	2.86%	**$ 3,857**	$ 15,102	**$ 11,245**
1845	Underground Conductors & Devices	$ 333,760		$ 4,260		$ 335,890	26.17	3.82%	**$ 12,835**	$ 36,645	**$ 23,810**
1850	Line Transformers	$ 1,124,891		$ 109,932		$ 1,179,857	28.72	3.48%	**$ 41,081**	$ 68,745	**$ 27,663**
1855	Services (Overhead & Underground)	$ -		$ -		$ -	-	0.00%	$ -	$ -	$ -
1860	Meters	$ -		$ -		$ -	-	0.00%	$ -	$ -	$ -
1860	Meters (Smart Meters)	$ 689,797		$ 70,152		$ 724,873	15.00	6.67%	**$ 48,325**	$ 72,842	**$ 24,517**
1905	Land	$ 16,562		$ -		$ 16,562	-	0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 634,008		$ -		$ 634,008	22.43	4.46%	**$ 28,266**	$ 35,296	**$ 7,030**
1910	Leasehold Improvements	$ -		$ -		$ -	-	0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 25,177		$ -		$ 25,177	10.00	10.00%	**$ 2,518**	$ 3,982	**$ 1,465**
1915	Office Furniture & Equipment (5 years)	$ -		$ -		$ -	-	0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 19,012		$ 1,351		$ 19,688	5.00	20.00%	**$ 3,938**	$ 3,371	**-$ 566**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -		$ -	-	0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -		$ -	-	0.00%	$ -	$ -	$ -
1930	Transportation Equipment	$ 554,966		$ 705		$ 555,318	10.00	10.00%	**$ 55,532**	$ 40,194	**-$ 15,338**
1935	Stores Equipment	$ -		$ -		$ -	-	0.00%	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment	$ -		$ -		$ -	10.00	10.00%	$ -	$ -	$ -
1945	Measurement & Testing Equipment	$ 72,058		$ -		$ 72,058	10.00	10.00%	**$ 7,206**	$ 6,809	**-$ 397**
1950	Power Operated Equipment	$ -		$ -		$ -	-	0.00%	$ -	$ -	$ -
1955	Communications Equipment	$ -		$ -		$ -	-	0.00%	$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -		$ -		$ -	-	0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ 35,709		$ 16,099		$ 43,759	10.00	10.00%	**$ 4,376**	$ 3,664	**-$ 712**
1970	Load Management Controls Customer Premises	$ -		$ -		$ -	-	0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -		$ -		$ -	-	0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 313,374		$ 2,469		$ 314,608	15.00	6.67%	**$ 20,974**	$ 28,028	**$ 7,054**
1985	Miscellaneous Fixed Assets	$ -		$ -		$ -	-	0.00%	$ -	$ -	$ -
1990	Other Tangible Property	$ -		$ -		$ -	-	0.00%	$ -	$ -	$ -
1995	Contributions & Grants	$ -		$ -		$ -	-	0.00%	$ -	$ -	$ -
2440	Deferred Revenue	-$ 169,970		-$ 43,418		-$ 191,679	25.00	4.00%	**-$ 7,667**	-$ 7,276	**$ 391**
2005	Property Under Finance Lease	$ -		$ -		$ -	-	0.00%	$ -	$ -	$ -
	Total	**$ 10,336,944**	**$ 30,009**	**$ 545,723**		**$ 10,579,796**	**$ 342**		**$ 459,528**	**$ 630,595**	**$ 171,067**

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Appendix 2-C
Depreciation and Amortization Expense

General: This appendix is to assess the reasonability of the depreciation expense that is included in rate base via. accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation
This appendix must be completed under MIFRS for each year for the earlier of:

Notes:
1. This should include assets in column A (excel column C) that become fully depreciated.
2. The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to
3. OEB policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.
4. The applicant must provide an explanation of material variances in its evidence.

Year 2018 **TBHEDI**

		Book Values					Service Lives		Expense		
Account	**Description**	**Opening Book Value of Assets**	**Less Fully Depreciated [1]**	**Current Year Additions**	**Disposals**	**Net Amount of Assets to be Depreciated**	**Remaining Life of Assets Existing [2]**	**Depreciation Rate Assets**	**Depreciation Expense on Assets [3]**	**Depreciation Expense per Appendix 2-BA Fixed Assets, Column J**	**Variance [4]**
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid	$ 1,272,321	$ -			$ 1,272,321	25.00	4.00%	**$ 50,893**	$ 50,893	**$ 0**
1611	Computer Software (Formally known as Account 1925)	$ 1,327,708	$ 1,304,537			$ 23,171	3.00	33.33%	**$ 7,724**	$ 7,726	**$ 2**
1612	Land Rights (Formally known as Account 1906)		$ -			$ -		0.00%	**$ -**	$ -	**$ -**
1805	Land	$ 131,186	$ -			$ 131,186		0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ 7,556,555	$ 68,528	$ 86,036		$ 7,531,045	35.06	2.85%	**$ 214,804**	$ 207,416	**-$ 7,388**
1810	Leasehold Improvements	$ 63,262	$ 63,262			$ -		0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV		$ -			$ -		0.00%	**$ -**	$ -	**$ -**
1820	Distribution Station Equipment <50 kV	$ 8,357,236	$ 6,506,519	$ 141,255		$ 1,921,344	11.73	8.53%	**$ 163,797**	$ 160,466	**-$ 3,331**
1825	Storage Battery Equipment		$ -			$ -		0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 48,559,926	$ 9,803,075	$ 4,439,850	$ 339,440	$ 40,637,336	35.83	2.79%	**$ 1,134,171**	$ 1,108,697	**-$ 25,474**
1835	Overhead Conductors & Devices	$ 43,605,989	$ 13,968,686	$ 3,197,239	$ 711,564	$ 30,524,359	49.62	2.02%	**$ 615,162**	$ 605,854	**-$ 9,308**
1840	Underground Conduit	$ 15,942,275	$ 8,268,668	$ 147,995	$ 94,343	$ 7,653,262	59.23	1.69%	**$ 129,213**	$ 128,613	**-$ 600**
1845	Underground Conductors & Devices	$ 21,658,200	$ 9,268,039	$ 729,991		$ 12,755,157	31.94	3.13%	**$ 399,347**	$ 392,398	**-$ 6,949**
1850	Line Transformers	$ 31,873,867	$ 13,455,262	$ 1,293,757	$ 345,496	$ 18,719,988	32.08	3.12%	**$ 583,541**	$ 577,315	**-$ 6,226**
1850	Line Transformers Inventory	$ 2,104,630				$ 2,104,630	-	0.00%	**$ -**		**$ -**
1855	Services (Overhead & Underground)	$ 23,133,861	$ 14,320,120	$ 234,027	$ 78,678	$ 8,852,077	38.01	2.63%	**$ 232,888**	$ 232,104	**-$ 784**
1860	Meters	$ 1,117,644	$ 722,781	$ 24,428		$ 407,077	41.08	2.43%	**$ 9,909**	$ -	**-$ 9,909**
1860	Meters (Smart Meters)	$ 8,726,317	$ 1,780,021	$ 234,997		$ 7,063,795	11.62	8.61%	**$ 607,900**	$ 610,275	**$ 2,376**
1860	Meters Inventory	$ 448,621		$ 278,345	$ 119,705	$ 468,089	-	0.00%	**$ -**		**$ -**
1905	Land		$ -			$ -		0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures		$ -			$ -		0.00%	**$ -**	$ -	**$ -**
1910	Leasehold Improvements		$ -			$ -		0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 1,669,563	$ 1,138,727	$ 21,685		$ 541,679	9.22	10.85%	**$ 58,750**	$ 59,080	**$ 330**
1915	Office Furniture & Equipment (5 years)		$ -			$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ 3,449,830	$ 3,007,465	$ 108,673	$ 44,784	$ 451,918	4.12	24.27%	**$ 109,689**	$ 107,079	**-$ 2,609**
1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -			$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -		0.00%	**$ -**	$ -	**$ -**
1930	Transportation Equipment	$ 7,812,822	$ 2,897,179	$ 611,013		$ 5,221,150	13.16	7.60%	**$ 396,744**	$ 398,035	**$ 1,291**
1935	Stores Equipment	$ 97,797	$ 63,417			$ 34,380	10.00	10.00%	**$ 3,438**	$ 2,579	**-$ 859**
1940	Tools, Shop & Garage Equipment	$ 2,979,753	$ 2,306,046	$ 148,624		$ 748,019	10.13	9.87%	**$ 73,842**	$ 77,010	**$ 3,168**
1945	Measurement & Testing Equipment	$ 450,038	$ 205,143	$ 88,031		$ 288,911	9.36	10.68%	**$ 30,867**	$ 33,655	**$ 2,788**
1950	Power Operated Equipment	$ 425,791	$ 13,488			$ 412,303	11.89	8.41%	**$ 34,676**	$ 35,007	**$ 331**
1955	Communications Equipment	$ 286,418	$ 276,683	$ 1,092		$ 10,281	5.64	17.73%	**$ 1,823**	$ 8,579	**$ 6,756**
1955	Communication Equipment (Smart Meters)		$ -			$ -		0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment		$ -			$ -		0.00%	**$ -**	$ -	**$ -**
1970	Load Management Controls Customer Premises		$ -			$ -		0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises		$ -			$ -		0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ 800,438	$ 168,759	$ 63,021		$ 663,190	8.82	11.34%	**$ 75,192**	$ 76,887	**$ 1,695**
1985	Miscellaneous Fixed Assets		$ -			$ -		0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property		$ -			$ -		0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	-$ 18,542,289	$ -			-$ 18,542,289	42.90	2.33%	**-$ 432,221**	-$ 432,680	**-$ 459**
2440	Deferred Revenue	-$ 7,832,731		-$ 1,243,211		-$ 8,454,337	45.00	2.22%	**-$ 187,874**	-$ 186,096	**$ 1,778**
2005	Property Under Finance Lease					$ -		0.00%	**$ -**	$ -	**$ -**
	Total	**$ 207,477,028**	**$ 89,606,404**	**$ 10,606,849**		**$ 120,167,717**	**$ 544**		**$ 4,314,275**	**$ 4,260,892**	**-$ 53,382**

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Appendix 2-C
Depreciation and Amortization Expense

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Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation
This appendix must be completed under MIFRS for each year for the earlier of:

Notes:
1 This should include assets in column A (excel column C) that become fully depreciated.
2 The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to
3 OEB policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.
4 The applicant must provide an explanation of material variances in its evidence.

Year 2018 **KHEC**

		Book Values					Service Lives		Expense		
Account	**Description**	**Opening Book Value of Assets**	**Less Fully Depreciated [1]**	**Current Year Additions**	**Disposals**	**Net Amount of Assets to be Depreciated**	**Remaining Life of Assets Existing [2]**	**Depreciation Rate Assets**	**Depreciation Expense on Assets [3]**	**Depreciation Expense per Appendix 2-BA Fixed Assets, Column J**	**Variance [4]**
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid	$ -		$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1611	Computer Software (Formally known as Account 1925)	$ 30,009		$ -	-$ 30,009	$ 60,017	-	0.00%	$ -	$ -	$ -
1612	Land Rights (Formally known as Account 1906)	$ -		$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1805	Land	$ 2,366		$ -	$ -	$ 2,366	-	0.00%	$ -	$ -	$ -
1808	Buildings	$ 33,698		$ -	$ -	$ 33,698	22.71	4.40%	$ 1,484	$ 1,774	$ 290
1810	Leasehold Improvements	$ -		$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ 2,788,918		$ 24,197	$ -	$ 2,801,016	36.08	2.77%	$ 77,633	$ 115,485	$ 37,851
1820	Distribution Station Equipment <50 kV	$ -		$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1825	Storage Battery Equipment	$ -		$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 3,058,656		$ 161,654	$ -	$ 3,139,483	21.59	4.63%	$ 145,414	$ 178,916	$ 33,502
1835	Overhead Conductors & Devices	$ 1,018,982		$ 45,314	$ -	$ 1,041,639	38.70	2.58%	$ 26,916	$ 37,580	$ 10,665
1840	Underground Conduit	$ 139,144		$ 6,642	$ -	$ 142,465	35.00	2.86%	$ 4,070	$ 15,292	$ 11,221
1845	Underground Conductors & Devices	$ 338,020		$ 7,861	$ -	$ 341,950	27.22	3.67%	$ 12,562	$ 36,930	$ 24,368
1850	Line Transformers	$ 1,234,823		$ 310,799	-$ 10,863	$ 1,401,086	28.57	3.50%	$ 49,040	$ 71,085	$ 22,044
1855	Services (Overhead & Underground)	$ -		$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1860	Meters	$ -		$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1860	Meters (Smart Meters)	$ 759,949		$ 12,625	-$ 27,728	$ 793,990	15.00	6.67%	$ 52,933	$ 45,955	-$ 6,977
1905	Land	$ 16,562		$ -	$ -	$ 16,562	-	0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 634,008		$ -	$ -	$ 634,008	22.71	4.40%	$ 27,918	$ 35,296	$ 7,379
1910	Leasehold Improvements	$ -		$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 25,177		$ -	$ -	$ 25,177	10.00	10.00%	$ 2,518	$ 3,982	$ 1,465
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 20,363		$ 2,492	$ -	$ 21,609	5.00	20.00%	$ 4,322	$ 2,578	-$ 1,743
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1930	Transportation Equipment	$ 555,671		$ 11,110	$ -	$ 561,226	10.00	10.00%	$ 56,123	$ 38,403	-$ 17,719
1935	Stores Equipment	$ -		$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment	$ -		$ -	$ -	$ -	10.00	10.00%	$ -	$ -	$ -
1945	Measurement & Testing Equipment	$ 72,058		$ -	$ -	$ 72,058	10.00	10.00%	$ 7,206	$ 6,809	-$ 397
1950	Power Operated Equipment	$ -		$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1955	Communications Equipment	$ -		$ 30,124	$ -	$ 15,062	10.00	10.00%	$ 1,506	$ 3,012	$ 1,506
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ 51,809		$ 6,660	$ -	$ 55,139	10.00	10.00%	$ 5,514	$ 4,330	-$ 1,184
1970	Load Management Controls Customer Premises	$ -		$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -		$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 315,843		$ 7,020	$ -	$ 319,353	15.00	6.67%	$ 21,290	$ 28,496	$ 7,206
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1990	Other Tangible Property	$ -		$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1995	Contributions & Grants	$ -		$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
2440	Deferred Revenue	-$ 213,388		$ -	$ -	-$ 213,388	25.00	4.00%	-$ 8,536	-$ 7,276	$ 1,259
2005	Property Under Finance Lease	$ -		$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
	Total	**$ 10,882,667**	**$ -**	**$ 626,498**	**-$ 68,600**	**$ 11,264,516**	**$ 353**		**$ 487,913**	**$ 618,648**	**$ 130,735**

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Year 2019 **SNC**

Account	Description	Book Values					Service Lives		Expense			
		Opening Book Value of Assets	Less Fully Depreciated [1]	Opening Balance (KHEC)	Current Year Additions	Disposals	Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets,	Variance [4]
		a	b		c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid	$ 1,272,321	$ -				$ 1,272,321	25.00	4.00%	$ 50,893	$ 50,893	$ -
1611	Computer Software (Formally known as Account 1925)	$ 1,327,708	$ 1,304,487		$ 14,735		$ 30,589	5.00	20.00%	$ 6,118	$ 6,122	$ 4
1612	Land Rights (Formally known as Account 1906)		$ -				$ -		0.00%	$ -	$ -	$ -
1805	Land	$ 131,186	$ -	$ 18,928			$ 150,114		0.00%	$ -	$ -	$ -
1808	Buildings	$ 7,642,591	$ 2,217,383	$ 667,707	$ 40,996		$ 6,113,413	24.78	4.04%	$ 246,708	$ 246,695	-$ 12
1810	Leasehold Improvements	$ 63,262	$ 63,262				$ -		0.00%	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV		$ 574,800	$ 2,736,397			$ 2,161,597	22.32	4.48%	$ 96,846	$ 91,914	-$ 4,932
1820	Distribution Station Equipment <50 kV	$ 8,498,490	$ 6,706,844				$ 1,791,646	12.53	7.98%	$ 142,989	$ 168,068	$ 25,079
1825	Storage Battery Equipment		$ -				$ -		0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 52,660,336	$ 10,494,563	$ 2,538,751	$ 4,689,958	$ 369,542	$ 46,679,961	33.85	2.95%	$ 1,379,024	$ 1,346,959	-$ 32,065
1835	Overhead Conductors & Devices	$ 46,091,664	$ 13,998,802	$ 1,745,854	$ 2,663,301	$ 463,973	$ 34,706,394	48.22	2.07%	$ 719,751	$ 717,060	-$ 2,691
1840	Underground Conduit	$ 15,995,927	$ 8,243,641		$ 1,296,028	$ 37,968	$ 8,362,332	59.96	1.67%	$ 139,465	$ 132,166	-$ 7,299
1845	Underground Conductors & Devices	$ 22,388,191	$ 9,324,391	$ 532,494	$ 1,584,252	$ 148,967	$ 14,239,453	32.15	3.11%	$ 442,907	$ 425,540	-$ 17,367
1850	Line Transformers	$ 32,616,431	$ 12,714,079	$ 1,493,932	$ 2,126,682	$ 547,820	$ 21,911,805	29.75	3.36%	$ 736,531	$ 659,952	-$ 76,580
1850	Line Transformers Inventory	$ 2,310,328					$ 2,310,328	-	0.00%	$ -		$ -
1855	Services (Overhead & Underground)	$ 23,289,210	$ 14,175,379		$ 205,960	$ 334	$ 9,216,477	38.86	2.57%	$ 237,171	$ 237,566	$ 394
1860	Meters	$ 957,717	$ 555,596	$ 10,573		$ 3,482	$ 409,212	33.48	2.99%	$ 12,223	$ -	-$ 12,223
1860	Meters (Smart Meters)	$ 9,145,670	$ 3,255,893	$ 810,992	$ 387,330		$ 6,894,435	11.15	8.97%	$ 618,353	$ 684,808	$ 66,455
1860	Meter Inventory	$ 607,261			$ 116,100	$ 104,154	$ 561,157	-	0.00%	$ -		$ -
1905	Land		$ -				$ -		0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures		$ -				$ -		0.00%	$ -	$ -	$ -
1910	Leasehold Improvements		$ -				$ -		0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 1,691,248	$ 1,189,532	$ 25,177	$ 20,799		$ 537,292	9.00	11.11%	$ 59,699	$ 60,652	$ 952
1915	Office Furniture & Equipment (5 years)		$ -				$ -		0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 3,513,719	$ 3,050,764	$ 22,855	$ 448,241		$ 709,931	4.54	22.03%	$ 156,372	$ 155,664	-$ 708
1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -				$ -		0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -				$ -		0.00%	$ -	$ -	$ -
1930	Transportation Equipment	$ 8,423,834	$ 2,075,724	$ 566,781	$ 439,982	$ 1,435,148	$ 5,699,733	12.95	7.72%	$ 440,134	$ 463,865	$ 23,731
1935	Stores Equipment	$ 97,797	$ 63,417				$ 34,380	10.00	10.00%	$ 3,438	$ 3,438	$ 0
1940	Tools, Shop & Garage Equipment	$ 3,128,377	$ 2,428,538	$ 58,468	$ 34,848		$ 775,731	8.93	11.20%	$ 86,868	$ 89,399	$ 2,531
1945	Measurement & Testing Equipment	$ 538,069	$ 335,972	$ 72,058	$ 31,673		$ 289,991	7.26	13.78%	$ 39,954	$ 40,712	$ 758
1950	Power Operated Equipment	$ 425,791	$ 13,488				$ 412,303	11.89	8.41%	$ 34,676	$ 34,678	$ 2
1955	Communications Equipment	$ 287,510	$ 287,361	$ 30,124	$ 41,522		$ 51,034	4.58	21.83%	$ 11,143	$ 15,109	$ 3,966
1955	Communication Equipment (Smart Meters)		$ -				$ -		0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment		$ -				$ -		0.00%	$ -	$ -	$ -
1970	Load Management Controls Customer Premises		$ -				$ -		0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises		$ -				$ -		0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 863,460	$ 333,125	$ 322,863	$ 285,529		$ 995,962	8.14	12.28%	$ 122,288	$ 109,302	-$ 12,986
1985	Miscellaneous Fixed Assets		$ -				$ -		0.00%	$ -	$ -	$ -
1990	Other Tangible Property		$ -				$ -		0.00%	$ -	$ -	$ -
1995	Contributions & Grants	-$ 18,542,289	$ -				-$ 18,542,289	42.90	2.33%	-$ 432,221	-$ 432,680	-$ 459
2440	Deferred Revenue	-$ 9,075,942	$ -	-$ 213,398	-$ 2,517,223		-$ 10,547,952	45.00	2.22%	-$ 234,399	-$ 226,650	$ 7,748
2005	Property Under Finance Lease		$ -				$ -		0.00%	$ -	$ -	$ -
	Total	**$ 216,349,867**	**$ 93,407,042**	**$ 11,440,556**	**$ 11,910,713**		**$ 135,955,028**	**$ 542**		**$ 5,116,931**	**$ 5,081,231**	**-$ 35,700**

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Appendix 2-C
Depreciation and Amortization Expense

General: This appendix is to assess the reasonability of the depreciation expense that is included in rate base via. accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation
This appendix must be completed under MIFRS for each year for the earlier of:

Notes:
1 This should include assets in column A (excel column C) that become fully depreciated.
2 The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to
3 OEB policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.
4 The applicant must provide an explanation of material variances in its evidence.

Year 2020 **SNC**

		Book Values					Service Lives		Expense		
Account	Description	Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Disposals	Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [4]
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid	$ 1,272,321	$ -	$ -	$ -	$ 1,272,321	25.00	4.00%	$ 50,893	$ 50,893	$ -
1611	Computer Software (Formally known as Account 1925)	$ 1,342,443	$ 1,304,537	$ 14,290	$ -	$ 45,051	5.00	20.00%	$ 9,010	$ 9,990	$ 980
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1805	Land	$ 150,114	$ -	$ -	$ -	$ 150,114		0.00%	$ -	$ -	$ -
1808	Buildings	$ 8,351,294	$ 2,336,019	$ 26,061	$ -	$ 6,028,306	24.29	4.12%	$ 248,181	$ 248,253	$ 73
1810	Leasehold Improvements	$ 63,262	$ 63,262	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ 2,736,397	$ 574,800	$ -	$ -	$ 2,161,597	21.57	4.64%	$ 100,213	$ 122,054	$ 21,841
1820	Distribution Station Equipment <50 kV	$ 8,498,490	$ 7,173,792	$ -	$ -	$ 1,324,698	16.22	6.17%	$ 81,671	$ 121,161	$ 39,490
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 59,519,503	$ 10,551,080	$ 3,778,014	$ 377,747	$ 50,479,684	34.35	2.91%	$ 1,469,569	$ 1,460,459	-$ 9,110
1835	Overhead Conductors & Devices	$ 50,036,846	$ 11,522,386	$ 1,555,859	$ 345,214	$ 38,947,175	48.92	2.04%	$ 796,140	$ 759,764	-$ 36,376
1840	Underground Conduit	$ 17,253,986	$ 8,952,458	$ 733,915	$ -	$ 8,668,486	61.85	1.62%	$ 140,153	$ 147,471	$ 7,318
1845	Underground Conductors & Devices	$ 24,355,970	$ 9,918,840	$ 764,589	$ 36,033	$ 14,783,391	32.64	3.06%	$ 452,923	$ 460,558	$ 7,635
1850	Line Transformers	$ 35,367,421	$ 12,556,331	$ 1,628,063	$ 202,172	$ 23,422,949	32.39	3.09%	$ 723,154	$ 698,423	-$ 24,730
1850	Line Transformers Inventory	$ 2,632,133				$ 2,632,133	-	0.00%	$ -		$ -
1855	Services (Overhead & Underground)	$ 23,494,836	$ 12,240,062	$ 226,701	$ 938	$ 11,367,186	38.05	2.63%	$ 298,743	$ 242,634	-$ 56,109
1860	Meters	$ 2,163,130	$ 1,595,823	$ 43,359	$ -	$ 588,986	34.33	2.91%	$ 17,157	$ -	-$ 17,157
1860	Meters (Smart Meters)	$ 9,145,670	$ 1,499,420	$ 212,619	$ -	$ 7,752,559	11.21	8.92%	$ 691,575	$ 723,563	$ 31,988
1860	Meters Inventory	$ 619,207		$ 343,393	-$ 128,143	$ 919,046	-	0.00%	$ -		$ -
1905	Land	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 1,737,223	$ 1,284,072	$ 28,692	$ -	$ 467,497	9.26	10.80%	$ 50,486	$ 57,719	$ 7,233
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 3,984,815	$ 3,411,359	$ 176,819	$ -	$ 661,865	4.39	22.78%	$ 150,767	$ 176,423	$ 25,656
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1930	Transportation Equipment	$ 7,995,449	$ 2,223,775	$ 491,899	$ 52,746	$ 5,964,878	13.06	7.66%	$ 456,729	$ 447,450	-$ 9,279
1935	Stores Equipment	$ 97,797	$ 63,417	$ -	$ -	$ 34,380	10.00	10.00%	$ 3,438	$ 3,438	$ 0
1940	Tools, Shop & Garage Equipment	$ 3,221,693	$ 2,409,290	$ 112,542	$ -	$ 868,673	9.10	10.99%	$ 95,459	$ 94,998	-$ 461
1945	Measurement & Testing Equipment	$ 641,799	$ 297,050	$ 13,150	$ -	$ 351,324	7.35	13.61%	$ 47,799	$ 43,279	-$ 4,520
1950	Power Operated Equipment	$ 425,791	$ 204,487	$ -	$ -	$ 221,304	14.21	7.04%	$ 15,574	$ 21,620	$ 6,046
1955	Communications Equipment	$ 359,156	$ 283,980	$ -	$ -	$ 75,177	4.57	21.88%	$ 16,450	$ 15,483	-$ 967
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 1,471,851	$ 584,733	$ 83,670	$ -	$ 928,954	8.15	12.27%	$ 113,982	$ 112,285	-$ 1,697
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1995	Contributions & Grants	-$ 18,542,289	$ -	$ -	$ -	-$ 18,542,289	42.90	2.33%	-$ 432,221	-$ 432,680	-$ 459
2440	Deferred Revenue	-$ 11,806,553	$ -	-$ 2,922,524	$ -	-$ 13,267,815	45.00	2.22%	-$ 294,840	-$ 249,298	$ 45,543
2005	Property Under Finance Lease		$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
	Total	**$ 236,589,757**	**$ 91,050,973**	**$ 7,311,110**	**$ 886,707**	**$ 147,035,311**	**$ 554**		**$ 5,303,002**	**$ 5,335,942**	**$ 32,940**

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Appendix 2-C
Depreciation and Amortization Expense

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Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation
This appendix must be completed under MIFRS for each year for the earlier of:

Notes:
1 This should include assets in column A (excel column C) that become fully depreciated.
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3 OEB policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.
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Year 2021 **SNC**

		Book Values					Service Lives		Expense		
Account	**Description**	**Opening Book Value of Assets**	**Less Fully Depreciated [1]**	**Current Year Additions**	**Disposals**	**Net Amount of Assets to be Depreciated**	**Remaining Life of Assets Existing [2]**	**Depreciation Rate Assets**	**Depreciation Expense on Assets [3]**	**Depreciation Expense per Appendix 2-BA Fixed Assets, Column J**	**Variance [4]**
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid	$ 1,272,321	$ -	$ -	$ -	$ 1,272,321	25.00	4.00%	**$ 50,893**	$ 50,893	**$ -**
1611	Computer Software (Formally known as Account 1925)	$ 1,356,733	$ 1,313,458	$ 29,072	$ -	$ 57,811	3.79	26.39%	**$ 15,254**	$ 16,271	**$ 1,017**
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1805	Land	$ 150,114	$ -	$ -	$ 1,441	$ 148,673		0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ 8,377,355	$ 2,191,802	$ 44,365	$ -	$ 6,207,735	24.74	4.04%	**$ 250,919**	$ 249,587	**-$ 1,332**
1810	Leasehold Improvements	$ 63,262	$ 63,262	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ 2,736,397	$ 574,800	$ -	$ -	$ 2,161,597	22.32	4.48%	**$ 96,846**	$ 114,943	**$ 18,097**
1820	Distribution Station Equipment <50 kV	$ 8,498,490	$ 7,225,013	$ 5,055	$ -	$ 1,276,005	16.19	6.18%	**$ 78,814**	$ 67,343	**-$ 11,471**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 62,919,771	$ 9,883,854	$ 6,872,912	$ 593,643	$ 55,878,729	34.94	2.86%	**$ 1,599,277**	$ 1,592,872	**-$ 6,405**
1835	Overhead Conductors & Devices	$ 51,247,491	$ 13,230,159	$ 3,149,821	$ 694,535	$ 38,897,707	49.15	2.03%	**$ 791,408**	$ 792,328	**$ 920**
1840	Underground Conduit	$ 17,987,902	$ 8,348,952	$ 944,967	$ 18,984	$ 10,092,449	62.86	1.59%	**$ 160,554**	$ 159,613	**-$ 941**
1845	Underground Conductors & Devices	$ 25,084,525	$ 9,451,349	$ 1,173,468	$ 73,725	$ 16,146,185	33.08	3.02%	**$ 488,095**	$ 484,694	**-$ 3,401**
1850	Line Transformers	$ 36,546,921	$ 13,010,024	$ 1,951,091	$ 279,423	$ 24,233,020	32.86	3.04%	**$ 737,463**	$ 736,875	**-$ 588**
1850	Line Transformers Inventory	$ 2,878,524				$ 2,878,524	-	0.00%	**$ -**		**$ -**
1855	Services (Overhead & Underground)	$ 23,720,599	$ 13,878,312	$ 209,063	$ 98,915	$ 9,847,904	39.75	2.52%	**$ 247,746**	$ 248,403	**$ 657**
1860	Meters	$ 1,216,657	$ 611,170	$ -	$ -	$ 605,487	34.59	2.89%	**$ 17,505**	$ -	**-$ 17,505**
1860	Meters (Smart Meters)	$ 10,348,120	$ 2,441,494	$ 255,914	-$ 0	$ 8,034,583	11.31	8.84%	**$ 710,396**	$ 735,372	**$ 24,976**
1860	Meters Inventory	$ 834,457		$ 135,042	$ 123,713	$ 778,265	-	0.00%	**$ -**		**$ -**
1905	Land	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 1,765,915	$ 1,381,222	$ 2,799	$ -	$ 386,093	9.10	10.99%	**$ 42,428**	$ 50,331	**$ 7,904**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ 4,161,634	$ 3,468,036	$ 422,671	$ -	$ 904,933	4.53	22.08%	**$ 199,765**	$ 217,644	**$ 17,880**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1930	Transportation Equipment	$ 8,434,603	$ 2,711,237	$ 689,798	$ -	$ 6,068,265	13.27	7.54%	**$ 457,292**	$ 473,323	**$ 16,031**
1935	Stores Equipment	$ 97,797	$ 63,417	$ -	$ -	$ 34,380	10.00	10.00%	**$ 3,438**	$ 3,438	**$ 0**
1940	Tools, Shop & Garage Equipment	$ 3,334,234	$ 2,463,457	$ 64,714	$ -	$ 903,134	9.05	11.05%	**$ 99,794**	$ 99,906	**$ 112**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 1,977,378	$ 1,564,292	$ 51,000	$ -	$ 438,586	10.39	9.62%	**$ 42,212**	$ 61,370	**$ 19,158**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ 5,259,957	$ 3,980,660	$ 220,000	$ -	$ 1,389,297	4.53	22.08%	**$ 306,688**	$ 267,600	**-$ 39,088**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1930	Transportation Equipment	$ 9,983,868	$ 2,921,009	$ 600,000	$ -	$ 7,362,859	13.44	7.44%	**$ 547,832**	$ 556,133	**$ 8,301**
1935	Stores Equipment	$ 112,364	$ 63,417	$ -	$ -	$ 48,947	10.00	10.00%	**$ 4,895**	$ 3,438	**-$ 1,457**
1940	Tools, Shop & Garage Equipment	$ 3,677,816	$ 2,774,317	$ 120,000	$ -	$ 963,499	9.46	10.57%	**$ 101,850**	$ 142,592	**$ 40,742**
1945	Measurement & Testing Equipment	$ 677,634	$ 440,112	$ 51,170	$ -	$ 263,107	8.13	12.30%	**$ 32,363**	$ 11,394	**-$ 20,969**
1950	Power Operated Equipment	$ 425,791	$ 215,882	$ -	$ -	$ 209,909	14.54	6.88%	**$ 14,437**	$ 15,574	**$ 1,137**
1955	Communications Equipment	$ 533,274	$ 357,381	$ -	$ -	$ 175,893	5.04	19.84%	**$ 34,899**	$ 32,154	**-$ 2,746**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ 2,114,370	$ 655,708	$ 264,081	$ -	$ 1,590,703	13.43	7.45%	**$ 118,444**	$ 92,338	**-$ 26,106**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	-$ 18,542,289	$ -	$ -	$ -	-$ 18,542,289	42.90	2.33%	**-$ 432,221**	-$ 432,680	**-$ 459**
2440	Deferred Revenue	-$ 22,307,721	$ -	-$ 1,534,422	$ -	-$ 23,074,932	45.00	2.22%	**-$ 512,776**	-$ 516,145	**-$ 3,369**
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
	Total	**$ 277,432,903**	**$ 92,407,798**	**$ 14,876,780**	**$ 2,259,340**	**$ 188,931,834**	**$ 577**		**$ 6,404,924**	**$ 6,533,934**	**$ 129,010**