Exhibit 2

Rate Base and Capital

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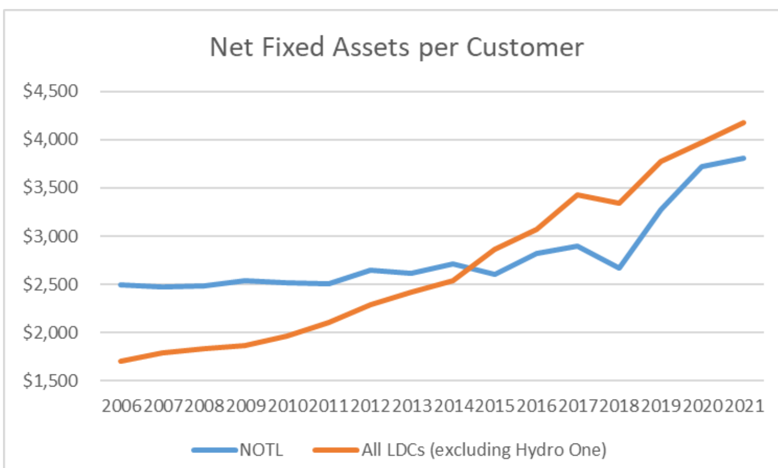
2.2.0 Executive Summary

As described in Exhibit 1, having low rates is a corporate objective of NOTL Hydro. NOTL Hydro's success in this regard is something that is promoted at its Annual General Meeting and elsewhere. Managing rate base appropriately is part of maintaining low rates and is a key element in NOTL Hydro's strategy.

Evidence of this can be seen in a couple of ways. First the growth in rate base over the last five years is largely in line with inflation and is driven by NOTL Hydro's capital spending. This spending is within 5% of that outlined in the 2019 Cost of Service application. This is described in more detail in section 2.2.1.2 below.

Second, is the long-term growth in NOTL Hydro's fixed assets. NOTL Hydro is not driven to increase its rate base by investing more in fixed assets. NOTL Hydro's fixed asset spending per customer has been much less than the industry average over the past 15 years.

Table 2.1: Net Fixed Assets per Customer



This does not mean that NOTL Hydro is not willing to spend where necessary. The growth in more recent years has been driven by the investments in the transmission stations. NOTL Hydro is also confident that the voltage conversion, undergrounding and asset management programs are more than adequate to keep the distribution grid performing appropriately. NOTL Hydro's reliability statistics are testament to this.

In managing its fixed asset growth, NOTL Hydro also does not favour capital solutions over operating solutions. In many cases it has made choices that increase OM&A costs but do not require significant capital investments.

- NOTL Hydro's use of UCS for its billing system means that any related expenditures are OM&A and not capital as the asset belongs to UCS and not NOTL Hydro.
- NOTL Hydro outsources its control center requirements even though it could invest in control room assets to support its distribution system.
- NOTL Hydro has moved much of its IT systems to cloud based systems even though this means monthly OM&A subscription costs and not capital investments.

2.2.1 Rate Base

2.2.1.1 Rate Base Overview

Niagara-on-the-Lake Hydro Inc.'s (NOTL Hydro) Rate Base is determined by taking the average of the asset balances at the beginning and the end of the 2024 Test Year, plus a working capital allowance which is 7.5% of the sum of the cost of power and controllable expenses. The use of a 7.5% rate is consistent with the Board's letter of June 3, 2015, the Filing Requirements as issued by the Ontario Energy Board and NOTL Hydro's 2019 Cost of Service.

The net fixed assets include those distribution assets associated with activities that enable the conveyance of electricity for distribution purposes. It also includes two transformer stations that step-down electricity from the Hydro One 115 kV lines to NOTL Hydro's distribution voltage of 27.6 kV. Controllable expenses include operations and maintenance, billing and collecting and administration expenses.

For the purpose of determining rate base, only in-service additions are included and not capital work in progress.

NOTL Hydro has calculated its 2024 Test Year rate base to be $35,547,664. This rate base is also used to determine the proposed revenue requirement found at Exhibit 6.

2.2.1.2 Rate Base

The table below presents NOTL Hydro's Rate Base calculations for all required years including the 2024 Test Year. Year-over-year variance analysis follows:

Table 2.2: Rate Base Trend

	MIFRS 2019	MIFRS 2019	MIFRS 2020	MIFRS 2021	MIFRS 2022	MIFRS 2023	MIFRS 2024
Particulars	**Board Appr**	**Actual**	**Actual**	**Actual**	**Actual**	**Bridge**	**Test**
Net Capital Assets in Service:							
Opening Balance		26,203,305	26,084,280	29,497,401	30,732,245	30,264,127	32,905,404
Ending Balance		26,084,280	29,497,401	30,732,245	30,264,127	32,905,404	33,466,174
Average Balance	28,311,753	26,143,792	27,790,840	30,114,823	30,498,186	31,584,765	33,185,789
Working Capital Allowance	2,145,223	2,188,969	2,488,316	2,204,021	2,158,894	2,142,595	2,361,874
Total Rate Base	**30,456,976**	**28,332,761**	**30,279,156**	**32,318,844**	**32,657,079**	**33,727,361**	**35,547,664**

Table 2.3: Allowance for Working Capital – Derivation

	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Expenses for Working Capital	**2019**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Eligible Distribution Expenses:	**Board Appr**	**Actual**	**Actual**	**Actual**	**Actual**	**Bridge**	**Test**
Distribution Expenses - Operation	711,610	623,207	717,525	730,154	767,087	783,175	792,135
Distribution Expenses - Maintenance	449,790	521,538	409,998	511,054	487,879	486,646	513,942
Billing and Collecting	632,867	520,425	630,975	618,632	677,732	740,878	800,299
Community Relations	11,485	656	0	0	0	0	0
General and Administrative Expenses	858,405	1,157,659	1,187,374	1,294,405	1,374,941	1,392,813	1,456,708
6105-Taxes other than Income Taxes	34,955	35,495	41,701	42,226	42,743	43,384	43,384
6205-Sub-account LEAP Funding	7,209	6,866	6,866	6,866	6,866	6,866	8,801
Total Eligible Distribution Expenses	2,706,322	2,865,846	2,994,441	3,203,337	3,357,248	3,453,762	3,615,268
3350-Power Supply Expenses	25,896,653	26,320,401	30,183,104	26,183,615	25,428,000	25,114,177	27,876,388
Total Expenses for Working Capital	28,602,975	29,186,247	33,177,544	29,386,952	28,785,248	28,567,939	31,491,657
Working Capital factor	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%
Total Working Capital	**2,145,223**	**2,188,969**	**2,488,316**	**2,204,021**	**2,158,894**	**2,142,595**	**2,361,874**

The Rate Base for the 2024 Test Year has increased 16.7% over the last Board Approved Rate Base. Compound inflation is 15.9% in this same period.

The increase in the net fixed assets accounted for 96% of the increase in rate base or $4.9 million. The installation of the 83 MVA transformer was the biggest contributor to the increase. 50% of it or $1.65 million was included in the 2019 net fixed assets, the full amount of around $2.9 million less depreciation is included in 2024 net fixed assets. Distribution assets grew by a net $2.1 million after allowing for customer contributions. Most of this is driven by NOTL Hydro's system renewal projects as the annual expenditure on these is higher than the offsetting depreciation due to inflation.

Most of the increase in net fixed assets was planned in 2019. The table below compares the forecast growth in fixed assets less customer contributions to the actual growth as per the fixed asset continuity tables. The actual increase was only $534k or 4.86% higher.

Table 2.4: 2019 Board approved vs Actual Net Fixed Asset Additions ($000's)

Year	Actual	2019 Cost of Service
2019	2,101	4,936
2020	3,147	1,524
2021	1,937	1,359
2022	2,094	1,374
2023	2,237	1,789
Total	**11,516**	**10,982**

A breakdown in the increase in rate base since 2019 is provided in the table below.

Table 2.5: 2024-2019 Board approved Rate Base Variances

	2019	2024	2024 vs. 2019	2024 vs. 2019
Particulars	**Board Appr**	**Test**	**BA vs. Test**	**BA vs. Test**
Net Capital Assets in Service:				
Opening Balance		32,905,404		
Ending Balance		33,466,174		
Average Balance	28,311,753	33,185,789	4,874,036	17.2%
Working Capital Allowance	2,145,223	2,361,874	216,651	10.1%
Total Rate Base	**30,456,976**	**35,547,664**	**5,090,687**	**16.7%**
	MIFRS	**MIFRS**	**MIFRS**	**MIFRS**
Expenses for Working Capital	**2019**	**2024**	**2024 vs. 2019**	**2024 vs. 2019**
Eligible Distribution Expenses:	**Board Appr**	**Test**	**BA vs. Test**	**BA vs. Test**
Distribution Expenses - Operation	711,610	792,135	80,525	11.3%
Distribution Expenses - Maintenance	449,790	513,942	64,151	14.3%
Billing and Collecting	632,867	800,299	167,432	26.5%
Community Relations	11,485	0	(11,485)	(100.0%)
General and Administrative Expenses	858,405	1,456,708	598,302	69.7%
6105-Taxes other than Income Taxes	34,955	43,384	8,429	24.1%
6205-Sub-account LEAP Funding	7,209	8,801	1,591	22.1%
Total Eligible Distribution Expenses	2,706,322	3,615,268	908,946	33.6%
3350-Power Supply Expenses	25,896,653	27,876,388	1,979,735	7.6%
Total Expenses for Working Capital	28,602,975	31,491,657	2,888,681	10.1%
Working Capital factor	7.5%	7.5%	-	0.0%
Total Working Capital	**2,145,223**	**2,361,874**	**216,651**	**10.1%**

2.2.2 Fixed Assets

2.2.2.1 Fixed Asset Continuity Schedule

This schedule presents a continuity schedule of NOTL Hydro's investment in capital assets, the associated accumulated amortization and the net book value for each account for the 2019-2022 actual balances plus projections for the 2023 Bridge Year and the 2024 Test Year.

After the implementation of the IFRS standard, Customer Contributions are no longer recorded in Account 1995 Contributions & Grants. Beginning in 2014 under IFRS, all new capital contributions were recorded in Account 2440 Deferred Revenue and allocated to revenue over the service life of the related assets. For the purpose of cost allocation, and continuity within this application, NOTL Hydro has included Account 2440 in the Continuity Schedules. This is consistent with the Boards required treatment.

The following Tables are the Board's Appendix 2-BA for 2019 - 2022 Actuals, the 2023 Bridge Year, and the 2024 Test Year.

Table 2.6: 2019 Fixed Asset Continuity Schedule

				Cost				Accumulated Depreciation				
CCA Class	**OEB FA**	**OEB Depr**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
47	1508	2105	ICM-Transformer Station Equipment >50 kV-Conc #5	2,565,528			2,565,528	186,416	53,433		239,849	2,325,679
N/A	1606	2105	Organization Costs	-			-	-			-	-
50	1611	2120	Computer Software (Formally known as Account 1925)	2,488,425	-	-	2,488,425	2,385,113	69,564	-	2,454,677	33,748
CEC	1612	2105	Land Rights (Formally known as Account 1906 and 1806)	-			-	-			-	-
N/A	1805	2105	Land	258,134	-	-	258,134	-	-	-	-	258,134
47	1808	2105	Buildings	-			-	-			-	-
13	1810	2105	Leasehold Improvements	-			-	-			-	-
47	1815	2105	Transformer Station Equipment >50 kV York Rd	2,782,447	6,896	(1,001)	2,788,342	947,040	50,649	(154)	997,535	1,790,807
47	1815	2105	Transformer Station Equipment >50 kV-Conc #5	2,538,231	278,851	(29,042)	2,788,040	663,169	48,115	(1,056)	710,229	2,077,811
47	1820	2105	Distribution Station Equipment <50 kV	-			-	-			-	-
43.1	1825	2105	Storage Battery Equipment	-			-	-			-	-
47	1830	2105	Poles, Towers & Fixtures	6,490,959	472,273	(106,050)	6,857,182	2,915,970	116,322	(106,050)	2,926,242	3,930,940
47	1835	2105	Overhead Conductors & Devices	7,442,180	439,956	(111,212)	7,770,924	3,732,813	88,025	(105,783)	3,715,055	4,055,868
47	1840	2105	Underground Conduit	6,347,431	208,168		6,555,599	2,657,551	73,304		2,730,855	3,824,744
47	1845	2105	Underground Conductors & Devices	11,140,191	340,918		11,481,109	5,650,609	194,995		5,845,604	5,635,505
47	1850	2105	Line Transformers	9,276,163	391,182	(187,850)	9,479,495	4,212,373	159,703	(94,678)	4,277,398	5,202,098
47	1851	2105	Transformer Inventory	186,640	(47,512)	107,364	246,491	98,465	3,679		102,144	144,347
47	1852	2105	Transformer Damaged	-			-	-			-	-
47	1853	2105	Transformer Spare	177,695	-	(177,695)	-	30,651	1,825		32,476	(32,476)
47	1855	2105	Services Overhead	661,958	10,768		672,726	185,903	9,577		195,480	477,246
47	1855	2105	Services Underground	3,715,121	170,074		3,885,195	995,363	76,625		1,071,988	2,813,207
47	1860	2105	Meters	818,397	121,458	(6,404)	933,451	538,095	20,351	(3,435)	555,011	378,440
47	1860	2105	Meters (Smart Meters)	1,932,408	123,172	(4,114)	2,051,465	989,538	149,662	(1,762)	1,137,438	914,027
47	1861	2105	Meters Inventory	43,811	(33,779)	(10,033)	-	30,507	(30,507)		-	-
47	1861	2105	Smart Meters Inventory	68,098	(68,098)		0	18,657	(18,657)		-	0
47	1861	2105	Meters Inventory CT/PT	5,716	(5,716)		-	75	(75)		-	-
N/A	1905	2105	Land	49,000			49,000	-			-	49,000
1b	1908	2105	Buildings & Fixtures	1,240,579	22,745		1,263,325	476,110	20,699		496,809	766,516
8	1908	2105	Buildings & Fixtures- PCB Shed	8,690			8,690	8,690			8,690	-
13	1910	2105	Leasehold Improvements	-			-	-			-	-
8	1915	2105	Office Furniture & Equipment (10 years)	233,409	2,995		236,404	210,951	6,085		217,036	19,368
8	1915	2105	Office Furniture & Equipment (5 years)	-			-	-			-	-
50	1920	2105	Computer Equipment - Hardware	478,131	62,068		540,199	458,508	21,521		480,029	60,170
45	1920	2105	Computer Equip.-Hardware(Post Mar. 22/04)	-			-	-			-	-
45	1920	2105	Computer Equip.-Hardware(Post Mar. 19/07)	-			-	-			-	-
10	1930	2105	Transportation Equipment < 3 TONS	169,769	84,178	(45,241)	208,706	156,280	14,676	(41,139)	129,817	78,889
10	1930	2105	Transportation Equipment > 3 TONS	1,055,166	-		1,055,166	534,964	97,917		632,881	422,284
10	1930	2105	Transportation Equipment Trailers	84,108	-		84,108	43,023	3,043		46,066	38,042
8	1935	2105	Stores Equipment	24,684	-		24,684	24,307	366		24,673	11
8	1940	2105	Tools, Shop & Garage Equipment	534,767	20,885		555,652	477,572	11,301		488,873	66,779
8	1945	2105	Measurement & Testing Equipment	-			-	-			-	-
8	1950	2105	Power Operated Equipment	-			-	-			-	-
8	1955	2105	Communications Equipment	54,383	-		54,383	53,996	336		54,332	51
8	1955	2105	Communication Equipment (Smart Meters)	-			-	-			-	-
8	1960	2105	Miscellaneous Equipment	-			-	-			-	-
47	1970	2105	Load Management Controls Customer Premises	-			-	-			-	-
47	1975	2105	Load Management Controls Utility Premises	-			-	-			-	-
47	1980	2105	System Supervisor Equipment	668,067	15,700		683,767	453,066	30,577		483,642	200,125
47	1985	2105	Miscellaneous Fixed Assets	-			-	-			-	-
47	1990	2105	Other Tangible Property	-			-	-			-	-
47	1995	2105	Contributions & Grants-O/H Poles	(238,366)			(238,366)	(89,329)	(4,548)		(93,877)	(144,489)
47	1995	2105	Contributions & Grants-O/H Conductor	(235,221)			(235,221)	(89,749)	(3,107)		(92,856)	(142,365)
47	1995	2105	Contributions & Grants-O/H Services	(146,562)			(146,562)	(60,221)	(1,878)		(62,099)	(84,463)
47	1995	2105	Contributions & Grants-U/G Conduit	(879,222)			(879,222)	(270,356)	(11,280)		(281,636)	(597,586)
47	1995	2105	Contributions & Grants-U/G Conductor	(1,788,778)			(1,788,778)	(748,399)	(32,681)		(781,079)	(1,007,699)
47	1995	2105	Contributions & Grants-U/G Services	(1,606,653)			(1,606,653)	(585,401)	(30,625)		(616,026)	(990,627)
47	1995	2105	Contributions & Grants-Transformers	(2,283,741)			(2,283,741)	(886,088)	(42,859)		(928,947)	(1,354,794)
47	1995	2105	Contributions & Grants-Meters	(7,344)			(7,344)	(4,787)	(294)		(5,081)	(2,263)
47	1995	2105	Contributions & Grants-Admin	(13,000)			(13,000)	(4,608)	(205)		(4,813)	(8,187)
47	1995	2105	Contributions & Grants-Rolling Stock	(9,722)			(9,722)	(9,722)			(9,722)	-
47	2440		Def Rev-Contributions & Grants-O/H Poles	(433,869)	(68,690)		(502,559)	(13,324)	(10,405)		(23,729)	(478,830)
47	2440		Def Rev-Contributions & Grants-O/H Conductor	(110,617)	(172,193)		(282,810)	(4,013)	(3,279)		(7,291)	(275,519)
47	2440		Def Rev-Contributions & Grants-O/H Services	(33,573)	(5,511)		(39,084)	(1,967)	(605)		(2,572)	(36,512)
47	2440		Def Rev-Contributions & Grants-U/G Conduit	(535,145)	(192,954)		(728,098)	(26,197)	(9,717)		(35,915)	(692,184)
47	2440		Def Rev-Contributions & Grants-U/G Conductor	(756,913)	(330,894)		(1,087,806)	(48,346)	(20,497)		(68,843)	(1,018,964)
47	2440		Def Rev-Contributions & Grants-U/G Services	(861,667)	(131,362)		(993,028)	(56,730)	(20,608)		(77,338)	(915,690)
47	2440		Def Rev-Contributions & Grants-Transformers	(1,132,666)	(211,631)		(1,344,297)	(57,114)	(27,522)		(84,636)	(1,259,661)
47	2440		Def Rev-Contributions & Grants-Meters	(91,734)	(66,839)		(158,573)	(7,234)	(5,006)		(12,240)	(146,333)
47	2440		Def Rev-Contributions & Grants-Admin	-			-	-			-	-
47	2440		Def rev-Contributions & Grants-Rolling Stock	-			-	-			-	-
47	2440		Def Rev-Contributions & Grants-Stations	-	(285,746)		(285,746)	-	(2,598)		(2,598)	(283,149)
47	2440		Def Rev-Contributions & Grant System Supervisory		(8,178)		(8,178)	-	(409)		(409)	(7,769)
43.1	2440		Def rev-Contributions & Grants-Battery	-			-	-			-	-
			Sub-Total	**52,375,496**	**1,143,184**	**(571,278)**	**52,947,402**	**26,172,191**	**1,044,989**	(354,058)	26,863,122	26,084,280
	2055		CWIP-Internal	505,012	1,727,743		2,232,754	-			-	-
	2056		CWIP-Customer Projects	944,538	(769,945)		174,593	-			-	-
			Total PP&E	**53,825,046**	**2,100,982**	**(571,278)**	**55,354,749**	**26,172,191**	**1,044,989**	**(354,058)**	**26,863,122**	**26,084,280**

Table 2.7: 2020 Fixed Asset Continuity Schedule

				Cost				Accumulated Depreciation				
CCA Class	**OEB FA**	**OEB Depr**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
47	1508	2105	ICM-Transformer Station Equipment >50 kV-Conc #5	2,565,528	(2,565,528)	-	-	239,849	(239,849)	-	-	-
N/A	1606	2105	Organization Costs	-	-	-	-	-	-	-	-	-
50	1611	2120	Computer Software (Formally known as Account 1925)	2,488,425	39,978	-	2,528,403	2,454,677	36,326	-	2,491,002	37,400
CEC	1612	2105	Land Rights (Formally known as Account 1906 and 1806)	-	-	-	-	-	-	-	-	-
N/A	1805	2105	Land	258,134	-	-	258,134	-	-	-	-	258,134
47	1808	2105	Buildings	-	-	-	-	-	-	-	-	-
13	1810	2105	Leasehold Improvements	-	-	-	-	-	-	-	-	-
47	1815	2105	Transformer Station Equipment >50 kV York Rd	2,788,342	2,334,812	-	5,123,154	997,535	72,977	-	1,070,512	4,052,642
47	1815	2105	Transformer Station Equipment >50 kV-Conc #5	2,788,040	2,565,528	-	5,353,568	710,229	343,915	-	1,054,144	4,299,424
47	1820	2105	Distribution Station Equipment <50 kV	-	-	-	-	-	-	-	-	-
43.1	1825	2105	Storage Battery Equipment	-	497,510	-	497,510	-	24,875	-	24,875	472,634
47	1830	2105	Poles, Towers & Fixtures	6,857,182	266,413	(39,016)	7,084,580	2,926,242	122,849	(36,358)	3,012,733	4,071,847
47	1835	2105	Overhead Conductors & Devices	7,770,924	60,993	(6,192)	7,825,725	3,715,055	91,701	(5,962)	3,800,794	4,024,931
47	1840	2105	Underground Conduit	6,555,599	77,334	-	6,632,932	2,730,855	75,639	-	2,806,495	3,826,438
47	1845	2105	Underground Conductors & Devices	11,481,109	706,513	-	12,187,622	5,845,604	207,015	-	6,052,619	6,135,003
47	1850	2105	Line Transformers	9,479,495	596,417	(122,363)	9,953,549	4,277,398	198,134	(31,678)	4,443,854	5,509,696
47	1851	2105	Transformer Inventory	246,491	(246,491)	-	(0)	102,144	(102,144)	-	(0)	(0)
47	1852	2105	Transformer Damaged	-	-	-	-	-	-	-	-	-
47	1853	2105	Transformer Spare	-	-	-	-	32,476	(32,476)	-	-	-
47	1855	2105	Services Overhead	672,726	16,536	-	689,262	195,480	9,826	-	205,306	483,955
47	1855	2105	Services Underground	3,885,195	199,127	-	4,084,322	1,071,988	80,847	-	1,152,835	2,931,487
47	1860	2105	Meters	933,451	42,166	(202,967)	772,650	555,011	14,787	(177,706)	392,091	380,559
47	1860	2105	Meters (Smart Meters)	2,051,465	106,832	(4,016)	2,154,281	1,137,438	140,933	(991)	1,277,380	876,901
47	1861	2105	Meters Inventory	-	-	-	-	-	-	-	-	-
47	1861	2105	Smart Meters Inventory	0	-	-	0	-	-	-	-	0
47	1861	2105	Meters Inventory CT/PT	-	-	-	-	-	-	-	-	-
N/A	1905	2105	Land	49,000	-	-	49,000	-	-	-	-	49,000
1b	1908	2105	Buildings & Fixtures	1,263,325	3,265	-	1,266,590	496,809	20,963	-	517,771	748,819
8	1908	2105	Buildings & Fixtures- PCB Shed	8,690	-	-	8,690	8,690	-	-	8,690	-
13	1910	2105	Leasehold Improvements	-	-	-	-	-	-	-	-	-
8	1915	2105	Office Furniture & Equipment (10 years)	236,404	6,396	-	242,800	217,036	5,433	-	222,469	20,332
8	1915	2105	Office Furniture & Equipment (5 years)	-	-	-	-	-	-	-	-	-
50	1920	2105	Computer Equipment - Hardware	540,199	19,706	-	559,906	480,029	30,582	-	510,611	49,295
45	1920	2105	Computer Equip.-Hardware(Post Mar. 22/04)	-	-	-	-	-	-	-	-	-
45	1920	2105	Computer Equip.-Hardware(Post Mar. 19/07)	-	-	-	-	-	-	-	-	-
10	1930	2105	Transportation Equipment < 3 TONS	208,706	32,478	-	241,183	129,817	23,213	-	153,029	88,154
10	1930	2105	Transportation Equipment > 3 TONS	1,055,166	-	-	1,055,166	632,881	93,658	-	726,539	328,627
10	1930	2105	Transportation Equipment Trailers	84,108	6,970	(4,230)	86,848	46,066	3,276	(4,230)	45,112	41,736
8	1935	2105	Stores Equipment	24,684	549	-	25,233	24,673	32	-	24,705	528
8	1940	2105	Tools, Shop & Garage Equipment	555,652	18,054	(5,600)	568,106	488,873	12,886	(5,600)	496,160	71,947
8	1945	2105	Measurement & Testing Equipment	-	-	-	-	-	-	-	-	-
8	1950	2105	Power Operated Equipment	-	-	-	-	-	-	-	-	-
8	1955	2105	Communications Equipment	54,383	-	-	54,383	54,332	51	-	54,383	-
8	1955	2105	Communication Equipment (Smart Meters)	-	-	-	-	-	-	-	-	-
8	1960	2105	Miscellaneous Equipment	-	-	-	-	-	-	-	-	-
47	1970	2105	Load Management Controls Customer Premises	-	-	-	-	-	-	-	-	-
47	1975	2105	Load Management Controls Utility Premises	-	-	-	-	-	-	-	-	-
47	1980	2105	System Supervisor Equipment	683,767	129,921	-	813,688	483,642	37,776	-	521,418	292,271
47	1985	2105	Miscellaneous Fixed Assets	-	-	-	-	-	-	-	-	-
47	1990	2105	Other Tangible Property	-	-	-	-	-	-	-	-	-
47	1995	2105	Contributions & Grants-O/H Poles	(238,366)	-	-	(238,366)	(93,877)	(4,548)	-	(98,424)	(139,942)
47	1995	2105	Contributions & Grants-O/H Conductor	(235,221)	-	-	(235,221)	(92,856)	(3,107)	-	(95,963)	(139,258)
47	1995	2105	Contributions & Grants-O/H Services	(146,562)	-	-	(146,562)	(62,099)	(1,878)	-	(63,977)	(82,586)
47	1995	2105	Contributions & Grants-U/G Conduit	(879,222)	-	-	(879,222)	(281,636)	(11,280)	-	(292,916)	(586,306)
47	1995	2105	Contributions & Grants-U/G Conductor	(1,788,778)	-	-	(1,788,778)	(781,079)	(32,681)	-	(813,760)	(975,018)
47	1995	2105	Contributions & Grants-U/G Services	(1,606,653)	-	-	(1,606,653)	(616,026)	(30,625)	-	(646,650)	(960,002)
47	1995	2105	Contributions & Grants-Transformers	(2,283,741)	-	-	(2,283,741)	(928,947)	(42,859)	-	(971,806)	(1,311,935)
47	1995	2105	Contributions & Grants-Meters	(7,344)	-	-	(7,344)	(5,081)	(294)	-	(5,374)	(1,969)
47	1995	2105	Contributions & Grants-Admin	(13,000)	-	-	(13,000)	(4,813)	(205)	-	(5,018)	(7,982)
47	1995	2105	Contributions & Grants-Rolling Stock	(9,722)	-	-	(9,722)	(9,722)	-	-	(9,722)	-
47	2440		Def Rev-Contributions & Grants-O/H Poles	(502,559)	(43,596)	-	(546,155)	(23,729)	(11,652)	-	(35,381)	(510,774)
47	2440		Def Rev-Contributions & Grants-O/H Conductor	(282,810)	30,015	-	(252,795)	(7,291)	(4,463)	-	(11,755)	(241,041)
47	2440		Def Rev-Contributions & Grants-O/H Services	(39,084)	(13,701)	-	(52,784)	(2,572)	(766)	-	(3,338)	(49,447)
47	2440		Def Rev-Contributions & Grants-U/G Conduit	(728,098)	(9,211)	-	(737,310)	(35,915)	(11,272)	-	(47,187)	(690,123)
47	2440		Def Rev-Contributions & Grants-U/G Conductor	(1,087,806)	(51,092)	-	(1,138,899)	(68,843)	(24,741)	-	(93,584)	(1,045,315)
47	2440		Def Rev-Contributions & Grants-U/G Services	(993,028)	(121,673)	-	(1,114,701)	(77,338)	(23,419)	-	(100,757)	(1,013,944)
47	2440		Def Rev-Contributions & Grants-Transformers	(1,344,297)	(46,108)	-	(1,390,406)	(84,636)	(30,386)	-	(115,021)	(1,275,384)
47	2440		Def Rev-Contributions & Grants-Meters	(158,573)	(8,822)	-	(167,395)	(12,240)	(6,519)	-	(18,760)	(148,636)
47	2440		Def Rev-Contributions & Grants-Admin	-	-	-	-	-	-	-	-	-
47	2440		Def rev-Contributions & Grants-Rolling Stock	-	-	-	-	-	-	-	-	-
47	2440		Def Rev-Contributions & Grants-Stations	(285,746)	-	-	(285,746)	(2,598)	(5,195)	-	(7,793)	(277,953)
47	2440		Def Rev-Contributions & Grant System Supervisory	(8,178)	-	-	(8,178)	(409)	(818)	-	(1,227)	(6,951)
43.1	2440		Def rev-Contributions & Grants-Battery	-	(94,520)	-	(94,520)	-	(4,726)	-	(4,726)	(89,794)
			Sub-Total	**52,947,402**	**4,556,769**	**(384,384)**	**57,119,787**	**26,863,122**	**1,021,790**	(262,526)	27,622,387	29,497,401
	2055		CWIP-Internal	2,232,754	(1,559,667)		673,087	-			-	-
	2056		CWIP-Customer Projects	174,593	150,358		324,951	-			-	-
			Total PP&E	**55,354,749**	**3,147,460**	**(384,384)**	**58,117,825**	**26,863,122**	**1,021,790**	**(262,526)**	**27,622,387**	**29,497,401**

Table 2.8: 2021 Fixed Asset Continuity Schedule

				Cost				Accumulated Depreciation				
CCA Class	**OEB FA**	**OEB Depr**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
47	1508	2105	ICM-Transformer Station Equipment >50 kV-Conc #5	-	-	-	-	-	-	-	-	-
N/A	1606	2105	Organization Costs	-	-	-	-	-	-	-	-	-
50	1611	2120	Computer Software (Formally known as Account 1925)	2,528,403	47,086	(33,549)	2,541,939	2,491,002	25,259	(33,549)	2,482,712	59,227
CEC	1612	2105	Land Rights (Formally known as Account 1906 and 1806)	-	-	-	-	-	-	-	-	-
N/A	1805	2105	Land	258,134	-	-	258,134	-	-	-	-	258,134
47	1808	2105	Buildings	-	-	-	-	-	-	-	-	-
13	1810	2105	Leasehold Improvements	-	-	-	-	-	-	-	-	-
47	1815	2105	Transformer Station Equipment >50 kV York Rd	5,123,154	90,664	-	5,213,818	1,070,512	95,803	-	1,166,315	4,047,503
47	1815	2105	Transformer Station Equipment >50 kV-Conc #5	5,353,568	544,462	-	5,898,030	1,054,144	108,755	-	1,162,899	4,735,131
47	1820	2105	Distribution Station Equipment <50 kV	-	-	-	-	-	-	-	-	-
43.1	1825	2105	Storage Battery Equipment	497,510	-	-	497,510	24,875	49,751	-	74,626	422,883
47	1830	2105	Poles, Towers & Fixtures	7,084,580	541,254	(28,723)	7,597,111	3,012,733	131,577	(28,082)	3,116,228	4,480,883
47	1835	2105	Overhead Conductors & Devices	7,825,725	192,348	(65,070)	7,953,002	3,800,794	93,758	(62,110)	3,832,443	4,120,560
47	1840	2105	Underground Conduit	6,632,932	58,393	-	6,691,326	2,806,495	76,544	-	2,883,039	3,808,287
47	1845	2105	Underground Conductors & Devices	12,187,622	180,918	-	12,368,540	6,052,619	210,233	-	6,262,852	6,105,688
47	1850	2105	Line Transformers	9,953,549	472,847	(46,352)	10,380,044	4,443,854	178,239	(31,576)	4,590,517	5,789,527
47	1851	2105	Transformer Inventory	(0)	-	-	(0)	(0)	-	-	(0)	(0)
47	1852	2105	Transformer Damaged	-	-	-	-	-	-	-	-	-
47	1853	2105	Transformer Spare	-	-	-	-	-	-	-	-	-
47	1855	2105	Services Overhead	689,262	34,808	-	724,069	205,306	10,232	-	215,538	508,531
47	1855	2105	Services Underground	4,084,322	239,102	-	4,323,424	1,152,835	85,597	-	1,238,432	3,084,992
47	1860	2105	Meters	772,650	7,437	(554)	779,533	392,091	15,710	(62)	407,739	371,794
47	1860	2105	Meters (Smart Meters)	2,154,281	100,744	(9,072)	2,245,953	1,277,380	146,812	(5,479)	1,418,713	827,240
47	1861	2105	Meters Inventory	-	-	-	-	-	-	-	-	-
47	1861	2105	Smart Meters Inventory	0	-	-	0	-	-	-	-	0
47	1861	2105	Meters Inventory CT/PT	-	-	-	-	-	-	-	-	-
N/A	1905	2105	Land	49,000	-	-	49,000	-	-	-	-	49,000
1b	1908	2105	Buildings & Fixtures	1,266,590	359,932	-	1,626,522	517,771	23,942	-	541,713	1,084,808
8	1908	2105	Buildings & Fixtures- PCB Shed	8,690	-	-	8,690	8,690	-	-	8,690	-
13	1910	2105	Leasehold Improvements	-	-	-	-	-	-	-	-	-
8	1915	2105	Office Furniture & Equipment (10 years)	242,800	1,972	-	244,773	222,469	3,551	-	226,020	18,753
8	1915	2105	Office Furniture & Equipment (5 years)	-	-	-	-	-	-	-	-	-
50	1920	2105	Computer Equipment - Hardware	559,906	42,081	-	601,987	510,611	36,111	-	546,721	55,266
45	1920	2105	Computer Equip.-Hardware(Post Mar. 22/04)	-	-	-	-	-	-	-	-	-
45	1920	2105	Computer Equip.-Hardware(Post Mar. 19/07)	-	-	-	-	-	-	-	-	-
10	1930	2105	Transportation Equipment < 3 TONS	241,183	62,930	-	304,114	153,029	29,624	-	182,653	121,461
10	1930	2105	Transportation Equipment > 3 TONS	1,055,166	-	-	1,055,166	726,539	77,350	-	803,889	251,277
10	1930	2105	Transportation Equipment Trailers	86,848	42,063	(12,322)	116,589	45,112	4,910	(12,322)	37,700	78,889
8	1935	2105	Stores Equipment	25,233	-	-	25,233	24,705	59	-	24,764	469
8	1940	2105	Tools, Shop & Garage Equipment	568,106	7,818	-	575,925	496,160	13,801	-	509,961	65,964
8	1945	2105	Measurement & Testing Equipment	-	-	-	-	-	-	-	-	-
8	1950	2105	Power Operated Equipment	-	-	-	-	-	-	-	-	-
8	1955	2105	Communications Equipment	54,383	-	-	54,383	54,383	-	-	54,383	-
8	1955	2105	Communication Equipment (Smart Meters)	-	-	-	-	-	-	-	-	-
8	1960	2105	Miscellaneous Equipment	-	-	-	-	-	-	-	-	-
47	1970	2105	Load Management Controls Customer Premises	-	-	-	-	-	-	-	-	-
47	1975	2105	Load Management Controls Utility Premises	-	-	-	-	-	-	-	-	-
47	1980	2105	System Supervisor Equipment	813,688	85,345	-	899,034	521,418	48,161	-	569,579	329,455
47	1985	2105	Miscellaneous Fixed Assets	-	-	-	-	-	-	-	-	-
47	1990	2105	Other Tangible Property	-	-	-	-	-	-	-	-	-
47	1995	2105	Contributions & Grants-O/H Poles	(238,366)	-	-	(238,366)	(98,424)	(4,548)	-	(102,972)	(135,394)
47	1995	2105	Contributions & Grants-O/H Conductor	(235,221)	-	-	(235,221)	(95,963)	(3,107)	-	(99,071)	(136,151)
47	1995	2105	Contributions & Grants-O/H Services	(146,562)	-	-	(146,562)	(63,977)	(1,878)	-	(65,855)	(80,708)
47	1995	2105	Contributions & Grants-U/G Conduit	(879,222)	-	-	(879,222)	(292,916)	(11,280)	-	(304,196)	(575,026)
47	1995	2105	Contributions & Grants-U/G Conductor	(1,788,778)	-	-	(1,788,778)	(813,760)	(32,681)	-	(846,441)	(942,337)
47	1995	2105	Contributions & Grants-U/G Services	(1,606,653)	-	-	(1,606,653)	(646,650)	(30,625)	-	(677,275)	(929,378)
47	1995	2105	Contributions & Grants-Transformers	(2,283,741)	-	-	(2,283,741)	(971,806)	(42,859)	-	(1,014,665)	(1,269,076)
47	1995	2105	Contributions & Grants-Meters	(7,344)	-	-	(7,344)	(5,374)	(294)	-	(5,668)	(1,676)
47	1995	2105	Contributions & Grants-Admin	(13,000)	-	-	(13,000)	(5,018)	(205)	-	(5,222)	(7,778)
47	1995	2105	Contributions & Grants-Rolling Stock	(9,722)	-	-	(9,722)	(9,722)	-	-	(9,722)	-
47	2440		Def Rev-Contributions & Grants-O/H Poles	(546,155)	(82,785)	-	(628,940)	(35,381)	(13,057)	-	(48,438)	(580,502)
47	2440		Def Rev-Contributions & Grants-O/H Conductor	(252,795)	(25,734)	-	(278,529)	(11,755)	(4,428)	-	(16,182)	(262,347)
47	2440		Def Rev-Contributions & Grants-O/H Services	(52,784)	(11,751)	-	(64,535)	(3,338)	(978)	-	(4,315)	(60,220)
47	2440		Def Rev-Contributions & Grants-U/G Conduit	(737,310)	(19,081)	-	(756,391)	(47,187)	(11,490)	-	(58,677)	(697,714)
47	2440		Def Rev-Contributions & Grants-U/G Conductor	(1,138,899)	(139,533)	-	(1,278,431)	(93,584)	(26,859)	-	(120,443)	(1,157,988)
47	2440		Def Rev-Contributions & Grants-U/G Services	(1,114,701)	(150,405)	-	(1,265,106)	(100,757)	(26,442)	-	(127,200)	(1,137,907)
47	2440		Def Rev-Contributions & Grants-Transformers	(1,390,406)	(183,658)	-	(1,574,064)	(115,021)	(32,939)	-	(147,960)	(1,426,104)
47	2440		Def Rev-Contributions & Grants-Meters	(167,395)	(20,213)	-	(187,609)	(18,760)	(7,100)	-	(25,860)	(161,749)
47	2440		Def Rev-Contributions & Grants-Admin	-	-	-	-	-	-	-	-	-
47	2440		Def rev-Contributions & Grants-Rolling Stock	-	-	-	-	-	-	-	-	-
47	2440		Def Rev-Contributions & Grants-Stations	(285,746)	-	-	(285,746)	(7,793)	(5,195)	-	(12,988)	(272,758)
47	2440		Def Rev-Contributions & Grant System Supervisory	(8,178)	-	-	(8,178)	(1,227)	(818)	-	(2,044)	(6,133)
43.1	2440		Def rev-Contributions & Grants-Battery	(94,520)	(23,359)	-	(117,879)	(4,726)	(10,620)	-	(15,346)	(102,533)
			Sub-Total	**57,119,787**	**2,455,686**	**(195,643)**	**59,379,830**	**27,622,387**	**1,198,379**	(173,180)	28,647,586	30,732,245
	2055		CWIP-Internal	673,087	(419,390)		253,697	-			-	-
	2056		CWIP-Customer Projects	324,951	(99,108)		225,843	-			-	-
			Total PP&E	**58,117,825**	**1,937,188**	**(195,643)**	**59,859,371**	**27,622,387**	**1,198,379**	**(173,180)**	**28,647,586**	**30,732,245**

Table 2.9: 2022 Fixed Asset Continuity Schedule

				Cost				Accumulated Depreciation				
CCA Class	OEB FA	OEB Depr	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
47	1508	2105	ICM-Transformer Station Equipment >50 kV-Conc #5	-	-	-	-	-	-	-	-	-
N/A	1606	2105	Organization Costs	-	-	-	-	-	-	-	-	-
50	1611	2120	Computer Software (Formally known as Account 1925)	2,541,939	12,251	-	2,554,190	2,482,712	31,063	-	2,513,775	40,415
CEC	1612	2105	Land Rights (Formally known as Account 1906 and 1806)	-	-	-	-	-	-	-	-	-
N/A	1805	2105	Land	258,134	-	(2,594)	255,540	-	-	-	-	255,540
47	1808	2105	Buildings	-	-	-	-	-	-	-	-	-
13	1810	2105	Leasehold Improvements	-	-	-	-	-	-	-	-	-
47	1815	2105	Transformer Station Equipment >50 kV York Rd	5,213,818	-	-	5,213,818	1,166,315	96,628	-	1,262,942	3,950,876
47	1815	2105	Transformer Station Equipment >50 kV-Conc #5	5,898,030	27,618	-	5,925,648	1,162,899	113,955	-	1,276,854	4,648,794
47	1820	2105	Distribution Station Equipment <50 kV	-	-	-	-	-	-	-	-	-
43.1	1825	2105	Storage Battery Equipment	497,510	-	-	497,510	74,626	49,751	-	124,377	373,132
47	1830	2105	Poles, Towers & Fixtures	7,597,111	305,319	(6,406)	7,896,025	3,116,228	140,983	(6,406)	3,250,806	4,645,219
47	1835	2105	Overhead Conductors & Devices	7,953,002	56,398	-	8,009,400	3,832,443	95,831	-	3,928,273	4,081,127
47	1840	2105	Underground Conduit	6,691,326	14,991	-	6,706,317	2,883,039	77,109	-	2,960,147	3,746,170
47	1845	2105	Underground Conductors & Devices	12,368,540	69,483	(12,000)	12,426,022	6,262,852	212,796	(7,833)	6,467,816	5,958,207
47	1850	2105	Line Transformers	10,380,044	254,146	(27,515)	10,606,675	4,590,517	185,946	(17,731)	4,758,732	5,847,943
47	1851	2105	Transformer Inventory	(0)	-	-	(0)	(0)	-	-	(0)	(0)
47	1852	2105	Transformer Damaged	-	-	-	-	-	-	-	-	-
47	1853	2105	Transformer Spare	-	-	-	-	-	-	-	-	-
47	1855	2105	Services Overhead	724,069	43,867	-	767,936	215,538	10,888	-	226,426	541,510
47	1855	2105	Services Underground	4,323,424	353,614	-	4,677,038	1,238,432	92,183	-	1,330,614	3,346,424
47	1860	2105	Meters	779,533	19,233	(801)	797,965	407,739	16,161	(172)	423,728	374,237
47	1860	2105	Meters (Smart Meters)	2,245,953	43,207	(7,957)	2,281,202	1,418,713	150,329	(3,412)	1,565,631	715,572
47	1861	2105	Meters Inventory	-	-	-	-	-	-	-	-	-
47	1861	2105	Smart Meters Inventory	0	-	-	0	-	-	-	-	0
47	1861	2105	Meters Inventory CT/PT	-	-	-	-	-	-	-	-	-
N/A	1905	2105	Land	49,000	-	-	49,000	-	-	-	-	49,000
1b	1908	2105	Buildings & Fixtures	1,626,522	8,186	-	1,634,708	541,713	27,010	-	568,723	1,065,985
8	1908	2105	Buildings & Fixtures- PCB Shed	8,690	-	-	8,690	8,690	-	-	8,690	-
13	1910	2105	Leasehold Improvements	-	-	-	-	-	-	-	-	-
8	1915	2105	Office Furniture & Equipment (10 years)	244,773	10,561	-	255,334	226,020	3,593	-	229,613	25,721
8	1915	2105	Office Furniture & Equipment (5 years)	-	-	-	-	-	-	-	-	-
50	1920	2105	Computer Equipment - Hardware	601,987	10,797	-	612,784	546,721	32,740	-	579,461	33,322
45	1920	2105	Computer Equip.-Hardware(Post Mar. 22/04)	-	-	-	-	-	-	-	-	-
45	1920	2105	Computer Equip.-Hardware(Post Mar. 19/07)	-	-	-	-	-	-	-	-	-
10	1930	2105	Transportation Equipment < 3 TONS	304,114	72,301	(100)	376,315	182,653	43,137	-	225,791	150,524
10	1930	2105	Transportation Equipment > 3 TONS	1,055,166	67,703	-	1,122,869	803,889	53,920	-	857,809	265,059
10	1930	2105	Transportation Equipment Trailers	116,589	9,212	(28,876)	96,925	37,700	6,155	(22,603)	21,252	75,673
8	1935	2105	Stores Equipment	25,233	-	-	25,233	24,764	57	-	24,821	412
8	1940	2105	Tools, Shop & Garage Equipment	575,925	15,277	-	591,201	509,961	14,726	-	524,686	66,515
8	1945	2105	Measurement & Testing Equipment	-	-	-	-	-	-	-	-	-
8	1950	2105	Power Operated Equipment	-	-	-	-	-	-	-	-	-
8	1955	2105	Communications Equipment	54,383	-	-	54,383	54,383	-	-	54,383	-
8	1955	2105	Communication Equipment (Smart Meters)	-	-	-	-	-	-	-	-	-
8	1960	2105	Miscellaneous Equipment	-	-	-	-	-	-	-	-	-
47	1970	2105	Load Management Controls Customer Premises	-	-	-	-	-	-	-	-	-
47	1975	2105	Load Management Controls Utility Premises	-	-	-	-	-	-	-	-	-
47	1980	2105	System Supervisor Equipment	899,034	-	-	899,034	569,579	51,813	-	621,392	277,642
47	1985	2105	Miscellaneous Fixed Assets	-	-	-	-	-	-	-	-	-
47	1990	2105	Other Tangible Property	-	-	-	-	-	-	-	-	-
47	1995	2105	Contributions & Grants-O/H Poles	(238,366)	-	-	(238,366)	(102,972)	(4,548)	-	(107,520)	(130,846)
47	1995	2105	Contributions & Grants-O/H Conductor	(235,221)	-	-	(235,221)	(99,071)	(3,107)	-	(102,178)	(133,044)
47	1995	2105	Contributions & Grants-O/H Services	(146,562)	-	-	(146,562)	(65,855)	(1,878)	-	(67,733)	(78,830)
47	1995	2105	Contributions & Grants-U/G Conduit	(879,222)	-	-	(879,222)	(304,196)	(11,280)	-	(315,476)	(563,746)
47	1995	2105	Contributions & Grants-U/G Conductor	(1,788,778)	-	-	(1,788,778)	(846,441)	(32,681)	-	(879,121)	(909,656)
47	1995	2105	Contributions & Grants-U/G Services	(1,606,653)	-	-	(1,606,653)	(677,275)	(30,625)	-	(707,900)	(898,753)
47	1995	2105	Contributions & Grants-Transformers	(2,283,741)	-	-	(2,283,741)	(1,014,665)	(42,859)	-	(1,057,524)	(1,226,217)
47	1995	2105	Contributions & Grants-Meters	(7,344)	-	-	(7,344)	(5,668)	(294)	-	(5,962)	(1,382)
47	1995	2105	Contributions & Grants-Admin	(13,000)	-	-	(13,000)	(5,222)	(205)	-	(5,427)	(7,573)
47	1995	2105	Contributions & Grants-Rolling Stock	(9,722)	-	-	(9,722)	(9,722)	-	-	(9,722)	-
47	2440		Def Rev-Contributions & Grants-O/H Poles	(628,940)	(231,209)	-	(860,149)	(48,438)	(16,545)	-	(64,983)	(795,166)
47	2440		Def Rev-Contributions & Grants-O/H Conductor	(278,529)	(20,535)	-	(299,064)	(16,182)	(4,813)	-	(20,996)	(278,069)
47	2440		Def Rev-Contributions & Grants-O/H Services	(64,535)	(20,335)	-	(84,871)	(4,315)	(1,245)	-	(5,560)	(79,310)
47	2440		Def Rev-Contributions & Grants-U/G Conduit	(756,391)	(15,544)	-	(771,936)	(58,677)	(11,756)	-	(70,433)	(701,502)
47	2440		Def Rev-Contributions & Grants-U/G Conductor	(1,278,431)	(41,674)	-	(1,320,105)	(120,443)	(28,873)	-	(149,316)	(1,170,789)
47	2440		Def Rev-Contributions & Grants-U/G Services	(1,265,106)	(168,590)	-	(1,433,696)	(127,200)	(29,987)	-	(157,186)	(1,276,509)
47	2440		Def Rev-Contributions & Grants-Transformers	(1,574,064)	(96,335)	-	(1,670,399)	(147,960)	(36,050)	-	(184,010)	(1,486,389)
47	2440		Def Rev-Contributions & Grants-Meters	(187,609)	(15,554)	-	(203,163)	(25,860)	(7,815)	-	(33,675)	(169,487)
47	2440		Def Rev-Contributions & Grants-Admin	-	-	-	-	-	-	-	-	-
47	2440		Def rev-Contributions & Grants-Rolling Stock	-	-	-	-	-	-	-	-	-
47	2440		Def Rev-Contributions & Grants-Stations	(285,746)	-	-	(285,746)	(12,988)	(5,195)	-	(18,184)	(267,562)
47	2440		Def Rev-Contributions & Grant System Supervisory	(8,178)	-	-	(8,178)	(2,044)	(818)	-	(2,862)	(5,315)
43.1	2440		Def rev-Contributions & Grants-Battery	(117,879)	-	-	(117,879)	(15,346)	(11,788)	-	(27,134)	(90,745)
			Sub-Total	**59,379,830**	**784,387**	**(86,250)**	**60,077,968**	**28,647,586**	**1,224,412**	**(58,156)**	29,813,842	30,264,127
	2055		CWIP-Internal	253,697	923,303		1,177,000	-			-	-
	2056		CWIP-Customer Projects	225,843	385,939		611,782	-			-	-
			Total PP&E	**59,859,371**	**2,093,629**	**(86,250)**	**61,866,750**	**28,647,586**	**1,224,412**	**(58,156)**	**29,813,842**	**30,264,127**

Table 2.10: 2023 Fixed Asset Continuity Schedule

				Cost				Accumulated Depreciation				
CCA Class	**OEB FA**	**OEB Depr**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
47	1508	2105	ICM-Transformer Station Equipment >50 kV-Conc #5	-	-		-	-	-		-	-
N/A	1606	2105	Organization Costs	-	-		-	-	-		-	-
50	1611	2120	Computer Software (Formally known as Account 1925)	2,554,190	12,947		2,567,137	2,513,775	29,263		2,543,039	24,098
CEC	1612	2105	Land Rights (Formally known as Account 1906 and 1806)	-	-		-	-	-		-	-
N/A	1805	2105	Land	255,540	-		255,540	-	-		-	255,540
47	1808	2105	Buildings	-	-		-	-	-		-	-
13	1810	2105	Leasehold Improvements	-	-		-	-	-		-	-
47	1815	2105	Transformer Station Equipment >50 kV York Rd	5,213,818	-		5,213,818	1,262,942	97,439		1,360,381	3,853,437
47	1815	2105	Transformer Station Equipment >50 kV-Conc #5	5,925,648	30,340		5,955,988	1,276,854	113,704		1,390,558	4,565,429
47	1820	2105	Distribution Station Equipment <50 kV	-	-		-	-	-		-	-
43.1	1825	2105	Storage Battery Equipment	497,510	-		497,510	124,377	49,751		174,128	323,381
47	1830	2105	Poles, Towers & Fixtures	7,896,025	724,060	(55,984)	8,564,101	3,250,806	151,560	(38,205)	3,364,161	5,199,940
47	1835	2105	Overhead Conductors & Devices	8,009,400	585,045	(122,597)	8,471,849	3,928,273	103,885	(70,999)	3,961,159	4,510,689
47	1840	2105	Underground Conduit	6,706,317	566,062		7,272,379	2,960,147	85,273		3,045,420	4,226,959
47	1845	2105	Underground Conductors & Devices	12,426,022	571,859		12,997,881	6,467,816	224,392		6,692,208	6,305,674
47	1850	2105	Line Transformers	10,606,675	1,213,177	(21,080)	11,798,772	4,758,732	208,045	(10,000)	4,956,777	6,841,995
47	1851	2105	Transformer Inventory	(0)	-		(0)	(0)	-		(0)	(0)
47	1852	2105	Transformer Damaged	-	-		-	-	-		-	-
47	1853	2105	Transformer Spare	-	-		-	-	-		-	-
47	1855	2105	Services Overhead	767,936	43,982		811,918	226,426	11,922		238,347	573,570
47	1855	2105	Services Underground	4,677,038	350,353		5,027,391	1,330,614	99,963		1,430,577	3,596,813
47	1860	2105	Meters	797,965	11,593		809,558	423,728	16,366		440,094	369,464
47	1860	2105	Meters (Smart Meters)	2,281,202	88,057	(8,000)	2,361,259	1,565,631	154,849	(4,000)	1,716,480	644,779
47	1861	2105	Meters Inventory	-	-		-	-	-		-	-
47	1861	2105	Smart Meters Inventory	0	-		0	-	-		-	0
47	1861	2105	Meters Inventory CT/PT	-	-		-	-	-		-	-
N/A	1905	2105	Land	49,000	-		49,000	-	-		-	49,000
1b	1908	2105	Buildings & Fixtures	1,634,708	500,000		2,134,708	568,723	31,324		600,047	1,534,661
8	1908	2105	Buildings & Fixtures- PCB Shed	8,690	-		8,690	8,690	-		8,690	-
13	1910	2105	Leasehold Improvements	-	-		-	-	-		-	-
8	1915	2105	Office Furniture & Equipment (10 years)	255,334	6,000		261,334	229,613	3,839		233,452	27,882
8	1915	2105	Office Furniture & Equipment (5 years)	-	-		-	-	-		-	-
50	1920	2105	Computer Equipment - Hardware	612,784	8,550		621,334	579,461	20,951		600,412	20,921
45	1920	2105	Computer Equip.-Hardware(Post Mar. 22/04)	-	-		-	-	-		-	-
45	1920	2105	Computer Equip.-Hardware(Post Mar. 19/07)	-	-		-	-	-		-	-
10	1930	2105	Transportation Equipment < 3 TONS	376,315	40,000		416,315	225,791	39,917		265,708	150,607
10	1930	2105	Transportation Equipment > 3 TONS	1,122,869	423,000		1,545,869	857,809	78,380		936,189	609,679
10	1930	2105	Transportation Equipment Trailers	96,925	-		96,925	21,252	6,462		27,713	69,212
8	1935	2105	Stores Equipment	25,233	-		25,233	24,821	55		24,876	357
8	1940	2105	Tools, Shop & Garage Equipment	591,201	6,000		597,201	524,686	16,076		540,763	56,439
8	1945	2105	Measurement & Testing Equipment	-	-		-	-	-		-	-
8	1950	2105	Power Operated Equipment	-	-		-	-	-		-	-
8	1955	2105	Communications Equipment	54,383	-		54,383	54,383	-		54,383	-
8	1955	2105	Communication Equipment (Smart Meters)	-	-		-	-	-		-	-
8	1960	2105	Miscellaneous Equipment	-	-		-	-	-		-	-
47	1970	2105	Load Management Controls Customer Premises	-	-		-	-	-		-	-
47	1975	2105	Load Management Controls Utility Premises	-	-		-	-	-		-	-
47	1980	2105	System Supervisor Equipment	899,034	95,000		994,034	621,392	56,563		677,956	316,078
47	1985	2105	Miscellaneous Fixed Assets	-	-		-	-	-		-	-
47	1990	2105	Other Tangible Property	-	-		-	-	-		-	-
47	1995	2105	Contributions & Grants-O/H Poles	(238,366)	-		(238,366)	(107,520)	(4,548)		(112,067)	(126,299)
47	1995	2105	Contributions & Grants-O/H Conductor	(235,221)	-		(235,221)	(102,178)	(3,107)		(105,285)	(129,936)
47	1995	2105	Contributions & Grants-O/H Services	(146,562)	-		(146,562)	(67,733)	(1,878)		(69,611)	(76,952)
47	1995	2105	Contributions & Grants-U/G Conduit	(879,222)	-		(879,222)	(315,476)	(11,280)		(326,756)	(552,466)
47	1995	2105	Contributions & Grants-U/G Conductor	(1,788,778)	-		(1,788,778)	(879,121)	(32,681)		(911,802)	(876,976)
47	1995	2105	Contributions & Grants-U/G Services	(1,606,653)	-		(1,606,653)	(707,900)	(30,625)		(738,524)	(868,128)
47	1995	2105	Contributions & Grants-Transformers	(2,283,741)	-		(2,283,741)	(1,057,524)	(42,859)		(1,100,383)	(1,183,358)
47	1995	2105	Contributions & Grants-Meters	(7,344)	-		(7,344)	(5,962)	(294)		(6,256)	(1,088)
47	1995	2105	Contributions & Grants-Admin	(13,000)	-		(13,000)	(5,427)	(205)		(5,632)	(7,368)
47	1995	2105	Contributions & Grants-Rolling Stock	(9,722)	-		(9,722)	(9,722)	-		(9,722)	-
47	2440		Def Rev-Contributions & Grants-O/H Poles	(860,149)	(257,552)		(1,117,701)	(64,983)	(17,463)		(82,447)	(1,035,254)
47	2440		Def Rev-Contributions & Grants-O/H Conductor	(299,064)	(211,838)		(510,902)	(20,996)	(7,384)		(28,380)	(482,522)
47	2440		Def Rev-Contributions & Grants-O/H Services	(84,871)	(33,982)		(118,853)	(5,560)	(2,114)		(7,674)	(111,178)
47	2440		Def Rev-Contributions & Grants-U/G Conduit	(771,936)	(116,342)		(888,278)	(70,433)	(13,821)		(84,254)	(804,023)
47	2440		Def Rev-Contributions & Grants-U/G Conductor	(1,320,105)	(122,138)		(1,442,243)	(149,316)	(31,754)		(181,069)	(1,261,174)
47	2440		Def Rev-Contributions & Grants-U/G Services	(1,433,696)	(270,353)		(1,704,049)	(157,186)	(35,943)		(193,129)	(1,510,919)
47	2440		Def Rev-Contributions & Grants-Transformers	(1,670,399)	(220,434)		(1,890,833)	(184,010)	(38,118)		(222,127)	(1,668,705)
47	2440		Def Rev-Contributions & Grants-Meters	(203,163)	(17,389)		(220,552)	(33,675)	(7,845)		(41,521)	(179,031)
47	2440		Def Rev-Contributions & Grants-Admin	-	-		-	-	-		-	-
47	2440		Def rev-Contributions & Grants-Rolling Stock	-	-		-	-	-		-	-
47	2440		Def Rev-Contributions & Grants-Stations	(285,746)	-		(285,746)	(18,184)	(5,195)		(23,379)	(262,367)
47	2440		Def Rev-Contributions & Grant System Supervisory	(8,178)	-		(8,178)	(2,862)	(818)		(3,680)	(4,498)
43.1	2440		Def rev-Contributions & Grants-Battery	(117,879)	-		(117,879)	(27,134)	(11,788)		(38,922)	(78,957)
			Sub-Total	**60,077,968**	**4,025,997**	**(207,660)**	**63,896,304**	**29,813,842**	**1,300,262**	(123,204)	30,990,900	32,905,404
	2055		CWIP-Internal	1,177,000	(1,177,000)		-	-			-	-
	2056		CWIP-Customer Projects	611,782	(611,782)		-	-			-	-
			Total PP&E	**61,866,750**	**2,237,215**	**(207,660)**	**63,896,304**	**29,813,842**	**1,300,262**	**(123,204)**	**30,990,900**	**32,905,404**

Table 2.11: 2024 Fixed Asset Continuity Schedule

				Cost					Accumulated Depreciation						
CCA Class	**OEB FA**	**OEB Depr**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**AVG Assets**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**	**AVG Gross Bal**	**AVG AccDep**
47	1508	2105	ICM-Transformer Station Equipment >50 kV-Conc #5	-	-		-	-	-	-		-	-	-	-
N/A	1606	2105	Organization Costs	-	-		-	-	-	-		-	-	-	-
50	1611	2120	Computer Software (Formally known as Account 1925)	2,567,137	57,426		2,624,563	2,595,850	2,543,039	26,482		2,569,520	55,043	2,595,850	2,556,279
CEC	1612	2105	Land Rights (Formally known as Account 1906 and 1806)	-	-		-	-	-	-		-	-	-	-
N/A	1805	2105	Land	255,540	-		255,540	255,540	-	-		-	255,540	255,540	-
47	1808	2105	Buildings	-	-		-	-	-	-		-	-	-	-
13	1810	2105	Leasehold Improvements	-	-		-	-	-	-		-	-	-	-
47	1815	2105	Transformer Station Equipment >50 kV York Rd	5,213,818	-		5,213,818	5,213,818	1,360,381	97,933		1,458,314	3,755,504	5,213,818	1,409,348
47	1815	2105	Transformer Station Equipment >50 kV-Conc #5	5,955,988	5,000		5,960,988	5,958,488	1,390,558	113,965		1,504,524	4,456,464	5,958,488	1,447,541
47	1820	2105	Distribution Station Equipment <50 kV	-	-		-	-	-	-		-	-	-	-
43.1	1825	2105	Storage Battery Equipment	497,510	-		497,510	497,510	174,128	49,751		223,879	273,630	497,510	199,004
47	1830	2105	Poles, Towers & Fixtures	8,564,101	302,500	(15,000)	8,851,601	8,707,851	3,364,161	163,142	(10,000)	3,517,302	5,334,299	8,707,851	3,440,732
47	1835	2105	Overhead Conductors & Devices	8,471,849	247,000	(15,000)	8,703,849	8,587,849	3,961,159	110,984	(10,000)	4,062,143	4,641,705	8,587,849	4,011,651
47	1840	2105	Underground Conduit	7,272,379	197,500		7,469,879	7,371,129	3,045,420	91,286		3,136,706	4,333,174	7,371,129	3,091,063
47	1845	2105	Underground Conductors & Devices	12,997,881	202,500		13,200,381	13,099,131	6,692,208	233,141		6,925,348	6,275,033	13,099,131	6,808,778
47	1850	2105	Line Transformers	11,798,772	400,500	(20,457)	12,178,815	11,988,794	4,956,777	226,177	(10,000)	5,172,955	7,005,861	11,988,794	5,064,866
47	1851	2105	Transformer Inventory	(0)	-		(0)	(0)	(0)	-		(0)	(0)	(0)	(0)
47	1852	2105	Transformer Damaged	-	-		-	-	-	-		-	-	-	-
47	1853	2105	Transformer Spare	-	-		-	-	-	-		-	-	-	-
47	1855	2105	Services Overhead	811,918	40,000		851,918	831,918	238,347	12,643		250,991	600,927	831,918	244,669
47	1855	2105	Services Underground	5,027,391	340,000		5,367,391	5,197,391	1,430,577	107,753		1,538,330	3,829,061	5,197,391	1,484,454
47	1860	2105	Meters	809,558	10,000		819,558	814,558	440,094	16,733		456,827	362,731	814,558	448,461
47	1860	2105	Meters (Smart Meters)	2,361,259	85,000	(8,000)	2,438,259	2,399,759	1,716,480	154,791	(4,000)	1,867,271	570,988	2,399,759	1,791,875
47	1861	2105	Meters Inventory	-	-		-	-	-	-		-	-	-	-
47	1861	2105	Smart Meters Inventory	0	-		0	0	-	-		-	0	0	-
47	1861	2105	Meters Inventory CT/PT	-	-		-	-	-	-		-	-	-	-
N/A	1905	2105	Land	49,000	-		49,000	49,000	-	-		-	49,000	49,000	-
1b	1908	2105	Buildings & Fixtures	2,134,708	13,441		2,148,149	2,141,428	600,047	35,650		635,697	1,512,452	2,141,428	617,872
8	1908	2105	Buildings & Fixtures- PCB Shed	8,690	-		8,690	8,690	8,690	-		8,690	-	8,690	8,690
13	1910	2105	Leasehold Improvements	-	-		-	-	-	-		-	-	-	-
8	1915	2105	Office Furniture & Equipment (10 years)	261,334	6,000		267,334	264,334	233,452	4,314		237,766	29,568	264,334	235,609
8	1915	2105	Office Furniture & Equipment (5 years)	-	-		-	-	-	-		-	-	-	-
50	1920	2105	Computer Equipment - Hardware	621,334	17,911		639,245	630,289	600,412	15,063		615,475	23,769	630,289	607,944
45	1920	2105	Computer Equip.-Hardware(Post Mar. 22/04)	-	-		-	-	-	-		-	-	-	-
45	1920	2105	Computer Equip.-Hardware(Post Mar. 19/07)	-	-		-	-	-	-		-	-	-	-
10	1930	2105	Transportation Equipment < 3 TONS	416,315	-		416,315	416,315	265,708	35,479		301,187	115,128	416,315	283,447
10	1930	2105	Transportation Equipment > 3 TONS	1,545,869	455,000		2,000,869	1,773,369	936,189	122,280		1,058,470	942,399	1,773,369	997,330
10	1930	2105	Transportation Equipment Trailers	96,925	-		96,925	96,925	27,713	6,462		34,175	62,750	96,925	30,944
8	1935	2105	Stores Equipment	25,233	-		25,233	25,233	24,876	55		24,931	302	25,233	24,903
8	1940	2105	Tools, Shop & Garage Equipment	597,201	6,000		603,201	600,201	540,763	15,756		556,518	46,683	600,201	548,640
8	1945	2105	Measurement & Testing Equipment	-	-		-	-	-	-		-	-	-	-
8	1950	2105	Power Operated Equipment	-	-		-	-	-	-		-	-	-	-
8	1955	2105	Communications Equipment	54,383	-		54,383	54,383	54,383	-		54,383	-	54,383	54,383
8	1955	2105	Communication Equipment (Smart Meters)	-	-		-	-	-	-		-	-	-	-
8	1960	2105	Miscellaneous Equipment	-	-		-	-	-	-		-	-	-	-
47	1970	2105	Load Management Controls Customer Premises	-	-		-	-	-	-		-	-	-	-
47	1975	2105	Load Management Controls Utility Premises	-	-		-	-	-	-		-	-	-	-
47	1980	2105	System Supervisor Equipment	994,034	165,000		1,159,034	1,076,534	677,956	69,614		747,569	411,465	1,076,534	712,762
47	1985	2105	Miscellaneous Fixed Assets	-	-		-	-	-	-		-	-	-	-
47	1990	2105	Other Tangible Property	-	-		-	-	-	-		-	-	-	-
47	1995	2105	Contributions & Grants-O/H Poles	(238,366)	-		(238,366)	(238,366)	(112,067)	(4,548)		(116,615)	(121,751)	(238,366)	(114,341)
47	1995	2105	Contributions & Grants-O/H Conductor	(235,221)	-		(235,221)	(235,221)	(105,285)	(3,107)		(108,392)	(126,829)	(235,221)	(106,839)
47	1995	2105	Contributions & Grants-O/H Services	(146,562)	-		(146,562)	(146,562)	(69,611)	(1,878)		(71,488)	(75,074)	(146,562)	(70,550)
47	1995	2105	Contributions & Grants-U/G Conduit	(879,222)	-		(879,222)	(879,222)	(326,756)	(11,280)		(338,036)	(541,186)	(879,222)	(332,396)
47	1995	2105	Contributions & Grants-U/G Conductor	(1,788,778)	-		(1,788,778)	(1,788,778)	(911,802)	(32,681)		(944,483)	(844,295)	(1,788,778)	(928,142)
47	1995	2105	Contributions & Grants-U/G Services	(1,606,653)	-		(1,606,653)	(1,606,653)	(738,524)	(30,625)		(769,149)	(837,504)	(1,606,653)	(753,836)
47	1995	2105	Contributions & Grants-Transformers	(2,283,741)	-		(2,283,741)	(2,283,741)	(1,100,383)	(42,859)		(1,143,242)	(1,140,499)	(2,283,741)	(1,121,812)
47	1995	2105	Contributions & Grants-Meters	(7,344)	-		(7,344)	(7,344)	(6,256)	(294)		(6,549)	(794)	(7,344)	(6,403)
47	1995	2105	Contributions & Grants-Admin	(13,000)	-		(13,000)	(13,000)	(5,632)	(205)		(5,836)	(7,164)	(13,000)	(5,734)
47	1995	2105	Contributions & Grants-Rolling Stock	(9,722)	-		(9,722)	(9,722)	(9,722)	-		(9,722)	-	(9,722)	(9,722)
47	2440		Def Rev-Contributions & Grants-O/H Poles	(1,117,701)	(25,000)		(1,142,701)	(1,130,201)	(82,447)	(20,603)		(103,050)	(1,039,652)	(1,130,201)	(92,748)
47	2440		Def Rev-Contributions & Grants-O/H Conductor	(510,902)	(25,000)		(535,902)	(523,402)	(28,380)	(9,866)		(38,246)	(497,656)	(523,402)	(33,313)
47	2440		Def Rev-Contributions & Grants-O/H Services	(118,853)	(30,000)		(148,853)	(133,853)	(7,674)	(2,647)		(10,322)	(138,531)	(133,853)	(8,998)
47	2440		Def Rev-Contributions & Grants-U/G Conduit	(888,278)	(66,250)		(954,528)	(921,403)	(84,254)	(15,225)		(99,479)	(855,048)	(921,403)	(91,867)
47	2440		Def Rev-Contributions & Grants-U/G Conductor	(1,442,243)	(71,250)		(1,513,493)	(1,477,868)	(181,069)	(33,902)		(214,972)	(1,298,521)	(1,477,868)	(198,021)
47	2440		Def Rev-Contributions & Grants-U/G Services	(1,704,049)	(260,000)		(1,964,049)	(1,834,049)	(193,129)	(41,836)		(234,965)	(1,729,084)	(1,834,049)	(214,047)
47	2440		Def Rev-Contributions & Grants-Transformers	(1,890,833)	(82,500)		(1,973,333)	(1,932,083)	(222,127)	(41,484)		(263,611)	(1,709,722)	(1,932,083)	(242,869)
47	2440		Def Rev-Contributions & Grants-Meters	(220,552)	(15,000)		(235,552)	(228,052)	(41,521)	(8,061)		(49,582)	(185,970)	(228,052)	(45,551)
47	2440		Def Rev-Contributions & Grants-Admin	-	-		-	-	-	-		-	-	-	-
47	2440		Def rev-Contributions & Grants-Rolling Stock	-	-		-	-	-	-		-	-	-	-
47	2440		Def Rev-Contributions & Grants-Stations	(285,746)	-		(285,746)	(285,746)	(23,379)	(5,195)		(28,575)	(257,172)	(285,746)	(25,977)
47	2440		Def Rev-Contributions & Grant System Supervisory	(8,178)	-		(8,178)	(8,178)	(3,680)	(818)		(4,498)	(3,680)	(8,178)	(4,089)
43.1	2440		Def rev-Contributions & Grants-Battery	(117,879)	-		(117,879)	(117,879)	(38,922)	(11,788)		(50,710)	(67,170)	(117,879)	(44,816)
			Sub-Total	**63,896,304**	**1,975,778**	**(58,457)**	**65,813,625**	**64,854,965**	**30,990,900**	**1,390,551**	(34,000)	32,347,451	33,466,174	64,854,965	31,669,176
	2055		CWIP-Internal	-			-	-	-			-	-	-	-
	2056		CWIP-Customer Projects	-			-	-	-			-	-	-	-
			Total PP&E	**63,896,304**	**1,975,778**	**(58,457)**	**65,813,625**	**64,854,965**	**30,990,900**	**1,390,551**	**(34,000)**	**32,347,451**	**33,466,174**	**64,854,965**	**31,669,176**

2.2.2.2 Gross Assets Variance Analysis

NOTL Hydro chose to break down and explain variances in nine categories to give the analysis meaning:

- Distribution equipment includes all the standard distribution assets in the field including poles, transformers, conduit and meters.
- Transmission stations includes all NOTL Hydro assets at NOTL MTS2 and York MTS1 that steps down the 115 kV transmission voltage to the 27.6 kV distribution voltage.
- Systems equipment includes the SCADA system and all the automated switches and reclosures. It also includes the 250 kW lithium-ion battery.
- Land and buildings includes the main office plus the land at the transformer stations and former distribution stations.
- Vehicles are line trucks, service trucks and trailers.
- Computer assets include investments in software systems and computer hardware.
- Other assets include furniture, tools, garage equipment and communications equipment.
- Contributed capital includes all the payments from customers and third parties contributing to the purchase of the above assets. Contributed capital is amortized at the same rate as the assets being purchased.
- Work in progress captures the cost of jobs that have not been completed but for which expenditures have still been made. For capital planning purposes, NOTL Hydro includes work in progress in its calculations as it still represents capital expenditures.

The change in accumulated depreciation in all years is the depreciation in the year less the accumulated depreciation on any disposed equipment.

There were no ICM or ACMs since 2019.

The table below summarizes NOTL Hydro's assets in the nine categories:

Table 2.12: Gross Asset Summary

Gross Assets	2019	2020	2021	2022	2023	2024	2019 BA
Distribution equipment	$ 49,933,638	$ 51,384,923	$ 53,063,002	$ 54,168,581	$ 58,115,109	$ 59,881,652	$ 51,057,174
Transmission Stations	$ 8,141,910	$ 10,476,722	$ 11,111,848	$ 11,139,466	$ 11,169,806	$ 11,174,806	$ 11,355,676
Systems equipment	$ 738,150	$ 1,365,581	$ 1,450,926	$ 1,450,926	$ 1,545,926	$ 1,710,926	$ 822,621
Land and buildings	$ 1,579,149	$ 1,582,415	$ 1,942,346	$ 1,947,938	$ 2,447,938	$ 2,461,379	$ 1,580,060
Vehicles	$ 1,347,980	$ 1,383,197	$ 1,475,868	$ 1,596,108	$ 2,059,108	$ 2,514,108	$ 1,338,353
Computer assets	$ 3,028,624	$ 3,088,308	$ 3,143,926	$ 3,166,974	$ 3,188,471	$ 3,263,808	$ 2,978,488
Other assets	$ 816,740	$ 836,140	$ 845,930	$ 871,768	$ 883,768	$ 895,768	$ 817,364
Contributed Capital	$ (12,638,789)	$ (12,997,498)	$ (13,654,017)	$ (14,263,794)	$ (15,513,821)	$ (16,088,821)	$ (12,835,662)
Work in Progress	$ 2,407,347	$ 998,038	$ 479,540	$ 1,788,782	$ -	$ -	$ -
	$ 55,354,749	$ 58,117,825	$ 59,859,370	$ 61,866,750	$ 63,896,304	$ 65,813,625	$ 57,114,074

Accumulated Depreciation	2019	2020	2021	2022	2023	2024	2019 BA
Distribution equipment	$ 22,589,691	$ 23,144,107	$ 23,965,501	$ 24,912,172	$ 25,845,224	$ 26,927,873	$ 22,999,069
Transmission Stations	$ 1,947,612	$ 2,124,655	$ 2,329,214	$ 2,539,797	$ 2,750,940	$ 2,962,838	$ 1,979,869
Systems equipment	$ 537,974	$ 600,676	$ 698,588	$ 800,153	$ 906,467	$ 1,025,832	$ 544,215
Land and buildings	$ 505,499	$ 526,462	$ 550,404	$ 577,413	$ 608,737	$ 644,387	$ 505,515
Vehicles	$ 808,764	$ 924,680	$ 1,024,242	$ 1,104,851	$ 1,229,610	$ 1,393,832	$ 847,117
Computer assets	$ 2,934,706	$ 3,001,613	$ 3,029,434	$ 3,093,237	$ 3,143,451	$ 3,184,995	$ 2,923,460
Other assets	$ 730,582	$ 743,333	$ 760,745	$ 779,120	$ 799,090	$ 819,215	$ 732,409
Contributed Capital	$ (3,191,706)	$ (3,443,140)	$ (3,710,540)	$ (3,992,902)	$ (4,292,620)	$ (4,611,521)	$ (3,214,728)
Work in Progress	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	$ 26,863,123	$ 27,622,387	$ 28,647,586	$ 29,813,842	$ 30,990,900	$ 32,347,451	$ 27,316,926

Net Book Value	2019	2020	2021	2022	2023	2024	2019 BA
Distribution equipment	$ 27,343,947	$ 28,240,816	$ 29,097,501	$ 29,256,409	$ 32,269,885	$ 32,953,779	$ 28,058,105
Transmission Stations	$ 6,194,297	$ 8,352,066	$ 8,782,635	$ 8,599,670	$ 8,418,866	$ 8,211,968	$ 9,375,807
Systems equipment	$ 200,176	$ 764,905	$ 752,338	$ 650,774	$ 639,459	$ 685,095	$ 278,406
Land and buildings	$ 1,073,650	$ 1,055,953	$ 1,391,943	$ 1,370,524	$ 1,839,200	$ 1,816,991	$ 1,074,545
Vehicles	$ 539,215	$ 458,517	$ 451,626	$ 491,257	$ 829,498	$ 1,120,276	$ 491,236
Computer assets	$ 93,918	$ 86,695	$ 114,493	$ 73,737	$ 45,020	$ 78,812	$ 55,028
Other assets	$ 86,158	$ 92,807	$ 85,185	$ 92,648	$ 84,677	$ 76,553	$ 84,955
Contributed Capital	$ (9,447,083)	$ (9,554,359)	$ (9,943,477)	$ (10,270,892)	$ (11,221,202)	$ (11,477,301)	$ (9,620,934)
Work in Progress	$ 2,407,347	$ 998,038	$ 479,540	$ 1,788,782	$ -	$ -	$ -
	$ 28,491,626	$ 30,495,438	$ 31,211,784	$ 32,052,908	$ 32,905,404	$ 33,466,174	$ 29,797,147

2019 Board Approved vs. to 2019 Actual:

Table 2.13: Board Approved vs 2019 Actual

Gross Assets	2019 BA	2019	Variance $	Variance %
Distribution equipment	$ 51,057,174	$ 49,933,638	$ (1,123,537)	(2.2%)
Transmission Stations	$ 11,355,676	$ 8,141,910	$ (3,213,766)	(28.3%)
Systems equipment	$ 822,621	$ 738,150	$ (84,470)	(10.3%)
Land and buildings	$ 1,580,060	$ 1,579,149	$ (911)	(0.1%)
Vehicles	$ 1,338,353	$ 1,347,980	$ 9,627	0.7%
Computer assets	$ 2,978,488	$ 3,028,624	$ 50,136	1.7%
Other assets	$ 817,364	$ 816,740	$ (624)	(0.1%)
Contributed Capital	$ (12,835,662)	$ (12,638,789)	$ 196,873	(1.5%)
Work in Progress	$ -	$ 2,407,347	$ 2,407,347	100.0%
	$ 57,114,074	$ 55,354,749	$ (1,759,325)	(3.1%)
Accumulated Depreciation				
Distribution equipment	$ 22,999,069	$ 22,589,691	$ (409,378)	(1.8%)
Transmission Stations	$ 1,979,869	$ 1,947,612	$ (32,256)	(1.6%)
Systems equipment	$ 544,215	$ 537,974	$ (6,241)	(1.1%)
Land and buildings	$ 505,515	$ 505,499	$ (16)	(0.0%)
Vehicles	$ 847,117	$ 808,764	$ (38,352)	(4.5%)
Computer assets	$ 2,923,460	$ 2,934,706	$ 11,245	0.4%
Other assets	$ 732,409	$ 730,582	$ (1,827)	(0.2%)
Contributed Capital	$ (3,214,728)	$ (3,191,706)	$ 23,022	(0.7%)
Work in Progress	$ -	$ -	$ -	0.0%
	$ 27,316,926	$ 26,863,123	$ (453,804)	(1.7%)
Net Book Value				
Distribution equipment	$ 28,058,105	$ 27,343,947	$ (714,158)	(2.5%)
Transmission Stations	$ 9,375,807	$ 6,194,297	$ (3,181,510)	(33.9%)
Systems equipment	$ 278,406	$ 200,176	$ (78,230)	(28.1%)
Land and buildings	$ 1,074,545	$ 1,073,650	$ (895)	(0.1%)
Vehicles	$ 491,236	$ 539,215	$ 47,979	9.8%
Computer assets	$ 55,028	$ 93,918	$ 38,891	70.7%
Other assets	$ 84,955	$ 86,158	$ 1,203	1.4%
Contributed Capital	$ (9,620,934)	$ (9,447,083)	$ 173,851	(1.8%)
Work in Progress	$ -	$ 2,407,347	$ 2,407,347	100.0%
	$ 29,797,147	$ 28,491,626	$ (1,305,521)	(4.4%)

The total difference between the Board approved expenditure and the actual expenditure of $1.8 million can be explained by the transformer project of which $1.5 million out of a $3.3 million budget was spent in 2019.

Distribution Equipment – ($1,124k)

The shortfall in distribution system expenditures is due to the expenditure in work in progress ($900k) and the shortfall in the estimated customer jobs ($197k).

<u>Transmission Stations – ($3,214k)</u>

This variance is all timing. The new transformer project of $3.3 million was all included in 2019 for the rate application but, due primarily to delays by the manufacturer, was not installed at York Station until 2020. The York Station transformer was moved to NOTL Station in 2021 and further related work was done in 2021. The project was completed under budget.

<u>Systems Equipment – ($84k)</u>

The Board approved plan called for $80k of new switches to be installed in 2019. None were installed that year, but a number were installed in 2020 and 2021.

<u>Computer Assets – $50k</u>

Actual expenditures on computer was higher primarily due to the purchase of a new security system including surveillance cameras due to concerns about theft from the yard and protecting staff.

<u>Contributed Capital – $197k</u>

This balance varies from year to year depending on projects initiated by customers. NOTL Hydro has no control over these projects so does not try to estimate them internally.

<u>Work in Progress – $2,407k</u>

Work in progress includes $1.5 million spent on the transformer project and around $900k on both customer jobs and system renewal projects that have not been closed. No work in progress was assumed in the Board approved plan.

2019 Actual vs. 2020 Actual:

Table 2.14: 2019 Actual vs. 2020 Actual

Gross Assets	2019	2020	Variance $	Variance %
Distribution equipment	$ 49,933,638	$ 51,384,923	$ 1,451,285	2.9%
Transmission Stations	$ 8,141,910	$ 10,476,722	$ 2,334,812	28.7%
Systems equipment	$ 738,150	$ 1,365,581	$ 627,431	85.0%
Land and buildings	$ 1,579,149	$ 1,582,415	$ 3,265	0.2%
Vehicles	$ 1,347,980	$ 1,383,197	$ 35,217	2.6%
Computer assets	$ 3,028,624	$ 3,088,308	$ 59,684	2.0%
Other assets	$ 816,740	$ 836,140	$ 19,400	2.4%
Contributed Capital	$ (12,638,789)	$ (12,997,498)	$ (358,709)	2.8%
Work in Progress	$ 2,407,347	$ 998,038	$ (1,409,309)	(58.5%)
	$ 55,354,749	$ 58,117,825	$ 2,763,076	5.0%
Accumulated Depreciation				
Distribution equipment	$ 22,589,691	$ 23,144,107	$ 554,416	2.5%
Transmission Stations	$ 1,947,612	$ 2,124,655	$ 177,043	9.1%
Systems equipment	$ 537,974	$ 600,676	$ 62,702	11.7%
Land and buildings	$ 505,499	$ 526,462	$ 20,963	4.1%
Vehicles	$ 808,764	$ 924,680	$ 115,916	14.3%
Computer assets	$ 2,934,706	$ 3,001,613	$ 66,908	2.3%
Other assets	$ 730,582	$ 743,333	$ 12,751	1.7%
Contributed Capital	$ (3,191,706)	$ (3,443,140)	$ (251,434)	7.9%
Work in Progress	$ -	$ -	$ -	0.0%
	$ 26,863,123	$ 27,622,387	$ 759,264	2.8%
Net Book Value				
Distribution equipment	$ 27,343,947	$ 28,240,816	$ 896,869	3.3%
Transmission Stations	$ 6,194,297	$ 8,352,066	$ 2,157,769	34.8%
Systems equipment	$ 200,176	$ 764,905	$ 564,729	282.1%
Land and buildings	$ 1,073,650	$ 1,055,953	$ (17,697)	(1.6%)
Vehicles	$ 539,215	$ 458,517	$ (80,699)	(15.0%)
Computer assets	$ 93,918	$ 86,695	$ (7,223)	(7.7%)
Other assets	$ 86,158	$ 92,807	$ 6,649	7.7%
Contributed Capital	$ (9,447,083)	$ (9,554,359)	$ (107,276)	1.1%
Work in Progress	$ 2,407,347	$ 998,038	$ (1,409,309)	(58.5%)
	$ 28,491,626	$ 30,495,438	$ 2,003,812	7.0%

<u>Distribution Equipment - $1,451k</u>

The growth in distribution equipment is driven by both customer driven projects ($613k) and capital replacement programs ($977k) less disposals ($374k). Capital replacement programs include part of the underground system in Garrison Village which had a poor outage history ($460k) and the Board of NOTL Hydro determined should be given a priority. Other projects included Johnson Street underground voltage conversion ($133k) and the overhead replacement of a section of Line 4 due to poor pole conditions ($68k). Disposals included $200k of meters due to smart meter replacements and meter reverifications.

<u>Transmission Stations - $2,334k</u>

During 2020, the new 83 MVA transformer was installed at the York transmission station.

<u>Systems Equipment - $627k</u>

The battery installed as part of the Smart Grid Fund project ($498k) was the major item along with 3 new automated switches ($129k).

<u>Vehicles - $35k</u>

A pick-up truck was purchased for the locates service being brought in-house.

<u>Computer Assets - $60k</u>

Major items included a new payroll software ($12k), updates to the SCADA system ($14k) and new computers ($20k).

<u>Other Assets - $19k</u>

Tools were purchased for the locates service being brought in-house.

<u>Contributed Capital – ($359k)</u>

This represents payments made by customers and developers towards the purchase of distribution equipment on customer driven jobs.

<u>Work in Progress – ($1,410)</u>

The CWIP balance declined with the transformer going live and the $1.5 million in CWIP at the end of 2019 being booked to transmission station assets.

2020 Actual vs. 2021 Actual:

Table 2.15: 2020 Actual vs. 2021 Actual

Gross Assets	2020	2021	Variance $	Variance %
Distribution equipment	$ 51,384,923	$ 53,063,002	$ 1,678,079	3.3%
Transmission Stations	$ 10,476,722	$ 11,111,848	$ 635,127	6.1%
Systems equipment	$ 1,365,581	$ 1,450,926	$ 85,345	6.2%
Land and buildings	$ 1,582,415	$ 1,942,346	$ 359,932	22.7%
Vehicles	$ 1,383,197	$ 1,475,868	$ 92,671	6.7%
Computer assets	$ 3,088,308	$ 3,143,926	$ 55,618	1.8%
Other assets	$ 836,140	$ 845,930	$ 9,790	1.2%
Contributed Capital	$ (12,997,498)	$ (13,654,017)	$ (656,519)	5.1%
Work in Progress	$ 998,038	$ 479,540	$ (518,498)	(52.0%)
	$ 58,117,825	$ 59,859,370	$ 1,741,546	3.0%
Accumulated Depreciation				
Distribution equipment	$ 23,144,107	$ 23,965,501	$ 821,394	3.5%
Transmission Stations	$ 2,124,655	$ 2,329,214	$ 204,558	9.6%
Systems equipment	$ 600,676	$ 698,588	$ 97,912	16.3%
Land and buildings	$ 526,462	$ 550,404	$ 23,942	4.5%
Vehicles	$ 924,680	$ 1,024,242	$ 99,562	10.8%
Computer assets	$ 3,001,613	$ 3,029,434	$ 27,821	0.9%
Other assets	$ 743,333	$ 760,745	$ 17,412	2.3%
Contributed Capital	$ (3,443,140)	$ (3,710,540)	$ (267,401)	7.8%
Work in Progress	$ -	$ -	$ -	0.0%
	$ 27,622,387	$ 28,647,586	$ 1,025,199	3.7%
Net Book Value				
Distribution equipment	$ 28,240,816	$ 29,097,501	$ 856,685	3.0%
Transmission Stations	$ 8,352,066	$ 8,782,635	$ 430,568	5.2%
Systems equipment	$ 764,905	$ 752,338	$ (12,567)	(1.6%)
Land and buildings	$ 1,055,953	$ 1,391,943	$ 335,990	31.8%
Vehicles	$ 458,517	$ 451,626	$ (6,891)	(1.5%)
Computer assets	$ 86,695	$ 114,493	$ 27,798	32.1%
Other assets	$ 92,807	$ 85,185	$ (7,621)	(8.2%)
Contributed Capital	$ (9,554,359)	$ (9,943,477)	$ (389,118)	4.1%
Work in Progress	$ 998,038	$ 479,540	$ (518,498)	(52.0%)
	$ 30,495,438	$ 31,211,784	$ 716,347	2.3%

Distribution Equipment - $1,678k

The growth in distribution equipment is driven by both customer driven projects ($654k) and capital replacement programs ($1,234k) less disposals ($253k). Capital replacement projects included an overhead voltage conversion project along Lakeshore Rd ($366k), a rebuild of part of Line 8 due to poor pole conditions ($85k) and part of the Gate St underground voltage conversion project ($143k). $250k was also spent on new transformers in anticipation of rising prices with the oncoming inflation. Disposals included $177k of meters due to smart meter replacements and meter reverifications.

Transmission Stations - $635k

The 41.7 MVA transformer, which had been at the York Station, was installed at the NOTL Station replacing an old 25 MVA transformer. Upgrade work related to the new transformers continued at both stations including breakers for a new feeder line at the York Station.

Systems Equipment - $85k

Two new automated switches and a reclosure were installed.

Land and Buildings variance - $360k

An upgraded and bigger boardroom and kitchen was installed in the office. This was needed to meet the distancing requirements of the pandemic.

Vehicles - $93

A new trailer ($30k) and a new pick-up truck ($63k) were purchased for the new underground excavation crew.

Computer Assets - $56k

A number of laptops and Splashtop licences were purchased so that all staff could work from home if needed.

Contributed Capital – ($657k)

This represents payments made by customers and developers towards the purchase of distribution equipment on customer driven jobs.

Work in Progress – ($518k)

The number of jobs carried over the year end declined.

2021 Actual vs. 2022 Actual:

Table 2.16: 2021 Actual vs. 2022 Actual

Gross Assets	**2021**	**2022**	**Variance $**	**Variance %**
Distribution equipment	$ 53,063,002	$ 54,168,581	$ 1,105,579	2.1%
Transmission Stations	$ 11,111,848	$ 11,139,466	$ 27,618	0.2%
Systems equipment	$ 1,450,926	$ 1,450,926	$ -	0.0%
Land and buildings	$ 1,942,346	$ 1,947,938	$ 5,592	0.3%
Vehicles	$ 1,475,868	$ 1,596,108	$ 120,240	8.1%
Computer assets	$ 3,143,926	$ 3,166,974	$ 23,047	0.7%
Other assets	$ 845,930	$ 871,768	$ 25,838	3.1%
Contributed Capital	$ (13,654,017)	$ (14,263,794)	$ (609,776)	4.5%
Work in Progress	$ 479,540	$ 1,788,782	$ 1,309,241	273.0%
	$ 59,859,370	$ 61,866,750	$ 2,007,379	3.4%
Accumulated Depreciation				
Distribution equipment	$ 23,965,501	$ 24,912,172	$ 946,672	4.0%
Transmission Stations	$ 2,329,214	$ 2,539,797	$ 210,583	9.0%
Systems equipment	$ 698,588	$ 800,153	$ 101,564	14.5%
Land and buildings	$ 550,404	$ 577,413	$ 27,010	4.9%
Vehicles	$ 1,024,242	$ 1,104,851	$ 80,609	7.9%
Computer assets	$ 3,029,434	$ 3,093,237	$ 63,803	2.1%
Other assets	$ 760,745	$ 779,120	$ 18,375	2.4%
Contributed Capital	$ (3,710,540)	$ (3,992,902)	$ (282,361)	7.6%
Work in Progress	$ -	$ -	$ -	0.0%
	$ 28,647,586	$ 29,813,842	$ 1,166,255	4.1%
Net Book Value				
Distribution equipment	$ 29,097,501	$ 29,256,409	$ 158,908	0.5%
Transmission Stations	$ 8,782,635	$ 8,599,670	$ (182,965)	(2.1%)
Systems equipment	$ 752,338	$ 650,774	$ (101,564)	(13.5%)
Land and buildings	$ 1,391,943	$ 1,370,524	$ (21,418)	(1.5%)
Vehicles	$ 451,626	$ 491,257	$ 39,631	8.8%
Computer assets	$ 114,493	$ 73,737	$ (40,756)	(35.6%)
Other assets	$ 85,185	$ 92,648	$ 7,462	8.8%
Contributed Capital	$ (9,943,477)	$ (10,270,892)	$ (327,415)	3.3%
Work in Progress	$ 479,540	$ 1,788,782	$ 1,309,241	273.0%
	$ 31,211,784	$ 32,052,908	$ 841,124	2.7%

Distribution Equipment - $1,106k

Customer driven projects were a big driver with $610k projects closed during the year with much of this being upgrade work for Bell.

Transmission Stations - $28k

Work was performed on a new feeder coming out of York Station.

Vehicles - $120k

An excavator ($68k) for the underground crew and a new pick-up truck ($72k) were purchased.

Computer Assets - $23k

Various software upgrades and some new computers.

Other Assets - $26k

Various tools for the underground crew were purchased.

Contributed Capital – ($610k)

This represents payments made by customers and developers towards the purchase of distribution equipment on customer driven jobs.

Work in Progress - $1,309k

A number of major projects including the Gates St underground project ($505k), the Concession 6 and Warner Rd overhead project ($201k) and the Concession 6 and Line 1 project ($97k) are not fully completed by the end of the year.

2022 Actual vs. 2023 Bridge Forecast:

Table 2.17: 2022 Actual vs. 2023 Forecast

Gross Assets	**2022**	**2023**	**Variance $**	**Variance %**
Distribution equipment	$ 54,168,581	$ 58,115,109	$ 3,946,527	7.3%
Transmission Stations	$ 11,139,466	$ 11,169,806	$ 30,340	0.3%
Systems equipment	$ 1,450,926	$ 1,545,926	$ 95,000	6.5%
Land and buildings	$ 1,947,938	$ 2,447,938	$ 500,000	25.7%
Vehicles	$ 1,596,108	$ 2,059,108	$ 463,000	29.0%
Computer assets	$ 3,166,974	$ 3,188,471	$ 21,497	0.7%
Other assets	$ 871,768	$ 883,768	$ 12,000	1.4%
Contributed Capital	$ (14,263,794)	$ (15,513,821)	$ (1,250,028)	8.8%
Work in Progress	$ 1,788,782	$ -	$ (1,788,782)	(100.0%)
	$ 61,866,750	$ 63,896,304	$ 2,029,555	3.3%
Accumulated Depreciation				
Distribution equipment	$ 24,912,172	$ 25,845,224	$ 933,051	3.7%
Transmission Stations	$ 2,539,797	$ 2,750,940	$ 211,143	8.3%
Systems equipment	$ 800,153	$ 906,467	$ 106,314	13.3%
Land and buildings	$ 577,413	$ 608,737	$ 31,324	5.4%
Vehicles	$ 1,104,851	$ 1,229,610	$ 124,759	11.3%
Computer assets	$ 3,093,237	$ 3,143,451	$ 50,214	1.6%
Other assets	$ 779,120	$ 799,090	$ 19,970	2.6%
Contributed Capital	$ (3,992,902)	$ (4,292,620)	$ (299,718)	7.5%
Work in Progress	$ -	$ -	$ -	0.0%
	$ 29,813,842	$ 30,990,900	$ 1,177,058	3.9%
Net Book Value				
Distribution equipment	$ 29,256,409	$ 32,269,885	$ 3,013,476	10.3%
Transmission Stations	$ 8,599,670	$ 8,418,866	$ (180,803)	(2.1%)
Systems equipment	$ 650,774	$ 639,459	$ (11,314)	(1.7%)
Land and buildings	$ 1,370,524	$ 1,839,200	$ 468,676	34.2%
Vehicles	$ 491,257	$ 829,498	$ 338,241	68.9%
Computer assets	$ 73,737	$ 45,020	$ (28,717)	(38.9%)
Other assets	$ 92,648	$ 84,677	$ (7,970)	(8.6%)
Contributed Capital	$ (10,270,892)	$ (11,221,202)	$ (950,309)	9.3%
Work in Progress	$ 1,788,782	$ -	$ (1,788,782)	(100.0%)
	$ 32,052,908	$ 32,905,404	$ 852,496	2.7%

Distribution Equipment - $3,947k

The increase includes the system renewal projects for 2023 ($1,560), customer projects ($400k) and new connections ($310k) as well as the construction work in progress at the end of 2022 ($1,789k) which is projects that had not been closed off on the books of NOTL Hydro at that time.

Transmission Stations - $30k

Minor upgrades to protection and control equipment.

Systems equipment - $95k

More automated switches are being installed in key areas of the line.

Land and Buildings - $500k

A new garage is being built and a second entrance/exit to the yard is being created.

Vehicles variance - $463k

A new digger has been ordered for delivery this year.

Computer Assets - $21k

Desktop upgrades.

Other Assets - $12k

Regular tools and equipment.

Contributed Capital – ($1,250k)

This represents payments made by customers and developers towards the purchase of distribution equipment on customer driven jobs.

Work in Progress – ($1,789k)

Projects that had not been closed off on the books of NOTL Hydro at the end of the year. For the purpose of the rate application, it has been assumed that all projects are closed by the end of the year.

2023 Bridge Forecast vs. 2024 Test Forecast:

Table 2.18: 2023 Forecast vs. 2024 Forecast

Gross Assets	**2023**	**2024**	**Variance $**	**Variance %**
Distribution equipment	$ 58,115,109	$ 59,881,652	$ 1,766,543	3.0%
Transmission Stations	$ 11,169,806	$ 11,174,806	$ 5,000	0.0%
Systems equipment	$ 1,545,926	$ 1,710,926	$ 165,000	10.7%
Land and buildings	$ 2,447,938	$ 2,461,379	$ 13,441	0.5%
Vehicles	$ 2,059,108	$ 2,514,108	$ 455,000	22.1%
Computer assets	$ 3,188,471	$ 3,263,808	$ 75,337	2.4%
Other assets	$ 883,768	$ 895,768	$ 12,000	1.4%
Contributed Capital	$ (15,513,821)	$ (16,088,821)	$ (575,000)	3.7%
Work in Progress	$ -	$ -	$ -	0.0%
	$ 63,896,304	$ 65,813,625	$ 1,917,321	3.0%
Accumulated Depreciation				
Distribution equipment	$ 25,845,224	$ 26,927,873	$ 1,082,649	4.2%
Transmission Stations	$ 2,750,940	$ 2,962,838	$ 211,898	7.7%
Systems equipment	$ 906,467	$ 1,025,832	$ 119,365	13.2%
Land and buildings	$ 608,737	$ 644,387	$ 35,650	5.9%
Vehicles	$ 1,229,610	$ 1,393,832	$ 164,221	13.4%
Computer assets	$ 3,143,451	$ 3,184,995	$ 41,545	1.3%
Other assets	$ 799,090	$ 819,215	$ 20,124	2.5%
Contributed Capital	$ (4,292,620)	$ (4,611,521)	$ (318,901)	7.4%
Work in Progress	$ -	$ -	$ -	0.0%
	$ 30,990,900	$ 32,347,451	$ 1,356,551	4.4%
Net Book Value				
Distribution equipment	$ 32,269,885	$ 32,953,779	$ 683,894	2.1%
Transmission Stations	$ 8,418,866	$ 8,211,968	$ (206,898)	(2.5%)
Systems equipment	$ 639,459	$ 685,095	$ 45,635	7.1%
Land and buildings	$ 1,839,200	$ 1,816,991	$ (22,209)	(1.2%)
Vehicles	$ 829,498	$ 1,120,276	$ 290,779	35.1%
Computer assets	$ 45,020	$ 78,812	$ 33,792	75.1%
Other assets	$ 84,677	$ 76,553	$ (8,124)	(9.6%)
Contributed Capital	$ (11,221,202)	$ (11,477,301)	$ (256,099)	2.3%
Work in Progress	$ -	$ -	$ -	0.0%
	$ 32,905,404	$ 33,466,174	$ 560,770	1.7%

<u>Distribution Equipment - $1,767k</u>
The increase includes the system renewal projects for 2023 ($997), customer projects ($400k) and new connections ($290k).

<u>Systems equipment - $165k</u>
More automated switches are being installed in key areas of the line.

<u>Land and Buildings - $13k</u>
Regular upgrades within the building.

<u>Vehicles - $445k</u>
A new bucket truck has been ordered with expected delivery in January 2024.

<u>Computer Assets - $75k</u>
GIS upgrade and new servers.

<u>Other Assets – $12k</u>
Miscellaneous tools.

<u>Contributed Capital – ($575k)</u>
This represents payments made by customers and developers towards the purchase of distribution equipment on customer driven jobs.

2.2.2.3 Disposals

NOTL Hydro regularly disposes of assets in the normal course of business. Where possible the assets are sold for salvage value or as scrap. In most cases the assets have little or no value. Any gains and losses on the disposals and sales is booked to Other Revenue. No amounts have been included in the 1575, IFRS-CGAAP Transitional PP&E amount.

Significant disposals in the period 2019-2024 include:

- In 2019, NOTL Hydro disposed of one of the old 25 MVA transformers at the NOTL Station that was originally installed by Ontario Hydro in 1985. The disposal of this asset reduced NOTL Hydro's net book value for 2019 by approximately $225k.

- In 2020, $203k of meters were disposed as part of the meter verification process. It was determined that it was more cost effective to replace these meters than have them verified.

2.2.4 Depreciation, Amortization and Depletion

NOTL Hydro has adopted depreciation rates based on the Kinectrics Asset Depreciation Study. The rates used are presented below. NOTL Hydro was approved to utilize a 10-year useful life for System Supervisory Equipment in its 2014 Cost of Service application (EB-2013-0155) and it is showing as outside the min range in Appendix 2-BB.

NOTL Hydro's depreciable lives by asset class are presented in the table below:

Table 2.19: NOTL Hydro Depreciation Rates

USoA Account Number	USoA Account Description	Current		Proposed	
		Years	Rate	Years	Rate
1815	TS Equipment>50KV-Transformer	45	2%	45	2%
1815	TS Equipment>50KV-Transformer	55	2%	55	2%
1830	Poles, Towers and Fixtures	45	2%	45	2%
1835	Overhead Conductors & Devices	60	2%	60	2%
1840	Underground Conduit	65	2%	65	2%
1840	Underground Conduit	65	2%	65	2%
1845	Underground Conductors & Devices	45	2%	45	2%
1845	Underground Conductors & Devices	45	2%	45	2%
1850	Line Transformers	45	2%	45	2%
1850	Line Transformers	45	2%	45	2%
1855	Services-OH	60	2%	60	2%
1855	Services-UG	45	2%	45	2%
1860	Meters-Non Stranded	25	4%	25	4%
1860	Meters-CT/PT	40	3%	40	3%
1860	Meters	15	7%	15	7%
1860	Meters	15	7%	15	7%
1908	Building & Fixtures	60	2%	60	2%
1908	Building & Fixtures-PCB Shed	30	3%	30	3%
1915	Office Furniture & Equipment	10	10%	10	10%
1920	Computer Equipment - Hardware	3	33%	3	33%
1925	Computer Equipment - Software	3	33%	3	33%
1930	Transportation Equipment <3 Tons	5	20%	5	20%
1930	Transportation Equipment >3 Tons	10	10%	10	10%
1930	Transportation Equipment- Trailers	15	7%	15	7%
1935	Stores Equipment	10	10%	10	10%
1940	Tools, Shops Garage Equipment	8	13%	8	13%
1955	Communication Equipment	10	10%	10	10%
1980	System Supervisory Equipment	10	10%	10	10%

NOTL Hydro's depreciation rates have not changed since the 2019 Cost of Service application (EB-2018-0056) and NOTL Hydro is not proposing any changes in this application.

NOTL Hydro does not have any AROs.

NOTL Hydro uses the half year rule for recording depreciation. NOTL Hydro use the Modified International Financial Reporting Standard (MIFRS) and separates significant components appropriately. These are captured in NOTL Hydro's IFRS policy (Appendix 2B).

2.2.5 Allowance for Working Capital

2.2.5.1 Derivation of Working Capital

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

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

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

Table 2.20: Allowance for Working Capital Calculation

	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Expenses for Working Capital	**2019**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Eligible Distribution Expenses:	**Board Appr**	**Actual**	**Actual**	**Actual**	**Actual**	**Bridge**	**Test**
Distribution Expenses - Operation	711,610	623,207	717,525	730,154	767,087	783,175	792,135
Distribution Expenses - Maintenance	449,790	521,538	409,998	511,054	487,879	486,646	513,942
Billing and Collecting	632,867	520,425	630,975	618,632	677,732	740,878	800,299
Community Relations	11,485	656	0	0	0	0	0
General and Administrative Expenses	858,405	1,157,659	1,187,374	1,294,405	1,374,941	1,392,813	1,456,708
6105-Taxes other than Income Taxes	34,955	35,495	41,701	42,226	42,743	43,384	43,384
6205-Sub-account LEAP Funding	7,209	6,866	6,866	6,866	6,866	6,866	8,801
Total Eligible Distribution Expenses	2,706,322	2,865,846	2,994,441	3,203,337	3,357,248	3,453,762	3,615,268
3350-Power Supply Expenses	25,896,653	26,320,401	30,183,104	26,183,615	25,428,000	25,114,177	27,876,388
Total Expenses for Working Capital	28,602,975	29,186,247	33,177,544	29,386,952	28,785,248	28,567,939	31,491,657
Working Capital factor	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%
Total Working Capital	**2,145,223**	**2,188,969**	**2,488,316**	**2,204,021**	**2,158,894**	**2,142,595**	**2,361,874**

Power Supply Expense

The power supply expense is made up of the sum of IESO monthly charges. For the 2023 bridge year and the 2024 test year these have been estimated in the following manner:

Table 2.21: Summary of Cost of Power Expenses 2023-2024

2023			2024		
4705 -Power Purchased	$	18,325,689	4705 -Power Purchased	$	19,682,178
4707- Global Adjustment	$	3,698,152	4707- Global Adjustment	$	3,745,495
4708-Charges-WMS	$	1,230,011	4708-Charges-WMS	$	1,343,437
4714-Charges-NW	$	1,406,220	4714-Charges-NW	$	2,585,444
4716-Charges-CN	$	404,870	4716-Charges-CN	$	469,805
4750-Charges-LV	$	-	4750-Charges-LV	$	-
4751-IESO SME	$	49,235	4751-IESO SME	$	50,029
Misc A/R or A/P	$	-	Misc A/R or A/P	$	-
TOTAL	**$**	**25,114,177**	**TOTAL**	**$**	**27,876,388**

Power Purchased

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

Table 2.22: Summary of Cost of Power Expenses

Commodity Pricing

Forecasted Commodity Prices	Table 1: Average RPP Supply Cost Summary*		**non-RPP**	**RPP**
HOEP ($/MWh)	Load-Weighted Price for RPP Consumers		$58.33	$58.33
Global Adjustment ($/MWh)	Impact of the Global Adjustment		$39.04	$39.04
Adjustments ($/MWh)				($3.97)
TOTAL ($/MWh)	Average Supply Cost for RPP Consumers			**$93.40**

Commodity Expense
(volumes for the test year is loss adjusted)

Commodity					2023					
Customer		**Revenue**	**Expense**							
Class Name	UoM	USA #	USA #	Class A Non-RPP Volume**		Class B Non-RPP Volume**	Class B RPP Volume**	Average HOEP	Average RPP Rate	Amount
Residential	kWh	4006	4705	-		850,531	80,864,808	$ 0.05833	$ 0.09340	$7,602,385
GS < 50	kWh	4010	4705	-		4,965,056	41,523,625	$ 0.05833	$ 0.09340	$4,167,918
GS > 50	kWh	4035	4705	5,129,784		79,405,901	4,296,714	$ 0.05833	$ 0.09340	$5,332,280
Large User	kWh	4020	4705	19,798,695		-	-	$ 0.05833	$ 0.09340	$1,154,858
USL	kWh	4025	4705	-		146,882	246,379	$ 0.05833	$ 0.09340	$31,579
Street Light	kWh	4025	4705	-		510,849	73,565	$ 0.05833	$ 0.09340	$36,669
TOTAL										**$18,325,689**

Class A - non-RPP Global Adjustment					2023			
Customer		**Revenue**	**Expense**		kWh Volume		Hist. Avg GA/kWh ***	**Amount**
GS>50	kWh	4035	4707		5,129,784		0.06733768	$345,428
Large Use	kWh	4010	4707		19,798,695		0	$0
				-	24,928,479			**$345,428**

Class B - non-RPP Global Adjustment					2023					
Customer		**Revenue**	**Expense**							Amount
Class Name	UoM	USA #	USA #			Class B Non-RPP Volume			GA Rate/kWh	
Residential	kWh	4006	4707			850,531			$ 0.03904	$33,205
GS < 50	kWh	4010	4707			4,965,056			$ 0.03904	$193,836
GS > 50	kWh	4035	4707			79,405,901			$ 0.03904	$3,100,006
Large User	kWh	4010	4707			0			$ 0.03904	$0
USL	kWh	4025	4707			146,882			$ 0.03904	$5,734
Street Light	kWh	4025	4707			510,849			$ 0.03904	$19,944
Total Volume						**85,879,218**				
TOTAL										**$3,352,725**

Total Non-RPP Global Adjustment **$3,698,152**

Commodity Pricing

Forecasted Commodity Prices	Table 1: Average RPP Supply Cost Summary*		**non-RPP**	**RPP**
HOEP ($/MWh)	Load-Weighted Price for RPP Consumers		$58.33	$58.33
Global Adjustment ($/MWh)	Impact of the Global Adjustment		$39.04	$39.04
Adjustments ($/MWh)				($3.97)
TOTAL ($/MWh)	Average Supply Cost for RPP Consumers			**$93.40**

Commodity Expense
(volumes for the test year is loss adjusted)

Commodity					2024					
Customer		**Revenue**	**Expense**							
Class Name	UoM	USA #	USA #	Class A Non-RPP Volume**		Class B Non-RPP Volume**	Class B RPP Volume**	Average HOEP	Average RPP Rate	Amount
Residential	kWh	4006	4705	-		860,092	81,773,823	$ 0.05833	$ 0.09340	$7,687,844
GS < 50	kWh	4010	4705	-		5,020,869	41,990,399	$ 0.05833	$ 0.09340	$4,214,771
GS > 50	kWh	4035	4705	5,196,471		80,438,177	4,352,572	$ 0.05833	$ 0.09340	$5,401,599
Large User	kWh	4020	4705	39,597,390		-	-	$ 0.05833	$ 0.09340	$2,309,716
USL	kWh	4025	4705	-		146,882	246,379	$ 0.05833	$ 0.09340	$31,579
Street Light	kWh	4025	4705	-		510,849	73,565	$ 0.05833	$ 0.09340	$36,669
TOTAL										**$19,682,178**

Class A - non-RPP Global Adjustment					2024			
Customer		**Revenue**	**Expense**		**kWh Volume**		**Hist. Avg GA/kWh *** **	**Amount**
GS>50	kWh	4035	4707		5,196,471		0.06733768	$349,918
Large Use	kWh	4010	4707		39,597,390		0	$0
				-	44,793,861			**$349,918**

Class B - non-RPP Global Adjustment					2024					
Customer		**Revenue**	**Expense**							Amount
Class Name	UoM	USA #	USA #			Class B Non-RPP Volume			GA Rate/kWh	
Residential	kWh	4006	4707			860,092			$ 0.03904	$33,578
GS < 50	kWh	4010	4707			5,020,869			$ 0.03904	$196,015
GS > 50	kWh	4035	4707			80,438,177			$ 0.03904	$3,140,306
Large User	kWh	4010	4707			0			$ 0.03904	$0
USL	kWh	4025	4707			146,882			$ 0.03904	$5,734
Street Light	kWh	4025	4707			510,849			$ 0.03904	$19,944
Total Volume						**86,976,869**				
TOTAL										**$3,395,577**

Total Non-RPP Global Adjustment **$3,745,495**

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

Wholesale Market Service and Rural and Remote Rate Protection Charges

The WMS cost of power in the table above has aggregated the various wholesale market service charges and the rural and remote rate protection charges in the following manner.

Table 2.23: Forecast Total WMS and RRRP Costs 2023-2024

	2023	**2024**
Wholesale market service charge	$972,636	$1,064,455
Class A CBR	5,752	10,672
Class B CBR	85,154	86,165
RRRP	166,469	182,145
Total	**$1,230,011**	**$1,343,437**

NOTL Hydro used $0.0041 per kilowatt hour for the Wholesale Market Service charge in its 2023 bridge year and 2024 Test Year cost of power calculations.

Table 2.24: Forecast Wholesale Market Service Costs 2023-2024

Wholesale Market Service	Units	2023	RPP		2023	Non-RPP		
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	80,864,808	0.0041	331,546	850,531	0.0041	3,487	335,033
GS < 50	kWh	41,523,625	0.0041	170,247	4,965,056	0.0041	20,357	190,604
GS > 50	kWh	4,296,714	0.0041	17,617	84,535,685	0.0041	346,596	364,213
Large User	kWh		0.0041	-	19,798,695	0.0041	81,175	81,175
USL	kWh	246,379	0.0041	1,010	146,882	0.0041	602	1,612
Street Light	kWh		0.0041	-		0.0041	-	-
SUB-TOTAL				520,419			452,217	$ 972,636

Wholesale Market Service	Units	2024	RPP		2024	Non-RPP		
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	81,773,823	0.0041	335,273	860,092	0.0041	3,526	338,799
GS < 50	kWh	41,990,399	0.0041	172,161	5,020,869	0.0041	20,586	192,746
GS > 50	kWh	4,352,572	0.0041	17,846	85,634,649	0.0041	351,102	368,948
Large User	kWh		0.0041	-	39,597,390	0.0041	162,349	162,349
USL	kWh	246,379	0.0041	1,010	146,882	0.0041	602	1,612
Street Light	kWh		0.0041	-		0.0041	-	-
SUB-TOTAL				526,289			538,166	$ 1,064,455

NOTL Hydro used $0.0002 per kilowatt hour for the Class A CBR charge in its 2023 bridge year and 2024 Test Year cost of power calculations.

Table 2.25: Forecast Class A CBR Costs 2023-2024

Class A CBR	Units	2023	RPP		2023	Non-RPP		
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
GS > 50	kWh			-	5,129,784	0.0002	844	844
Large User	kWh			-	19,798,695	0.0002	4,908	4,908
SUB-TOTAL				-			5,752	$ 5,752

Class A CBR	Units	2024	RPP		2024	Non-RPP		
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
GS > 50	kWh			-	5,196,471	0.0002	855	855
Large User	kWh			-	39,597,390	0.0002	9,817	9,817
SUB-TOTAL				-			10,672	$ 10,672

NOTL Hydro used $0.0004 per kilowatt hour for the Class B CBR charge in its 2023 bridge year and 2024 Test Year cost of power calculations.

Table 2.26: Forecast Class B CBR Costs 2023-2024

Class B CBR	Units	2023	RPP		2023	Non-RPP		
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	80,864,808	0.0004	32,346	850,531	0.0004	340	32,686
GS < 50	kWh	41,523,625	0.0004	16,609	4,965,056	0.0004	1,986	18,595
GS > 50	kWh	4,296,714	0.0004	1,719	79,405,901	0.0004	31,762	33,481
Large User	kWh	-	0.0004	-	-	0.0004	-	-
USL	kWh	246,379	0.0004	99	146,882	0.0004	59	157
Street Light	kWh	73,565	0.0004	29	510,849	0.0004	204	234
SUB-TOTAL				50,802			34,352	$ 85,154

Class B CBR	Units	2024	RPP		2024	Non-RPP		
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	81,773,823	0.0004	32,710	860,092	0.0004	344	33,054
GS < 50	kWh	41,990,399	0.0004	16,796	5,020,869	0.0004	2,008	18,805
GS > 50	kWh	4,352,572	0.0004	1,741	80,438,177	0.0004	32,175	33,916
Large User	kWh	-	0.0004	-	-	0.0004	-	-
USL	kWh	246,379	0.0004	99	146,882	0.0004	59	157
Street Light	kWh	73,565	0.0004	29	510,849	0.0004	204	234
SUB-TOTAL				51,375			34,791	$ 86,165

NOTL Hydro used $0.0007 per kilowatt hour for the Rural and Remote Electricity Rate Protection Charge in its 2023 bridge year and 2024 Test Year cost of power calculations.

Table 2.27: Forecast Rural and Remote Electricity Rate Protection Costs

RRRP	Units	2023	RPP		2023	Non-RPP		
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	80,864,808	0.0007	56,605	850,531	0.0007	595	57,201
GS < 50	kWh	41,523,625	0.0007	29,067	4,965,056	0.0007	3,476	32,542
GS > 50	kWh	4,296,714	0.0007	3,008	84,535,685	0.0007	59,175	62,183
Large User	kWh	0	0.0007	-	19,798,695	0.0007	13,859	13,859
USL	kWh	246,379	0.0007	172	146,882	0.0007	103	275
Street Light	kWh	73,565	0.0007	51	510,849	0.0007	358	409
SUB-TOTAL				88,904			77,565	$ 166,469

RRRP	Units	2024	RPP		2024	Non-RPP		
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	81,773,823	0.0007	57,242	860,092	0.0007	602	57,844
GS < 50	kWh	41,990,399	0.0007	29,393	5,020,869	0.0007	3,515	32,908
GS > 50	kWh	4,352,572	0.0007	3,047	85,634,649	0.0007	59,944	62,991
Large User	kWh	0	0.0007	-	39,597,390	0.0007	27,718	27,718
USL	kWh	246,379	0.0007	172	146,882	0.0007	103	275
Street Light	kWh	73,565	0.0007	51	510,849	0.0007	358	409
SUB-TOTAL				89,906			92,240	$ 182,145

Network and Connection Charges

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

- RTSR Network Charge - recovers the Uniform Transmission Rates (UTR) wholesale network service charge.
- RTSR Connection Charge - recovers the UTR wholesale line and transformation connection charges.

For determining the 2023 bridge year cost of power NOTL Hydro used its approved rates while for the 2024 test year the proposed rate were used.

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

Table 2.28: Forecast Network and Connection Transmission Costs

Transmission - Network	Units	2023	RPP		2023	Non-RPP		
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	80,864,808	0.0094	760,129	850,531	0.0094	7,995	360,946
GS < 50	kWh	41,523,625	0.0085	352,951	4,965,056	0.0085	42,203	83,293
GS > 50	kW	10,944	3.7546	41,090	207,255	3.7546	778,160	778,160
Large User	kW		5.8787	-	30,000	5.8787	176,361	178,455
USL	kWh	246,379	0.0085	2,094	146,882	0.0085	1,248	1,767
Street Light	kW	198	2.6196	519	1,374	2.6196	3,599	3,599
SUB-TOTAL				1,156,783			1,009,566	$ 1,406,220

Transmission - Connection	Units	2023	RPP		2023	Non-RPP		
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	80,864,808	0.0013	105,124	850,531	0.0013	1,106	106,229.94
GS < 50	kWh	41,523,625	0.0013	53,981	4,965,056	0.0013	6,455	60,435.29
GS > 50	kW	10,944	0.9575	10,479	207,255	0.9575	198,447	208,925.52
Large User	kW		0.9428	-	30,000	0.9428	28,284	28,284.00
USL	kWh	246,379	0.0013	320	146,882	0.0013	191	511.24
Street Light	kW	198	0.3077	61	1,374	0.3077	423	483.70
SUB-TOTAL				169,965			234,905	$ 404,870

Transmission - Network	Units	2024	RPP		2024	Non-RPP		
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	81,773,823	0.0105	858,625	860,092	0.0105	9,031	867,656
GS < 50	kWh	41,990,399	0.0095	398,909	5,020,869	0.0095	47,698	446,607
GS > 50	kW	11,086	4.1932	46,487	209,949	4.1932	880,359	926,846
Large User	kW		5.6000	-	60,000	5.6000	336,000	336,000
USL	kWh	246,379	0.0095	2,341	146,882	0.0095	1,395	3,736
Street Light	kW	198	2.9256	579	1,374	2.9256	4,020	4,599
SUB-TOTAL				1,306,941			1,278,504	$ 2,585,444

Transmission - Connection	Units	2024	RPP		2024	Non-RPP		
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	81,773,823	0.0014	114,483	860,092	0.0014	1,204	115,687.48
GS < 50	kWh	41,990,399	0.0014	58,787	5,020,869	0.0014	7,029	65,815.78
GS > 50	kW	11,086	1.0497	11,637	209,949	1.0497	220,384	232,021.03
Large User	kW		0.9200	-	60,000	0.9200	55,200	55,200.00
USL	kWh	246,379	0.0014	345	146,882	0.0014	206	550.57
Street Light	kW	198	0.3373	67	1,374	0.3373	463	530.24
SUB-TOTAL				185,319			284,486	$ 469,805

Smart Meter Entity Charges

NOTL Hydro used $0.57 per month for the Smart Meter Entity charge in its 2023 bridge year and 2024 Test Year cost of power calculations.

Table 2.29: Smart Meter Entity Costs

Smart Meter Entity Charge	Units	2023	RPP		2023	Non-RPP		
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	$	98,581	0.4200	41,404	67	0.4200	339	41,743
GS < 50	$	16,691	0.4200	7,010	96	0.4200	482	7,492
SUB-TOTAL				48,415			821	49,235

Smart Meter Entity Charge	Units	2024	RPP		2024	Non-RPP		
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	$	100,027	0.4200	42,011	68	0.4200	344	42,355
GS < 50	$	17,096	0.4200	7,180	98	0.4200	493	7,673
SUB-TOTAL				49,191			837	50,029

2.2.6 Distribution System Plan

NOTL Hydro has filed its 2024 Distribution System Plan with supporting appendices as Appendix 2A at the end of this Exhibit.

2.2.7 Policy Options for the Funding of Capital

NOTL Hydro is not planning on proposing any qualifying ACM capital projects as part of this cost of service application.

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

NOTL Hydro does not have any previously approved ACMs or ICMs to include in rate base.

2.2.9 Capitalization

NOTL Hydro has not changed its capitalization policy since its last Cost of Service application (EB-2018-0056). NOTL Hydro continues to report using Modified International Financial Reporting Standards (MIFRS). A copy of the policy provided in that application is attached as Appendix 2B. There have been no changes.

In summary, the following is the capitalization policy for all assets:

Material Costs:

The material cost is comprised of all the eligible material that is used on a capital project, including its freight to destination. No storage, stockroom expenses or administrative charges are added.

Labour Costs:

The labour cost is comprised of all the eligible wages for staff as well as their supervisors for time spent directly on a capital project. Wages are charged at a fully costed rate that includes employee benefits.

The Cost of an item of property, plant and equipment (PP&E) is recognized as an asset if and only if:

a) It is probable that future economic benefits will flow to the company; and
b) The cost of the item can be measured reliably.

2.2.9.1 Capitalization of Overhead

For self-constructed assets, NOTL Hydro uses a burden rate of 50% over base wages of employees to cover benefits and direct employee related costs. These burden rates were increased effective January 1, 2023 due to increased employee benefit costs. No other overhead is allocated to capital. As such, Chapter 2 Appendix 2-D will be all zeroes so is not provided.

NOTL Hydro uses the same rate for allocating costs to capital as it uses to charge customers for work performed on their behalf. Customers are also charged a mark-up of 20% on labour and 10% on materials and truck time. These additional amounts are included in Other Revenue and are not capitalized.

2.2.10 Cost of Eligible Investments for the Connection of Qualifying Generation Facilities

NOTL Hydro attests that it has not included any costs or included any Investments to Connect Qualifying Generation Facilities in its capital costs or in its 2024 Distribution System Plan. As a result, Chapter 2 Appendices 2-FA, 2-FB and 2-FC have not been completed.

Appendix

List of Appendices

Appendix 2A	NOTL Hydro Distribution System Plan
Appendix 2B	NOTL Hydro Capitalization Policy

APPENDIX 2A

Distribution System Plan

EB-2023-0041

Distribution System Plan

April 2023

Niagara on-the-Lake HYDRO

Table of Contents

5.0 Executive Summary

Niagara-On-The-Lake Hydro (NOTL Hydro) is in a position whereby it has completed or is undertaking all the major projects it has planned and has processes in place for the ongoing system upgrades. In particular:

- The two transmission stations have now been upgraded to that each station has the capacity to serve the entire customer load of NOTL Hydro with relatively new transformers.
- The ongoing projects for voltage conversion and both overhead and underground system renewals continue with clear plans for the next ten years.
- The asset management system is in place that is providing the needed information for targeted upgrades to the system based on asset condition.
- The fleet will have been upgraded so that the next large vehicle purchase is not needed for another five years. NOTL Hydro also hopes to start switching to electric vehicles if market conditions allow.
- Both the interior and exterior of the building will have been renovated positioning NOTL Hydro to continue to provide a high level of service.

While there is a cost to all this, NOTL Hydro still expects to have the lowest local delivery rates even once these expenditures are incorporated into rates. These are enhanced by low line losses and improving reliability.

As a result, NOTL Hydro's forecast for capital expenditures over the next five years is very stable.

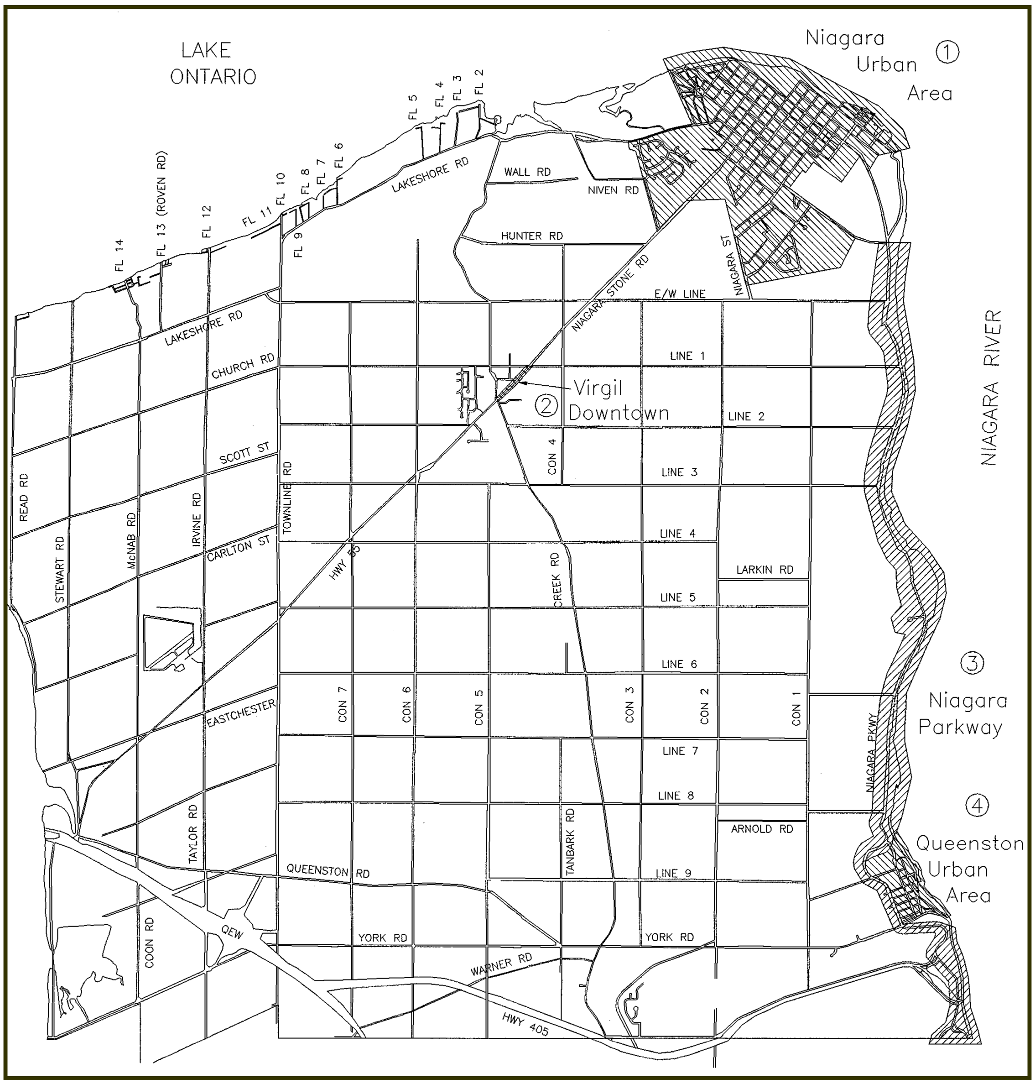
NOTL Hydro also knows that conditions can change (nobody forecast the pandemic in 2019) and has tried to build a flexible system to accommodate the change. NOTL Hydro has analyzed what the impact of a sudden increase in electric vehicles might mean and is making adjustments. NOTL Hydro has also made adjustments and used battery storage technology in an innovative way to increase its capacity for more solar generation on its system though this remains a challenge. NOTL Hydro is also expanding its internal skill sets so that it can more easily react to customer needs.

Finally, NOTL Hydro's biggest challenge in its capital efforts is accessing the contract support needed. A number of vendors have indicated they will not bid on the Old Town underground work while there is no shortage of other options. The general shortage of trades is also increasing costs and creating more of a challenge. NOTL Hydro has started to address this by hiring its own underground crew and may expand this if circumstances dictate.

5.1 Overview

NOTL Hydro's service territory is shown in the image below and it covers the municipal boundaries of the Town of Niagara-on-the-Lake including the villages of Virgil, Glendale, St. David's, the Old Town and Queenston. It services nearly 10,000 primarily Residential and General Service customers. In addition, there are over 160 embedded generation customers, including one hydro generation facility, that participate in the government's various feed-in-tariff (FIT) programs or have net-metering contracts.

Image 1 - Service Area Map



LEGEND

1. Niagara Old Town
2. Virgil Downtown
3. Niagara Parkway
4. Queenston Urban Area

The service territory is comprised of approximately 133 sq. km. bordered by Lake Ontario to the north, the Niagara River on the east, City of Niagara Falls to the South and St. Catharines to the west. The population of Niagara-on-the-Lake is approximately 19,003 (2021 Census) with the primary economic activity shared between an agricultural base and tourism. Niagara-on-the-Lake is also a retirement destination. Table below lists a breakout of the customer base to the end of 2022:

Table 2: Customer Count December 31, 2022

Customer Category	Count
Residential	8,220
General Service (<50kW)	1,466
General Service (>50kW)	130
Unmetered & streetlights	72
Total	**9,888**

The charts below show the trends in demand and consumption for NOTL Hydro.

Table 3: NOTL Hydro Peak Demand (2018-2022)

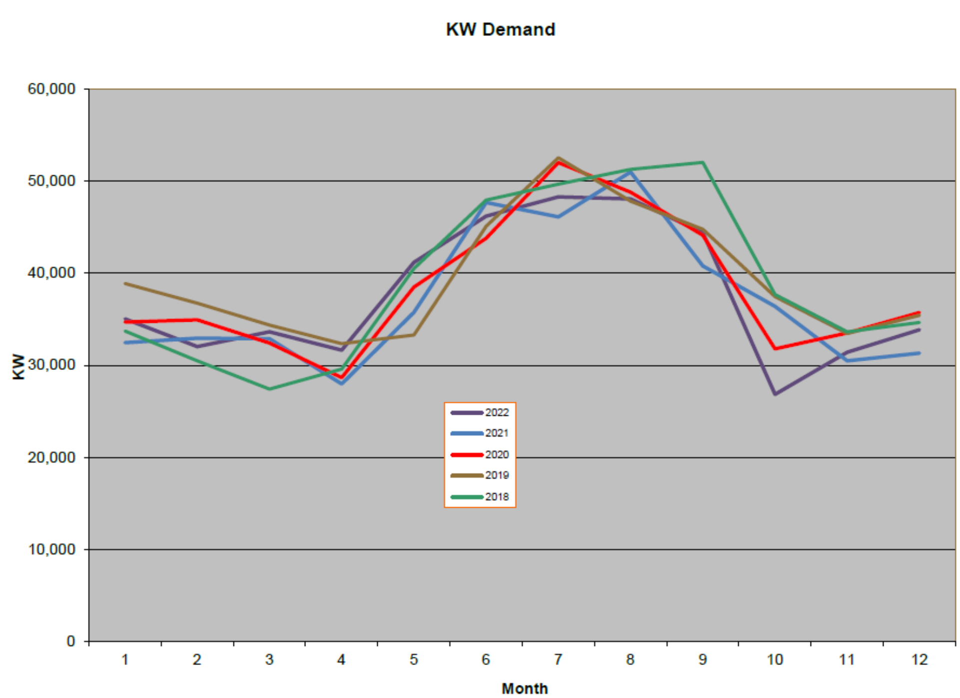
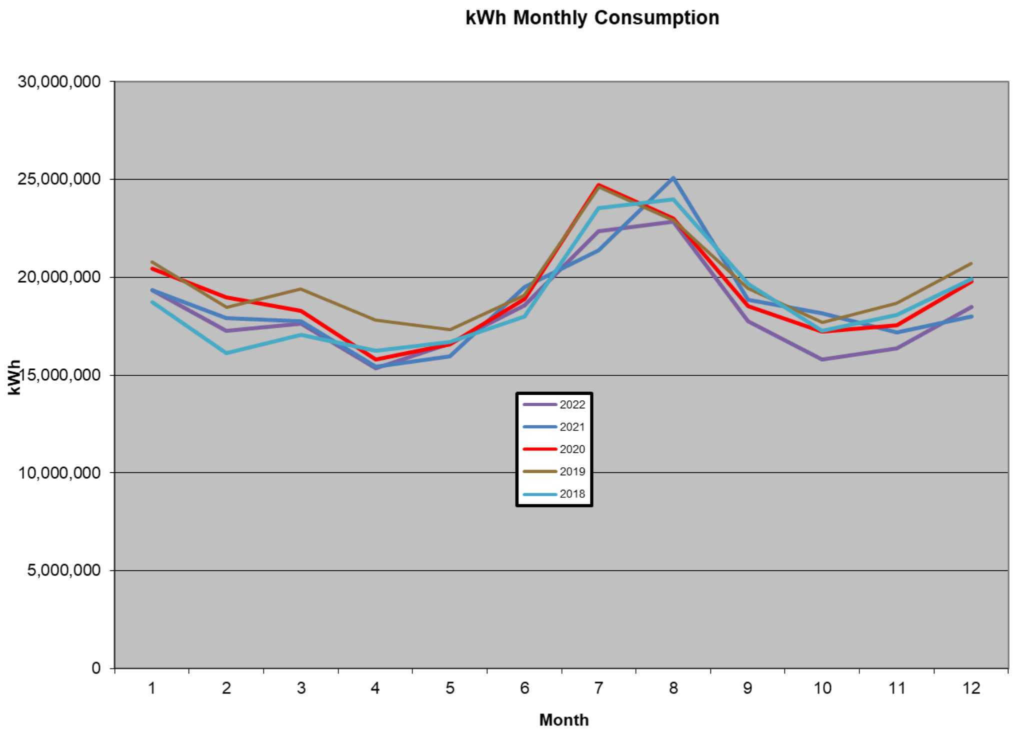


Table 4: NOTL Hydro Monthly Load (2018-2022)



NOTL Hydro acquired 95% of the current operating territory from Ontario Hydro in 1983. The combined system operated two sub-transmission 27.6 kV feeders and five substations where the voltage was stepped down to 4.16 kV. Since 1983, and after NOTL Hydro obtained the transformer station assets from Ontario Hydro and built the new York MTS1 station, this utility had embarked on a program to eliminate the older 4kV distribution system and replace it with 27.6 kV. Voltage conversion included replacing substantially all of the distribution system and eliminating all the 4 kV substations. The last of the stations, King DS, was decommissioned and the equipment removed from site in 2017. The existing pockets of 4kV distribution are serviced by a set of step-down distribution transformers mostly installed on poles. It is estimated that less than 5% of the load remains serviced at 4 kV.

5.2 Distribution System Plans

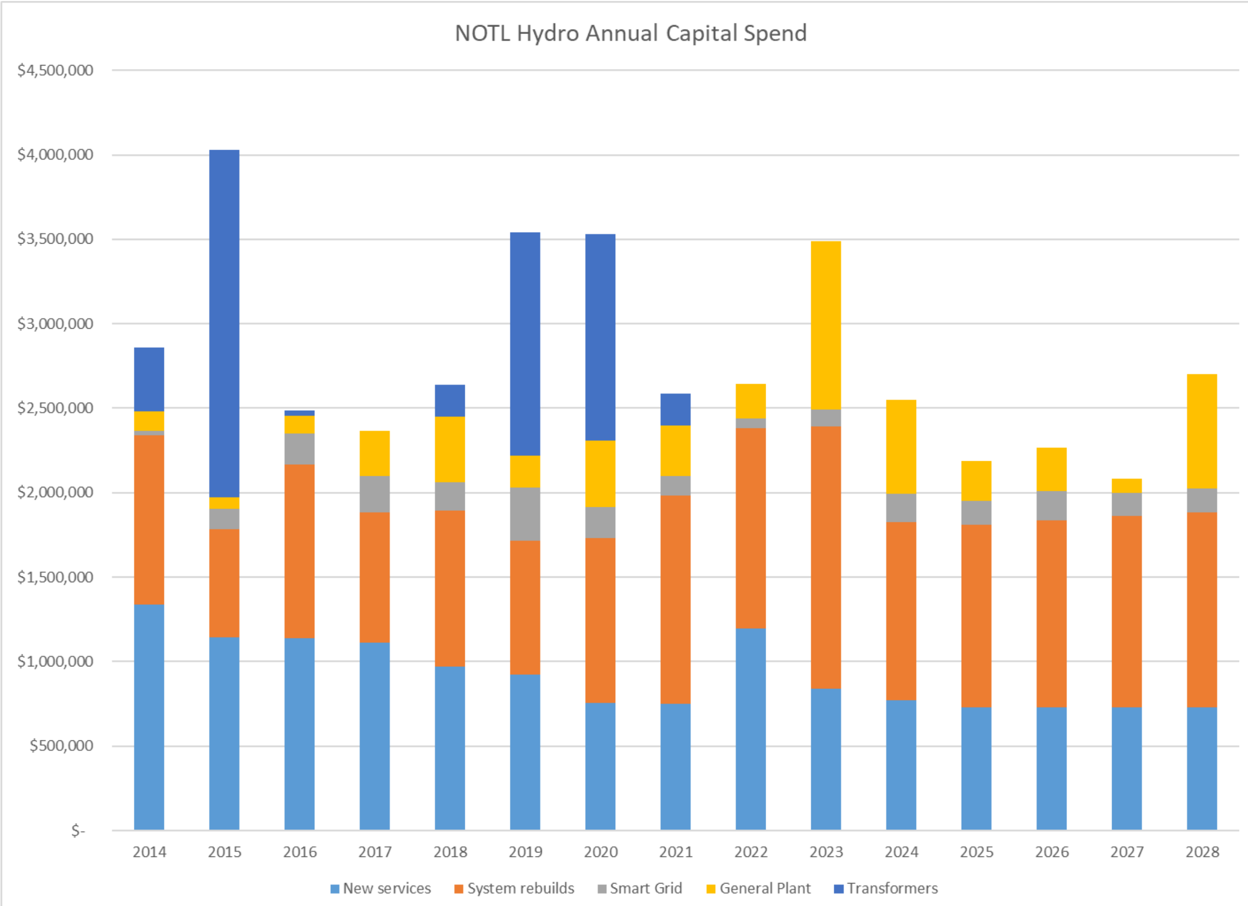
5.2.1 Distribution System Plan Overview

This Distribution System Plan provides a detailed analysis of NOTL Hydro's capital plans over the next five years. The planned investments, and the reasons for those investments, are set out herein. However, capital planning is a process and NOTL Hydro will continue to adapt these plans based on the needs, demands and priorities of its customers.

Consistent with what as included in the plan in the previous DSP, lower capital spending is expected in the period 2024-2028. The transformer station upgrades have put NOTL Hydro in an excellent position as relates to the security of supply. The building upgrades due to the pandemic, growth and the insourcing of certain services due to local conditions should be largely complete. Two of the three large vehicles in NOTL Hydro's fleet will also have been replaced so no new large vehicles purchases are expected until 2028.

The chart below summarizes NOTL Hydro's past and planned capital investments. NOTL Hydro deliberately maintains a constant level of investments for asset renewal (orange). These are required to maintain the system in good working order. Investments in smart grid assets (grey) have been growing as NOTL Hydro increased the flexibility and reactiveness of its system. General plant investments (yellow) are also steady though the periodic replacements of the service vehicles and building upgrades make for significantly higher investments in those years. The biggest individual investments are the transformers (blue) for NOTL Hydro transmission stations (NOTL MTS and York MTS) as NOTL Hydro invests to ensure there is redundant transformation capacity to support the Town at all times.

Chart 5: NOTL Hydro Capital Plan (2014-2028)



Most importantly, the overall plan is about how NOTL Hydro provides reliable service to its customers while keeping its rate low.

Key Elements of the DSP

Beyond the generally lower capital spending going forward, the key elements of the DSP are as follows:

a) The plan calls for a continuation of the conversion of the rural distribution voltages from 4 kV to 27.6 kV. This program reduces line losses and improves cost management by reducing the transformer inventory that needs to be carried. The 4 kV lines are also very old and in need of replacement. By 2024, all the major pockets of the rural areas will have been converted with the exception of the firelanes. The firelanes will become the focus starting in 2024.

b) The plan also calls for a continuation of the conversion of the urban distribution voltages from 4 kV to 27.6 kV while converting them to underground. This program improves reliability and reduces line losses. The 4 kV lines are also very old and in need of replacement. By 2033, all the major pockets of the Old Town will have been converted. The only remaining urban 4kV service will be a four-block area that is already underground (though 4 kV) and very stable.
c) Locates were brought inhouse in 2020 due to performance issues with the service provider. This was done in collaboration with the Town of Niagara-on-the-Lake. A vehicle and locate equipment were purchased for this service. Underground excavation work was brought in-house in 2022 due to the pending bankruptcy of the service provider whom NOTL Hydro had used for decades. A vehicle and an excavator were purchased for this service. These two changes are discussed in more detail in section 5.4.9. NOTL Hydro is considering whether to bring boring and/or vacuuming in-house but no decision has been made. The purchase of a boring machine in 2026 is provided as a placeholder.
d) The building was renovated in 2020-2021 with the creation of a larger boardroom and kitchen in response to the pandemic. A new garage, a second garage and expanded tarmac are being built in 2023 in response to growth demands, theft concerns and inventory management.
e) System Service investments continue as NOTL Hydro invests in smart grid assets to improve performance and prepare for a changing role in the future.

Customer Preferences and Expectations

NOTL Hydro held an open house on September 24, 2019 to discuss its ongoing voltage conversion and undergrounding project in the Old Town. Over 70 customers attended. Though nobody liked the mess during the construction the overall support for the ongoing program was high including some customers on Gate St requesting that the convergence and undergrounding of their street be brought forward.

The undergrounding project started in the 1980's under the previous Niagara-on-the-Lake Hydro Electric Commission. The objective was to move the more densely populated areas to an underground electrical service. Much of this can be done at the same time as the voltage conversion from 4.16 kV to 27.6 kV.

Most of NOTL is rural but there are some urban areas including the Old Town, Queenston, St. Davids, Virgil and the Glendale area. Most of St. Davids and Virgil are newer so are mostly underground already. The Glendale area is planned for future development. The first areas converted to underground were Queenston and Chautauqua (part of the Old Town). Remaining are the last few streets of the Old Town and the main street in Virgil. This is expected to last into the 2030's by which time this will have been a project of five decades.

NOTL Hydro has deliberately taken this length of time for this project so as to keep the annual capital costs and the resulting rate impact low. The effectiveness of this can be seen in NOTL Hydro's low rates. Moving the distribution grid underground in these areas has a number of safety and reliability benefits. The Old Town in particular was previously known for its large number of outages. Niagara-on-the-Lake is also a tourist town with over 2 million visitors a year so moving the equipment underground also assists aesthetically. An LDC cannot operate in isolation from its environment.

NOTL Hydro held an open house on March 8, 2023 to get customer feedback on its proposed plans for the next five years. Attendance was small with only five customers turning up and one completing the survey online. Two take-aways from this open house were:

- Reliability continued to be the most important service NOTL Hydro could provide. This message is consistent with recent surveys and other customer interaction.
- Customers were concerned about the impact of electric vehicles on the grid and were seeking assurance that NOTL Hydro was preparing and that their service would not be negatively impacted. NOTL Hydro recently published an article on this topic which may have heightened local awareness.

Cost Savings

The primary source of savings from an effective distribution system plan is reduced unplanned maintenance and repairs. NOTL Hydro has traditionally kept overtime to a minimum with only after-hours outages creating overtime. Over the forecast period, NOTL Hydro plans to continue its grid renewal investment program as this has served the company well.

Reduced line loss is also a major savings for NOTL Hydro customers. NOTL Hydro has successfully brought its line loss level down to the lowest in the Niagara Region. Continued investments in the voltage conversion program and constant upgrading of system assets will help try to further reduce the line loss rate over the forecast period. This is discussed in more detail in section 5.3.2.

A third source of savings is reduced outages. Outages cost customers in terms of lost time and efforts for businesses and lost services for residential customers. Outages cost NOTL Hydro with truck rolls, overtime, assets write-offs and lost revenue. NOTL Hydro's outage performance has trended positively. Continued investments in upgraded assets and in smart gird technologies will save customers by trying to keep the outages down. This is also discussed in more detail in section 5.3.2.

Changes since the Last DSP

The DSP for 2024-2028 is very similar to the DSP submitted in 2018 which included the years 2024-2028. Some changes that have been noted include:

- Subdivision and customer projects projected expenditures have been reduced to reflect the trends in these categories due to the limited room for expansion in Niagara-on-the-Lake. Most of the urban areas are built to their boundaries and the rural areas are protected from development due to the Green Belt legislation. These expenditure categories are not in NOTL Hydro control so may vary based on customer demand.
- The costs of the underground system renewal projects have been increased to reflect inflation and the challenges NOTL Hydro is facing with contracting support. For many decades, NOTL Hydro worked closely with Wiens Underground on both regular underground service work and the voltage conversion projects. Many other contractors have stated that they are not interested in working on projects in the Old Town due to some of the challenges that area presents. In 2019, the President of Wiens Underground passed away and in 2022 the company declared bankruptcy. NOTL Hydro has insourced its own underground excavating crew for the service work and is considering boring and vacuuming though no decisions have been made. NOTL Hydro has not been able to recreate the relationship it had with Wiens Underground with another contractor for the projects.

- Meter expenditures are forecast to be higher in 2024 due to ongoing meter reverification requirements.
- The timing of future vehicle purchases, both pick-up trucks and large line trucks, has been altered due to the recent availability issues. Future purchases are also forecast to be more expensive as they are anticipated to be electric vehicles.

Future Contingencies

None of NOTL Hydro's plans are contingent on future events. System Access activities are contingent on customer demand but there is a strong track record of this demand.

Given the excess capacity of NOTL Hydro's transformation, the arrival of a large customer is always a potential possibility. A cannabis grower did have a substantial operation for a number of years but they closed their operation in early 2022. Any future activities would be based on customer demand and costs would be charged based on the NOTL Hydro Conditions of Service. As noted in its rate application EB-2022-0158, NOTL Hydro does have a crypto currency miner establishing operations in NOTL Hydro service territory with up to 50 MW of load. Approval has been received from the IESO and Hydro One with System Impact Assessments and Connection Impact Assessments. The customer's own decision making will determine how much of this load becomes part of the NOTL Hydro system.

Future activities based on growing use of either EVs or DERs is unknown and will depend in the nature and type of growth.

The expected growth in generation lead by the IESO auction processes may provide opportunities for some NOTL Hydro customers to invest in gas-fired generation. NOTL Hydro has a good reputation in managing these opportunities with their customers and these will be dealt with on a case-by-case basis should they arise.

No incremental capital modules are planned at this time.

Long-term Energy Plan Investments

NOTL Hydro believes we must invest early to prepare for the future.

A historical example is our decision a couple of decades ago to use 100 kV pad mounted transformers rather than 50 kV as was the standard at the time. This has resulted in a system better prepared for the widespread adoption of EVs.

A second example is our investments in high voltage transformation so that NOTL Hydro has capacity for significant growth in demand from electrification.

A current example of this is NOTL Hydro's investments in smart grid technologies such as SCADA enhancements, switches and reclosures. NOTL Hydro believes the flexibility these provide will be valuable in the future. While these smart grid technology investments improve performance, they are also being made with a view to accommodating more varieties of demands (distributed energy, EVs, new generation and demand) on the NOTL Hydro system.

NOTL Hydro is also looking at what needs to be done should the use of electric vehicles become much more prevalent. This includes investing in upgrading local transformers and monitoring the installation of EV chargers. This is discussed in more detail in section 5.3.1.

NOTL Hydro will continue to look for opportunities to make investments that allow for more customer opportunities.

5.2.2 Coordinated Planning with Third Parties

NOTL Hydro works closely with third parties to ensure its investments and operations are conducted in a fashion that works efficiently with the investments and operations of these parties. The third parties include Hydro One, the IESO, Bell Canada, Cogeco, Rogers, Niagara Region, the Town of Niagara-on-the-Lake and adjacent LDCs.

Hydro One

In May 2021, Hydro One filed its Needs Assessment Report for the Niagara Region (Appendix A). The Needs Assessment Report was a first step in the creation of the Niagara

Region Integrated Regional Resource Plan which is described in more detail below. NOTL Hydro provided Hydro One with the material required as part of this report.

NOTL Hydro meets with Hydro One Account Management staff on an annual basis to discuss local issues. As a result of these meetings, a good working relationship has developed between NOTL Hydro and Hydro One. This has facilitated ensuring the timing of Hydro One maintenance work is scheduled in a manner conducive to both NOTL Hydro and Hydro One. This relationship was also helpful when NOTL Hydro was looking at a DESN (Dual Element Spot Network) structure for its transformation stations back in 2019-2020. This idea was ultimately shelved due to cost.

Regional Working Groups

NOTL Hydro participates in an informal regional working groups that meets periodically to discuss infrastructure issues in the region. Members of the working group include Hydro One, Enbridge, Bell Canada, Cogeco, local municipalities and local LDCs. These meetings provide an opportunity to get the right contacts at each company and to keep up-to-date on local issues and planned infrastructure investments.

NOTL Hydro participated in the Niagara Region planning led by the IESO which started in late 2020 with the Needs Assessment led by Hydro One. These efforts lead to the issuance of the Niagara Region Integrated Regional Resource Plan (IRRP) which is attached as Appendix B.

There are no inconsistencies between the DSP and any current Regional Plan.

Region of Niagara and Town of Niagara-on-the-Lake

NOTL Hydro keeps a close working relationship with both local governments so that we are aware of their plans and vice versa. In some cases, the cooperation is required due to the nature of the project. Some examples include:

- The Lakeshore Rd project in 2017-2018 was a road straightening project of the Niagara Region that required the movement of a line of NOTL Hydro poles. NOTL Hydro co-ordinated the timing and location of the poles with the Region and was partially compensated for this work by the Region.

- Where possible, NOTL Hydro coordinates its capital jobs with the Town of Niagara-on-the-Lake to minimize disruptions to customers. The voltage conversion and undergrounding in the Lansdowne area was performed in 2018 to coincide with work the Town was already planning on that road. The voltage conversion work in the Concession 6 and Warner Rd area was also delayed so that the work could coincide with a road widening project by the Town.
- In other cases, this cooperation provides opportunities. As part of a major refurbishment the Niagara Region plans to widen part of Niagara Stone Road (Highway 55) in 2023 (Appendix C) so NOTL Hydro will use this opportunity to replace and bury its line along part of that road. This minimizes disruptions to the customers and reduces the cost of the project.

Telecommunication Entities

Bell Canada, Cogeco and Niagara Regional Broadband Networks (NRBN) all have telecommunications assets in Niagara-on-the-Lake. Rogers has announced it will be expanding into Niagara-on-the-Lake in 2023 and contacts have been established with Rogers. NOTL Hydro has always worked closely with these companies to minimize costs for all parties.

In 2021-2022, Bell engaged in a significant expansion of its fibre infrastructure through much of Niagara-on-the-Lake. NOTL Hydro supported this with timely locates and with upgrades to its pole lines as requested by Bell. In 2021, NOTL Hydro likewise supported a small expansion by NRBN along Queenston Rd.

As part of its voltage conversion program, NOTL Hydro is replacing old 4 kV lines with either underground or above ground new 27.6 kV lines. If Bell Canada, Cogeco and NRBN have their lines on these poles then they will be required to move them as well. NOTL Hydro communicates its plans to both these companies well in advance and has been able to coordinate the use of the same contractor to reduce costs in some cases.

Renewable Energy Generation (REG)

There are several REG investments currently planned for the NOTL Hydro service territory. These are all net metering and all manageable under the current connection processes. They are not of a size that requires any coordination with the IESO and they do not impact any other LDCs. No significant investments by NOTL Hydro will be required as a result of these installations.

NOTL Hydro has historically worked closely with customers installing renewable energy generation by providing them with guidance and working with them on their installations. NOTL Hydro held an open house for potential solar generation installations in 2017 and was specifically invited and thanked at an open house held by one of the wineries who installed a sizable solar installation in 2017.

A comment letter from the IESO has been attached as Appendix J.

5.2.3 Performance Measurement for Continuous Improvement

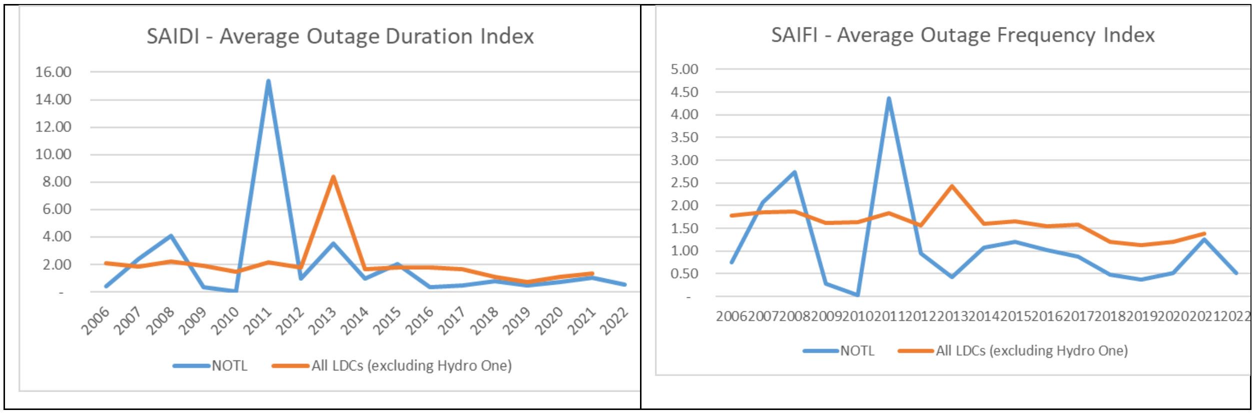
As a rate regulated LDC, NOTL Hydro is required to measure, record and submit a number of metrics related to performance to the Ontario Energy Board. This information is also utilized in the distribution system planning to evaluate effectiveness of the capital expenditure efforts which then gauges good service level for the customers. It is the goal at NOTL Hydro to develop a trend of continuously improving indices. These will be the result of ongoing inspections, repair and proactive maintenance and finally replacement.

The optimal level of a capital plan is to achieve the proper intersect between system renewal, customer feedback, financial ability to fund the plan, replacement due to obsolescence and preventing unnecessary increases in the OM&A budgets. At a macro level, by keeping rates reasonable relative to neighbouring utilities, system reliability high and capability to connect new load, local municipal leaders are able to use these to attract new businesses and a place to live.

Outage Indices

NOTL Hydro tracks its SAIDI and SAIFI results closely. These are provided in the table below. While the goal is a constantly improving outage performance, NOTL Hydro recognizes that in given years this may not be possible due to weather related events. NOTL Hydro's reliability results have been steady and better than the industry average over the past ten years.

Table 6: SAIFI and SAIDI



Interruptions

Full details of NOTL Hydro's outage record for the past five years is outlined in the table below. The number of outages has increased over the past few years due to growth in the system and better tracking. At the same time, both SAIDI and SAIFI have stayed at the same general levels. This is due to the investments that have been made to the local grid that are both reducing the size of the impact of outages and their duration for many of the customers affected.

Table 7: NOTL Hydro Outage Statistics (2018-2022)

	2018	2019	2020	2021	2022
Total interruptions					
# outages	55	42	50	78	91
# customers	6,807	3,653	5,004	21,888	5,323
# customer hours	11,699	4,799	7,072	22,073	5,120
SAIDI	0.72	0.50	0.73	2.27	0.54
SAIFI	1.24	0.38	0.52	2.25	0.52
Interruptions excluding loss of supply					
# outages	54	42	50	77	91
# customers	4,552	3,653	5,004	12,170	5,323
# customer hours	7,189	4,799	7,072	9,926	5,120
SAIDI	0.76	0.50	0.73	1.02	0.54
SAIFI	0.48	0.38	0.52	1.25	0.52
Interruptions excluding loss of supply and Major Events					
# outages	54	42	50	77	91
# customers	4,552	3,653	5,004	12,170	5,323
# customer hours	7,189	4,799	7,072	9,926	5,120
SAIDI	0.76	0.50	0.73	1.02	0.54
SAIFI	0.48	0.38	0.52	1.25	0.52
Unknown/Other					
# outages	11	8	6	3	3
# customers	359	482	77	4,898	54
# customer hours	475	683	60	1,832	71
Scheduled Outage					
# outages	12	4	13	24	24
# customers	946	37	185	274	269
# customer hours	2,474	155	656	429	731
Loss of Supply					
# outages	1	-	-	1	-
# customers	2,255	-	-	9,718	-
# customer hours	4,510	-	-	12,148	-

	2018	2019	2020	2021	2022
Tree Contacts					
# outages	11	9	11	12	15
# customers	371	523	2,744	571	2,244
# customer hours	696	921	2,983	884	2,270
Lightning					
# outages	2	3	2	3	-
# customers	157	1,131	1,398	136	-
# customer hours	505	272	2,463	223	-
Defective Equipment					
# outages	8	14	7	14	18
# customers	404	1,436	253	3,098	323
# customer hours	1,042	2,704	633	2,569	679
Adverse Weather					
# outages	4	-	2	3	5
# customers	2,053	-	255	1,437	2,043
# customer hours	1,625	-	211	2,293	939
Adverse Environment					
# outages	-	-	-	-	1
# customers	-	-	-	-	4
# customer hours	-	-	-	-	6
Human Element					
# outages	1	1	-	1	-
# customers	33	7	-	164	-
# customer hours	132	21	-	273	-
Foreign Interference					
# outages	5	3	9	17	25
# customers	229	37	92	1,592	386
# customer hours	240	43	66	1,422	424

Major Outage Events

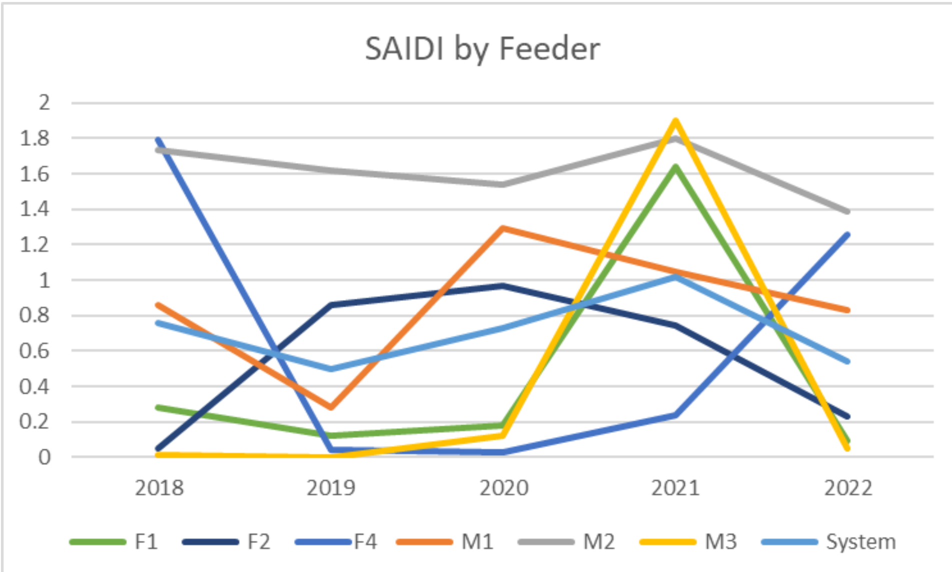
There was only one major outage event in the past five years. This occurred on October 9, 2021 at 1:30 AM and was a loss of supply from Hydro One. The NOTL Hydro NOTL Station was down so that Hydro One could perform maintenance on their Q11 transmission line. Hydro One lost power on their Q12 line that feeds the NOTL Hydro York Station meaning the entire Town of Niagara-on-the-Lake was without power. NOTL Hydro responded by shifting power back onto the NOTL Station though this took some time as is still a manual process. As part of its smart grid investments over the next five years NOTL Hydro will be installing switches so that this transfer process can be automated thus speeding up response times.

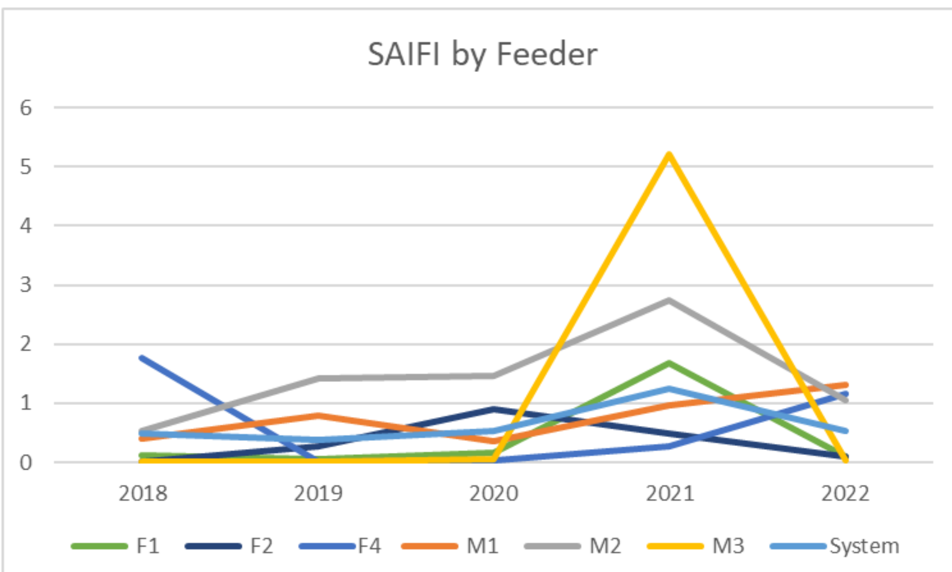
This outage cost NOTL Hydro customers around $90 thousand that became revenue to Hydro One. Hydro One profited by the outage due to transmission double billing. NOTL Hydro customers are billed based on the peak at each station separately so when NOTL Hydro shifts loads between stations like this the aggregate peak becomes much higher. NOTL Hydro normally tries to manage its system to avoid this, for instance by taking a station down for the full month when Hydro One needs an outage, but that cannot be avoided with an outage. NOTL Hydro will be intervening in the generic Hydro One transmission hearing on this issue.

Outages by Feeder

NOTL Hydro also tracks its outages by feeder.

Table 8: SAIFI and SAIDI by Feeder





The increase of SAIDI and SAIFI on certain feeders in 2021 were due to a couple of feeder wide outages that lead to the overall increase in these scores that year. The M2 line typically has the highest SAIDI and SAIFI of all the feeders. The M2 is one of the longest feeder lines in the NOTL Hydro system going from York Station down to Lakeshore Rd and then all along Lakeshore Rd. In addition to its length, this line has higher outages as it is subject to the weather coming off Lake Ontario. Weather coming from the north is more damaging than the normal weather that comes from the west. Lakeshore Rd also has a higher number of auto accidents.

NOTL Hydro has taken a number of steps to reduce the outage scores along the M2:

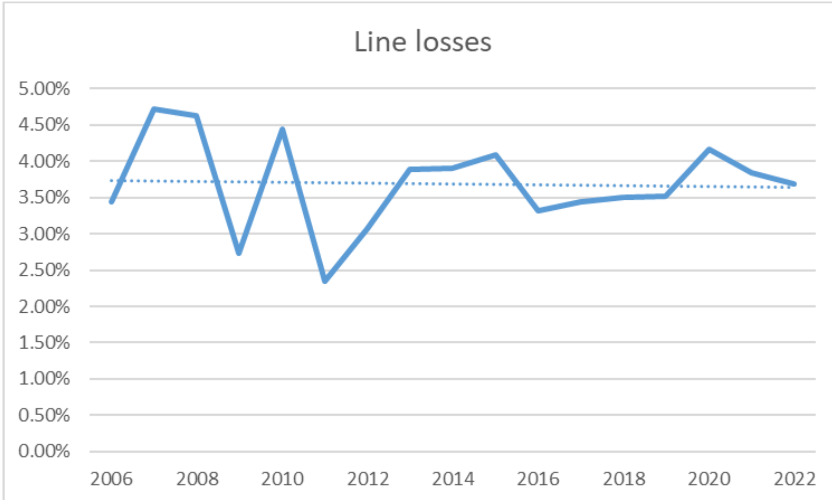
- an automated switch was installed so that the Lakeshore Rd section of the line can be isolated in the event of an outage on that section,
- the final section of Lakeshore Rd was converted to the 27,600 volts in 2021,
- Lakeshore Rd was straightened by the Niagara Region with the corresponding movement of the poles.

Going forward, the planned voltage conversion of the firelanes starting in 2025 will reduce outages due to newer infrastructure and improved line placement. Additional smart grid technology will also be installed.

Line Loss Evaluation

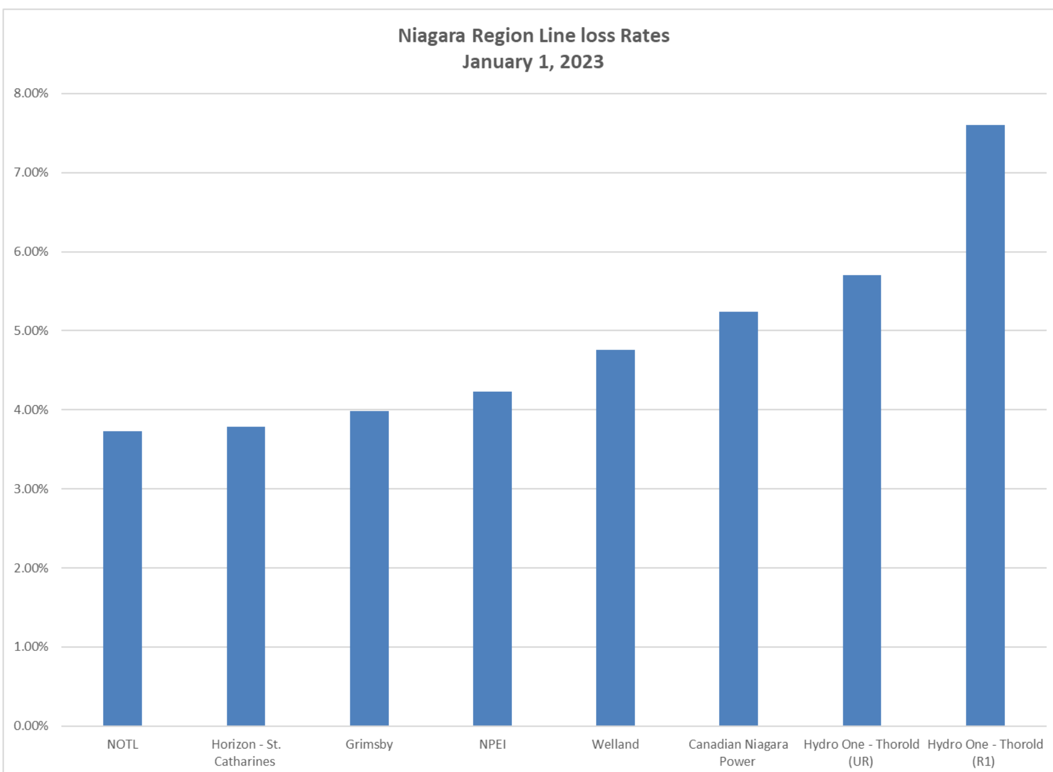
Line losses are another method of measuring performance. Line loss rates will vary by LDC, particularly depending on density levels, but are an indication of performance over time and across LDCs with similar characteristics. The table below provides the declining trend in line losses which is the theoretical difference between energy consumption recorded at the aggregate wholesale points and the sum of energy consumption that are billed to the customers recorded at the meters. This is a direct benefit of operating the distribution system with greater efficiency and programs described earlier have contributed to beneficially towards lowering it over time.

Table 9: NOTL Hydro Line Loss History (2003-2021)



NOTL Hydro currently has the lowest line loss rate in the Niagara Region (3.73%). This application includes a proposed rate of 3.74% which is almost identical.

Table 10: Niagara Region Line Loss Rates



5.3 Asset Management Process

5.3.1 Planning Process

Asset management is a valuable tool. NOTL Hydro agrees with the emphasis placed by the OEB on the use of proper asset management. NOTL Hydro has invested in its asset management over the past five years. In 2018, it created a new position which included asset management as part of its responsibilities. This individual undertakes much of the inspecting, testing and data management described in the NOTL Hydro process. In 2023, in collaboration with five other LDCs so as to effectively manage costs, NOTL Hydro will be gaining access to 20% of the time of a GIS technician to help keep NOTL Hydro's GIS maps up-to-date and to help NOTL Hydro make the best use of its GIS software.

One of the more recent additions to the tools used for asset management is an infra-red sensor. This detects hot spots that indicate equipment that is wearing out and should be replaced. Doing this based on testing is a proactive means of reducing outages.

While asset management reduces total costs, as reflected in NOTL Hydro's PEG results, it does add additional up-front operational costs for the testing, inspecting and date management as incurred by NOTL Hydro.

In 2021, NOTL Hydro developed and approved a Rotating Asset Management Plan which summarizes the steps NOTL Hydro takes to monitor the condition of its assets and the process by which this information leads to actions taken. The document is attached as Appendix D. Assets are rated using the following five conditions:

- **Immediate** – the asset should be replaced immediately
- **Critical** – the asset should be replaced in 1-2 years
- **Poor** – the asset should be replaced within 5 years
- **Good** – the asset should be replaced in 5-10 years
- **Excellent** – the asset is good for the next 10 years

Assets rated immediate are replaced within a few days so will not appear on any asset condition tables.

Asset management is one of the factors taken into account when determining the capital expenditure plan. Others include the voltage conversion program, local initiatives, customer needs as they relate to the grid (as opposed to direct connection needs) and budgetary restrictions. Depending on the year, the capital expenditure plan will reflect one or more of these drivers. During 2019-2023, a number of projects and expenditures were driven by the asset management system at NOTL Hydro. These are described in section 5.4.8.

NOTL Hydro is very aware of the potential impact of electrification and the demands this may place on the local and provincial grid if it occurs. NOTL Hydro's planning has taken this into account such as by:

- Its investments in its transformation stations so that NOTL Hydro has the capacity for future electrification demands;
- Its practice of using 100 kV or larger pad-mounted transformers for the past few decades which means the local transformers have the capacity to handle residential EV charging;
- Its awareness of the issue and plans to address the ramifications as they arise.

The President of NOTL Hydro wrote a public article on its preparations for EVs which was published in local newspapers. A copy of that article, along with the results of analysis done for the Board of NOTL Hydro, is provided as Appendices E thru G.

5.3.2 Overview of Assets Managed

NOTL Hydro manages one distribution system that is all in the Town of Niagara-on-the-Lake with the exception of a few customers in the City of Niagara Falls. The system is fed by two transformer stations which are described in more detail below. The stations are the only high voltage assets and are considered distribution assets for the purpose of the Cost of Service application. The feeders, currently seven in total, are interconnected so that the full system can be served by either station.

The service area is mostly rural with five separate smaller urban areas. The rural areas are all part of the Greenbelt so growth is limited in these areas. Most of the urban areas are near capacity with the exception of the Glendale area in which future dense growth is planned but not yet started. The urban areas are slowly being converted to being primarily underground services. Based on primary wire the system is 67% overhead and 33% underground while based on transformers it is 55% overhead and 45% underground.

The primary system is almost all 27.6 kV with some pockets of 4.16 kV primary in the Old Town, in a rural area near Virgil and in the firelanes. It is expected that the entire Town will be fully converted to 27.6 kV in 10-15 years. NOTL Hydro is neither a host nor an embedded distributor.

The NOTL Hydro system has the following asset attributes which affects its asset management and capital expenditure process.

Transformation Stations

NOTL Hydro is directly connected to the Hydro One 115 kV transmission line by way of two transformation stations: York Station (83 MVA) and NOTL Station (91.7 MVA). Each station currently has the capacity to serve the entire NOTL Hydro network. Getting to this stage has been a key goal for NOTL Hydro in its past capital expenditure planning. Both stations are 100% owned by NOTL Hydro.

As these stations have been upgraded, NOTL Hydro has worked with Hydro One and the IESO to ensure their protection and controls are to the latest standards. Given how important these stations are to the provision of electricity in Niagara-on-the-Lake, regular maintenance is outsourced to a third party with expertise in transmission stations.

Poles

NOTL Hydro only uses wooden poles, there are no concrete or metal poles in the NOTL Hydro system. Poles are tracked both by age and condition.

Table 11: NOTL Hydro Poles by Age and Condition

		Condition					
Age (Years)	Year Installed	Excellent	Good	Poor	Critical	Unknown	Total
0-9	2013-2022	1040	6	0	0	11	1057
19-Oct	2003-2012	727	2	0	5	10	744
20-29	1993-2002	833	58		2	3	896
30-39	1983-1992	213	80	4	7	2	306
40-49	1973-1982	255	422	12	18	0	707
50+	1972 or earlier	70	658	26	50	3	807
Unknown		0	1	1	0	263	265
Total		3138	1227	43	82	292	4782

The poles included in the analysis above are only those owned by NOTL Hydro as of December 2022. There are another 1,754 poles owned by Bell Canada or other utilities.

The replacement of a pole means the replacement of most of the equipment on the pole such as the crossbeams, insulators and any other equipment specific to that pole. When a section of poles is replaced then the wiring is also usually replaced though not always.

As discussed in section 5.4.8, the replacement of poles due to the asset management ratings, either individually or in sections, has been a significant driver of the overhead service renewal expenditures in 2019-2023. The number of poles replaced due to deteriorated condition is summarized below:

Table 12: NOTL Hydro Pole Replacement by Year

Poles	
Year	Replaced
2022	41
2021	84
2020	23
2019	90
2018	157

Transformers

Transformers are tracked both by age and condition. A table summarizing the number of transformers in the system is below.

Table 13: NOTL Hydro Transformers by Condition

Transformer Type	Condition					Total
	Excellent	Good	Poor	Critical	Unknown	
Pole mounted	1057	6	3	1	34	1101
Pad mounted	788	24	34	15	41	902
PMH Units	15	1	3	1	0	20
Junction Boxes	101	0	5	5	8	119
Transmission	4	0	0	0	0	4
Total	1965	31	45	22	83	2146

A transformer will be removed from service if there is a safety concern (too much rust) or potential environment damage (likely leak). If transformers are functioning properly, they are usually left in service. Most transformer replacements are driven by secondary factors such as the voltage conversion program or customer upgrade requirements.

The following is the aging of the pole mounted transformers, pad mounted transformers and PMH units. While this is tracked, NOTL Hydro relies more on the inspections for any replacement decisions.

Table 14: NOTL Hydro Transformers by Age

Age (Years)	Year Installed	
0-4	2018-2022	176
5-9	2013-2017	175
10-14	2008-2012	210
15-19	2003-2007	102
20-24	1998-2002	198
25+	2001 or earlier	1007
Unknown		155
Total		2023

NOTL Hydro also monitors the loading on its transformers. A summary of the loading on transformers for which we had a full years' data as of November 2022 is provided below.

Table 15: NOTL Hydro Transformers by Loading

Percentage Loading	# Transformers
> 150%	41
101-150%	151
51-100%	521
0-50%	989
Total	1702

The loading on the transformer is determined by aggregating the smart meter data for customers connected to that transformer. It is therefore comparing kwh data to kVa transformer ratings. The purpose of this analysis is therefore to identify transformers for investigation rather than to provide a list of transformers that need work.

The transformers with loadings over 100% are in the process of being investigated with the higher loaded transformers being investigated first. There are several reasons for a transformer to have a high loading ratio:

- The transformer could be truly overloaded and a change is recommended.
- The customers linked in the GIS system to the transformer could be incorrect. This data has been updated as part of the asset management program but there will still be errors in the GIS software. For safety reasons, this data is never relied upon without being checked in the field.
- The peaks could be momentary and non-recurring. In cases like this the transformer does not need to be replaced.

Wiring

NOTL Hydro tracks the wiring on its system by condition. The table summarizing their condition as of December 2022 is below.

Table 16: NOTL Hydro Wire by Condition

Wire Type	Condition (kms)					Total
	Excellent	Good	Poor	Critical	Unknown	
Primary OH	208.1	4.2	0.8	0	4.8	217.9
Primary UG	106.7	1.6	0	0	0.5	108.8
Secondary OH	144.6	7.4	1.6	3.8	0	157.4
Secondary UG	305.4	0.1	0.1	0	4.8	310.4
Total	764.8	13.3	2.5	3.8	10.1	794.5

The table summarizing their aging is also provided:

Table 17: NOTL Hydro Wire by Age

Age (Years)	Year Installed	Wire Length (km)				Total
		Primary OH	Primary UG	Secondary OH	Secondary UG	
0-4	2018-2022	7	5.7	5.4	17.1	35.2
5-9	2013-2017	18.8	1.7	10.5	6	37
10-14	2008-2012	11.6	13.2	11.4	35	71.2
15-19	2003-2007	9.3	4.2	4.7	23.8	42
20-24	1998-2002	3.5	0.3	1.3	21.1	26.2
25+	2001 or earlier	0	0.1	0.7	5.5	6.3
Unknown		167.7	83.6	123.4	201.9	576.6
Total		217.9	108.8	157.4	310.4	794.5

As can be seen, the age of most of the wire is unknown as was purchased from Ontario Hydro or was not tracked. Wire does not degrade much and as the inspections have determined over 95% of the wire to be in excellent condition this is not considered a significant issue. When wiring is an issue, such as in the underground network in Garrison Village, it is included in the evaluation of capital expenditures.

5.3.3 Asset Lifecycle Optimization Policies and Practices

As an LDC, NOTL Hydro is investing for the long-term. A such, NOTL Hydro tries to ensure its investments are at the right level and that its investments provide the greatest value for the expenditure.

In addition to the practices outlined with the processes and assets above, some of NOTL Hydro's lifecycle practices have been as follows:

- NOTL Hydro invests for the long-term and with reliability as the foremost concern. For instance, NOTL Hydro has oversized the transformers used for many decades even though this is theoretically inefficient and the transformers could be better sized to the load. This prudency has often been shown to have been effective as NOTL Hydro customers have increased their load in many areas with upgrades to their houses. This practice has not appeared to impact the line loss rate, where the inefficiency would show, as NOTL Hydro's line loss rate is the lowest in Niagara.
- As is noted in section 5.4.10, NOTL Hydro generally tries to reinvest in a manner that matches the lifecycle of the assets based on their depreciation. In any given year it is possible not to invest in asset replacement. However, in the long-term, this will result in poorer reliability and will necessitate much higher investment levels. It is best to invest steadily every year.
- NOTL Hydro is adaptable in its approach to capital expenditures. The most appropriate use of the capital is constantly evaluated and decisions can be made during a year if a better project arises. An example of this was the Garrison Village project in 2020. It was not originally planned but was added mid-year and the Gates St project was delayed for a year as replacing the direct buried underground wire which was causing outage issues was considered more important.

NOTL Hydro's asset life optimization policies, processes and tools are largely the same as those described in the 2019 DSP.

5.3.4 System Capability Assessment for Renewable Energy Generation

NOTL Hydro has over 160 embedded generators that are a mix of SOP, FIT, MicroFIT and Net Metering programs in its territory. This totals a connected embedded capacity of 6.1 MW. The connections vary in size from the 10 kW solar MicroFITS to a 2,200 kW hydro generation facility. Per capita, this may be one of the highest numbers of renewable energy connections in Ontario.

Table 18: Connected Renewable Generation

Generation Program	# Generators	Total Capacity (kW)
SOP	2	2,535
FIT	12	1,245
MicroFIT	145	1,450
Net Metering	10	823
Total	169	6,053

NOTL Hydro currently has 7 feeder lines; three from the York Station (MTS 1) and four from the NOTL Station (MTS 2). NOTL Hydro currently tracks the number of embedded generators on its feeders and analyzes the capacity of each feeder based on existing load and connected generation. The table below provides a summary of the connected load on each feeder and the remaining capacity. The capacity has been calculated using IEEE 1547 and the minimum load.

Table 19: Feeder Capacity to Connect Generation

STATION	YORK MTS1				NOTL MTS2		
FEEDER	M1	M2	M3	F1	F2	F3	F4
TOTAL CONNECTED GENERATION	2,006	690	2,225	862	359	0	505
REMAINING CAPACITY AVAILABLE	-6	504	1,071	442	1,077	95	703

As can be seen, one out of seven feeders is currently unable to connect any additional generation based on these calculations. Using these calculations, the only way additional generation could be connected to the feeders at capacity is if the generator installs a transfer trip. This is currently only required for generators with a capacity greater than 500 kW and is not economic for the smaller generators.

From 2018 to 2022, NOTL Hydro participated in a Government of Ontario Smart Grid Fund project to examine the impact of using a battery on a distribution feeder line. One of the objectives was to see if the battery could be used to increase the capacity of a feeder line. The project was technically successful and created some additional capacity on the feeder by charging the battery at peak generation times thereby creating load to offset the generation.

As part of the project, NOTL Hydro performed a detailed analysis of the M1 feeder comparing the load and the connected generation output on an hourly basis. This is a much more rigorous analysis than just comparing the lowest load, which is often at night, to the capacity of the generation, which is rarely achieved. This analysis determined that, at that time, rather than there being an excess generation of 691 kW on the feeder, there is actual the capacity for an additional 103 kW. This has now been reduced to -6 kW due to additional generation having been added.

NOTL Hydro updated all its feeder restrictions using this same analysis. These NOTL Hydro's feeder restrictions can be found on its website: https://www.notlhydro.com/learnandsave/self-generation/restricted-feeders/. Prior to this analysis, NOTL Hydro was showing three feeders at capacity; now there is only one.

As can be seen by the battery project, NOTL Hydro is interested in opportunities to expand the renewable energy generation capacity on its feeders. Other than additional load being added to the feeders, NOTL Hydro is not aware of any cost-effective means of adding capacity. However, NOTL Hydro is aware that IEEE 1547 is a guideline and was determined not with solar power but with other machinery being considered. There may be an opportunity to adjust these guidelines for solar power generation but these discussions will need to be wider than just NOTL Hydro.

One renewable generation activity NOTL Hydro would like to facilitate is community solar. Community solar projects are large solar installations in which local residents can share in the output as net metering customers even though they are not directly connected to the installation. With their larger size, community solar is more cost effective than solar installations at individual residences and they also allow households whose residence is not conducive to solar power to participate. While common in much of the US, community solar is not currently allowed in Ontario.

NOTL Hydro is not applying for the recovery of any costs specific to connecting renewable generation as part of this rate application.

There is no embedded distributor or host distributor so no constraints in that respect.

5.3.5 CDM Activities to Address System Needs

NOTL Hydro welcomes opportunities to provide CDM services to its customers if these will result in efficiencies or cost savings. NOTL Hydro significantly overachieved when LDCs had responsibilities for their own CDM activities. NOTL Hydro currently refers customers to the IESO centrally managed CDM programs.

NOTL Hydro currently has adequate transformation supply for the term of the DSP so there are no supply related capital plans that could be offset by CDM activities. NOTL Hydro has considered CDM programs for its customers but has not been able to identify any that achieve the goal or providing a net benefit. NOTL Hydro did try a specific agricultural CDM pilot back in 2014 but it was ultimately not successful. Should an opportunity be identified, NOTL Hydro will work with its customers to implement an effective and financially viable solution.

Therefore, at this time there are no CDM projects in the current planning process and NOTL Hydro is not applying for CDM funding through rates.

5.4 Capital Expenditure Plan (2019 – 2028)

5.4.1 Capital Expenditure Planning Process Overview

Risk Management

NOTL Hydro believes good management includes significant attention to risk management. The management of NOTL Hydro has been tasked by its Board of Directors with overseeing the operation of the utility. This means management must consider, assess, measure and plan for all nature of risks. The Capital Expenditure Plan has been developed with risk management considerations. Some examples of these include:

Financial liquidity risk – NOTL Hydro maintains a much lower debt-equity ratio than necessary. Should an opportunity or risk arise, NOTL Hydro will have the financial capacity to fund this risk or opportunity. The funding of the expansions of the transformation stations with loans from banks and the Town of NOTL is an example of this. The low and stable forecasted expenditures from 2024-2028 reflects this conservative approach.

Cyber-security – NOTL Hydro takes cyber-security risk very seriously. For example, the SCADA network has been completely isolated from the rest of the NOTL Hydro IT network. Should NOTL Hydro be the victim of a successful cyber attack the SCADA network should still be safe. This focus on cyber-security has led to lower capital expenditures and higher OM&A as NOTL Hydro has determined that outsourced or cloud-based solutions offer better security and have a lower total cost. Examples of this include:

- The CIS and billing system remains outsourced to UCS. As NOTL Hydro does not own the software, expenditures to update it cannot be capitalized as would be the case if kept inhouse.
- The management of firewalls and other protective software is outsourced to a local IT specialist. These services become an operational cost rather than servers and software which is capital to NOTL Hydro.
- NOTL Hydro uses third party services to provide customers with access to their account data. These include Customer Connect and Utilismart. If these services were brought in-house there would be reduced OM&A and higher capital and an overall higher total cost. NOTL Hydro notes that the Utilismart service was not accepted by the OEB as a factor in the proposed increase in OM&A in its 2019 Cost of Service decision but NOTL Hydro thought it important to provide this service to customers regardless.

Employees – NOTL Hydro works hard to create a culture in which employees are engaged and motivated to serve their customers. This improves customer service and results in a lower long-run total cost. No matter how successful this might be, as a small company, NOTL Hydro is always at risk to the best person leaving. Succession plans are maintained and cross-training provided wherever possible. In 2020-2021 NOTL Hydro invested in a new boardroom and kitchen facilities to improve the employee experience and meet the new pandemic requirements.

Safety – Safety is the biggest risk an LDC faces. NOTL Hydro works hard to keep safety the highest priority at all times. The 2023 investment in a new garage will improve safety by providing more garage space and allow some inventory to be brought indoors.

These are just a few examples. Other risks include regulatory, political, catastrophes, changing technology, digitisation, transformer failures, weather, distributed generation, M&A, rising interest rates, terrorism, labour disruption, employees being poached, fire, currency, communication links, supplier disruptions, the rising cost of electricity, etc. NOTL Hydro reports to the Board of Directors on the various risks in a regular fashion.

Customer Engagement

NOTL Hydro held an open house on September 24, 2019 to discuss its ongoing voltage conversion and undergrounding project in the Old Town and the planned remainder of the conversions (Appendix H). Over 70 customers attended. While some concern was expressed with the disruptions at the time the capital work is being performed, the overall reaction was one of support. These include:

- One customer whose street had been converted talked positively about how NOTL Hydro kept its promises on how and when it would be done.
- Another customer who, like many of our customers, had moved from Toronto a number of years ago, expressed how he had been converted from initial skepticism as to how a small town like Niagara-on-the-Lake could have its own LDC to one of full support.
- Customers were asked to comment on the timing of work on their street and several customers on Gate St. requested that the work be brought forward. This was accommodated.

An open house was held on March 8, 2023 to give ratepayers an opportunity to comment on the proposed plan including the rate increase. Turn-out was low at five and those that did come were generally more interested in discussing electric vehicles.

An open house is being planned for July to discuss the upcoming work on the firelanes. A sizable attendance is expected for this.

Five Years Forecast

NOTL Hydro has developed its capital expenditure plan on the expectation of slowing growth in the number of customers, load and demand in a manner largely consistent with the past five years. This includes:

- There will be few new subdivision developments so the residential growth will be slower. Much of Niagara-on-the-Lake is greenbelt so room for growth is limited. The one exception is the Glendale urban area which is planned for high density growth but this has not yet started and is not anticipated to start over the next five years.
- There is no planned replication of the Outlet Mall so small business class is expected to be limited;
- The eventual demand of the new Large Use customer is not known. The process NOTL Hydro has established for managing this uncertainty by way of the variance account means no revenue growth for NOTL Hydro.

Climate change will create hotter summers and colder winters though these will vary from year to year. This is expected to increase demand. Offsetting this, conservation measures by customers, with and without the support of NOTL Hydro, will reduce demand. NOTL Hydro expects the installation of renewable energy in the Town to continue slowly as solar installation costs are still not attractive compared to the cost of power. Any that do happen will be net metering projects assuming no further changes in Government policy. NOTL Hydro will continue to look for ways to accommodate these on the NOTL Hydro grid and may need to make more investments to support renewable generation. NOTL Hydro will continue to invest in smart grid products and functionality to make its grid more responsive and flexible.

5.4.2 Capital Expenditure Planning Prioritization

The following is a summary of the process NOTL Hydro uses to prioritize investments on its system.

System Access – System Access projects are driven by customer demands. These are always given a high priority. NOTL Hydro works with developers and known customers who are expanding to plan the investments so that they can be properly managed.

System Renewal – NOTL Hydro believes it is important to maintain a constant investment in its system. NOTL Hydro therefore budgets an annual investment that, in aggregate, is relatively consistent from year to year. The exceptions are larger investments, like in Virgil in 2023, whose timing is driven by third party projects where the overall benefit to the customer is considered to be higher than if the opportunity created by the project was ignored.

System Service – System Service investments are viewed as investments to improve the system and improve the service to customers. This includes the investments in transmission stations, the SCADA system and the smart grid technologies. System service investments are prioritized on a case-by case basis and so tend to vary considerably from year to year.

General Plant – General Plant investments are made based on maintaining a level of service. Whether it is new trucks, tools, IT equipment or software systems, NOTL Hydro needs a level of investment capacity in order to provide the needed service to customers. As such, general plant investments will vary from year to year depending on the needs and the external influences driving change.

5.4.3 Capital Expenditure Planning for Renewable Generation

NOTL Hydro allows renewable generation to be connected to the system on a first-come, first-served basis. Once a feeder has reached capacity then no further generation can be connected until NOTL Hydro can determine how to expand the capacity. NOTL Hydro does not own any distributed generation. NOTL Hydro has not had to make any recent investments to accommodate renewable generation.

5.4.4 Non-Distribution System Opportunities

NOTL Hydro's system does not have many capacity constraints so opportunities for non-distribution alternatives are limited. NOTL Hydro did temporarily install a battery to assess the possibility of expanding its capacity for renewable generation as part of a Smart Grid

Fund project. While this project was technically successful it was not cost effective so was discontinued.

5.4.5 CDM Opportunities

NOTL Hydro is not aware of any rate funded CDM opportunities in Niagara-on-the-Lake but will investigate them if they become known. To be fair to all customers it will be important to have a very strong cost/benefit analysis on any potential opportunities.

5.4.6 Non-Distribution Activities

NOTL Hydro does not and has not included any non-distribution expenditures in its Capital Expenditure Plan.

5.4.7 Impact of Capital Expenditure Plan on Operating & Maintenance Costs

The impact of a Capital Expenditure Plan on operating and maintenance costs can vary in a variety of ways.

- Insufficient capital spending can lead to increased maintenance costs if more than average repairs are needed to keep the system functional. NOTL Hydro's approach of a consistent annual spend on system renewal should limit unnecessary O&M costs.
- Growth leads to increased O&M as new assets will require ongoing maintenance.
- Investments in new technologies leads to increased O&M. For instance, the installing of smart grid technologies such as switches and reclosures increases ongoing SCADA costs as these new devices must be monitored.
- Changes in standards usually leads to increased O&M costs. For instance, protection and control requirements at transformation stations have increased over the years leading to higher O&M and capital costs.
- Changes in regulations also usually leads to higher O&M costs. For instance, the replacement of interval meters with smart meters has lead to higher meter data management costs.

- Accounting changes also impact the evaluation of alternatives between capital and O&M costs. Costs such as executive time and down time of capital labour (training, safety, vacation) which under GAAP would have been capital are now O&M under IFRS.

NOTL Hydro does look at alternative options when determining its capital investments. The biggest example of this is the use of cloud based computing options for the CIS and other software systems. NOTL Hydro could have purchased these systems resulting in lower O&M and higher capital costs. However, the total cost is lower with cloud based systems so NOTL Hydro went with this approach even though it results in higher O&M costs.

5.4.8 Capital Expenditure Planning Summary

The following copy of Appendix 2-AB summarizes the capital expenditure from 2019-2023 as compared to the Board approved rate submission from 2019. The proposed expenditures from 2024-2028 are also provided.

Table 20: Capital Expenditure Summary (2019-2028)

Niagara-on-the-Lake Hydro Inc.
Appendix 2-AB - Table 2 - Capital Expenditure Summary from Chapter 5 ConsolidatedDistribution System Plan Filing Requirements

First year of Forecast Period:

CATEGORY	**Historical Period** (previous plan[1] & actual)																**Forecast Period** (planned)				
	2018	**2019**			**2020**			**2021**			**2022**			**2023**			**2024**	**2025**	**2026**	**2027**	**2028**
	Var	**Plan**	**Actual[2]**	**Var**	**Plan**	**Actual[2]**	**Var**	**Plan**	**Actual[2]**	**Var**	**Plan**	**Actual[2]**	**Var**	**Plan**	**Actual[2]**	**Var**					
	%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access	1269.7%	836	1,625	94.5%	851	530	(37.8%)	842	1,033	22.6%	854	872	2.1%	873	841	(3.7%)	770	730	730	730	730
System Renewal	25.2%	972	792	(18.5%)	1,160	1,296	11.7%	935	795	(15.0%)	935	288	(69.2%)	969	1,550	60.0%	1,055	1,080	1,105	1,130	1,155
System Service	177.5%	3,832	8	(99.8%)	98	2,976	2945.8%	100	725	621.2%	130	31	(76.3%)	106	100	(5.9%)	170	142	175	140	140
General Plant	624.7%	84	193	130.3%	72	114	58.8%	149	560	276.7%	134	203	51.8%	535	996	86.3%	556	237	54	81	678
TOTAL EXPENDITURE	162.6%	5,724	2,617	(54.3%)	2,181	4,915	125.4%	2,027	3,112	53.6%	2,053	1,394	(32.1%)	2,483	3,487	40.5%	2,551	2,189	2,064	2,081	2,703
Capital Contributions	--	(787)	(1,474)	87.3%	(656)	(359)	(45.3%)	(667)	(657)	(1.6%)	(679)	(610)	(10.2%)	(694)	(638)	(8.1%)	(575)	(575)	(575)	(575)	(575)
Net Capital Expenditures	104.7%	4,936	1,143	(76.8%)	1,524	4,557	198.9%	1,359	2,456	80.7%	1,374	784	(42.9%)	1,789	2,849	59.3%	1,976	1,614	1,489	1,506	2,128
System O&M	8.4%	1,161	1,145	(1.4%)	1,161	1,128	(2.9%)	1,161	1,241	6.9%	1,161	1,255	8.1%	1,161	1,270	9.3%	1,306	1,306	1,306	1,306	1,306

The following copy of Appendix 2-AA summarizes in more detail the capital expenditure from 2019-2023 and the proposed expenditures from 2024-2028 are also provided

Table 21: Capital Expenditure Detail (2019-2028)

Niagara-on-the-Lake Hydro Inc.
Appendix 2-AA Capital Projects Table

Reporting Basis										
Projects	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
System Access										
Subdivisions	$392,863	$16,605	$100,162	$0	$65,000	$50,000	$50,000	$50,000	$50,000	$50,000
Customer Projects	$980,093	$138,692	$562,799	$425,568	$405,746	$350,000	$350,000	$350,000	$350,000	$350,000
New connections - overhead	$10,768	$16,536	$34,808	$43,867	$15,000	$15,000	$15,000	$15,000	$15,000	$15,000
New Connections - underground	$170,074	$199,127	$239,102	$353,614	$275,000	$275,000	$275,000	$275,000	$275,000	$275,000
Meters	$70,923	$142,210	$96,086	$49,076	$80,000	$80,000	$40,000	$40,000	$40,000	$40,000
Municipal Relocations	$0	$16,602	$0	$0	$0	$0	$0	$0	$0	$0
Sub-Total System Access - Gross Additions	$1,624,721	$529,772	$1,032,956	$872,125	$840,746	$770,000	$730,000	$730,000	$730,000	$730,000
Contributed Capital										
Subdivisions	($368,613)	($1,664)	($79,039)	$12,072	($32,500)	($25,000)	($25,000)	($25,000)	($25,000)	($25,000)
Customer Projects	($968,512)	($112,284)	($354,804)	($435,023)	($405,746)	($350,000)	($350,000)	($350,000)	($350,000)	($350,000)
New connections - overhead	($5,511)	($13,701)	($11,751)	($20,335)	($5,000)	($5,000)	($5,000)	($5,000)	($5,000)	($5,000)
New Connections - underground	($131,362)	($119,938)	($150,405)	($166,490)	($195,000)	($195,000)	($195,000)	($195,000)	($195,000)	($195,000)
Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Municipal Relocations	$0	($16,602)	$0	$0	$0	$0	$0	$0	$0	$0
Sub-Total System Access - Contributed Capital	($1,473,998)	($264,189)	($596,000)	($609,776)	($638,246)	($575,000)	($575,000)	($575,000)	($575,000)	($575,000)
Sub-Total System Access	**150,723**	**265,583**	**436,957**	**262,348**	**202,500**	**195,000**	**155,000**	**155,000**	**155,000**	**155,000**
System Renewal	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Overhead	$748,862	$362,323	$713,186	$164,372	$525,000	$555,000	$555,000	$555,000	$555,000	$555,000
Underground	$43,204	$933,743	$81,708	$123,762	$1,025,000	$500,000	$525,000	$550,000	$575,000	$600,000
Underground - Additional Virgil	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Sub-Total System Renewal - Gross Additions	$792,067	$1,296,066	$794,894	$288,134	$1,550,000	$1,055,000	$1,080,000	$1,105,000	$1,130,000	$1,155,000
Contributed Capital										
Overhead	$0	$0	($37,160)	$0	$0	$0	$0	$0	$0	$0
Underground	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Underground - Additional Virgil	$0	$0	$0	$0		$0	$0	$0	$0	$0
Sub-Total System Renewal - Contributed Capital	$0	$0	($37,160)	$0	$0	$0	$0	$0	$0	$0
Sub-Total System Renewal	**792,067**	**1,296,066**	**757,734**	**288,134**	**1,550,000**	**1,055,000**	**1,080,000**	**1,105,000**	**1,130,000**	**1,155,000**
System Service	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Transformer stations	$0	$2,334,812	$635,127	$27,618	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000
Battery	$0	$497,510	$0	$0	$0	$0	$0	$0	$0	$0
Integration	$0	$0	$0	$0						
SCADA / switches	$7,523	$143,442	$89,529	$3,136	$95,000	$165,000	$137,000	$170,000	$135,000	$135,000
Sub-Total System Service - Gross Additions	$7,523	$2,975,763	$724,655	$30,754	$100,000	$170,000	$142,000	$175,000	$140,000	$140,000
Contributed Capital										
Transformer stations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Battery	$0	($94,520)	($23,359)	$0	$0	$0	$0	$0	$0	$0
Integration	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SCADA / switches	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Sub-Total System Service - Contributed Capital	$0	($94,520)	($23,359)	$0	$0	$0	$0	$0	$0	$0
Sub-Total System Service	**7,523**	**2,975,763**	**724,655**	**30,754**	**100,000**	**170,000**	**142,000**	**175,000**	**140,000**	**140,000**
General Plant	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Buildings and fixtures	$47,830	$3,265	$359,932	$8,186	$500,000	$13,441	$43,695	$15,000	$15,270	$15,548
Office equipment	$2,995	$6,396	$1,972	$10,561	$6,000	$6,000	$6,000	$7,000	$7,000	$7,000
Hardware	$36,984	$19,706	$42,081	$10,797	$8,550	$17,911	$18,000	$18,000	$18,000	$18,000
Software	$0	$26,457	$42,903	$9,115	$12,947	$57,426	$88,000	$8,240	$33,487	$30,000
Rolling stock	$84,178	$39,448	$104,993	$81,513	$40,000	$0	$75,000	$0	$0	$0
Rolling stock - Line Trucks	$0	$0	$0	$67,703	$423,000	$455,000	$0	$0	$0	$600,000
Major Tools	$20,885	$18,604	$7,818	$15,277	$6,000	$6,000	$6,000	$6,000	$7,000	$7,000
Sub-Total General Plant - Gross Additions	$192,872	$113,876	$559,699	$203,152	$996,497	$555,778	$236,695	$54,240	$80,757	$677,548
Contributed Capital										
Buildings and fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Office equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Hardware	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Software	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Rolling stock	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Rolling stock - Line Trucks	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Major Tools	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Sub-Total General Plant - Contributed Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Sub-Total General Plant	**192,872**	**113,876**	**559,699**	**203,152**	**996,497**	**555,778**	**236,695**	**54,240**	**80,757**	**677,548**
Total Capital Expenditures	**$2,617,182**	**$4,915,478**	**$3,112,205**	**$1,394,164**	**$3,487,243**	**$2,550,778**	**$2,188,695**	**$2,064,240**	**$2,080,757**	**$2,702,548**

5.4.9 Historical Capital Expenditure Analysis

The following tables compare the actual or projected gross capital expenditures for 2019-2023 to those projected back in 2018. Where the variance exceeds the materiality amount of $10k, explanations are provided.

The table below measures the net capital expenditures approved in the 2019 Cost of Service against actual expenditures for 2019 to 2023 as per the fixed asset continuity schedule. It is net of contributions.

Table 22: Budgeted vs Actual (2019-2023)

Year	Actual	2019 Cost of Service
2019	2,101	4,936
2020	3,147	1,524
2021	1,937	1,359
2022	2,094	1,374
2023	2,237	1,789
Total	**11,516**	**10,982**

Though there will have been variation year-to-year in the actual expenditures as NOTL Hydro adjusted to changing conditions, particularly the pandemic, the total expenditures over the 5 years are within 5% of what was planned.

2019

Table 23: 2019 Capital Expenditure

Niagara-on-the-Lake Hydro Inc. Capital Expenditure Plan Variance Analysis				
	Actual 2019	2019 COS 2019	Variance $	Variance %
System Access				
Subdivisions	389,650	125,000	(264,650)	-212%
Customer Projects	276,624	360,500	83,876	23%
New connections - overhead	10,768	15,000	4,232	28%
New Connections - underground	168,641	275,000	106,359	39%
Meters	78,791	60,000	(18,791)	-31%
Municipal Relocations	-	-	-	
System Access Total	924,474	835,500		
System Renewal				
Overhead	485,676	637,000	151,324	24%
Underground	304,649	335,000	30,351	9%
System Renewal Total	790,325	972,000		
System Service				
Transformer stations	-	5,000	5,000	100%
Battery	237,207	442,340	205,133	46%
SCADA / switches / Smart grid	76,100	80,000	3,900	5%
System Service Total	313,307	527,340		
General Plant				
Buildings and fixtures	47,830	23,150	(24,680)	-107%
Office equipment	2,995	5,000	2,005	40%
Hardware	36,984	15,450	(21,534)	-139%
Software	-	5,150	5,150	100%
Rolling stock	84,178	30,000	(54,178)	-181%
Rolling stock - Line Trucks	-	-	-	
Locate services	-		-	
Underground services			-	
Major Tools	20,885	5,000	(15,885)	-318%
General Plant Total	192,872	83,750		
Recurring total	2,220,978	2,418,590	-	-
Transformer	1,319,764	3,305,000	1,985,236	60%
Total expenditure	3,540,742	5,723,590		

System Access - 2019

System access projects are all 100% driven by customer requirements with the exception of meters. In 2019, there were three subdivision each over $100k. Customer projects were all smaller projects with no single projects over $30k. New connections are volume driven so vary based on individual activities. Meter costs were higher than forecast as 2019 was the first year of meter reverifications with Measurement Canada.

System Renewal – 2019

Both the overhead and underground system renewal capital expenditure plans are a mix of the voltage conversion projects and regular ongoing small projects. The voltage conversion projects are multi-year but broken down into annual projects. The actual projects selected will vary from year to year.

For underground work the plan was for $60k of regular capital work and $275k for the voltage conversion which was along Johnson Street and an extension of the work done in 2018. The actual costs were $48k for the regular work and $256k for Johnson Street. For overhead work the plan was $240k in pole replacements and regular work and $397k in voltage conversion on Line 3 and Warner Road. Actual costs were $180k in voltage conversion on Line 3 and Line 1 and $306k in pole replacements and regular work. The pole replacements were a combination of individual poles and an 11 pole section of Lakeshore Rd where a stretch of line were fully replace. The pole replacements were driven by the results of the pole testing. Line 1 was substituted for Warner Rd as Warner Rd work would require Niagara Escarpment Commission approval and this was delayed so as to jointly work with the Town of Niagara-on-the-Lake in a future year.

System Service - 2019

The battery project was not fully completed in 2019 so all only $237k of the $442k plan was spent. See below for more detail.

General Plant – 2019

A camera and security system was installed for $25k in 2019 increasing the expenditure on the building. More desktop computers were purchased in 2019 than planned as part of cyber security management. Two new pick-up trucks were purchased in 2019. New chainsaws were ordered after a safety review of tools.

Transformer – 2019

The new transformer installation was not completed in 2019 so only $1,320k of $3,305k was spent. See section 5.4.10 below for more detail.

2020

Table 24: 2020 Capital Expenditure

Niagara-on-the-Lake Hydro Inc. Capital Expenditure Plan Variance Analysis				
	Actual 2020	2019 COS 2020	Variance $	Variance %
System Access				
Subdivisions	13,490	130,000	116,510	90%
Customer Projects	382,927	371,315	(11,612)	-3%
New connections - overhead	16,536	15,000	(1,536)	-10%
New Connections - underground	200,561	275,000	74,439	27%
Meters	142,210	60,000	(82,210)	-137%
Municipal Relocations	-	-	-	
System Access Total	755,724	851,315		
System Renewal				
Overhead	345,788	560,000	214,212	38%
Underground	631,099	425,000	(206,099)	-48%
System Renewal Total	976,887	985,000		
System Service				
Transformer stations	-	5,000	5,000	100%
Battery	147,305	-	(147,305)	
SCADA / switches / Smart grid	35,170	92,700	57,530	62%
System Service Total	182,475	97,700		
General Plant				
Buildings and fixtures	269,360	10,500	(258,860)	-2465%
Office equipment	6,396	5,000	(1,396)	-28%
Hardware	19,706	15,914	(3,792)	-24%
Software	39,978	5,305	(34,673)	-654%
Rolling stock	6,970	30,000	23,030	77%
Rolling stock - Line Trucks	-	-	-	
Locate services	47,903		(47,903)	
Underground services			-	
Major Tools	3,178	5,000	1,822	36%
General Plant Total	393,491	71,719		
Recurring total	2,308,577	2,005,734	-	-
Transformer	1,219,784	-	(1,219,784)	
Total expenditure	3,528,361	2,005,734		

System Access - 2020

System access projects are all 100% driven by customer requirements with the exception of meters. In 2020, there were no new subdivisions, just continued payments on older subdivisions. Customer projects were all smaller projects with no single projects over $40k. New connections are volume driven so vary based on individual activities. Meters were much higher than forecast due to meter reverifications with Measurement Canada and the replacement of some meters as that was cheaper in the long run than reverifying.

System Renewal – 2020

Overall, the system renewal expenditures were within 1% and $10k of plan.

The underground expenditures was higher than planned as the decision was made to replace one third of the underground system in Garrison Village at a cost of $460k. The underground system in Garrison Village was already 27.6 kV but was direct buried and was incurring a high number of outages. It was felt that replacement of this wiring could not be delayed. There is less rush for the remaining two thirds but they will be done within a reasonable time. Voltage conversion on Johnson Street continued with another $133k of work but Gate Street was delayed for a year. Regular underground work cost $39k.

Less than normal overhead voltage work was performed in 2020 though part of Line 2 was converted. There were a number of reasons for this including not wanting to commit internal resources during the uncertainty of the pandemic, wanting to limit expenditures due to the expected cost of the underground work in Garrison Village and there being no shortage of pole replacement and regular work. A section of Line 4 was replaced due to the condition of the poles for $68k with the rest of the expenditures being for regular work.

System Service – 2020

The remainder of the battery project was completed for $147k. See section 5.4.10 below for more detail. 3 new switches were purchased in 2020 but none were installed though some preparatory engineering work was performed.

General Plant – 2020

Significant renovations were made to the general office in 2020 at a cost of $266k; largely due to the pandemic. The old boardroom was very small and all the staff could only be in it if they sat shoulder to shoulder along the walls. Even just a Board meeting filled the room to over capacity. There was no audio-visual capacity to accommodate virtual meetings. The new boardroom is more than double in size allows for proper spacing and ventilation and had modern audio-visual. The old kitchen was also too small for anybody to eat in it; everyone would eat at their desk. The new kitchen has plenty of eating space and facilitates conversation. It also has a water unit with cooled and filtered water thereby eliminating the previous needs for bottled water and water jugs. Much of the building lighting was also updated to LED lights and no touch switches were installed. The existing building dates from the 1980's and was in need of some renovations. By adapting existing spaces the cost of the renovation was kept down.

Software was higher than planned due to the implementation of a new payroll system for $12k and the upgrade of the SCADA system for $15k. Only a small trailer was purchased in 2020 so the rolling stock expenditure was lower than planned. However, a new pick-up truck and other equipment was purchased as part of bringing locate services in-house. In 2020, a Locater was added. The cost of the outside service provider was growing and the backlog of locates was very high affecting performance. Locates were often six weeks or more behind schedule. This was affecting customers and productivity as certain work could not commence without the locates. Demand for locates was also rising due to the increased installations of broadband services by the telecom companies. The per unit cost of a locate was increasing and expected to continue to increase.

The Town of Niagara-on-the-Lake was having the same issue with their water, sewer and streetlight locates. Individually, neither NOTL Hydro or the Town had enough volume to justify hiring a Locator but together the volume was sufficient. The Locator was hired by NOTL Hydro but all his time and costs are charged on a full cost basis to the affiliate company. NOTL Hydro benefits due to the coverage of some overhead costs. The rate charged by the affiliate is also lower than that charged by the previous service provider so NOTL Hydro and the Town have lower costs.

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Transformer – 2020

A further $1,220k was spent on the transformer project. The 83 MVA transformer was energized at York Station. See section 5.4.10 below for more detail.

2021

Table 25: 2021 Capital Expenditure

Niagara-on-the-Lake Hydro Inc. Capital Expenditure Plan Variance Analysis				
	Actual 2021	2019 COS 2021	Variance $	Variance %
System Access				
Subdivisions	72,915	130,000	57,085	44%
Customer Projects	292,757	382,454	89,697	23%
New connections - overhead	34,808	15,000	(19,808)	-132%
New Connections - underground	253,845	275,000	21,155	8%
Meters	96,086	40,000	(56,086)	-140%
Municipal Relocations	-	-	-	
System Access Total	750,411	842,454		
System Renewal				
Overhead	796,254	510,000	(286,254)	-56%
Underground	437,930	425,000	(12,930)	-3%
System Renewal Total	1,234,184	935,000		
System Service				
Transformer stations	51,260	5,000	(46,260)	-925%
Battery	(23,359)	-	23,359	
SCADA / switches / Smart grid	85,345	95,482	10,137	11%
System Service Total	113,246	100,482		
General Plant				
Buildings and fixtures	93,837	10,725	(83,112)	-775%
Office equipment	1,972	6,000	4,028	67%
Hardware	42,081	16,391	(25,690)	-157%
Software	47,086	75,464	28,378	38%
Rolling stock	104,993	35,000	(69,993)	-200%
Rolling stock - Line Trucks	-	-	-	
Locate services			-	
Underground services			-	
Major Tools	7,818	5,000	(2,818)	-56%
General Plant Total	297,787	148,580		
Recurring total	2,395,628	2,026,516	-	-
Transformer	188,913	-	(188,913)	
Total expenditure	2,584,541	2,026,516		

System Access - 2021

System access projects are all 100% driven by customer requirements with the exception of meters. In 2021, there was one new subdivision and continued payments on four existing subdivisions. Customer projects were all smaller projects with only one project over $30k. New connections are volume driven so vary based on individual activities. Meters were higher than forecast due to meter reverifications with Measurement Canada.

System Renewal – 2021

In aggregate, the excess spend over plan was due to a $252k purchase of additional transformers made in advance of expected price increases. It was not known at this time that this would also help manage future supply chain issues.

Overhead projects included a voltage conversion along Lakeshore Rd for $366k, a start of the voltage conversion in the Concession 6 and Warner Rd areas for $37k and a rebuild of part of Line 8 for $85k due to the poor condition of the poles in that stretch. Regular work accounted for $206k.

Underground work included a start on the voltage conversion on Gate St for $143k, a small voltage conversion project on Dorchester for $47k, initial engineering on the Virgil underground project for $55k and regular work for $55k.

System Service – 2021

For the station work, the breakers for a new feeder line was installed at York station to prepare for future growth now that there is a larger transformer at that station. The credits for the battery project reflect the final payments from the Ministry of Energy. Two new automated switches and one reclosure were installed in 2021 as part of the continued grid modernization of the system supervisory equipment.

General Plant – 2021

The $94k spent on the building was the completion of the renovations from 2020. The $42k of hardware was for the purchase of new computers to facilitate the working from home of employees when required by provincial mandates. Software spending was under budget as much of the work was completed in 2020. Hardware and software spending will vary from year to year due to timing of projects. A new pole trailer and a new pick-up truck were purchased in 2021.

Transformer – 2021

The final expenditure on the transformer project in 2021 saw the energization of the 41.7 MVA transformer that had been moved from York Station and that replaced an old 25 MVA transformer at the NOTL Station. More details are provided in section 5.4.10 below.

2022

Table 26: 2022 Capital Expenditure

Niagara-on-the-Lake Hydro Inc. Capital Expenditure Plan Variance Analysis				
	Actual 2022	2019 COS 2022	Variance $	Variance %
System Access				
Subdivisions	12,072	130,000	117,928	91%
Customer Projects	739,292	393,928	(345,364)	-88%
New connections - overhead	43,867	15,000	(28,867)	-192%
New Connections - underground	353,614	275,000	(78,614)	-29%
Meters	49,076	40,000	(9,076)	-23%
Municipal Relocations	-	-	-	
System Access Total	1,197,920	853,928		
System Renewal				
Overhead	529,951	510,000	(19,951)	-4%
Underground	656,146	425,000	(231,146)	-54%
System Renewal Total	1,186,097	935,000		
System Service				
Transformer stations	52,958	25,000	(27,958)	-112%
Battery	-	-	-	
SCADA / switches / Smart grid	-	105,000	105,000	100%
System Service Total	52,958	130,000		
General Plant				
Buildings and fixtures	8,186	12,957	4,771	37%
Office equipment	10,561	6,000	(4,561)	-76%
Hardware	10,797	16,883	6,086	36%
Software	12,251	57,000	44,749	79%
Rolling stock	-	35,000	35,000	100%
Rolling stock - Line Trucks	-	-	-	
Locate services	-		-	
Underground services	160,834		(160,834)	
Major Tools	3,659	6,000	2,341	39%
General Plant Total	206,287	133,840		
Recurring total	2,643,261	2,052,768	-	-
Transformer	-	-	-	
Total expenditure	2,643,261	2,052,768		

System Access - 2022

System access projects are all 100% driven by customer requirements with the exception of meters. In 2022, there were continued payments on four existing subdivisions. Customer projects included three large projects: a new small development, some work for Bell for their fibre lines and work for the potential crypto mining customer. The capital expenditure was much higher than usual though offset by a similar increase in capital contributions. New connections are volume driven so vary based on individual activities. Meters were higher than forecast due to meter reverifications with Measurement Canada.

System Renewal – 2022

Overhead projects were close to plan and included the voltage conversion in the Concession 6 and Warner Rd areas for $168k, voltage conversion in the Concession 6 and Line 1 area for $48k, various pole replacements for $56k and new transformers for $46k. Regular work accounted for $31k.

Most of the underground work was for the voltage conversion on Gate St for $463k. This project was larger than a normal underground voltage conversion as was in response to requests from customers at the open house in 2019. It was also a challenge as NOTL Hydro was trying a new contractor which did not go well. Other expenditures included further engineering on the Virgil underground project for $22k, new transformers for $92k and regular work for $55k.

System Service – 2022

No new switches were installed in 2022. NOTL Hydro will often adjust its expenditures in this category depending on the expenditures in the system renewal projects as compared to plan. Some capital work on the NOTL Station that was originally planned for 2023 was moved forward when the station needed to be taken offline for the month of November as Hydro One needed to perform maintenance on their transmission line.

General Plant – 2022

NOTL Hydro's CIS and billing system and the new outage notification system are cloud based so any expenditures on these systems are operating costs under IFRS. Software capital expenditures are thus below plan. The pole trailer planned for 2022 had already been purchased so no new rolling stock expenditures were made in 2022 other than for underground services. In 2022, two new underground service staff were hired and a pick-up truck and an excavator were purchased for a total of $160k. This decision was made for a number of reasons:

- The contractor who provided this service previously was going bankrupt and other service providers did not have the flexibility and response times needed as were not as local.
- By bringing this service in-house, NOTL Hydro was able to improve service levels as the staff could be more easily directed to the jobs required.
- Having these skills inhouse provides greater flexibility in adapting to the needs of our customers.
- NOTL Hydro now has enough customer and internally driven work to keep this crew fully occupied.
- The overall cost on an hourly basis was lower resulting in savings.

The only real downside was the IFRS requirement to book any time not of customer jobs (training, etc.) to operating costs while with an outside service all the costs would be capital.

2023

Table 27: 2023 Capital Expenditure

Niagara-on-the-Lake Hydro Inc. Capital Expenditure Plan Variance Analysis				
	Actual 2023	2019 COS 2023	Variance $	Variance %
System Access				
Subdivisions	65,000	137,000	72,000	53%
Customer Projects	405,746	405,746	-	0%
New connections - overhead	15,000	15,000	-	0%
New Connections - underground	275,000	275,000	-	0%
Meters	80,000	40,000	(40,000)	-100%
Municipal Relocations	-	-	-	
System Access Total	840,746	872,746		
System Renewal				
Overhead	525,000	535,000	10,000	2%
Underground	1,025,000	434,000	(591,000)	-136%
System Renewal Total	1,550,000	969,000		
System Service				
Transformer stations	5,000	5,000	-	0%
Battery	-	-	-	
SCADA / switches / Smart grid	95,000	101,296	6,296	6%
System Service Total	100,000	106,296		
General Plant				
Buildings and fixtures	500,000	98,195	(401,805)	-409%
Office equipment	6,000	6,000	-	0%
Hardware	8,550	17,389	8,839	51%
Software	12,947	7,210	(5,737)	-80%
Rolling stock	-	-	-	#DIV/0!
Rolling stock - Line Trucks	423,000	400,000	(23,000)	
Locate services	-		-	
Underground services	40,000		(40,000)	
Major Tools	6,000	6,000	-	0%
General Plant Total	996,497	534,794		
Recurring total	3,487,243	2,482,836	-	-
Transformer	-	-	-	
Total expenditure	3,487,243	2,482,836		

2023 is still in progress so this analysis is based on planned activities, adjusted for any work to-date, as compared to what was planned for 2023 back in 2018.

System Access - 2023

System access projects are all 100% driven by customer requirements with the exception of meters. In 2023, there is one new subdivision expected along with minor payments on existing subdivisions. Customer projects has been estimated based on recent history though that will change with customer demand; particularly by the potential crypto mining customer. New connections are volume driven so vary based on individual activities. These have been estimated at plan. Meters are expected to be higher than forecast due to meter reverifications with Measurement Canada.

System Renewal

The planned overhead expenditures levels are largely consistent with than planned in 2018. The voltage conversion project on Concession 6 between Line 1 and Line 2 will continue. In addition, there are three line replacements driven by asset management testing. These are Line 3 between Concession 1 and the Niagara Parkway, Line 1 between Concession 1 and the Niagara Parkway and Carlton between Stewart Rd and Seaway Haulage Rd.

The only planned project in the annual underground spend is the Highway 55 redevelopment located in Virgil. Virgil is an urban area with significant growth around the Niagara Stone Rd (Highway 55) corridor which flows through it. Most of the tourist traffic to Niagara-on-the-Lake flows through Virgil. As a result, a growing number of businesses have been established in Virgil catering to both the tourist and local trade and this specific section is considered highly urbanized. NOTL Hydro plans to move its infrastructure along Niagara Stone Rd underground consistent with the work that is being done in the Old Town and was previously done in Queenston and is done in many urban areas in Ontario.

The timing is being driven by the much larger project involving both the Region of Niagara and the Town of Niagara-on-the-Lake in redeveloping the infrastructure in this area. This larger project was originally conceived over ten years ago and the environmental assessment was completed in 2013. At that time the Board of NOTL Hydro made it own decision and committed to moving the hydro lines underground to take advantage of the synergies of doing so at the same time as all the other construction. Unfortunately, the whole project has been delayed numerous times but is now finally scheduled for 2023. A public notice of this has been attached as Appendix I. The forecast cost includes the civil work of $604k which is the NOTL Hydro share of the work done under the contract with the Region of Niagara. Doing the project at this time shares this cost resulting in a significant savings as compared to if NOTL Hydro were to do this on its own and, more importantly, reduces the aggravation to the residents and businesses of Niagara-on-the-Lake with only the one interruption.

NOTL Hydro's normal practice would be to split a project like this over two years as is done in the Old Town and as is consistent with the recommendation contained in the 2019 Cost of Service Decision. Unfortunately, the timing is being driven by the larger project so the full costs are being incurred in the limited project timeline in 2023.

General Plant

In 2022, the decision was made to build a second garage in the NOTL Hydro yard and revamp the yard at a cost of $500k. The existing yard dated from the 1980's and a number of issues had arisen over time:

- There was only one gate providing access in and out of the yard. This was a safety and reliability concern; especially as it was now breaking down frequently.
- With growth the parking of all the vehicles had become an issue and involved daily maneuvering.
- Most of the wire and all the transformers were stored outside in the yard. Theft was a mounting concern as the fence around the yard had been found cut several times.
- Delivery vehicles sometimes had difficult turns to get out of the yard once they were in creating a safety concern.

The project involves:

- The extension of the existing paved area around the building to the other side where the second gate would be installed as well as some additional outside storage (poles).
- Replacing the controls on the existing gate.
- Building a new 4 bay garage for both vehicles and inventory storage. To manage costs the building will not have running water but will have non-carbon based heating.

In 2018, future large utility vehicle purchases were projected for 2023 and 2025. Due to ordering opportunities and wear and tear on the existing vehicles, these vehicles are now being delivered in 2023 and 2024. This includes a bucket truck and a digger.

In 2023, a reel trailer is being purchased to assist the underground crew in their installing new underground wiring. This is part of the move to bring some of the underground work in house.

5.4.10 Multi-year Projects

There were two multi-year capital projects included in the 2019 Cost of Service.

New Transformer

A new 83 MVA transformer was proposed for the York Station to replace the existing 41.7 MVA transformer. With this transformer, both of the NOTL Hydro stations would have the capacity to serve the entire town at peak loads. The 41.7 MVA transformer would then be moved to the NOTL Station where it would replace an existing 25 MVA transformer that was near end-of-life.

The total budgeted cost for the project was $3,050k.

The project was completed in 2021 with a final cost of $2,919k.

Battery

In 2018, The Smart Grid Fund of the Government of Ontario approved a battery storage project to test the suitability of using a battery to expand the capacity of a feeder to support distributed generation. The battery was also to be tested for peak shaving and voltage management.

The budgeted capital cost for the project was $442k.

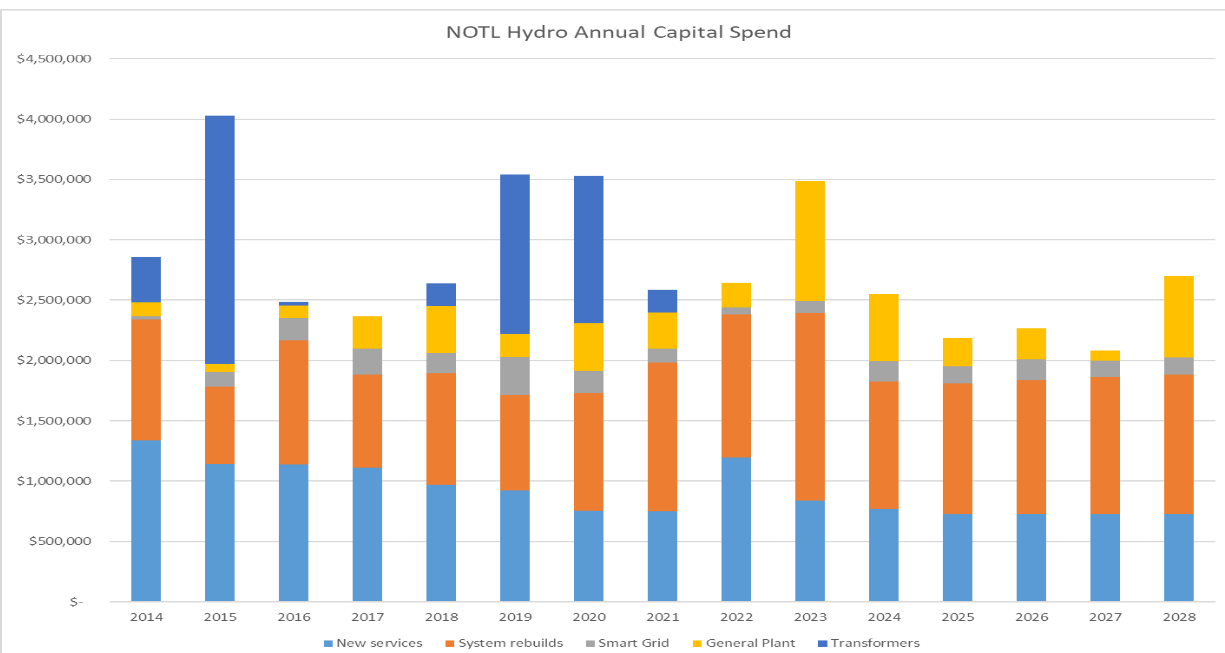
The actual cost was $479k. The overage was all in the cost of installing the transformer and linking it in with the feeder line. This was more difficult than anticipated.

5.4.11 Future Capital Expenditures Plan

Table 28: NOTL Hydro Capital Plan (2014-2028)

Niagara-on-the-Lake Hydro Inc.
Capital Expenditure Plan
2014 - 2028

	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Actual 2021	Actual 2022	Forecast 2023	Forecast 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028
System Access															
Subdivisions	627,189	454,185	491,428	161,462	142,423	389,650	13,490	72,915	12,072	65,000	50,000	50,000	50,000	50,000	50,000
Customer Projects	368,389	302,157	316,873	330,604	575,521	276,624	382,927	292,757	739,292	405,746	350,000	350,000	350,000	350,000	350,000
New connections - overhead	13,740	14,725	12,303	5,770	11,944	10,768	16,536	34,808	43,867	15,000	15,000	15,000	15,000	15,000	15,000
New Connections - underground	276,278	335,603	283,555	197,926	88,338	168,641	200,561	253,845	353,614	275,000	275,000	275,000	275,000	275,000	275,000
Meters	49,591	35,818	36,417	47,692	58,236	78,791	142,210	96,086	49,076	80,000	80,000	40,000	40,000	40,000	40,000
Municipal Relocations	-	-	-	367,310	93,712	-	-	-	-	-	-	-	-	-	-
System Access Total	1,335,187	1,142,488	1,140,576	1,110,764	970,174	924,474	755,724	750,411	1,197,920	840,746	770,000	730,000	730,000	730,000	730,000
System Renewal															
Overhead	671,928	453,329	572,989	513,654	719,670	485,676	345,788	796,254	529,951	525,000	555,000	555,000	555,000	555,000	555,000
Underground	332,974	186,316	452,077	256,601	203,811	304,649	631,099	437,930	656,146	1,025,000	500,000	525,000	550,000	575,000	600,000
System Renewal Total	1,004,902	639,645	1,025,066	770,255	923,481	790,325	976,887	1,234,184	1,186,097	1,550,000	1,055,000	1,080,000	1,105,000	1,130,000	1,155,000
System Service															
Transformer stations	-	-	29,230	62,902	129,531	-	-	51,260	52,958	5,000	5,000	5,000	5,000	5,000	5,000
Battery					18,477	237,207	147,305	(23,359)	-	-					
SCADA / switches / Smart grid	26,201	121,282	153,433	155,915	18,652	76,100	35,170	85,345	-	95,000	165,000	137,000	170,000	135,000	135,000
System Service Total	26,201	121,282	182,663	218,817	166,660	313,307	182,475	113,246	52,958	100,000	170,000	142,000	175,000	140,000	140,000
General Plant															
Buildings and fixtures	5,717	7,008	81,142	49,690	51,004	47,830	269,360	93,837	8,186	500,000	13,441	43,695	15,000	15,270	15,548
Office equipment	(667)	4,969	1,542	4,854	6,078	2,995	6,396	1,972	10,561	6,000	6,000	6,000	7,000	7,000	7,000
Hardware	6,033	34	6,938	17,583	11,033	36,984	19,706	42,081	10,797	8,550	17,911	18,000	18,000	18,000	18,000
Software	103,174	6,256	4,624	33,979	24,512	-	39,978	47,086	12,251	12,947	57,426	88,000	8,240	33,487	30,000
Rolling stock	-	44,963	-	-	690	84,178	6,970	104,993	-	-	-	75,000	-	-	-
Rolling stock - Line Trucks	-	-	-	151,950	257,995	-	-	-	-	423,000	455,000	-	-	-	600,000
Locate services						-	47,903		-						
Underground services									160,834	40,000		-	200,000		
Major Tools	512	3,842	13,286	9,498	36,528	20,885	3,178	7,818	3,659	6,000	6,000	6,000	6,000	7,000	7,000
General Plant Total	114,769	67,072	107,532	267,554	387,840	192,872	393,491	297,787	206,287	996,497	555,778	236,695	254,240	80,757	677,548
Recurring total	2,481,059	1,970,487	2,455,837	2,367,390	2,448,155	2,220,978	2,308,577	2,395,628	2,643,261	3,487,243	2,550,778	2,188,695	2,264,240	2,080,757	2,702,548
Transformer	375,965	2,059,240	28,781	-	190,217	1,319,764	1,219,784	188,913	-	-	-	-	-	-	-
Total expenditure	2,857,024	4,029,727	2,484,618	2,367,390	2,638,372	3,540,742	3,528,361	2,584,541	2,643,261	3,487,243	2,550,778	2,188,695	2,264,240	2,080,757	2,702,548



The following is a summary of all the material planned investments.

System Access

System access expenditures are those required to provide or to enhance a customer's access to the local grid. The expenditure required will therefore vary from year to year based on customer requirements. Internally, with the exception of meters, NOTL Hydro does not budget for system access expenditures because they are outside the control of NOTL Hydro. System access expenditures will get the highest priority as they directly impact the customer.

Subdivisions

These are the payments to developers for NOTL Hydro's share of any system expansion costs. The expenditures vary from year to year based on developer activity and NOTL Hydro has no control over the amount of the annual payments. Based on forecast activity, NOTL Hydro anticipates that subdivision expenditures will not be as high as pre-pandemic levels but will be higher than the low levels seen in the past few years.

Customer Projects

These are the costs of projects initiated by customers. Most of the time the cost is fully paid by the customer so the cost of the investment is offset by capital contributions which are accounted for separately to net the amount for rate base purposes. NOTL Hydro has no control over the volume of these requests but expects them to continue at levels similar to what has been seen over the past few years.

New Connections

These are new connections of any customer class. The distribution system code defines what is NOTL Hydro's responsibility and what is the customers. Much of this cost is paid by the customer so the cost of the investment is somewhat offset by capital contributions which are accounted for separately to net the amount for rate base purposes. NOTL Hydro has no control over the volume of these requests but expects them to continue at levels similar to what has been seen over the past few years. Most new connections are underground.

Meters

This is the cost of both replacement meters and meters for new connections. The forecast cost for 2024 is higher due to the continuation of the reverification program. After that the annual expenditure is expected to revert to normal levels.

System Renewal

System renewal expenditures are those required to maintain the local grid in good condition. This reduces outages and provides an opportunity to upgrade the grid. NOTL Hydro currently has three general types of system renewal projects.

1. Voltage conversion – NOTL Hydro has been slowly eliminating its 4 kV system since the 1980's. In the rural areas this has meant replacing all the infrastructure on a section of road with 27.6 kV infrastructure. This also increases the height and strength of the poles. In urban areas this has meant installing and underground 27.6 system. The 4 kV lines are all over 50 years old so need to be replaced.
2. Line replacement – NOTL Hydro will also replace a section of line in order just to upgrade it. This may be due to the condition of the infrastructure as determined by asset management activities, outage history or to take advantage of other civil work.
3. Small jobs – NOTL Hydro is often upgrading small parts of the system due to equipment deterioration, changes in local customer demand or other needs.

As a rule of thumb, the annual system renewal expenditure should be the equivalent of the average depreciation expense, adjusted for inflation. The assets being replaced are thus equivalent in cost to the assets being added.

Table 29: Depreciation vs. System Renewal ($000's)

	2018	2019	2020	2021
Depreciation	$512	$530	$585	$614
Inflation adjustment	152%	152%	152%	157%
Required expenditure	$778	$806	$889	$964
Actual expenditure	$923	$790	$977	$1,234
Variance	$145	($16)	$88	$270

Annual depreciation of the system assets adjusted for inflation is thus about $1 million and this will continue to grow with the current high inflation. NOTL Hydro's annual investment from 2024-2028 of $1.055 - $1.155 is thus set to match the annual deterioration of the system. As the new investments are of the latest technology, the system as a whole should be improving each year.

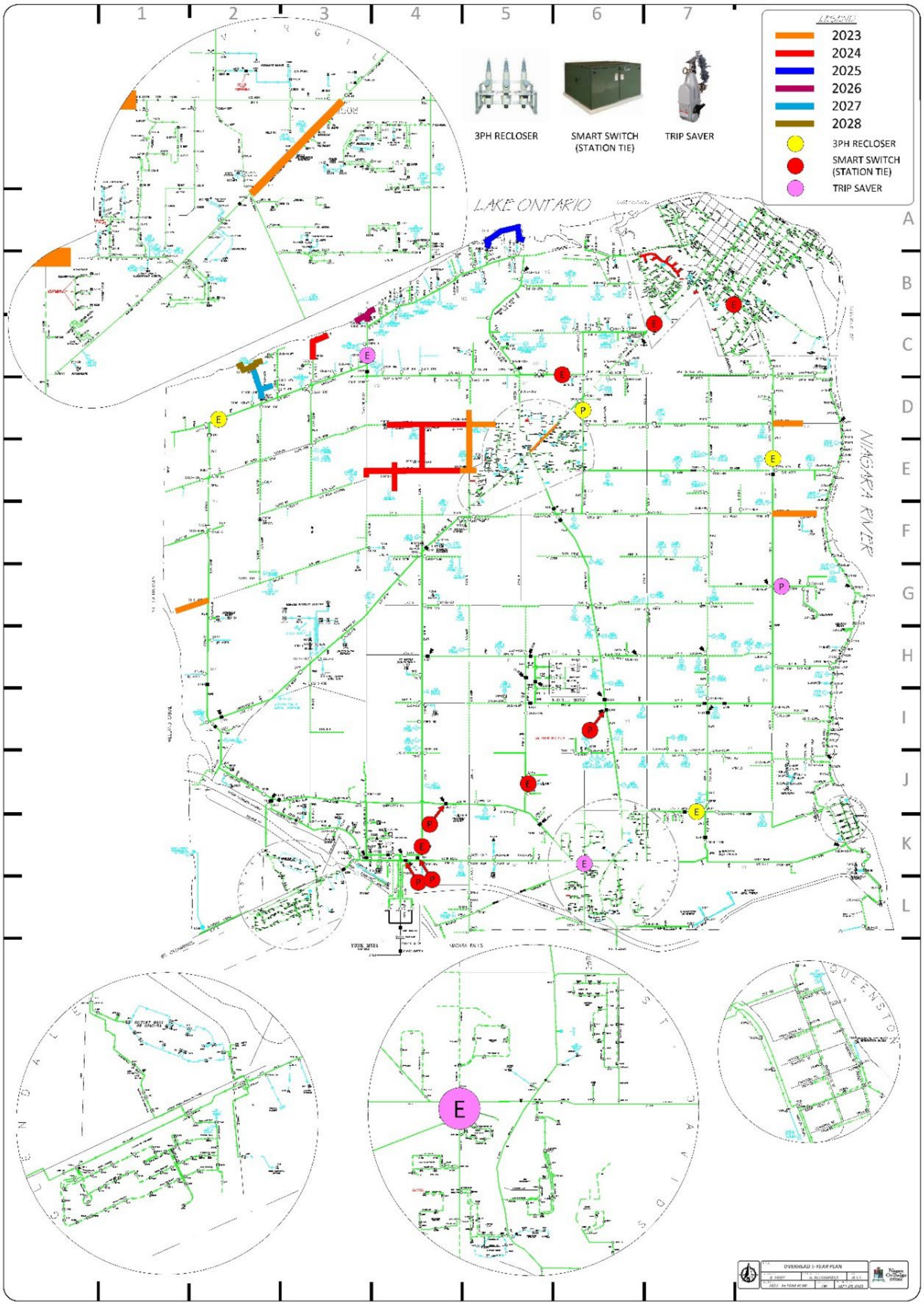
Overhead

2024 will be the last year of overhead voltage conversion for the rural system located on town roads. The lines located on Line 1 and Line 2 between Townline Rd and Concession 6 as well the line on Concession 7 located between Line 1 and Line 2 will be converted. Once this section is converted, the only remaining 4 kV rural lines will be on the firelanes.

The firelanes pose a particular challenge as the roads are privately owned. In addition, NOTL Hydro does not have easements for almost all of the locations of its infrastructure as these were all purchased from Ontario Hydro in 1983. There are 14 firelanes in total of varying lengths and complexity. The objective will be to install new 27.6 kV lines that have a path more suitable given the growth in the firelanes and to have easements for the lines. NOTL Hydro will be holding public meetings later in 2023. Based on the receptivity of the property owners this will determine the order in which the firelanes are converted beginning in 2024 and continuing until complete. The firelanes are narrow so due to the complexity of the conditions each year as much work will be done as budgeting allows. The firelanes shown on the map below are the desirable projects based on asset conditions.

As in 2023, each year NOTL Hydro will also be assessing if any other upgrades of sections of line are needed based on asset conditions.

Table 30: Planned Overhead Projects (2023-2028)



Underground

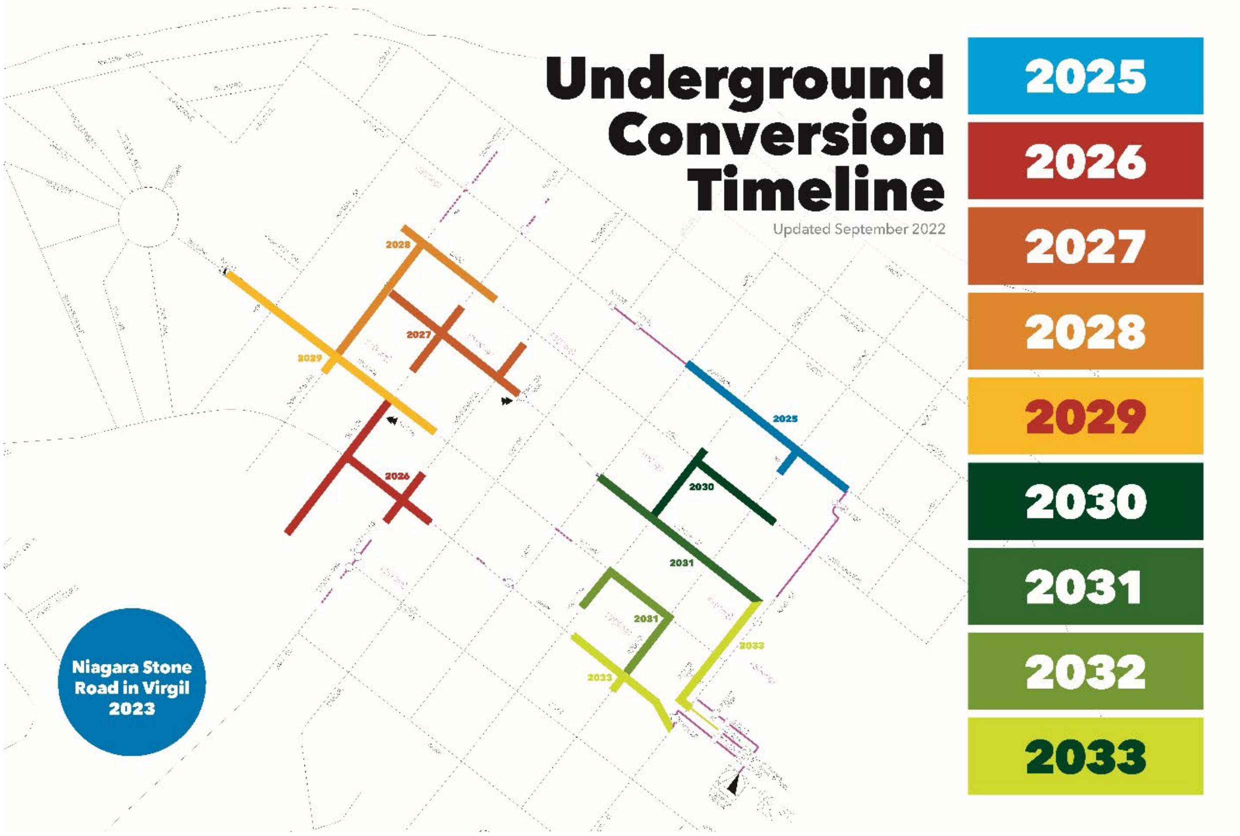
The following is a description of the underground projects planned for each year from 2024-2028.

Table 31: Planned Underground Projects (2024-2028)

Year	Project	Description
2024	Garrison Village	Replacement of 1/3 of the existing 27.6 kV system in the Garrison Village due to poor asset condition.
2025	Johnson St	Converting the overhead 4 kV system from Gate St to King St to an underground 27.6 kV system.
2026	Butler St.	Converting the overhead 4 kV system in the Butler St and Mary St. area to an underground 27.6 kV system.
2027	Centre St.	Converting the overhead 4 kV system from Dorchester St to Mississauga St to an underground 27.6 kV system.
2028	Dorchester St	Converting the overhead 4 kV system from Gage St to William St to an underground 27.6 kV system.

As per the map below, based on current plans, the voltage conversion project in the Old Town should be completed by 2033.

Table 32: Planned Old Town Underground Projects (2025-2033)



System Service

System service expenditures are designed to improve the capability of the overall system. NOTL Hydro has invested significantly in transformer station upgrades and in smart devices in recent years so, unless there is a large change in demand, less investments will be required over the 2024-2028 period.

Scada / Switches / Smart Grid

The only system service plans for 2024-2028 are for the continued installation of smart devices (switches, reclosures, tripsavers) with SCADA capability as means to reducing outage effect on customers, improving efficiency of response to outages and reducing their duration by pinpointing sources of damage.

General Plant

General plant expenditures are those required to allow NOTL Hydro to perform its duties of maintaining the grid and billing its customers.

Buildings and Fixtures

NOTL Hydro has a major expansion underway in 2023 to add an additional garage and adjust the access to the yard. This was needed for growth and safety reasons. As such, the planned expenditures each year are less than $20k and are for general improvements in the existing buildings as required. The only exception is $30k shown in 2025 for a potential expansion of the lineman's room.

Hardware and Software

The hardware plan is for new computers and servers. The amount will vary from year to year as per the historical spend. The large software expenditures forecast in 2024 and 2025 is for an upgrade to the GIS system as ESRI is phasing out its support for the current version in use. Any expenditures on software, such as our CIS and billing system, that is cloud-based is not a capital expenditure under IFRS. Most software is moving to cloud-based systems.

Rolling Stock

A replacement pick-up truck or van is planned for 2025 as the current van was purchased in 2010. A new bucket truck is also planned for 2028 as the existing truck was purchased in 2018.

Underground Services

$200k has been planned for 2026 should we decide to bring boring inhouse. This decision will depend on how successful we are in the next few years in using outsourced services. We do not anticipate the Garrison Village project in 2025 being a challenge as we have experience with a good contractor on the previous Garrison Village section in 2020. This contractor is not interested in the jobs in the Old Town.

Appendix

List of Appendices

A	Hydro One 2023 Needs Assessment Report
B	Niagara Region Integrated Regional Resource Plan
C	Highway 55 Project article
D	NOTL Hydro Rotating Asset Management Plan
E	EV Newspaper Article
F	NOTL Hydro EV Analysis #1
G	NOTL Hydro EV Analysis #2
H	Underground Customers Open House
I	Public Notice on Virgil Underground Project

Niagara on-the-Lake HYDRO

DISTRIBUTION SYSTEM PLAN APPENDIX A

Hydro One Needs Assessment Report

EB-2023-0041

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

NEEDS ASSESSMENT REPORT

Niagara Region

Date: May 24, 2021

Prepared by: Niagara Region Study Team

Disclaimer

This Needs Assessment (NA) Report was prepared for the purpose of identifying potential needs in the Niagara Region and to recommend which need may be a) directly addressed by developing a preferred plan as part of NA phase and b) identify needs requiring further assessment and/or regional coordination. The results reported in this Needs Assessment are based on the input and information provided by the Study Team for this region.

The Study Team 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 Needs Assessment Report was prepared (“the Intended Third Parties”) or to any other third party reading or receiving the Needs Assessment 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 Niagara (the "Region")

LEAD Hydro One Networks Inc. ("HONI")

START DATE: March 25th 2021 **END DATE:** May 24th 2021

1. INTRODUCTION

The first cycle of the Regional Planning process for the Niagara Region was completed in April 2016 with the publication of the Needs Assessment Report. As no further regional coordination or planning was required, the NA identified needs to be addressed between relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required.

This is the second cycle of regional planning starting with a Needs Assessment ("NA"). The purpose of this NA is a) to identify any new needs and/or to reaffirm needs identified in the previous Niagara Regional Planning cycle and b) recommend which need may be a) met more directly by distributors or other customers and their respective transmitter b) identify needs requiring further assessment and/or regional coordination.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the regional planning cycle should be triggered at least once every five years.

3. SCOPE OF NEEDS ASSESSMENT

This assessment's primary objective is to identify the electrical infrastructure needs over the study period (2021 – 2030) and recommend which needs require further regional coordination.

The scope of this NA includes:

- Review and reaffirm needs/plans identified in the previous NA;
- Identification and assessment of system capacity, reliability, operation, and aging infrastructure needs in the region; and
- Identify needs that can be addressed at the local level directly by Hydro One and the area LDCs. Other regional needs requiring further coordination can be studied by the Study Team during the other stages of the Regional Planning process.

4. INPUTS/DATA

The Study Team representatives from Local Distribution Companies ("LDC"), the Independent Electricity System Operator ("IESO"), and Hydro One provided input and relevant information for this Region regarding capacity needs, reliability needs, operational issues, and major assets/facilities approaching end-of-life ("EOL").

5. ASSESSMENT METHODOLOGY

The assessment methodology includes review of planning information such as load forecast, conservation and demand management ("CDM") forecast and available distributed generation ("DG") information, any system reliability and operation issues, and major high voltage equipment identified to be at or near the end of their life.

A technical assessment of needs was undertaken based on:

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

6. RESULTS

I. Needs Identified from Previous Cycle

- The previous needs assessment had identified the need to upgrade the Sir Adam Beck SS #1 x Portal Junction section of 115kV circuit Q4N. This upgrade work was completed in 2019.
- A few instances (<54 hours / year) of power factor below 0.9 (between 0.89 - 0.9) were observed at the HV side of Thorold TS. It was decided to. continue to monitor the power factors. Further detail is provided in Section 8.

II. Results of Current Review

- <u>230/115 kV Autotransformers and 230kV and 115kV Transmission lines</u>

All 230kV and 115kV transmission line facilities are adequate over ths study period for the loss of a single circuit.

- <u>230 kV and 115 kV Connection Facilities</u>

A station capacity assessment was performed over the study period for the 230 kV and 115 kV transformer stations in the Region using the station summer peak load forecast provided by the study team. All stations, except for Beamsville TS and Crowland TS, in the area have adequate supply capacity for the study period. These are further discussed in Section 8.2.4.

- <u>System Reliability, Operation and Restoration</u>

Load restoration is adequate in the area and meet the ORTAC load restoration criteria.

The needs assessment did not identify any additional issues with meeting load restoration as per the ORTAC load restoration criteria.

III. Newly Identified Needs in the region

- Beamsville TS - This station will exceed its normal supply capacity by 2027 based on the summer demand forecast. A solution is required to address the upcoming station capacity need.

- Crowland TS - Based on the summer demand forecast, this station will exceed supply in 2028 after the station refurbishment project where Hydro One will be upgrading the transformers with two new 115/27.6kV 83MVA units in 2024. A solution is required to address the midterm station capacity need.

7. RECOMMENDATIONS

- Beamsville TS – Hydro One will coordinate with the connected LDCs and their embedded customers (as needed) to address the immediate supply capacity constraints that may appear within 2027. Solution(s) will require further regional coordination to verify if non-wires options would be beneficial. All identified wire options needs will be best addressed through local planning led by Hydro One.

- Crowland TS – The station transformer replacement is presently underway and scheduled to be in service in 2024. Hydro One will try to expedite the replacement as quickly as possible to manage overloading risk to the existing end-of-life transformers. The Working Group will continue to develop supply capacity solution(s) for the Welland area load growth.

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List of Tables and Figures

2 INTRODUCTION

The first cycle of the Regional Planning process for the Niagara Region was completed in April 2016 with the publication of the Needs Assessment (“NA”) Report.

The purpose of this Needs Assessment is to identify new needs and to reconfirm needs identified in the previous Niagara regional planning cycle. Since the previous regional planning cycle, some new needs in the region have been identified.

This report was prepared by the Niagara Region Study Team (“Study Team”), led by Hydro One Networks Inc. Participants of the Study Team are listed below in Table 1. The report presents the results of the assessment based on information provided by the Hydro One, the Local Distribution Companies (“LDC”) and the Independent Electricity System Operator (“IESO”).

Table 1: Niagara Region Study Team Participants

Niagara Study Team
Hydro One Networks Inc. (Lead Transmitter)
Alectra Utilities
Canadian Niagara Power Inc.
Grimsby Power Inc.
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator
Niagara on the Lake Hydro Inc.
Niagara Peninsula Energy Inc.
Welland Hydro Electric System Corp.

3 REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. As such, the 2nd Regional Planning cycle was triggered for the Niagara region.

4 SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the Niagara region and includes:

- Review the status of needs/plans identified in the previous NA; and
- Identification and assessment of any new needs (e.g. system capacity, reliability, operation, and aging infrastructure)

The Study Team may identify additional needs during the next phases of the regional planning process, namely Scoping Assessment ("SA"), Local Planning ("LP"), Integrated Regional Resource Plan ("IRRP"), and/or Regional Infrastructure Plan ("RIP").

5 REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

For regional planning purposes, the Niagara region includes the City of Port Colborne, City of Welland, City of Thorold, City of Niagara Falls, Town of Niagara-on-the-Lake, City of St. Catharines, Town of Fort Erie, Town of Lincoln, Township of West Lincoln, Town of Grimsby, Township of Wainfleet, and Town of Pelham. Haldimand County has also been included in the regional infrastructure planning needs assessment for Niagara region.

The boundaries of the Niagara Region is shown below in Fig. 1.

Electrical supply for this region is provided through a network of 230kV and 115kV transmission circuits supplied mainly by the local generation from Sir Adam Beck #1, Sir Adam Beck #2, Decew Falls GS, Thorold GS and the 230kV/115kV autotransformers at Allanburg TS.

Bulk supply is provided through the 230kV circuits (Q23BM, Q24HM, Q25BM, Q26M, Q28A, Q29HM, Q30M, and Q35M) from Sir Adam Beck #2 SS. These circuits connect this region to Hamilton/Burlington.

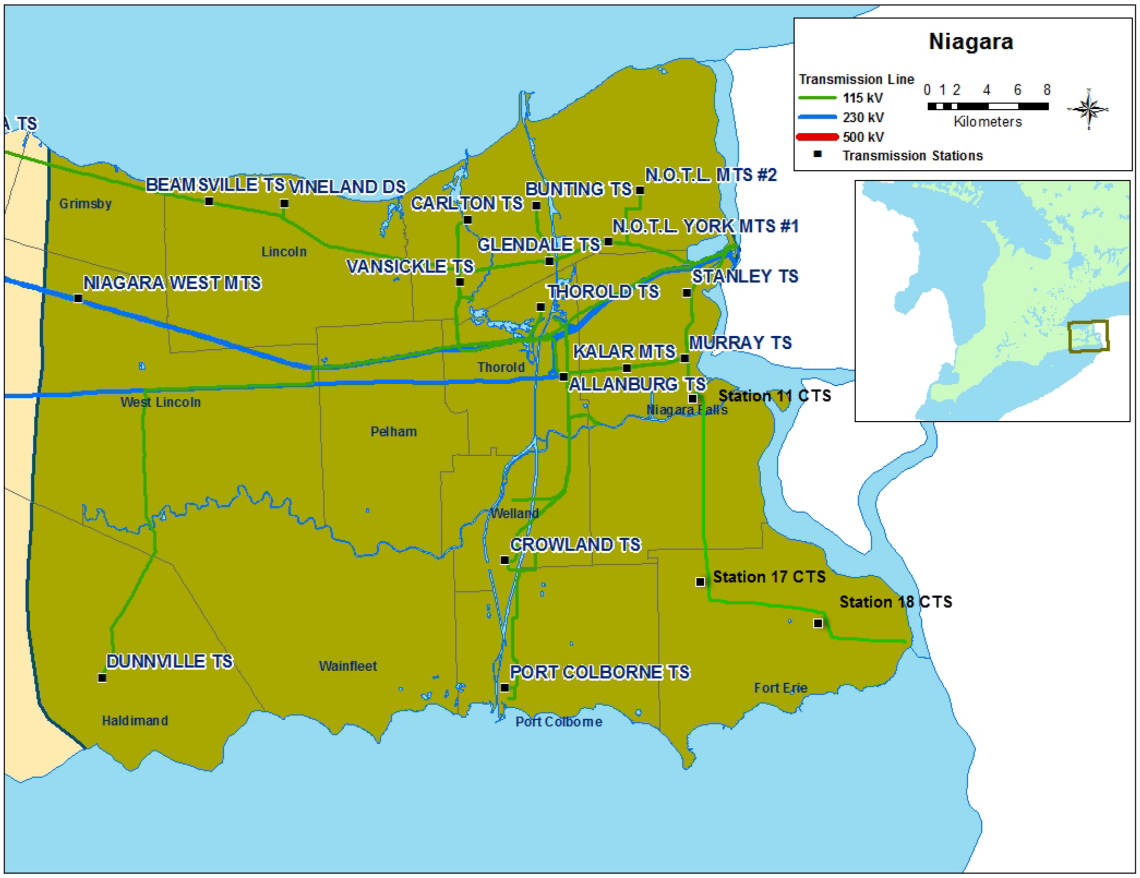

Figure 1: Geographical Area of Niagara Region with Electrical Layout

Winona TS is not included in the Niagara Region, as this is included in the Nanticoke/Burlington Region.

The existing facilities in the Region are summarized below and depicted in the single line diagram shown in Figure 2. The 230kV system is part of the bulk power system and is not studied as part of this Needs Assessment.

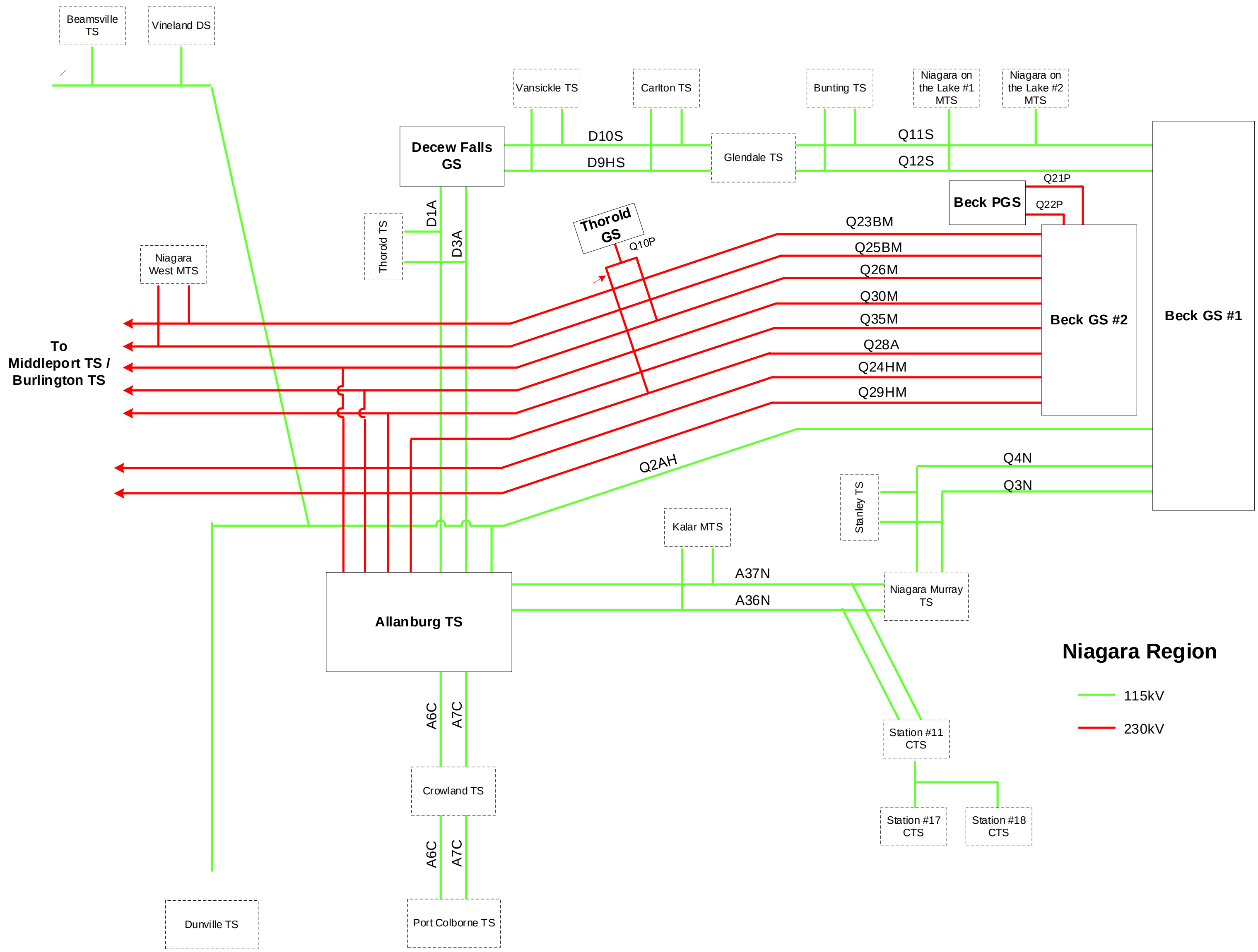

Figure 2: Single Line Diagram of Niagara Region

6 INPUTS AND DATA

Study Team participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the Niagara Region NA. The information provided includes the following:

- Niagara Load Forecast for all supply stations;
- Known capacity and reliability needs, operating issues, and/or major assets approaching the end of life (“EOL”); and
- Planned/foreseen transmission and distribution investments that are relevant to regional planning for the Niagara Region.

7 ASSESSMENT METHODOLOGY

The following methodology and assumptions are made in this Needs Assessment:

Information gathering included:

i. Load forecast: The LDCs provided load forecasts for all the stations supplying their loads in the Niagara region for the 10-year study period. The IESO provided a Conservation and Demand Management (“CDM”) and Distributed Generation (“DG”) forecast for the Niagara region. The region’s extreme summer non-coincident peak gross load forecast for each station were prepared by applying the LDC load forecast load growth rates to the actual 2020 summer peak weather corrected loads. The summer weather correction factors were provided by Hydro One. The net weather summer load forecasts were produced by reducing the gross load forecasts for each station by the percentage CDM and then by the amount of effective DG capacity provided by the IESO for that station. It is to be noted that in the mid-term (5 to 10 year) time frame, contracts for existing DG resources in the region begin to expire, at which point the load forecast indicates a decreasing contribution from local DG resources, and an increase in net demand. These load forecasts for the individual stations in the Niagara region is given in Appendix A;

ii. Extreme weather scenario factor for 2020 of 0.9835 was also assessed for capacity planning over the study term[1];

iii. Relevant information regarding system reliability and operational issues in the region; and

iv. List of major HV transmission equipment planned and/or identified to be refurbished and/or replaced due to the end of life which is relevant for regional planning purposes. This includes HV transformers, autotransformers, HV Breakers, and overhead lines.

A technical assessment of needs was undertaken based on:

[1]The extreme weather correction factor for 2020 was calculated to be of less than 1, given 2020 peak weather was already more than extreme. With the Covid-19 pandemic, the load was more weather sensitive than usual as many people were working from home and Industrial Conservation Initiative (ICI) was not in effect. The latter conditions is not expected to be repeated in the future (e.g., ICI is back in 2021)

- Current and future station capacity and transmission adequacy;
- System reliability and operational concerns; and
- Any major high voltage equipment reaching the end of life.

8 NEEDS

This section describes emerging needs identified in the Niagara Region, and also reaffirms the near, mid, and long-term needs already identified in the previous regional planning cycle.

The status of the previously identified needs is summarized in Table 2 below.

Table 2: Needs Identified in the Previous Regional Planning Cycle

Needs identified in the previous RP cycle	**Needs Details**	**Current Status/Recommended Action**	**In-Service**
Line Rating	Under high generation scenarios at Sir Adam Beck GS #1, the loading on the *Beck SS #1 x Portal Junction* section (egress out from the GS) of 115kV circuit Q4N can exceed circuit ratings.	This line section has been upgraded.	2019
	A few instances (<54 hours / year) of power factor below 0.9 (between 0.89 - 0.9) were observed at the HV side of Thorold TS. Hydro One will investigate these instances and work with Distribution customers to address.	Less than 3 MVAR required to bring power factor to 0.9. Correction required at the Distribution feeder level. Hydro One to continue monitoring with LDC.	-

8.1 End-Of-Life (EOL) Equipment Needs

Hydro One and LDCs have provided high voltage asset information under the following categories that have been identified at this time and are likely to be replaced over the next 10 years:

- Power transformers
- HV breakers
- Line conductor

The end-of-life assessment for the above high voltage equipment typically included consideration of the following options:

- Replacing equipment with similar equipment and built to current standards (i.e., "like-for-like" replacement);
- Replacing equipment with similar equipment of higher / lower ratings i.e. right sizing opportunity and built to current standards;
- Replacing equipment with lower ratings and built to current standards by transferring some load to other existing facilities;
- Eliminating equipment by transferring all of the load to other existing facilities;

In addition, 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.

Accordingly, following major high voltage equipment has been identified as approaching its end of life over the next 10 years and assessed for right sizing opportunity.

Station	Proposed I/S	Description
Port Colborne TS: T61, T62 & Switchyard Refurbishment	**2022**	• Complete station refurbishment that will replace all assets including transformers T61, T62, medium voltage switching facilities and station protection and control equipment
Thorold TS: T1 & MV Switchgear Replacement	**2024**	• Replace T1 transformer with a new 45/60/75 MVA unit and the existing low voltage (LV) E/Q and B/Y metalclad switchgear
Crowland TS: T5, T6 & Component Replacement	**2024**	• Replace transformers T5 and T6 with 50/66.7/83.3 MVA units
D1A/D3A Tx Line Refurbishment	**2024**	• Line refurbishment of 2.6km route length between Gibson JCT x Thorold TS
Q2AH Tx Line Refurbishment	**2025**	• Line refurbishment of 11.2km between Rosedene JCT X St.Anns JCT
Murray TS: T14, T13 & Component Replacement	**2025**	• Replacement of T13 and T14 power transformers and metalclad at Murray TS. .
Bunting TS: T3 & MV Switchgear Replacement	**2026**	• Replacement of transformer T3, all station medium voltage switching facilities considered legacy and non-standard along with deploying a new protection and control protocol for all station protection and control equipment
Carlton TS: Switchyard Refurbishment and Reconfig.	**2026**	• Replace existing H/K metalclad switchgear with current Hydro One standard indoor air insulated (AIS) metalclad switchgear • Replace the existing B/Y switchyard with current Hydro One standard indoor air insulated (AIS) metalclad switchgear
Glendale TS: Station Refurbishment and Reconfiguration	**2027**	• Replace the existing 45/60/75 MVA T1 transformer with a new 45/60/75 MVA unit • Replace the existing 45/60/75 MVA T2 transformer with a new 45/60/75 MVA unit • Replace and reconfigure the LV switching facilities with current Hydro One standard air insulated (AIS) metalclad switchgear.
Vansickle TS: : MV Switchgear Replacement	**2027**	• Replacement of the 14.2kV BY metalclad.

Murray TS: T11, T12 & Component Replacement	**2029**	• Replacement of T11 and T12 power transformers at Murray TS.

8.2 Station and Transmission Capacity Needs in the Niagara Region

The following Station and Transmission supply capacities needs have been identified in the Niagara region during the study period of 2021 to 2030.

8.2.1 230/115 kV Autotransformers

The 230kV/115kV autotransformers at Allanburg TS (T1/T2/T3/T4) remain within limits for the study period based on both and summer demand forecast.

8.2.2 230 kV Transmission Lines

The 230kV circuits supplying the Region are adequate over the study period for the loss of a single 230kV circuit in the Region.

8.2.3 115kV Transmission Lines

The 115kV circuits supplying the Region are adequate over the study period for the loss of a single 115kV circuit in the Region.

8.2.4 230 kV and 115 kV Connection Facilities

A station capacity assessment was performed over the study period for the 230 kV and 115 kV TSs in the Region using summer station peak load forecasts provided by the study team. The results are as follows:

a. Beamsville TS

Beamsville TS has a summer 10-day LTR of 60.3MW and will exceed its normal supply capacity by 2027 based on the summer demand forecast. Between 2019 and 2020, there has been a 12% surge (6.6MW) in load between the historical peak demand. It is uncertain if this temporary increase is a result of the current pandemic with more residents working from home, as the 10 year load forecast is only expecting a modest 5% growth (3.1MW).

The Working Group has agreed to further monitor the load growth and substantiate if the one year increase is attributed to the pandemic. Furthermore, the Working Group will investigate transferring load to nearby stations, and possible CDM/DG initiatives to provide the capacity relief needed to meet the upcoming demand. It is worthwhile to note that the existing 115/27.6kV transformers were installed in 2003 and if needed, can be upgraded to larger units in agreement with the connected LDCs.

b. Crowland TS

Crowland TS presently has a 10-Day LTR of 102MW which will exceed its normal supply capacity in the year 2026 based on the summer demand forecast. The Crowland TS project to replace the two EOL transformers T5 and T6 is currently underway. The two new 115/27.6kV 83MVA transformers are expected to increase the station supply capacity to at least 107 MW based on minimum 10-day LTR capability of new transformers. With the new units installed, station LTR will be exceeded in the summer 2028 and additional supply capacity will be required.

Although capacity does appear to be available for the near and mid-term, Welland Hydro and Hydro One distribution also see a supply capacity constraint at the 27.6kV feeder level by 2028. The Working Group will further evaluate a new station east of the Welland Canal if nearby transformer stations cannot alleviate the demand of the new area load.

c. Other TSs in the Region

All the other transformer stations (TSs) in the region are forecasted to remain within their normal supply capacity during the study period. Capacity needs for these stations will be reviewed in the next planning cycle.

8.3 System Reliability, Operation and Restoration Review

No new significant system reliability and operating issues identified for this Region. Based on the net coincident load forecast, the loss of one element will not result in load interruption greater than 150MW. The maximum load interrupted by configuration due to the loss of two elements is below the load loss limit of 600MW by the end of the 10-year study period.

9 CONCLUSION AND RECOMMENDATIONS

The Study Team recommends the following –

a. Beamsville TS – Hydro One will coordinate with the connected LDCs and their embedded customers (as needed) to address the immediate supply capacity constraints that may appear within 2027. Hydro One will continue to monitor the load to see if any load transfers are required. Solution(s) will require further regional coordination to verify if non-wires options would be beneficial. All identified wire options needs will be best addressed through local planning led by Hydro One.

b. Crowland TS – The station transformer replacement is presently underway and scheduled to be in service in 2024. Hydro One will try to expedite the replacement as quickly as possible to manage overloading risk to the existing transformers. The Working Group will continue to develop supply capacity solution(s) for the Welland area load growth.

Appendix A: Weather Adjusted Non-Coincident Summer Forecast

Transformer Station	DESN ID	Transformer Size	10 Day LTR MVA	10 Day LTR MW	Customer Data (MW)	Summer Peak Load												
						Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
						2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Allanburg TS	*T7/T8*	*25/33/42*	*61.1*	*58.0*	Total Gross Peak Forecast				39.3	39.9	40.5	40.9	41.4	41.8	42.3	42.8	43.2	43.7
					Historical Load	34.3	35.2	40.0										
					Extreme Weather Correction			39.3	38.7	39.2	39.9	40.3	40.7	41.1	41.6	42.1	42.6	43.0
					DG				0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43
					CDM				0.7%	1.5%	2.5%	3.2%	3.8%	4.0%	4.3%	4.4%	4.5%	4.6%
					Net Load Forecast				**37.9**	**38.2**	**38.4**	**38.5**	**38.7**	**39.1**	**39.4**	**39.8**	**40.2**	**40.6**
Beamsville TS	*T3/T4*	*25/33/42*	*62.8*	*60.3*[2]	Total Gross Peak Forecast				61.1	61.7	62.4	63.0	63.6	64.2	64.9	65.5	66.2	66.8
					Historical Load	56.1	53.4	60.0										
					Extreme Weather Correction			59.0	60.1	60.7	61.4	62.0	62.6	63.2	63.9	64.5	65.2	65.9
					DG				0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43
					CDM				0.7%	1.5%	2.5%	3.2%	3.8%	4.0%	4.3%	4.4%	4.5%	4.6%
					Net Load Forecast				**59.3**	**59.4**	**59.4**	**59.5**	**59.8**	**60.3**	**60.7**	**61.3**	**61.8**	**62.4**
Bunting TS	*T3/T4*	*45/60/75*	*83.2*	*74.9*	Total Gross Peak Forecast				55.0	55.5	56.1	56.6	57.2	58.1	58.9	59.8	60.7	61.6
					Historical Load	50.6	47.4	54.7										
					Extreme Weather Correction			53.8	54.1	54.6	55.2	55.7	56.3	57.2	58.0	58.9	59.8	60.7
					DG				3.21	3.21	3.21	3.21	3.21	3.21	3.21	3.21	0.25	0.25
					CDM				0.7%	1.5%	2.5%	3.2%	3.8%	4.0%	4.3%	4.4%	4.5%	4.6%
					Net Load Forecast				**50.5**	**50.6**	**50.6**	**50.7**	**51.0**	**51.7**	**52.3**	**53.1**	**56.9**	**57.7**
Carlton TS	*T1/T2*	*45/60/75*	*104.8*	*99.6*	Total Gross Peak Forecast				79.4	80.2	81.0	81.8	82.6	83.9	85.1	86.4	87.7	89.0
					Historical Load	83.7	74.2	78.6										
					Extreme Weather Correction			77.3	78.1	78.9	79.7	80.5	81.3	82.6	83.8	85.1	86.4	87.7
					DG				5.96	9.07	9.07	9.07	9.07	9.07	9.07	9.07	9.07	3.74
					CDM				0.7%	1.5%	2.5%	3.2%	3.8%	4.0%	4.3%	4.4%	4.5%	4.6%
					Net Load Forecast				**71.6**	**68.6**	**68.6**	**68.8**	**69.2**	**70.2**	**71.2**	**72.3**	**73.4**	**80.0**
Crowland TS	*T5/T6*	*50/60/83*	*107*	*101.7*	Total Gross Peak Forecast				97.4	99.5	101.7	103.8	105.9	115.5	117.6	119.7	121.8	123.9
					Historical Load	83.9	76.4	85.1										
					Extreme Weather Correction			83.7	95.9	98.1	100.3	102.4	104.5	114.1	116.2	118.3	120.4	122.5
					DG				5.36	5.36	5.36	5.36	5.36	5.36	5.36	5.36	5.36	5.36
					CDM				0.7%	1.5%	2.5%	3.2%	3.8%	4.0%	4.3%	4.4%	4.5%	4.6%
					Net Load Forecast				**89.9**	**91.3**	**92.4**	**93.7**	**95.1**	**104.1**	**105.9**	**107.8**	**109.7**	**111.6**
Dunnville TS	*T1/T2*	*25/33/42*	*62*	*55.8*	Total Gross Peak Forecast				29.7	30.2	30.7	31.1	31.4	31.7	32.1	32.5	32.9	33.3
					Historical Load	27.0	25.8	30.2										
					Extreme Weather Correction			29.7	29.2	29.7	30.2	30.6	30.9	31.2	31.6	32.0	32.4	32.8
					DG				4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	3.46	3.46

[2] @ 0.96 power factor, as per historical loading

					CDM				0.7%	1.5%	2.5%	3.2%	3.8%	4.0%	4.3%	4.4%	4.5%	4.6%
					Net Load Forecast				**24.7**	**25.0**	**25.2**	**25.3**	**25.4**	**25.7**	**26.0**	**26.3**	**27.5**	**27.8**
Glendale TS	*T1/T2*	*45/60/75*	*103.6*	*93.2*	Total Gross Peak Forecast				25.0	25.3	25.5	25.8	26.0	26.4	26.8	27.2	27.6	28.1
					Historical Load	40.4	37.7	24.8										
					Extreme Weather Correction			24.4	24.6	24.9	25.1	25.4	25.6	26.0	26.4	26.8	27.2	27.6
					DG				0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
					CDM				0.7%	1.5%	2.5%	3.2%	3.8%	4.0%	4.3%	4.4%	4.5%	4.6%
					Net Load Forecast				**24.2**	**24.2**	**24.2**	**24.3**	**24.4**	**24.7**	**25.0**	**25.4**	**25.8**	**26.1**
Glendale TS	*T3/T4*	*11/15*	*20.1*	*18.1*	Total Gross Peak Forecast				13.6	13.7	13.8	14.0	14.1	14.3	14.6	14.8	15.0	15.2
					Historical Load	14.1	20.0	13.4										
					Extreme Weather Correction			13.2	13.4	13.5	13.6	13.8	13.9	14.1	14.3	14.5	14.8	15.0
					DG				0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
					CDM				0.7%	1.5%	2.5%	3.2%	3.8%	4.0%	4.3%	4.4%	4.5%	4.6%
					Net Load Forecast				**13.0**	**13.0**	**13.0**	**13.1**	**13.1**	**13.3**	**13.5**	**13.7**	**13.9**	**14.1**
Kalar MTS	*T1/T2*	*45/60/75*	*75*	*67.5*	Total Gross Peak Forecast				40.7	41.2	41.6	42.0	42.4	42.8	43.3	43.7	44.1	44.6
					Historical Load	38.9	38.4	39.2										
					Extreme Weather Correction			38.5	40.1	40.5	40.9	41.3	41.8	42.2	42.6	43.0	43.5	43.9
					DG				1.04	1.04	1.04	1.04	1.04	1.04	1.04	0.00	0.00	0.00
					CDM				0.7%	1.5%	2.5%	3.2%	3.8%	4.0%	4.3%	4.4%	4.5%	4.6%
					Net Load Forecast				**38.8**	**38.9**	**38.9**	**39.0**	**39.1**	**39.4**	**39.7**	**41.1**	**41.5**	**41.9**
Murray TS	*T11/T12*	*45/60/75*	*79.6*	*71.6*	Total Gross Peak Forecast				64.6	65.3	65.9	66.6	67.2	67.9	68.6	69.3	70.0	70.7
					Historical Load	64.0	63.6	58.0										
					Extreme Weather Correction			57.1	63.7	64.3	65.0	65.6	66.3	67.0	67.6	68.3	69.0	69.7
					DG				0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18
					CDM				0.7%	1.5%	2.5%	3.2%	3.8%	4.0%	4.3%	4.4%	4.5%	4.6%
					Net Load Forecast				**63.0**	**63.2**	**63.2**	**63.3**	**63.6**	**64.1**	**64.6**	**65.1**	**65.7**	**66.4**
Murray TS	*T13/T14*	*45/60/75*	*85.8*	*81.5*	Total Gross Peak Forecast				41.9	42.4	42.9	43.3	43.7	44.1	44.5	44.9	45.4	45.8
					Historical Load	40.8	44.1	37.2										
					Extreme Weather Correction			36.6	41.3	41.8	42.3	42.7	43.1	43.5	43.9	44.3	44.8	45.2
					DG				0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18
					CDM				0.7%	1.5%	2.5%	3.2%	3.8%	4.0%	4.3%	4.4%	4.5%	4.6%
					Net Load Forecast				**40.8**	**41.0**	**41.0**	**41.1**	**41.3**	**41.5**	**41.8**	**42.2**	**42.6**	**42.9**
Niagara West MTS	*T1/T2*	*40/53.3/66.7*	*66.7*	*60.0*	Total Gross Peak Forecast				45.0	45.4	45.9	46.3	46.8	47.3	47.8	48.2	48.7	49.2
					Historical Load	37.7	36.5	41.4										
					Extreme Weather Correction			40.7	44.3	44.8	45.2	45.7	46.1	46.6	47.1	47.5	48.0	48.5
					DG				4.24	4.24	4.24	4.24	4.24	4.24	4.24	4.24	4.24	4.24
					CDM				0.7%	1.5%	2.5%	3.2%	3.8%	4.0%	4.3%	4.4%	4.5%	4.6%
					Net Load Forecast				**39.7**	**39.8**	**39.8**	**39.9**	**40.1**	**40.5**	**40.8**	**41.2**	**41.6**	**42.1**
NOTL York MTS	*T1/T2*		*56*	*50.4*	Total Gross Peak Forecast				22	22	23	23	24	24	25	25	25	26
					Historical Load	20.0	17.0	20.0										
					Extreme Weather Correction			19.7	21.7	21.7	22.7	22.7	23.7	23.7	24.7	24.7	24.7	25.7
					DG				1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	0.32

					CDM				0.7%	1.5%	2.5%	3.2%	3.8%	4.0%	4.3%	4.4%	4.5%	4.6%
					Net Load Forecast				**19.7**	**19.5**	**20.3**	**20.1**	**21.0**	**20.9**	**21.8**	**21.8**	**21.8**	**24.2**
NOTL #2 MTS	*T1/T2*		*70*	*63*	Total Gross Peak Forecast				31	32	32	33	33	34	34	34	35	35
					Historical Load	30.0	32.0	36.0										
					Extreme Weather Correction			35.4	30.4	31.4	31.4	32.4	32.4	33.4	33.4	33.4	34.4	34.4
					DG				0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.44
					CDM				0.7%	1.5%	2.5%	3.2%	3.8%	4.0%	4.3%	4.4%	4.5%	4.6%
					Net Load Forecast				**29.4**	**30.2**	**29.8**	**30.6**	**30.4**	**31.3**	**31.2**	**31.2**	**32.1**	**32.4**
Port Colborne TS	*T61/T62*	*28/37/47*	*52.9*	*47.6*	Total Gross Peak Forecast				36.7	37.1	37.5	37.9	38.2	38.6	39.0	39.4	39.8	40.2
					Historical Load	35.8	33.6	34.8										
					Extreme Weather Correction			34.3	36.2	36.5	36.9	37.3	37.7	38.0	38.4	38.8	39.2	39.6
					DG				0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48
					CDM				0.7%	1.5%	2.5%	3.2%	3.8%	4.0%	4.3%	4.4%	4.5%	4.6%
					Net Load Forecast				**35.4**	**35.5**	**35.5**	**35.6**	**35.8**	**36.0**	**36.3**	**36.6**	**37.0**	**37.3**
Stanley TS	*T1/T2*	*45/60/75*	*110.2*	*99.2*	Total Gross Peak Forecast				60.6	61.2	61.8	62.5	63.1	63.7	64.4	65.0	65.6	66.3
					Historical Load	57.5	56.9	57.5										
					Extreme Weather Correction			56.5	59.7	60.3	60.9	61.5	62.1	62.8	63.4	64.0	64.7	65.4
					DG				0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
					CDM				0.7%	1.5%	2.5%	3.2%	3.8%	4.0%	4.3%	4.4%	4.5%	4.6%
					Net Load Forecast				**59.0**	**59.1**	**59.1**	**59.3**	**59.5**	**60.0**	**60.5**	**61.0**	**61.6**	**62.2**
Thorold TS	*T1/T2*	*45/60/75*	*98.2*	*88.4*	Total Gross Peak Forecast				22.9	23.2	23.4	23.6	23.7	23.8	24.0	24.1	24.3	24.4
					Historical Load	23.3	21.1	23.4										
					Extreme Weather Correction			23.1	22.6	22.8	23.1	23.2	23.3	23.4	23.6	23.8	23.9	24.0
					DG				0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
					CDM				0.7%	1.5%	2.5%	3.2%	3.8%	4.0%	4.3%	4.4%	4.5%	4.6%
					Net Load Forecast				**22.3**	**22.4**	**22.4**	**22.4**	**22.3**	**22.4**	**22.5**	**22.6**	**22.8**	**22.9**
Vansickle TS	*T5/T6*	*45/60/75*	*108.2*	*97.4*	Total Gross Peak Forecast				47.5	48.0	48.4	48.9	49.4	50.1	50.9	51.7	52.4	53.2
					Historical Load	52.1	48.0	51.0										
					Extreme Weather Correction			50.2	46.6	47.1	47.6	48.1	48.6	49.3	50.1	50.8	51.6	52.4
					DG				0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34
					CDM				0.7%	1.5%	2.5%	3.2%	3.8%	4.0%	4.3%	4.4%	4.5%	4.6%
					Net Load Forecast				**45.9**	**46.1**	**46.1**	**46.2**	**46.4**	**47.0**	**47.6**	**48.2**	**48.9**	**49.7**
Vineland DS	*T1/T2*	*15/20/25*	*27.8*	*25.0*	Total Gross Peak Forecast				21.8	21.6	20.3	22.2	22.0	20.7	22.5	23.1	22.6	25.2
					Historical Load	21.6	18.4	19.5										
					Extreme Weather Correction			19.2	21.5	21.3	20.0	21.8	21.7	20.4	22.2	22.8	22.3	24.9
					DG				0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57
					CDM				0.7%	1.5%	2.5%	3.2%	3.8%	4.0%	4.3%	4.4%	4.5%	4.6%
					Net Load Forecast				**20.7**	**20.4**	**18.9**	**20.5**	**20.3**	**19.0**	**20.7**	**21.2**	**20.7**	**23.2**
CNPI Station #17 MTS	*TF*	*37.5/50/62.5*	*62.5*	*56.3*	Total Gross Peak Forecast				45.3	45.7	46.2	46.6	47.1	47.6	48.0	48.5	49.0	49.5
					Historical Load	39.4	20.5	42.0										
					Extreme Weather Correction			41.3	44.6	45.0	45.5	45.9	46.4	46.9	47.3	47.8	48.3	48.8
					DG				0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03

					CDM				0.7%	1.5%	2.5%	3.2%	3.8%	4.0%	4.3%	4.4%	4.5%	4.6%
					Net Load Forecast				**44.2**	**44.3**	**44.3**	**44.4**	**44.6**	**44.9**	**45.3**	**45.7**	**46.1**	**46.5**
CNPI Station #18 MTS	*TF1/TF2*	*37.5/50/62.5*	*62.5*	*56.3*	Total Gross Peak Forecast				39.9	40.3	40.7	41.1	41.5	42.0	42.4	42.8	43.2	43.7
					Historical Load	36.0	32.5	35.6										
					Extreme Weather Correction			35.0	39.3	39.7	40.1	40.5	41.0	41.4	41.8	42.2	42.6	43.1
					DG				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
					CDM				0.7%	1.5%	2.5%	3.2%	3.8%	4.0%	4.3%	4.4%	4.5%	4.6%
					Net Load Forecast				**39.0**	**39.1**	**39.1**	**39.2**	**39.4**	**39.7**	**40.0**	**40.4**	**40.7**	**41.1**

Appendix B: Lists of Step-Down Transformer Stations

Sr. No.	Transformer Stations	Voltages (kV)
1.	Allanburg TS	230/115/27.6
2.	Beamsville TS	115/27.6
3.	Bunting TS	115/13.8
4.	Carlton TS	115/13.8
5.	Crowland TS	115/27.6
6.	Dunnville TS	115/27.6
7.	GlendaleTS	115/13.8
8.	Kalar MTS	115/13.8
9.	Murray TS	115/13.8
10.	Niagara West MTS	230/27.6
11.	NOTL York MTS	115/27.6
12.	NOTL #2 MTS	115/27.6
13.	Port Colborne TS	115/27.6
14.	Stanley TS	115/27.6
15.	Thorold TS	115/13.8
16.	Vansickle TS	115/13.8
17.	Vineland DS	115/27.6
18.	CNPI Station #11 MTS	115/27.6
19.	CNPI Station #17 MTS	115/27.6
20.	CNPI Station #18 MTS	115/27.6

Appendix C: Lists of Transmission Circuits

Sr. No.	Circuit ID	From Station	To Station	Voltage (kV)
1.	Q3N/Q4N	Sir Adam Beck SS #1	Murray TS	115
2.	Q11S/Q12S	Sir Adam Beck SS #1	Glendale TS	115
3.	Q2AH	Sir Adam Beck SS #1	Allanburg TS / Beamsville TS / Dunnville TS	115
4.	A36N/A37N	Murray TS	Allanburg TS / Station #18 CTS	115
5.	A6C/A7C	Allanburg TS	Port Colborne TS	115
6.	D1A/D3A	Allanburg TS	Decew Falls SS	115
7.	D9HS/D10S	Glendale TS	Decew Falls SS	115

Appendix D: Lists of LDCs in the Niagara Region

Sr. No.	Company	Connection Type (TX/DX)
1.	Hydro One Networks Inc. (Distribution)	TX/DX
2.	Alectra Utilities	DX
3.	Canadian Niagara Power Inc.	TX/DX
4.	Grimsby Power Inc.	TX/DX
5	Niagara on the Lake Hydro Inc.	TX
6.	Niagara Peninsula Energy Inc.	TX/DX
7.	Welland Hydro Electric System Corp.	DX

Appendix E: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
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
ICI	Industrial Conservation Initiative
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
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

Niagara on-the-Lake Hydro

DISTRIBUTION SYSTEM PLAN APPENDIX B

Niagara IRRP Report

EB-2023-0041

Niagara Integrated Regional Resource Plan

December 22, 2022

Connecting Today.
Powering Tomorrow.

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List of Acronyms

Acronym	Definition
CDM	Conservation and Demand Management
CNPI	Canadian Niagara Power Inc.
DG	Distributed Generation
DR	Demand Response
DS	Distribution Station
FIT	Feed-in-Tariff
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	kilovolt
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTR	Limited Time Rating
MTS	Municipal Transformer Station
MVA	Megavolt ampere
MW	Megawatt
NERC	North American Electric Reliability Corporation
NOTL	Niagara-on-the-Lake
NPCC	Northeast Power Coordinating Council

Acronym	Definition
NPEI	Niagara Peninsula Energy Inc.
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
TS	Transformer Station

1. Introduction

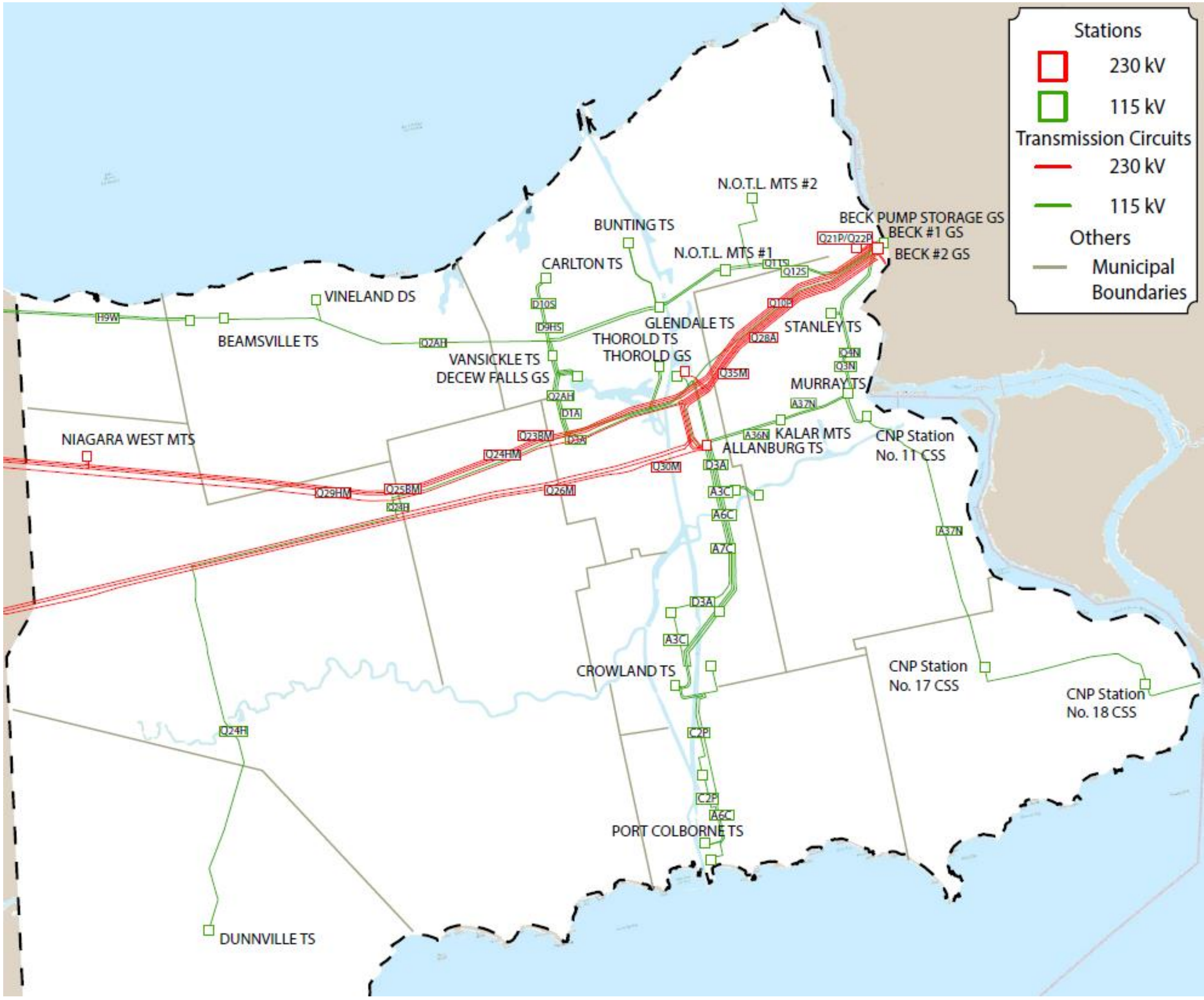
This Integrated Regional Resource Plan ("IRRP") addresses the electricity needs of the Niagara Region over the next 20 years, from 2022 to 2041. The Niagara Region is located between Lake Ontario and Lake Erie, and includes one upper-tier municipality (Regional Municipality of Niagara) and 12 lower-tier municipalities: Fort Erie, Grimsby, Lincoln, Niagara Falls, Niagara-on-the-Lake, Pelham, Port Colborne, St. Catharines, Thorold, Wainfleet, Welland, and West Lincoln.

This region also includes the following First Nations and Métis Nation of Ontario councils:

- Mississaugas of the New Credit
- Oneida Nation of the Thames
- Six Nations of the Grand River (Six Nations Elected Council and Haudenosaunee Confederacy Chiefs Council)
- Métis Nation of Ontario Niagara Region Métis Council

The Niagara Region is summer-peaking and, over the last five years, peak electrical demand has remained steady at an average of 810 MW. Electrical supply is provided primarily through 230/115 kilovolt ("kV") autotransformers at Allanburg Transformer Station ("TS"), and is generally served by 230 kV and 115 kV transmission lines and step-down transformation facilities as shown in Figure 1. The region is defined electrically by the 230 kV transmission circuits that connect Sir Adam Beck Generating Station ("GS") #2 in the east to Burlington TS and Middleport in the west. Other large transmission-connected generating facilities include Sir Adam Beck GS #1 and Decew Falls GS connecting to the 115 kV system, and Thorold GS connecting to the 230 kV system.

Figure 1 | Overview of the Niagara Region



The region's electricity is delivered by six local distribution companies ("LDCs"): Alectra Utilities, Canadian Niagara Power Inc. ("CNPI"), Grimsby Power Inc., Hydro One Networks Inc. (Distribution), Niagara on the Lake Hydro Inc., Niagara Peninsula Energy Inc. ("NPEI"), and Welland Hydro Electric System Corp. Hydro One Networks Inc. (Transmission) is the primary transmission asset owner. This IRRP report was prepared by the Independent Electricity System Operator ("IESO") on behalf of a Technical Working Group, composed of the LDCs, Hydro One, and the IESO.

Development of the Niagara IRRP was initiated in August 2021, following the publications of the Needs Assessment report in May 2021 by Hydro One and the Scoping Assessment Outcome Report in August 2021 by the IESO. The Scoping Assessment identified needs for further assessment through an IRRP. The Technical Working Group was then formed to gather data, identify near- to long-term needs in the region, and develop the recommended actions included in this IRRP.

This report is organized as follows:

- A summary of the recommended plan for the region is provided in Section 2;

- The process and methodology used to develop the plan are discussed in Section 3;
- The context for electricity planning in the region and the study scope are discussed in Section 4;
- Demand forecast scenarios, and conservation and demand management and distributed generation assumptions, are described in Section 5;
- Electricity needs in the region are presented in Section 6;
- Alternatives and recommendations for meeting needs are addressed in Section 7;
- A summary of engagement activities is provided in Section 8; and
- The conclusion is provided in Section 9.

2. The Integrated Regional Resource Plan

This IRRP provides recommendations to address the electricity needs of the Niagara Region over the next 20 years. The needs identified are based on the demand growth anticipated in the region and the capability of the existing transmission system, as evaluated through application of the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC") and reliability standards governed by the North American Electric Reliability Corporation ("NERC"). The IRRP's recommendations are informed by an evaluation of different options to meet the needs and consider: reliability, cost, technical feasibility, maximizing the use of the existing electricity system (where economic), and feedback from stakeholders.

The Niagara electricity demand forecast, provided by the LDCs, projects sustained growth driven by community area, employment area, and rural settlement expansions. This growth spans multiple municipalities, including (but is not limited to): Lincoln, West Lincoln, Welland, Thorold, and Niagara Falls.

The IRRP recommendations below are organized under a near-/medium-term plan and other ongoing or long-term initiatives. This distinction reflects the different levels of forecast certainty, lead time for development, and planning commitment required over these time horizons. This approach ensures that the IRRP provides clear direction on investments needed in the near and medium term, while retaining flexibility over the long term, as electrification, energy efficiency, and development plans evolve.

2.1 Near-/Mid-Term Plan

The near- and mid-term plan comprises several recommendations to accommodate load growth, maintain reliability, and optimize asset replacement. Where possible, needs are grouped to align with integrated sets of solutions. These recommendations are summarized in Table 1 and further discussed below.

Table 1 | Summary of the Near/Mid-Term Plan for the Niagara IRRP

Need(s)	Lead Responsibility	Technical Working Group Recommendation	Expected In-Service Date
• Beamsville TS station capacity	• Grimsby Power • NPEI • Hydro One Distribution	• Coordinate load transfers to offload Beamsville TS to Niagara West MTS in the near-term	• 2023

Need(s)	Lead Responsibility	Technical Working Group Recommendation	Expected In-Service Date
• Beamsville TS, Niagara West Municipal Transformer Station (“MTS”), and Vineland Distribution System (“DS”) station capacity • Niagara 115 kV sub-system supply capacity	• Grimsby Power • NPEI • Hydro One Distribution • Hydro One Transmission	• Initiate development of a new 230 kV station supplied from Q23BM and Q25BM, or an expansion of Niagara West MTS	• 2026-2027
• Beamsville TS, Niagara West MTS, and Vineland DS station capacity	• Grimsby Power • NPEI • Hydro One Distribution	• Monitor load growth between regional planning cycles	• Ongoing
• Beamsville TS and Vineland DS station capacity	• Technical Working Group	• Investigate opportunities to target incremental conservation and demand management (“CDM”) to Beamsville TS and Vineland DS	• Ongoing
• Crowland TS station capacity and asset replacement • A6C/A7C load security • Niagara 115 kV sub-system supply capacity	• Hydro One Transmission	• Initiate development for the replacement of Crowland TS with a new 230 kV station, supplied by new 230 kV double-circuit lines from Q24HM and Q29HM	• 2028
• Niagara 115 kV sub-system supply capacity	• Hydro One Transmission	• Develop and implement a new 115 kV sub-system load rejection scheme	• 2024

Need(s)	Lead Responsibility	Technical Working Group Recommendation	Expected In-Service Date
• Niagara 115 kV sub-system supply capacity	• Hydro One Transmission	• Uprate Q28A	• 2024
• Niagara 115 kV sub-system supply capacity	• Technical Working Group	• Monitor load growth between regional planning cycles	• Ongoing
• Niagara 115 kV sub-system supply capacity	• Technical Working Group	• Investigate opportunities to target incremental CDM to the 115 kV sub-system	• Ongoing
• Murray TS (T11/T12) station capacity	• NPEI • Hydro One Transmission	• Monitor load growth and transfer load in excess of the station limit to Murray TS transformer 13 and 14 (T13/T14)	• 2023

2.1.1 Load Transfers from Beamsville TS and a New or Expanded 230 kV Station

Stations limits are typically dictated by the lowest rated transformer. Beamsville TS is fully utilized today and there is no remaining capacity for growth. Nearby stations Niagara West MTS and Vineland DS are also forecast to reach their capacity limits by 2026 and 2030, respectively.

The IRRP considered the merits of a portfolio of "non-wires" (non-transmission) options as well as integrated "wires" (transmission) options. Based on planning-level cost estimates and its ability to address capacity shortfalls at the three stations, the Technical Working Group recommends that a new 230 kV station supplied by Q23BM and Q25BM is built. This could be accomplished by expanding the existing Niagara West MTS. Development and implementation for additional capacity should begin as soon as possible for a targeted in-service date of 2026-2027. The next stage of regional planning, the Regional Infrastructure Plan ("RIP") led by Hydro One, should confirm the party who will lead development work (i.e., Grimsby Power, NPEI, or Hydro One).

In the meantime, the IRRP recommends that the local distributors (Grimsby Power, NPEI, Hydro One Distribution), in conjunction with Hydro One Transmission where appropriate, develop a plan to transfer load from Beamsville TS to the other nearby stations (Niagara West MTS, Vineland DS) to manage the urgent Beamsville TS need until the new station is in-service.

2.1.2 Major High Voltage Equipment Replacement of Crowland TS, New 230 kV Transmission Lines, Q28A Upgrade, and Control Actions

The existing T5 and T6 transformers at Crowland TS will require major high voltage ("HV") equipment replacement in 2026, and are forecast to be fully utilized in 2022. Crowland TS, as well as other stations supplied by the A6C/A7C circuits, are also impacted by a load security need that exists today. Moreover, Crowland TS is included in the broader Niagara 115 kV sub-system whose supply capacity need exists today and continues to grow by the end of the planning horizon.

The IRRP developed and evaluated portfolios of non-wires options, standalone generation, and wires alternatives for the multiple needs in this area. Ultimately, the most feasible and cost-effective solution at this time requires wires reinforcements: the upgrade of Q28A, the replacement of 115 kV Crowland TS with a larger 230 kV station supplied by new 230 kV transmission lines from Q24HM and Q29HM, and a new load rejection scheme developed to manage the Niagara 115 kV sub-system load. The IRRP recommends that Hydro One should begin implementation as soon as possible for a targeted in-service dates of 2024, 2024, and 2028 for the load rejection scheme, Q28A upgrade, and new 230 kV station and lines, respectively. Measures to manage the HV equipment replacement infrastructure at Crowland TS should be implemented by Hydro One until the station replacement is in-service.

2.1.3 Load Transfers from Murray TS (T11/T12)

Murray TS (T11/T12) is forecast to be beyond capacity in 2022 during its station peak. Given the small magnitude of this need and the available capacity on the other set of transformers at Murray TS (T13/T14), the IRRP recommends that some load is re-allocated to T13/T14 and growth continues to be monitored.

2.2 Ongoing Initiatives

In addition to the near- and mid-term plan above, two ongoing actions were identified to manage needs expected in the long-term.

2.2.1 Monitor Load Growth

Carlton TS and Kalar MTS are expected to reach capacity in 2028 and 2030, respectively. In the case of Carlton TS, distribution-level load transfers to Bunting TS have been indicated as an option. Given the timing, no firm recommendation is required at this time for either need; the Technical Working Group will continue to monitor load growth and revisit these needs in the next cycle of regional planning. As part of broader monitoring, the Technical Working Group should also keep apprised of and participate in any future Community Energy Plans developed by municipalities of the Niagara Region.

2.2.2 Explore Opportunities for Targeted CDM

In addition to monitoring how the forecast demand materializes, the IRRP recommends continuing to consider opportunities for targeted CDM. During the options analyses, the benefits and potential of incremental, cost-effective CDM were identified – particularly if targeted to manage near-term needs until transmission reinforcements are in-service (as is the case for the Beamsville TS/Vineland DS/Niagara West MTS area, as well as the 115 kV sub-system), or to defer long-term needs (such as at Kalar MTS). The Technical Working Group should continue to support and monitor CDM uptake, and bring these insights into the next cycle of regional planning for the Niagara Region.

3. Development of the Plan

3.1 The Regional Planning Process

In Ontario, preparing to meet the electricity needs of customers at a regional level is achieved through regional planning. Regional planning assesses the interrelated needs of a region – defined by common electricity supply infrastructure – over the near, medium, and long-term, and results in a plan to ensure cost-effective and reliable electricity supply. A regional plan considers the existing electricity infrastructure in an area, forecasts growth and customer reliability, evaluates options for addressing needs, and recommends actions.

The current regional planning process was formalized by the Ontario Energy Board in 2013 and is performed on a five-year cycle for each of the 21 planning regions in the province. The process is carried out by the IESO, in collaboration with the transmitters and LDCs in each region. The process consists of four main components:

1. A Needs Assessment, led by the transmitter, which completes an initial screening of a region's electricity needs and determines if there are electricity needs requiring regional coordination;
2. A Scoping Assessment, led by the IESO, which identifies the appropriate planning approach for the identified needs and the scope of any recommended planning activities;
3. An IRRP, led by the IESO, which proposes recommendations to meet the identified needs requiring coordinated planning; and/or
4. A RIP, led by the transmitter, which provides further details on recommended wires solutions.

Regional planning is not the only type of electricity planning in Ontario. Other types include bulk system planning and distribution system planning. There are inherent overlaps in all three levels of electricity infrastructure planning. Further details on the regional planning process and the IESO's approach to it can be found in Appendix A.

The IESO has recently completed a review of the regional planning process, following the completion of the first cycle of regional planning for all 21 regions. Additional information on the Regional Planning Process Review, along with the final report is posted on the IESO's website.

3.2 Niagara and IRRP Development

The process to develop the Niagara IRRP initiated in August 2021, following the publication of the Needs Assessment report in May 2021 by Hydro One and the Scoping Assessment Outcome Report in August 2021 by the IESO. The Scoping Assessment recommended that the needs identified for the Niagara Region be considered through an IRRP in a coordinated regional approach, supported with public engagement. The Technical Working Group was then formed to develop the terms of reference for this IRRP, gather data, identify needs, develop options, and recommend solutions for the region.

4. Background and Study Scope

This is the second cycle of regional planning for the Niagara Region. This region roughly encompasses the municipalities Fort Erie, Grimsby, Lincoln, Niagara Falls, Niagara-on-the-Lake, Pelham, Port Colborne, St. Catharines, Thorold, Wainfleet, Welland, and West Lincoln. This region also includes the following First Nations and Métis Nation of Ontario Councils: Mississaugas of the New Credit, Oneida Nation of the Thames, Six Nations of the Grand River (Six Nations Elected Council and Haudenosaunee Confederacy Chiefs Council), and the Métis Nation of Ontario Niagara Region Métis Council. Following a Needs Assessment and Scoping Assessment in 2016, a RIP was initiated by Hydro One and subsequently published in 2017, concluding the first planning cycle for the Niagara Region. An IRRP was not developed, as two electricity needs were identified in 2016, but no further regional coordination was required.

The current cycle of regional planning began in 2021 with the publication of the Needs Assessment Report, where several needs requiring further regional coordination were identified. The 2021 Niagara Scoping Assessment recommended an IRRP for the entire region to address needs in a coordinated manner. This report presents an integrated regional electricity plan for the next 20-year period starting from 2022.

This IRRP develops and recommends options to meet the electricity needs of the Niagara Region in the near, medium, and long term. The plan was prepared by the IESO on behalf of the Technical Working Group, and includes consideration of forecast electricity demand growth, CDM, distributed generation ("DG"), transmission and distribution system capability, relevant community plans, condition of transmission assets, and developments on the bulk transmission system.

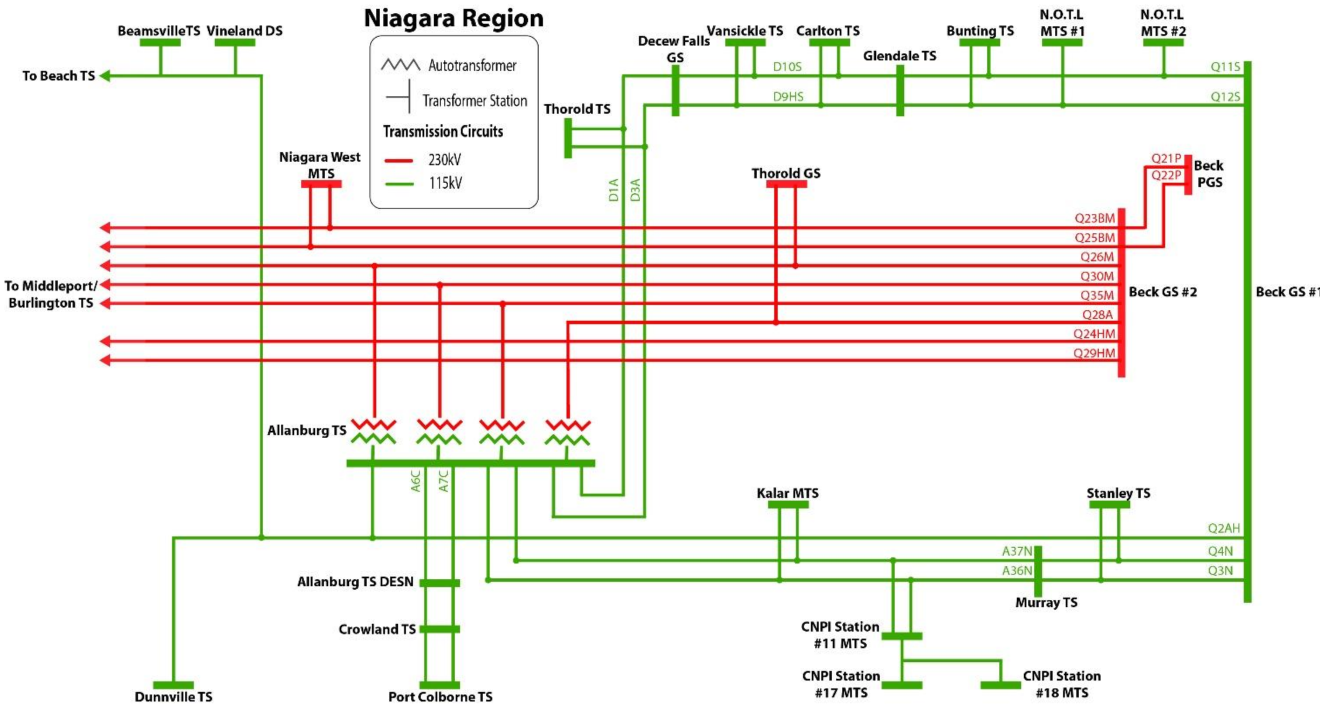
The following transmission facilities were included in the scope of this study:

- Transformer stations: Allanburg TS, Beamsville TS, Bunting TS, Carlton TS, Crowland TS, Dunnville TS, Glendale TS, Kalar MTS, Murray TS, Niagara West MTS, Niagara-on-the-Lake ("NOTL") York MTS, NOTL #2 MTS, Port Colborne TS, Stanley TS, Thorold TS, Vansickle TS, Vineland DS, CNPI #11 MTS, CNPI #17 MTS, CNPI #18 MTS. Except for Niagara West MTS, all stations are supplied from 115 kV transmission circuits.
- 115 kV transmission circuits: Q3N/Q4N, Q11S/Q12S, Q2AH, A36N/A37N, A6C/A7C, D1A/D3A, D9HS/D10S.
- 230 kV transmission circuits: Q23BM, Q24HM, Q25BM, Q26M, Q28A, Q29HM, Q30M, Q35M.

The single line diagram of the Niagara Region is shown in Figure 2 below. Note that the bulk system transfer capabilities on the Queenston Flow West interface[1] through the region is not within the scope of the IRRP and would be separately studied in a bulk transmission plan, as required. The schedule of bulk planning activities is identified through the IESO's Annual Planning Outlook.

[1]Includes flow out at Beck (Q25BM + Q23BM + Q24HM + Q29HM) and flow in at Middleport (Q30M + Q26M + Q35M).

Figure 2 | Single Line Diagram of the Niagara Region



The Niagara IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast and establishing needs over this timeframe (as described in the following steps);
    - Examining the load meeting capability ("LMC") and reliability of the existing transmission system, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices. Needs were established by applying ORTAC and NERC criteria;
    - Assessing system needs by applying a contingency-based assessment and reliability performance standards for transmission supply in the IESO-controlled grid;
    - Confirming identified asset replacement needs and timing with the transmitter and LDCs;
- Establishing alternatives to address system needs including, where feasible and applicable, generation, transmission and/or distribution, and other approaches such as non-wires alternatives including CDM;
- Engaging with the community on needs and possible alternatives;
- Evaluating alternatives to address near- and long-term needs; and
- Communicating findings, conclusions, and recommendations within a detailed plan.

5. Electricity Demand Forecast

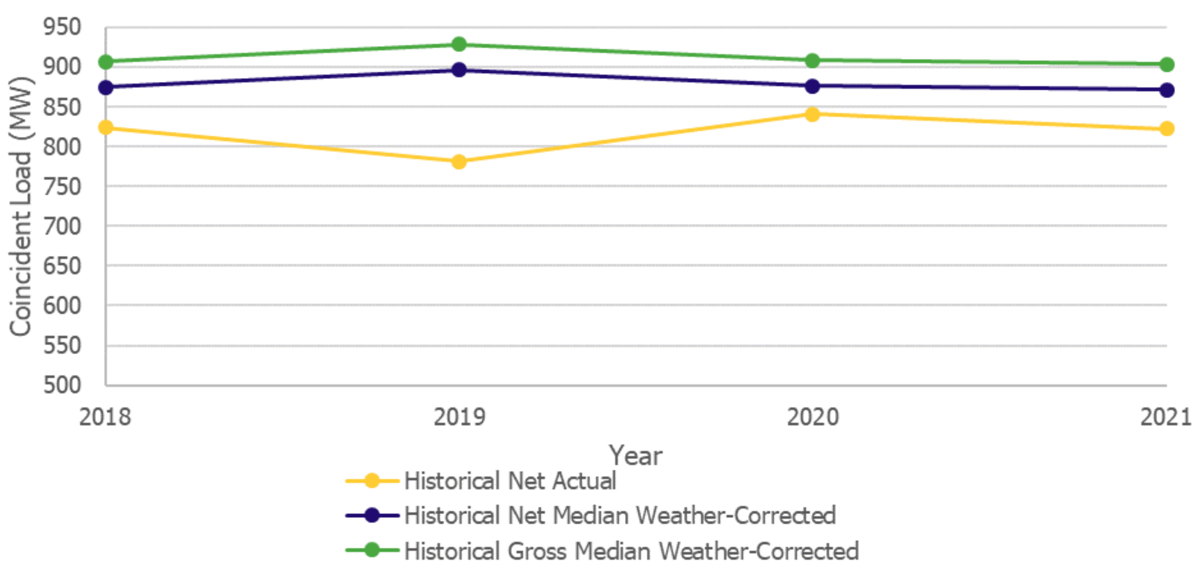
Regional planning in Ontario is driven by having to meet peak electricity demand requirements in the region. This section describes the development of the demand forecast for the Niagara Region. It highlights the assumptions made for peak demand forecasts, including weather correction, the contribution of CDM and DG, and the development of a high growth scenario. The reference net extreme weather demand forecast is used in assessing the electricity needs of the area over the planning horizon; the high forecast scenario, used as the basis for a sensitivity analysis, is described further in Section 5.7.

To evaluate the reliability of the electricity system, the regional planning process is typically concerned with the coincident peak demand for a given area. This is the demand observed at each station for the hour of the year in which overall demand in the study area is at its maximum. This differs from a non-coincident peak, which refers to each station's individual peak, regardless of whether these peaks occur at different times. Within the Niagara Region, the peak loading hour for each year has historically occurred in the summer.

5.1 Historical Demand

Peak electricity demand within the Niagara Region has been steady over the last four years. Figure 3 below shows the coincident net actual (as observed at the metering point), net median weather-corrected (adjusted to reflect median weather conditions), and gross median weather-corrected (contribution of DG removed) historical demand. The gross median weather-corrected demand has averaged 910 megawatts ("MW") over the past four years, with the peak demand hour for each year occurring consistently in the summer between approximately 4 PM to 7 PM. The 2021 gross median weather-corrected peak at each station in the Niagara Region was used as the starting point for the forecast.

Figure 3 | Historical Demand in the Niagara Region

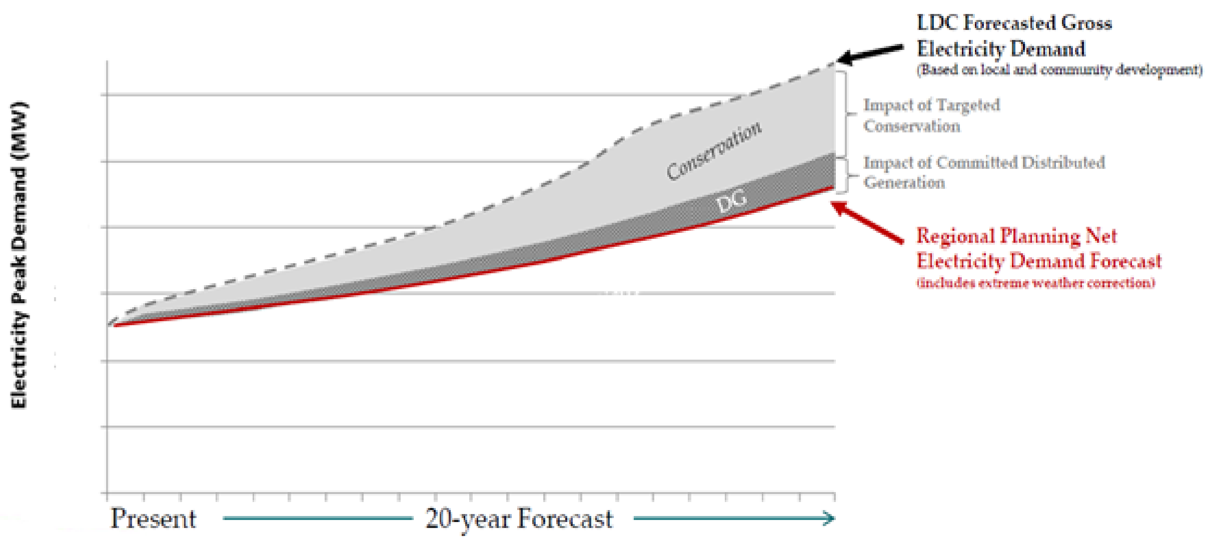


5.2 Demand Forecast Methodology

The steps taken to develop a 20-year IRRP peak demand forecast are depicted in Figure 4. Gross demand forecasts, which assume the weather conditions of an average year based on historical weather conditions (referred to as "normal weather"), were developed by the LDCs. These forecasts were then modified to reflect the peak demand impacts of provincial conservation targets and DG contracted through previous provincial programs such as Feed-In Tariff ("FIT") and microFIT, and adjusted to reflect extreme weather conditions in order to produce a reference forecast for planning assessments. This net forecast was then used to assess the electricity needs in the region.

Additional details related to the development of the demand forecast are provided in Appendix B. Though the Niagara IRRP forecast was created prior to October 2022, the Ontario Energy Board also since published a [Load Forecast Guideline] for regional planning, through the [Regional Planning Process Advisory Group].

Figure 4 | Illustrative Development of Demand Forecast

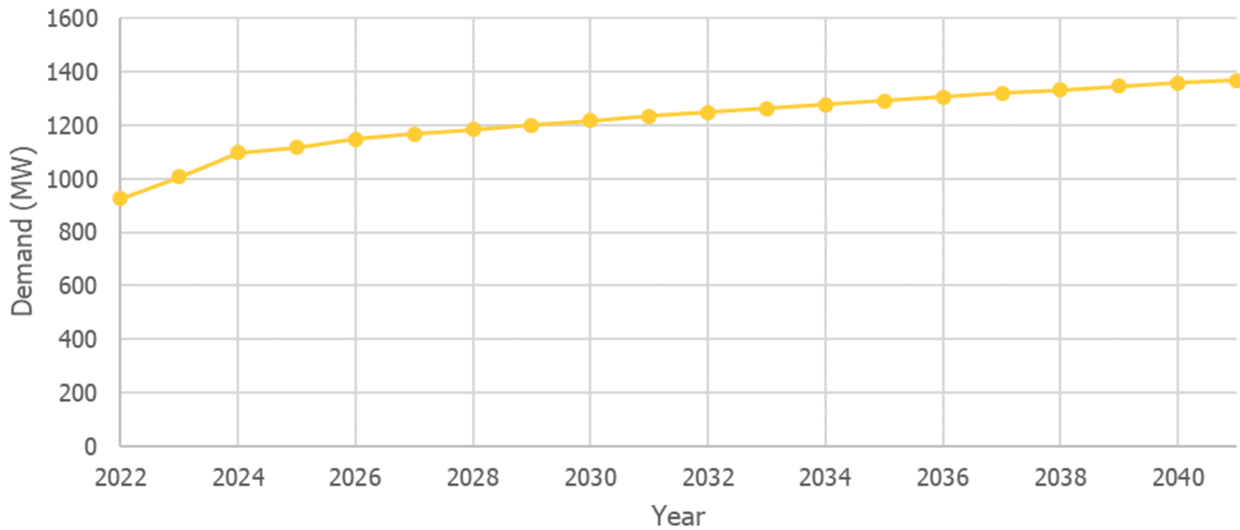


5.3 Gross LDC Forecast

Each participating LDC in the Niagara Region prepared gross demand forecasts at the station level, or at the station bus level for multi-bus stations. These gross demand forecasts account for increases in demand from new or intensified development, plus known connection applications. The LDCs cited alignment with municipal and regional official plans, and credited them as a source for input data. LDCs were also expected to account for changes in consumer demand resulting from typical efficiency improvements and response to increasing electricity prices ("natural conservation"), but not for the impact of future DG or new conservation measures (such as codes and standards and CDM programs), which are accounted for by the IESO (discussed in Section 5.4). The gross LDC forecast assumes median on-peak weather conditions, and station loading that is coincident to the region.

LDCs have a better understanding of future local demand growth and drivers than the IESO, since they have the most direct involvement with their customers, connection applicants, and municipalities and communities which they serve. The IESO typically carries out demand forecasting at the provincial level. More details on the LDCs' load forecast assumptions can be found in Appendix B.2 to B.8. Figure 5 below shows the total gross demand forecast provided by the LDCs for the Niagara Region.

Figure 5 | Total Gross Demand Forecast Provided by LDCs (Median Weather)[2]



5.4 Contribution of Conservation to the Forecast

Conservation and demand management is a clean and cost-effective resource that helps meet Ontario's electricity needs, and has been an integral component of provincial and regional planning. Conservation is achieved through a mix of codes and standards amendments, as well as CDM program-related activities. These approaches complement each other to maximize conservation results.

The estimate of demand reduction due to codes and standards are based on expected improvement in the codes for new and renovated buildings, and through regulation of minimum efficiency standards for equipment used by specified categories of consumers (i.e., residential, commercial and industrial consumers).

The estimates of demand reduction due to program-related activities account for the 2021-2024 CDM Framework, federal programs that result in electricity savings in Ontario, and forecasted long-term energy efficiency programs. The 2021 – 2024 CDM Framework is the main piece, in which the IESO centrally delivers programs on a province-wide basis to serve business and low-income customers, as well as Indigenous communities.

Figure 6 shows the estimated total yearly reduction to the demand forecast due to conservation (from codes, standards, and CDM programs) for each of the residential, commercial, and industrial consumers. Additional details are provided in Appendix B.9.

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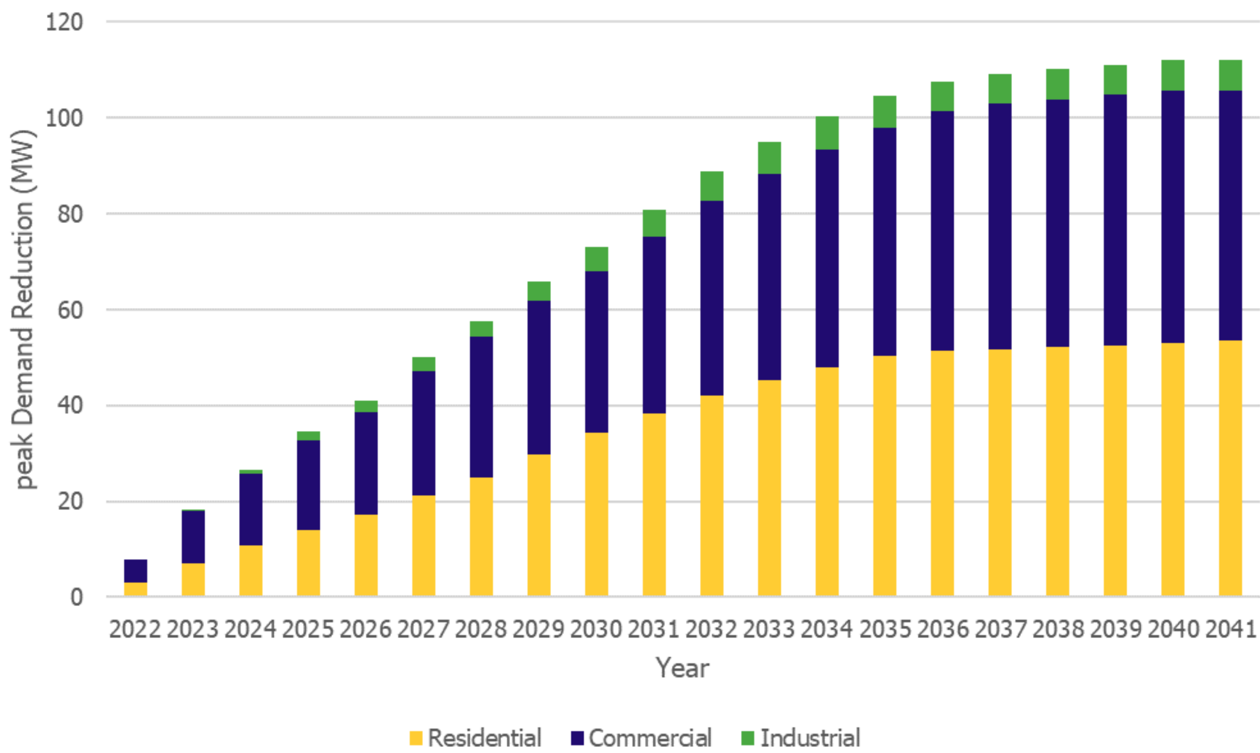
[2] Excludes existing transmission-connected industrial customers in the Niagara Region (historically contributing an average of 15 MW to the coincident peak demand).

Figure 6 | Total Forecast Peak Demand Reduction (Codes, Standards, and CDM Programs)

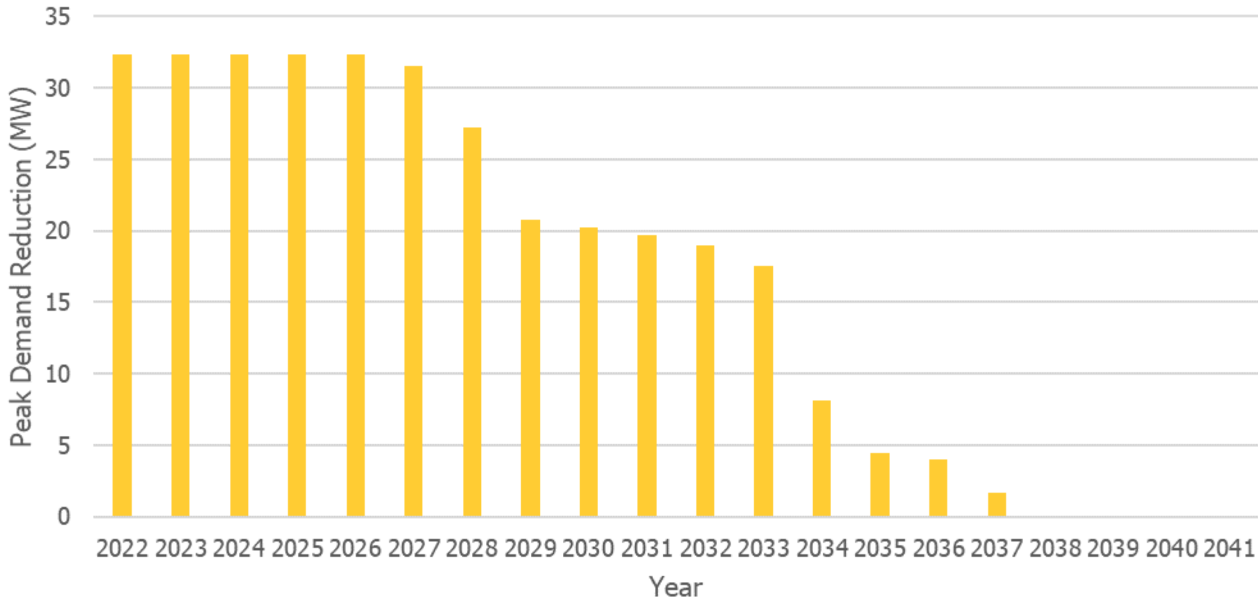


5.5 Contribution of Distributed Generation to the Forecast

In addition to conservation resources, DG in the Niagara Region is also forecast to offset peak-demand requirements. The introduction of Ontario's FIT Program increased the significance of distributed renewable generation which, while intermittent, contributes to meeting the province's electricity demands. The installed DG capacity by fuel type and contribution factor assumptions can be found in Appendix B.10. Most of the total contracted installed DG capacity in the Niagara Region is solar, wind, and waterpower, with some biogas, landfill gas, and natural gas facilities.

After reducing the demand forecast due to conservation, as described in Section 5.4, the forecast is further reduced by the expected contribution from contracted DG. Figure 7 shows the impact of DG on reducing the Niagara Region demand forecast. Note that any facilities without a contract with the IESO are not currently included in the DG peak demand reduction forecast.

Figure 7 | Peak Demand Reduction to Demand Forecast, Due to DG



In the long term, the contribution of DG is expected to diminish as their contracts expire. A total of 32 MW of peak contribution is identified for the Niagara Region in 2022, reducing throughout the 2030s to 0 MW by 2038. This reduction is reflected in the high forecast scenario (see Section 5.7 for more details on its development and assumptions), but not the reference forecast. Rather, the reference Niagara IRRP forecast assumes a constant contribution of approximately 32 MW each year for the entire study period. This aligns with the Technical Working Group decision to assume that already-existing DG facilities with expired contracts will continue to offset demand.

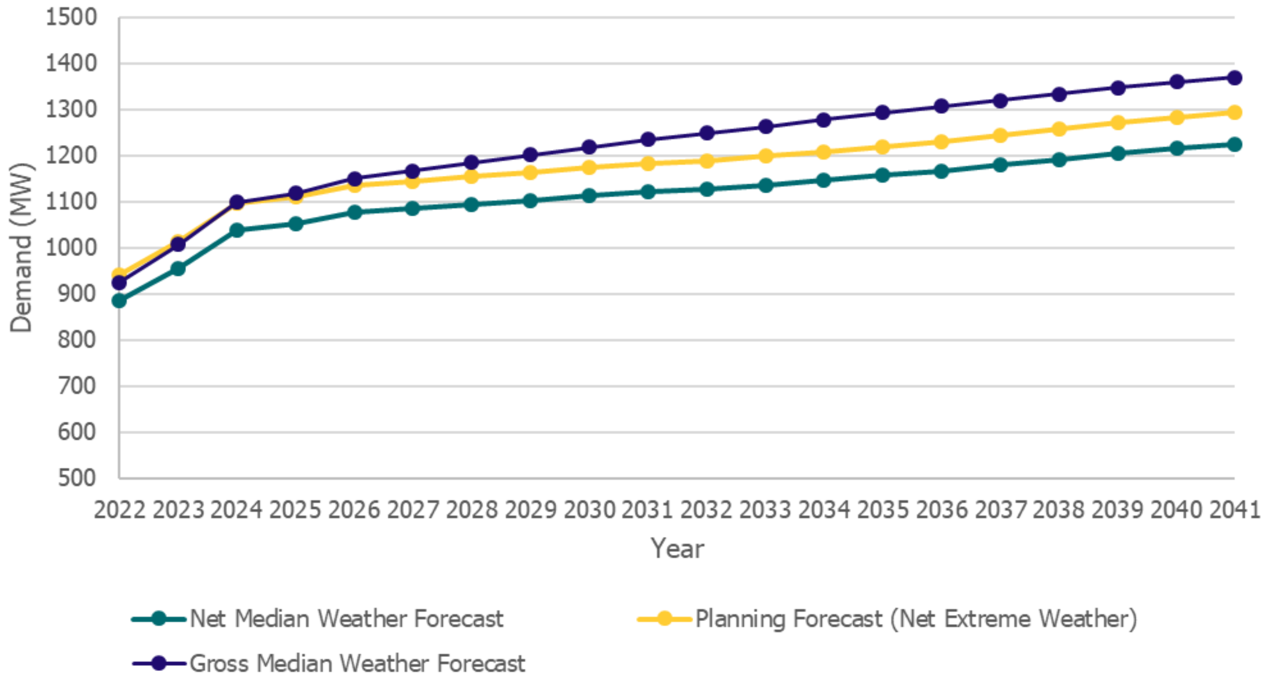
5.6 Net Extreme Weather ("Planning") Forecast

The net extreme weather forecast, also known as the "planning" forecast, is created by adjusting the net median weather forecast (the gross demand forecast, plus the forecast DG and conservation impacts as described above) for extreme weather conditions. The weather correction methodology is described in Appendix B.1.

Note that this planning forecast is coincident, meaning that each station forecast reflects its expected contribution to the regional peak demand level. This supports the identification of need dates for regional needs that are driven by more than one station. For station-specific needs, the non-coincident forecast is calculated by applying a non-coincidence factor. The factor is based on the historical non-coincident peaks of each station compared to the station's contribution to the region's coincident peaks over the past six years.

The coincident net extreme weather forecast for the Niagara Region is shown in Figure 8 below.

Figure 8 | Net Extreme Weather ("Planning") Forecast for the Niagara Region[3]



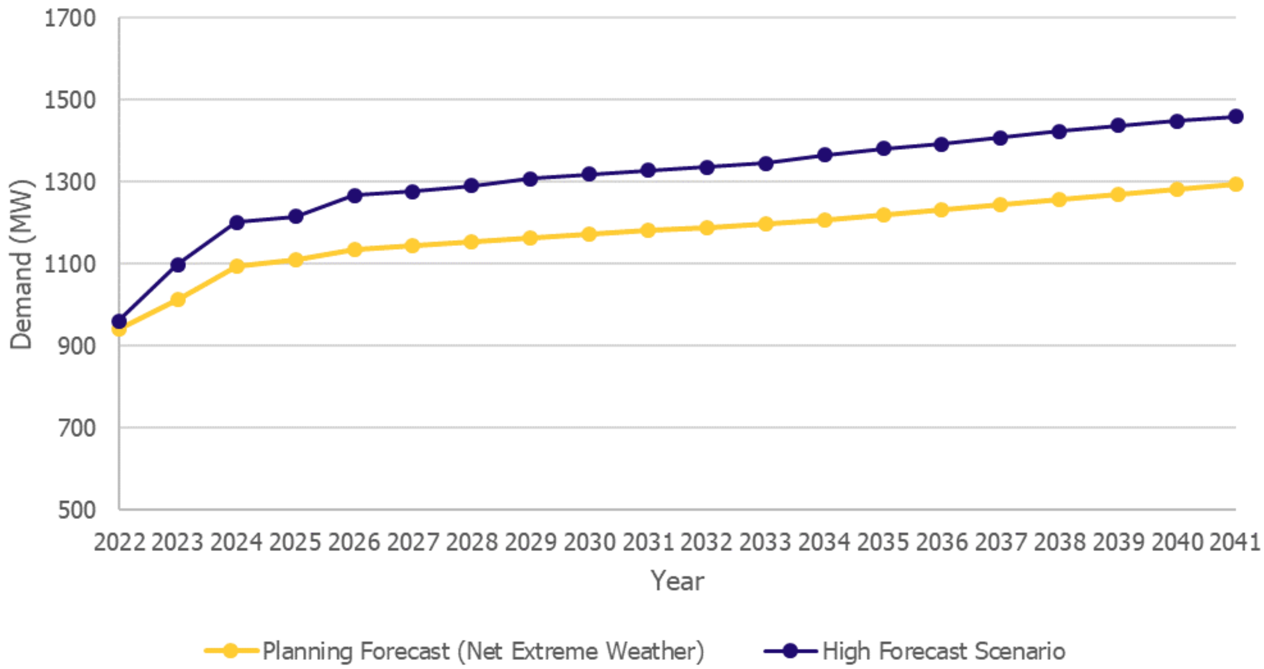
5.7 High Forecast Scenario

The Technical Working Group opted to develop a high forecast sensitivity scenario for the Niagara Region. This higher demand scenario is to take into account a variety of factors that could drive demand higher over the next 20 years, including but not limited to: electric vehicle charging infrastructure, electrified space heating installations, unanticipated new industrial customers, or general higher-than-expected growth. However, the Technical Working Group did not have specific end-use data available to develop the high forecast. Instead, the DG contribution to peak (as described in Section 5.5) was removed according to contract expiries, resulting in approximately 3% higher total regional load by 2041 when compared to the reference planning forecast. The impact on stations with greater contracted DG is higher.

The high forecast also included several large industrial customers whose connection was uncertain at the time of finalizing the reference forecast. These include customers that members of the Technical Working Group were aware of and liaising with, as well as customers that initiated a System Impact Assessment with the IESO during the Niagara IRRP development. In total, another 132 MW was added due to this assumption, when compared to the reference planning forecast. This is shown in Figure 9.

[3] See footnote 2.

Figure 9 | High Forecast Scenario for the Niagara Region[4]



The higher demand scenario was not used to drive any firm recommendations for this IRRP; however, it was used to help the Technical Working Group identify where the future pinch points may be and when they could materialize. This information can also be useful for communities conducting Community Energy Plans, for the Technical Working Group in determining areas to monitor in future planning cycles, and for communities and stakeholders as they think about various projects in the region. Moreover, during this IRRP, the Technical Working Group also considered the flexibility of evaluated options to accommodate greater long-term growth. This is later described in Section 7.

5.8 Hourly Forecast Profiles

In addition to the annual peak forecast, hourly load profiles (8,760 hours per year over the 20-year forecast horizon) for certain stations with identified needs were developed to characterize their needs with finer granularity. The profiles were based on historical load data, adjusted for variables that impact demand such as calendar day (i.e., holidays and weekends) and weather. The profiles were then scaled to match the IRRP peak planning forecast for each year. As described later in Section 7, these profiles were used to quantify the magnitude, frequency, and duration of needs to better evaluate the suitability of generation and distributed energy resource options.

Additional load profile details including hourly heat maps for each need can be found in Appendix D. Note that this data is used to roughly inform the overall energy requirements needed to develop and evaluate alternatives; it cannot be used to deterministically specify the precise hourly energy requirements. Real-time loading is subject to various factors like actual weather, customer operation strategies, and future customer segmentation. Demand patterns can change significantly as consumer behaviour evolves, new industries emerge, and trends like electrification are more widely adopted. Hence, these hourly forecasts are only used to select suitable technology types and roughly

[4] See footnote 2.

estimate costs for the needs and options studied in the IRRP. The Technical Working Group will continue to monitor forecast changes as part of implementation of the plan.

6. Needs

6.1 Needs Assessment Methodology

Based on the planning demand forecast, system capability, the transmitter's identified asset replacement plans, and the application of ORTAC, NERC TPL-001-4, and Northeast Power Coordinating Council ("NPCC") Directory #1 standards, the Technical Working Group identified electricity needs in the near-, medium- and long-term timeframes. These needs can be categorized according to the following:

- **Station Capacity Needs** describe the electricity system's inability to deliver power to the local distribution network through the regional step-down transformer stations during peak demand. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by station equipment. Station ratings are often determined based on the 10-day Limited Time Rating ("LTR") of a station's smallest transformer under the assumption that the largest transformer is out of service. A transformer station can also be more limited by downstream or upstream equipment, i.e., breakers, disconnect switches, low-voltage bus or high voltage circuits.
- **Supply Capacity Needs** describe the electricity system's inability to provide continuous supply to a local area during peak demand. This is limited by the LMC of the transmission supply. The LMC is determined by evaluating the maximum demand that can be supplied to an area after accounting for limitations of the transmission elements (i.e., a transmission line, group of lines, or autotransformer), when subjected to contingencies and criteria prescribed by ORTAC, TPL-001-4, and NPCC Directory #1. LMC studies are conducted using power system simulation analyses.
- **Asset Replacement Needs** are identified by the transmitter by an asset condition assessment, which is based on a range of considerations such as equipment deterioration due to aging infrastructure or other factors; technical obsolescence due to outdated design; lack of spare parts availability or manufacturer support; and/or potential health and safety hazards, etc. Replacement needs identified in the near- and early mid-term timeframe would typically reflect more condition-based information, while replacement needs identified in the medium to long term are often based on the equipment's expected service life. As such, any recommendations for medium- to long-term needs should reflect the potential for the need date to change as condition information is routinely updated.
- **Load Security and Restoration Needs** describe the electricity system's inability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements are prescribed by Section 7 of ORTAC.

Technical study results for the Niagara IRRP can be found in Appendix G. The needs identified are discussed in Sections 6.2 – 6.5 below.

6.2 Station Capacity Needs

In the near/mid-term, there are summer station capacity needs at Beamsville TS, Murray TS, Crowland TS, and Niagara West MTS. In the longer term, there are station capacity needs at Carlton TS, Vineland DS, and Kalar MTS. Table 2 below summarizes transformer capacity limitations for the Niagara Region.

Table 2 | Summary of Station Capacity Needs in the Niagara Region

Need	10-day LTR Rating (MW)[5]	Need Date[6]	Size of Need by 2041
Beamsville TS	57	2022	44
Murray TS (T11/T12)	72	2022	14
Crowland TS	96	2022	25
Niagara West MTS	60	2026	22
Carlton TS	94	2028	11
Kalar MTS	68	2030	7
Vineland DS	25	2030	3

6.2.1 Beamsville TS, Niagara West MTS, and Vineland DS

The three stations supplying the Lincoln, West Lincoln, and Grimsby areas (Beamsville TS, Niagara West MTS, and Vineland DS) are forecast to reach their individual station limits, as well as their collective limit (sum of their LTRs). Beamsville TS and Vineland DS each comprise two 115 kV/27.6 kV transformers, with summer LTRs of 57 MW and 25 MW, respectively. The Beamsville TS capacity need exists today (Figure 10), whereas the Vineland DS need is forecast to start in 2030 (Figure 12). Niagara West MTS consists of two 230 kV/27.6 kV transformers, with a summer LTR of 60 MW and a need beginning in 2026 (Figure 11). Cumulatively, the capacity need at these three stations grows to 57 MW by 2041 (Figure 13).

[5] Assuming a 0.9 power factor.
[6] Based on non-coincident station forecasts, as explained in Section 5.6.

Figure 10 | Beamsville TS Capacity Need

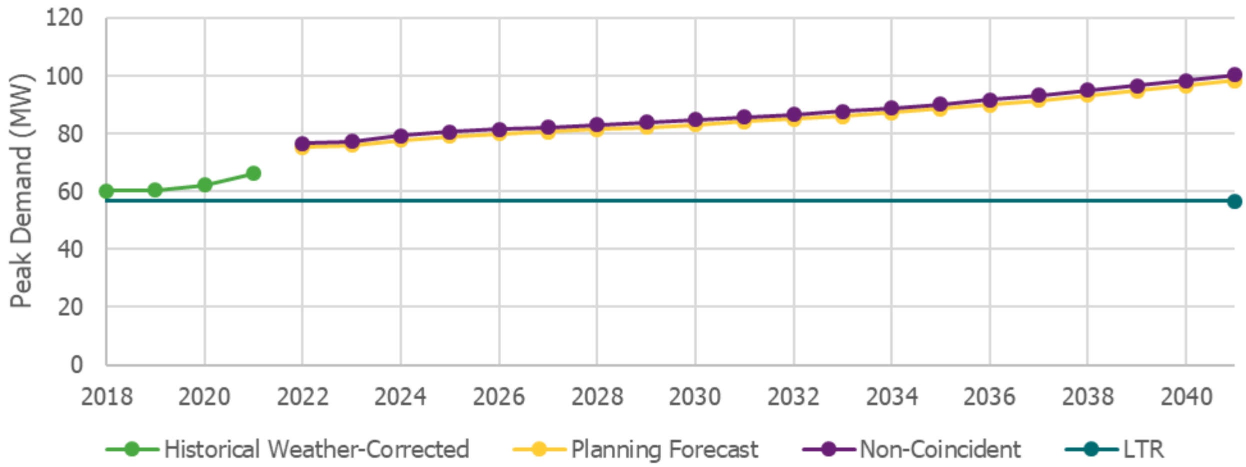


Figure 11 | Niagara West MTS Capacity Need

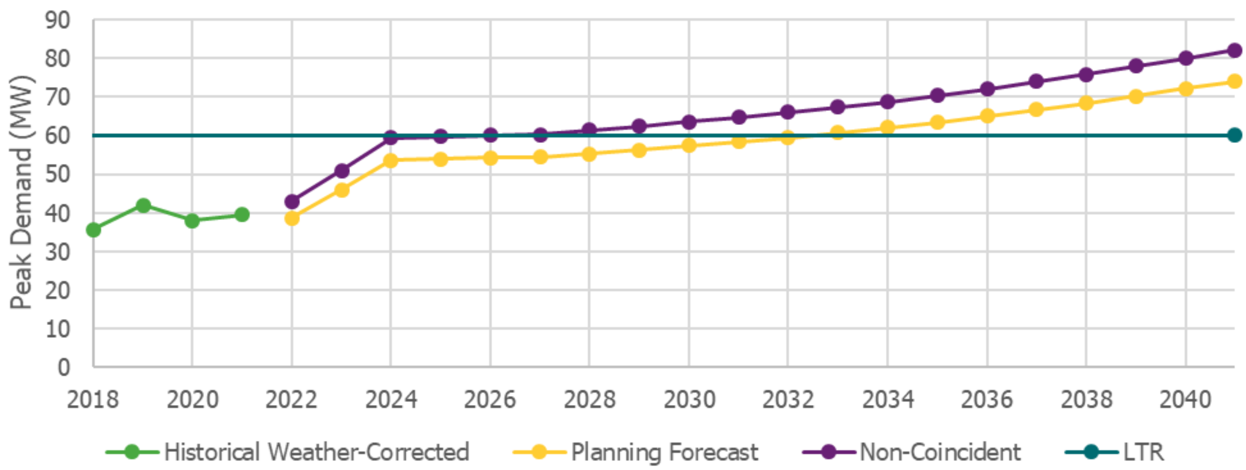


Figure 12 | Vineland DS Capacity Need

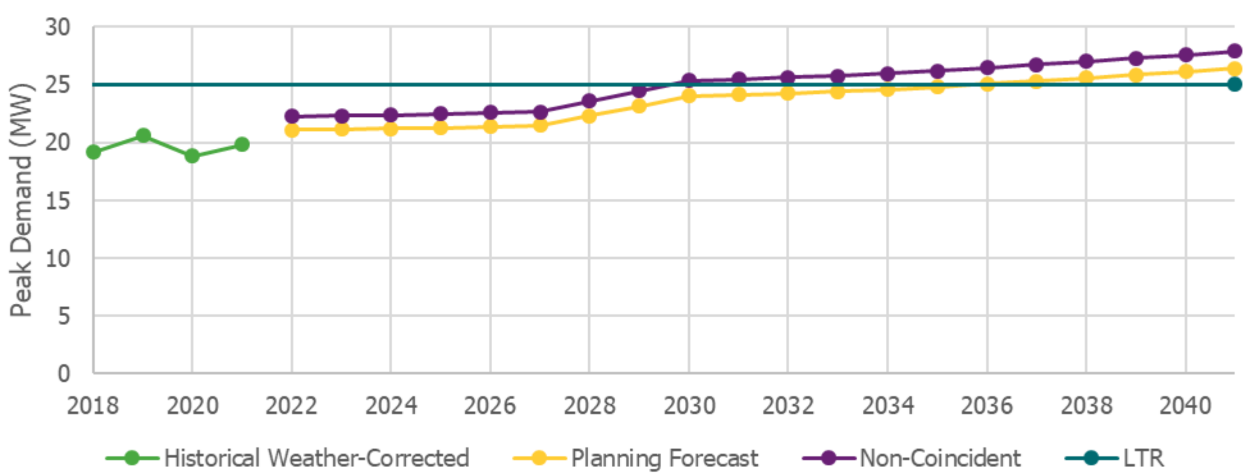
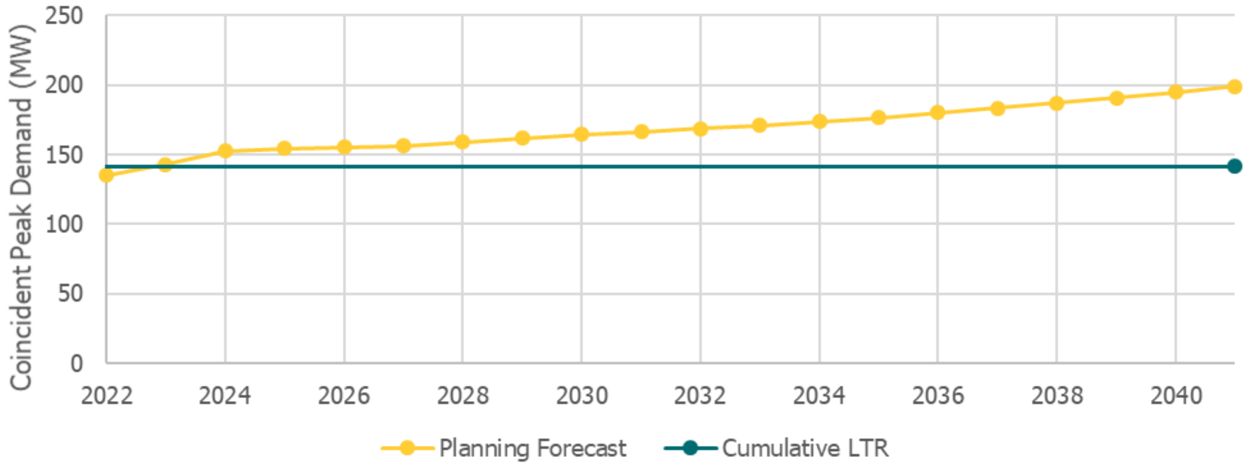


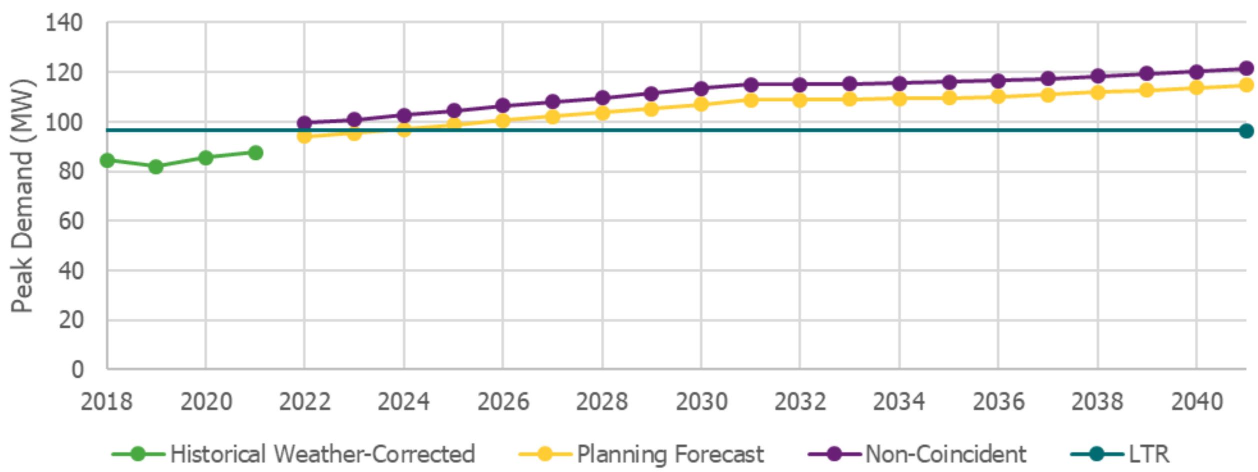
Figure 13 | Beamsville TS, Vineland DS, and Niagara West MTS Cumulative Coincident Capacity Need



6.2.2 Crowland TS

Supplying Welland, Crowland TS is forecast to reach its summer station capacity limit in 2022 and grow to a 25 MW need by 2041. This station comprises two 115 kV/27.6 kV transformers with an LTR of 96 MW.

Figure 14 | Crowland TS Capacity Need



6.2.3 Carlton TS, Kalar MTS, and Murray TS (T11/T12)

Carlton TS and Kalar MTS each comprise two 115 kV/13.8 kV transformers, with summer LTRs of 94 MW and 68 MW, respectively. Carlton TS is forecast to reach capacity starting in 2028 (Figure 15) while the Kalar MTS need arises in 2030 (Figure 16). Each need will increase to 11 MW and 7 MW, respectively, by 2041. Murray TS consists of four 230 kV/13.8 kV transformers; T11 and T12 have a summer LTR of 72 MW, whereas T13 and T14 are rated to 77 MW. The T11/T12 capacity need exists today, growing to 14 MW by 2041 (Figure 17).

Figure 15 | Carlton TS Capacity Need

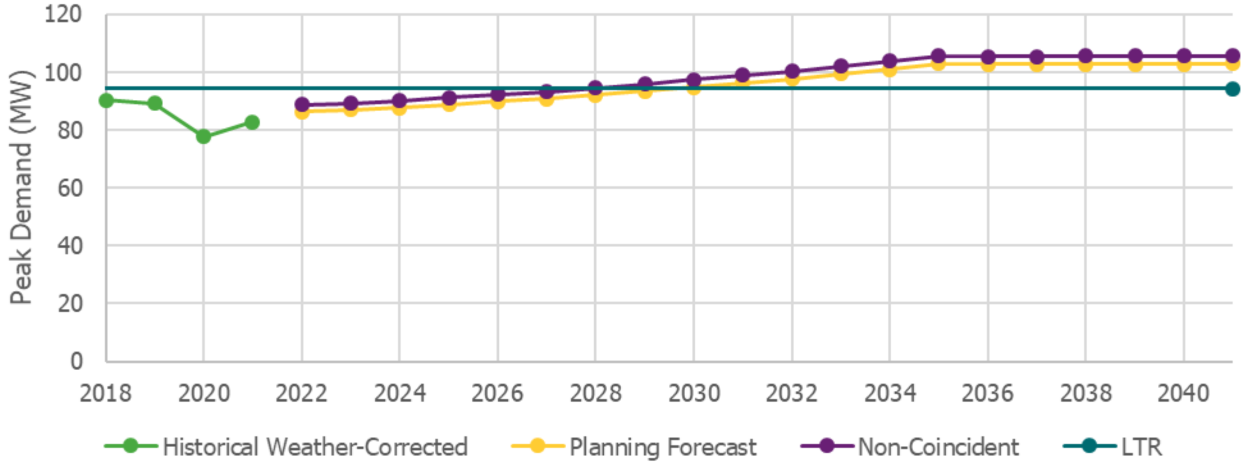


Figure 16 | Kalar MTS Capacity Need

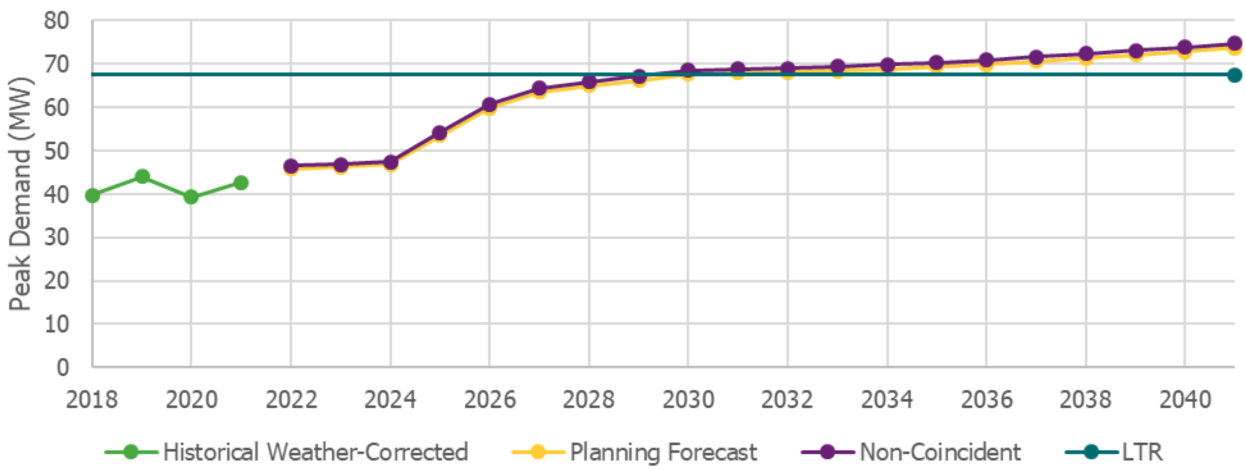


Figure 17 | Murray TS (T11/T12) Capacity Need

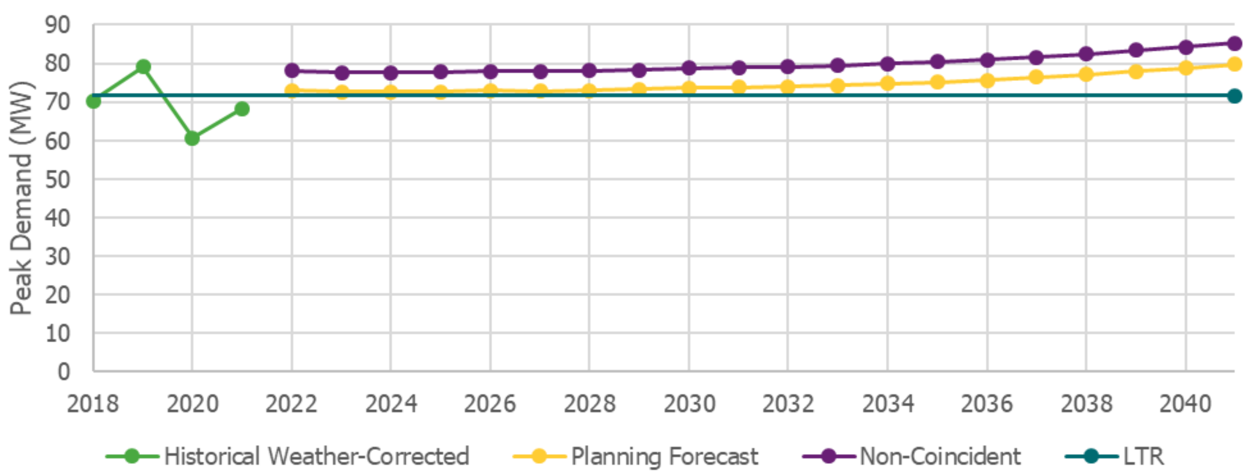
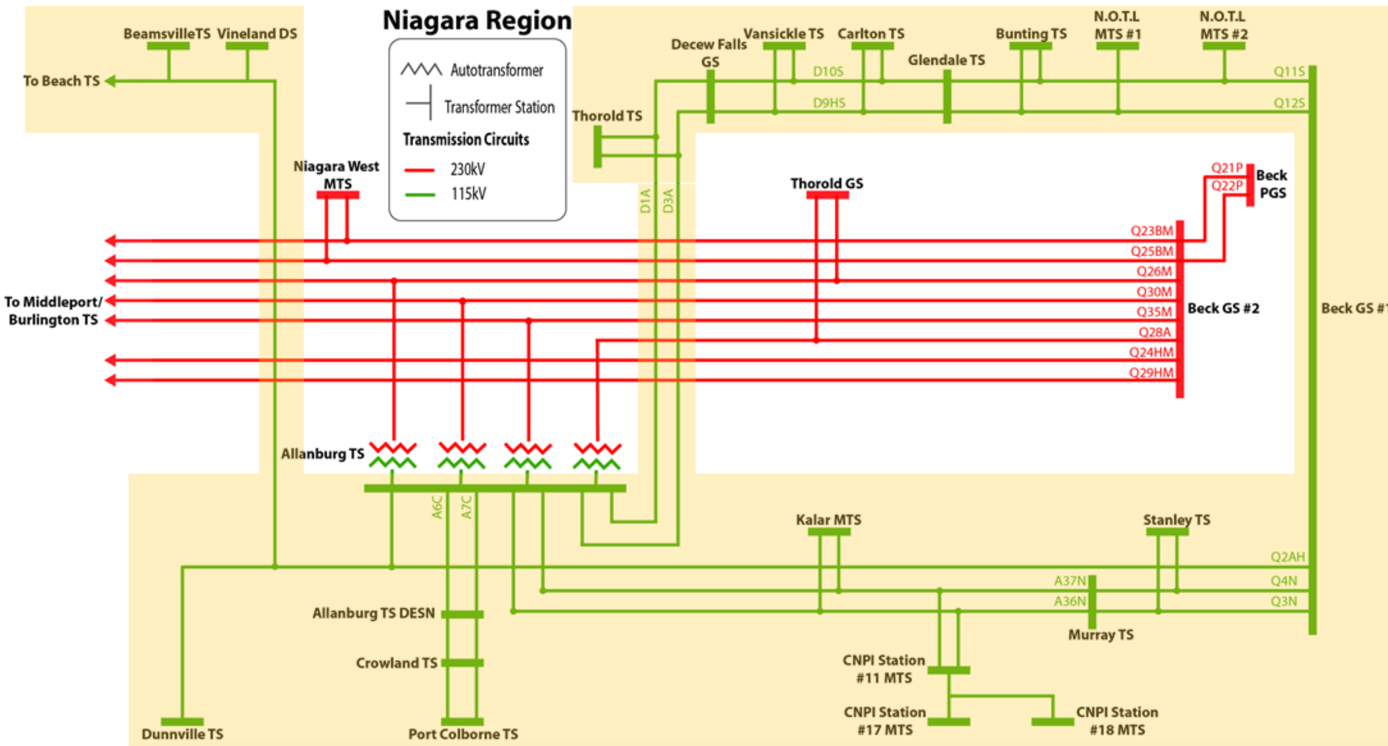


Figure 15 to Figure 17 demonstrate the non-coincident peak demand forecasts at these stations compared to their individual LTRs. Note that these station capacity needs have been presented together in this sub-section, since this IRRP is not yet recommending infrastructure reinforcements to address them. Section 7.2.1.3 describes this in more detail.

6.3 Supply Capacity Needs

The majority of load in the Niagara Region is supplied through its 115 kV transmission sub-system, which in turn is supplied from the 230/115 kV autotransformers at Allanburg TS, Sir Adam Beck GS #1, and Decew Falls GS. The LMC of the 115 kV sub-system is therefore limited by the capability at Allanburg TS under the various planning scenarios and applicable contingencies. The sub-system is demonstrated in Figure 18.

Figure 18 | Niagara Region's 115 kV Sub-System (Highlighted Yellow)

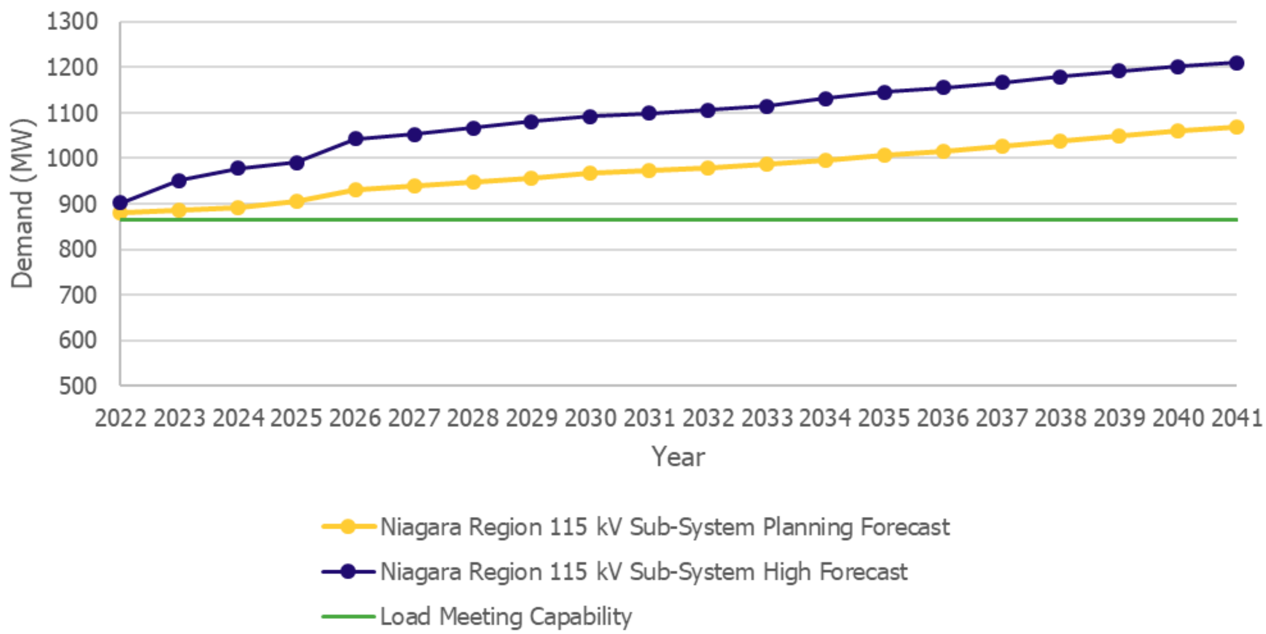


The LMC of the Niagara 115 kV sub-system, presented in Figure 19 against the forecast load, reflects limitations of the existing transmission system. Under certain outage and contingency conditions (such as contingencies impacting two circuits between Beck GS #2 and Middleport/Burlington, or Beck GS #1), the lowest-rated Allanburg autotransformer is overloaded and is the first limiting phenomenon that restricts total reliable supply into the 115 kV sub-system. However, the LMC for this area can also be restricted by other phenomena, including the thermal capability of a section of Q28A during other contingency events and specific generation outage conditions. There are further, more local restrictions within this sub-system too – such as thermal constraints limiting the supply to loads between Allanburg TS and Beck GS #1 through the 115 kV circuits.[7] All of these transmission limits are described in Appendix G.

[7] This particular need, which occurs under outage conditions, could be addressed through permissible operational control actions and would be impacted by a customer's System Impact Assessment that is ongoing at the time of regional planning.

Between 2018 – 2021, the 115 kV sub-system has had a peak coincident weather-corrected load of up to approximately 830 MW. With the reference planning forecast, the 115 kV sub-system load increases such that the supply capacity need grows to approximately 200 MW by 2041; under the high scenario, it is about 340 MW.

Figure 19 | Niagara Region 115 kV Supply Capacity Need



6.4 Asset Replacement Needs

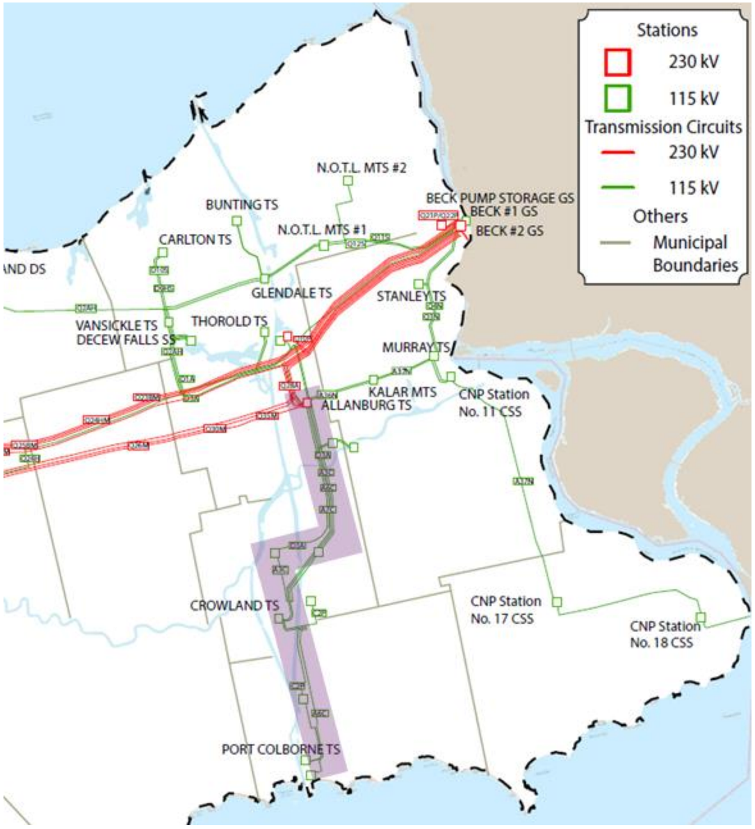
At the time of the Niagara Region Needs Assessment, Hydro One identified a number of assets requiring replacement in the next 10 years. This included Crowland TS, whose transformers were originally scheduled to be replaced with like-for-like 115/27.6 kV 83 megavolt ampere ("MVA") units before 2026. As described in the Niagara Region Scoping Assessment, the Technical Working Group agreed that sustainment plans identified by Hydro One would be assumed to proceed as described in the Needs Assessment – unless an opportunity arose for "right-sizing".

Through the development of the IRRP, during which a more comprehensive demand forecast was created and extended to a 20-year planning horizon, and additional needs were identified or refined, the Crowland TS like-for-like replacement plan was reconsidered. This need and its relevance to the other regional needs are described further in Section 7.4.

6.5 Load Security Needs

The circuits designated as A6C/A7C form a 115 kV double-circuit line from Allanburg TS to Crowland TS, before supplying Port Colborne TS as A6C and C2P. These circuits also serve a number of transmission-connected industrial customers that are south of Allanburg TS, primarily east of the Welland Canal. Figure 20 provides an overview of this portion of the transmission system in the Niagara Region.

Figure 20 | Niagara Region Transmission System: A6C/A7C (Highlighted Purple)



The aforementioned stations and transmission-connected customers on the A6C/A7C circuits are included in the Allanburg Load Rejection Scheme; operational actions are taken to disconnect these loads in the event of certain contingencies to prevent voltage decline upon the coincidental loss of Allanburg T1 and T2. At the 2022 expected load levels on the A6C/A7C circuits, a double contingency on the Q26M and Q28A circuits will trigger over 180 MW of load being disconnected from the system. This is a violation of Section 7.1 of the ORTAC, which specifies that only up to 150 MW of planned load curtailment is permissible under these conditions. The load supplied by A6C/A7C is also expected to grow throughout the study period (i.e., up to 2041). By 2041, it is expected that the load security need will grow to approximately 75 MW in excess of the permissible amount. More details regarding this load security need are provided in Appendix G.

6.6 Summary of Identified Needs

Below is an overview of all needs identified in this Niagara IRRP.

Table 3 | Summary of Needs in the Niagara Region

Need	Need Date
Beamsville TS Station Capacity	2022
Murray TS (T11/T12) Station Capacity	2022
A6C/A7C Load Security Need	2022

Need	Need Date
Niagara 115 kV Sub-System Supply Capacity	2022
Crowland TS Station Capacity	2022
Crowland TS Asset Replacement	2026
Niagara West MTS Station Capacity	2026
Carlton TS Station Capacity	2028
Kalar MTS Station Capacity	2030
Vineland DS Station Capacity	2030

7. Plan Options and Recommendations

This section describes the options considered and recommendations to address the needs in the Niagara Region. In developing the plan, the Technical Working Group considered a range of integrated options. Considerations in assessing alternatives included maximizing use of existing infrastructure, provincial electricity policy, feasibility, cost, and consistency with longer-term needs in the area.

Generally speaking, there are two approaches for addressing regional needs that arise as electricity demand increases:

- Build new infrastructure to increase the LMC of the area. These are commonly referred to as "wires" options and can include things like new transmission lines, autotransformers, step-down transformer stations, voltage control devices, or upgrades to existing infrastructure. Wires options may also include control actions or protection schemes that influence how the system is operated to avoid or mitigate certain reliability concerns.
- Install or implement measures to reduce the net peak demand to maintain loading within the system's existing LMC. These are commonly referred to as "non-wires" options and can include things like local utility-scale generation, distributed energy resources (including distribution-connected generation and demand response), or CDM.

Section 7.1 begins with a more in-depth overview of all option types considered in IRRPs. Section 7.2 describes the screening approach used to assess which needs would be best suited for a more detailed assessment for non-wires options. Subsequently, Section 7.3 to Section 7.5 present the options that were ultimately developed and evaluated (including a cost comparison) before the Technical Working Group made a recommendation.

7.1 Options Considered in IRRPs

Wires options are always considered in regional planning, and are developed by designing transmission reinforcements or control actions that are appropriate for the specific limiting phenomenon (voltage, thermal, stability, etc) of each need. These are identified through discussions with the Technical Working Group.

While traditional wires infrastructure is always a viable option for regional needs, some non-wires options are more suitable for specific need types and characteristics. Hence, to select and size suitable generation and other non-wires options, additional work is required – including creation of an hourly load profile, as described in Section 5.8. The most suitable technology type and capacity is chosen by examining the "unserved energy" profile, which is the hourly demand above the existing LMC. The profile indicates the duration, frequency, magnitude, and total energy associated with each need. Some of these characteristics are shown visually in Appendix D for the Niagara Region needs.

High-level cost estimates for wires options are usually provided by the transmitter. In contrast, cost estimates for generation and other non-wires options are based on benchmark capital and operating cost characteristics for each resource type and size. Generally speaking, the most cost-effective transmission-connected options for meeting local needs in the Niagara Region are resources with a performance and costs on par with simple cycle gas turbines. New natural gas-fired generation was considered in the economic analysis for illustrative purposes, as it was representative of the lowest cost generation option. Energy storage, such as lithium nickel manganese cobalt oxide batteries, are also becoming cost-competitive due to declining technology costs and the expectation of carbon prices increasing in line with federal policy. Other energy resources (which are typically distribution-connected) are also considered.

CDM measures can also help decrease the net electricity demand. Centrally delivered energy efficiency measures under the 2021-2024 CDM Framework and Save on Energy brand are already included in the load forecast, as discussed in the Section 5.4. As part of this current Framework, the IESO was directed to deliver a new program to address regional and/or local system needs. The Local Initiative Program is now one tool that is available to target the delivery of additional CDM savings at specific areas of the province with identified system needs. LDCs can also use the Ontario Energy Board's CDM Guidelines to leverage distribution rates to help address distribution and transmission system needs using non-wires alternatives.[8] Generally, incremental CDM measures are suitable for needs where growth is slow and the magnitude of the overload relative to the total demand is very small (i.e., on the order of few percent per year). These considerations are discussed further in Section 7.2, as part of the screening of options that was conducted.

For both wires and non-wires options, the upfront capital and operating are compiled to generate levelized annual capacity costs ($/kW-year). A cash flow of the levelized costs for the options are compared over the lifespan of the wires option (typically 70 years for transmission infrastructure). The non-wires options also include any system capacity benefit that they could contribute to provincial resource adequacy needs, ensuring that they are both sized to address the local need and are comparable to the wires options. The net present value (in 2021 CAD dollars) of these levelized costs are the primary basis through which feasible options are compared.

It is important to recognize that there is a significant error margin around costs estimates at the planning stage, as they are only intended to enable comparison between options during the IRRP. The RIP (which is conducted after the IRRP) performs additional detailed analysis and allows the opportunity to refine wires cost estimates before implementation work begins. The IESO continues to participate in the Technical Working Group during the RIP and revisits these recommendations if costs estimates differ significantly. Furthermore, in cases where other barriers downstream of the regional planning process (i.e., regulatory frameworks for cost-sharing and recovery, or operationalization to meet local reliability constraints) impede the adoption of some of these cost-effective options, pilot or demonstration projects can be explored.[9]

The list of assumptions made in the economic analysis can be found in Appendix F.

7.2 Screening Options

As explained in Section 7.1, an array of options can be developed to meet local needs during an IRRP, but options are ultimately evaluated to recommend the most cost-effective and technically

[8] More information about the CDM Guidelines is available on the Ontario Energy Board's website.

[9] Barriers to non-wires alternatives and recommendations to address them were a part of the Regional Planning Process Review.

feasible solution. This process is complemented by considerations for stakeholder preferences and feedback.

Screening occurs early in the IRRP study after local reliability needs are known but before options analysis. It helps direct time-intensive aspects of detailed non-wires analysis (hourly need characterization, options development, financial analysis, and engagement) towards the most promising options. The three-step, high-level approach is shown in Figure 21, and the results of its application to the Niagara IRRP needs are summarized in Table 4 and then further described in the sections below. More details on the steps and inputs used in the screening mechanism can be found in Appendix C.

Figure 21 | IRRP Screening Mechanism

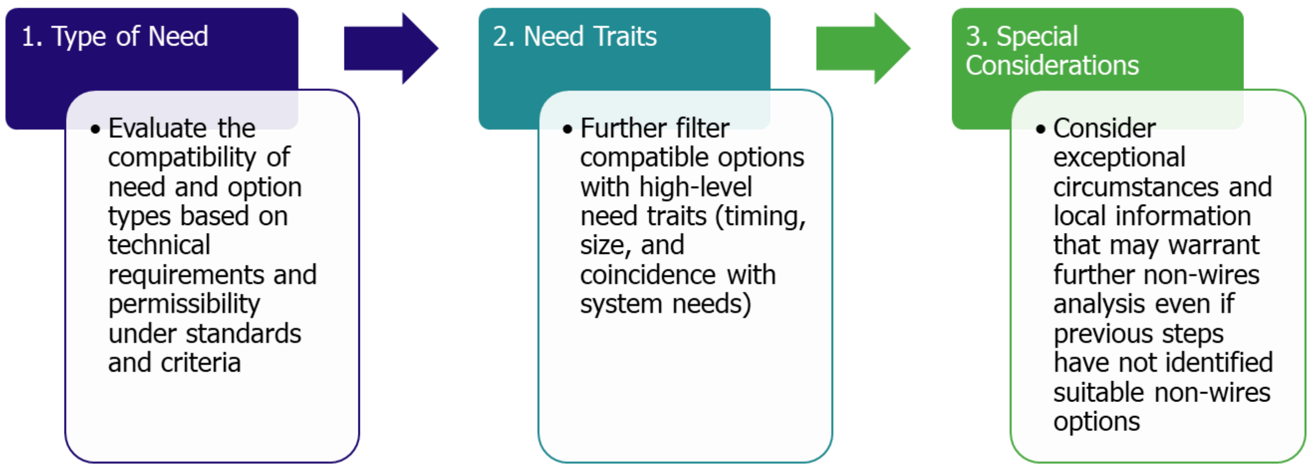


Table 4 | Results of Niagara IRRP Screening

Need Type	Impacted Element	Options Screened In	Options Screened Out
Station capacity	Beamsville TS	Wires, demand response ("DR"), DG, CDM	Transmission-connected generation
Station capacity	Vineland DS	Wires, CDM	Transmission-connected generation, DR, DG
Station capacity	Crowland TS	Wires, DR, DG, CDM	Transmission-connected generation
Station capacity	Kalar MTS	Wires, CDM	Transmission-connected generation, DR, DG
Station capacity	Carlton TS	Wires	All non-wires

Need Type	Impacted Element	Options Screened In	Options Screened Out
Station capacity	Murray TS (T11/T12)	Wires	All non-wires
Supply capacity	Niagara 115 kV sub-system	Wires, transmission-connected generation, CDM	DR, DG
Asset replacement	Crowland TS	Coordinated with the Crowland TS station capacity need	Coordinated with the Crowland TS station capacity need
Load security	Load supplied by A6C/A7C circuits	Wires	All non-wires

7.2.1 Non-Wires Options for the Capacity Needs

Based on the nature of the need, Step 1 of the screening mechanism identifies that in general, non-wires options can resolve supply and station capacity needs by reducing net load in the affected area. For station capacity needs specifically, these options must be resources that are connected downstream of the limiting step-down transformer. The following sections outline when Steps 2 and 3 of the screening resulted in further analysis of non-wires options.

7.2.1.1 Beamsville TS, Niagara West MTS, and Vineland DS

As described previously in Section 6.2.1, there are forecast station capacity needs at Beamsville TS, Niagara West MTS, and Vineland DS, as well as a collective capacity shortfall in the area supplied by the three stations. Though eventually considered together given their geographic proximity, Beamsville TS and Vineland DS were screened independently. For Beamsville TS, with its large near-term capacity need, all applicable non-wires options were considered. Conversely, for the small long-term need at Vineland DS, the focus (in terms of a non-wires option) was on incremental CDM.

At the time of screening, the Technical Working Group did not identify a station capacity need at Niagara West MTS; this occurred later in the IRRP development when the forecast was updated by Grimsby Power. Hence, formal screening was not conducted for Niagara West MTS – but this IRRP does ultimately include recommendations that address its need (see Section 7.3).

7.2.1.2 Crowland TS

For Crowland TS, all applicable non-wires options were developed in further detail. Initially, at the time of the screening, the Crowland TS and Kalar MTS station needs were approached together given their perceived geographic proximity. However, recommendations were eventually made for these stations separately after considering factors that made an integrated approach impractical. These factors include distribution voltage level differences, distance to supply forecast growth areas, and misaligned capacity need timing between the two stations.

7.2.1.3 Carlton TS, Kalar MTS, and Murray TS (T11/T12)

For some needs, further analysis of non-wires is not warranted if there is the high potential for an inexpensive and simple wires alternative that maximizes the use of existing infrastructure. This can include load transfers or control actions that are sufficient to meet the need.

This was the case for the station capacity needs at Carlton TS and Murray TS (T11/T12). At the time of screening, Alectra Utilities indicated plans to reallocate some forecast demand at Carlton TS to a nearby station with additional capacity (Bunting TS). At Murray TS, NPEI is supplied by both T11/T12 and T13/T14. While forecast demand for T11/T12 exceeds its LTR, there is sufficient remaining capacity at T13/T14.[10] Managing the load distribution between the four transformers at Murray TS is expected to address the need at T11/T12.

For the small long-term need at Kalar MTS, incremental CDM was screened in for additional analysis.

7.2.1.4 Niagara 115 kV Sub-System Supply

Due to the nature of supply capacity needs, most non-wires options can be potential solutions – either alone or as a part of an integrated package of recommendations. However, for the Niagara 115 kV sub-system, the magnitude of the capacity need was large enough that the option development focused on transmission-connected generation or storage, with some consideration for additional locally targeted CDM.

Other non-wires options such as DR and DG were screened out from further analysis for a number of reasons. For instance, the connection of DG (regardless of fuel type) is subject to equipment limitations such as minimum loading, feeder capacity, station thermal capacity, and short circuit requirements. With an approximately 200 MW supply capacity need, the amount of incremental DG required would not be able to connect to a single transformer station in the Niagara Region, and would be unlikely to be accommodated, coordinated, and operated across multiple stations to meet the local supply constraint.[11] Recall that existing contracted DG output at peak was already accounted for during the development of the net demand forecast.

Similarly, DR was screened out due to the magnitude of the Niagara 115 kV supply capacity need. Though DR can be considered as a potential option to the extent that loads in the area can be curtailed during peak hours, the amount of DR that has historically been acquired for system capacity needs can help indicate this option's feasibility. For the 2021 summer obligation period in the capacity auction, approximately 20 MW of total capacity cleared for the Niagara zone. These past auction results provide context as to the scale of demand response that would be required to address the Niagara supply capacity need; this is unlikely to be achievable in the near-term. It is also worth noting that the Capacity Auction acquires resources designed to meet provincial adequacy rather than specific local or regional needs.

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[10] Approximately 50 MW of remaining capacity is available at Murray TS (T13/T14) according to the IRRP reference planning forecast.

[11] For existing station DG connection availability, consider Hydro One's capacity evaluation tool for generation applicants.

7.2.2 Non-Wires Options for the Asset Replacement Needs

Outcomes of screening non-wires options for the Crowland TS asset replacement need were aligned with the screening outcomes for the Crowland TS incremental station capacity need (i.e., the capacity need that persists even if the station is replaced like-for-like).

7.2.3 Non-Wires Options for the Load Security Needs

Due to the nature of planning criteria outlined in ORTAC 7.2, non-wires options such as CDM and DG cannot be applied to load security needs because they usually do not enable uninterruptable power supply to customers in the event of transmission contingencies. While voluntary load loss such as DR could help address the intent of load security planning criteria, it is an option type currently procured through the provincial capacity auction. This implementation mechanism is not the optimal approach, as its current design does not include the monitoring of local adequacy nor permit immediate responses after specific local contingencies. For these reasons, non-wires options are typically screened out for load security needs unless there are exceptional circumstances identified during the IRRP development.

7.3 Options and Recommendations for Meeting the Beamsville TS, Niagara West MTS, and Vineland DS Needs

7.3.1 Transmission Options

Due to the geographic proximity of Beamsville TS, Niagara West MTS, and Vineland DS, integrated transmission options were developed to address the station capacity needs in a coordinated manner. Three options for additional station capacity for the area were considered:

1. The replacement of existing Niagara West MTS with new 2 x 75/125 MVA transformers;
2. The expansion of Niagara West MTS with two new 67 MVA transformer units; or
3. A new, separate 230 kV station supplied from Q23BM and Q25BM.

Option 1 was ruled out, given that there was no indication of asset replacement needs at the existing Niagara West MTS (resulting in stranded asset costs), plus the risk of reduced reliability expected when implementing the replacement. Option 2 was estimated to cost as little as $17M and require three years from the commitment date, whereas Option 3 was estimated to cost up to $40M (depending on the size of the transformers and implementer) and would take three to four years.[12]

Given the immediate need at Beamsville TS, the Technical Working Group also considered load transfer capabilities in the near-term. Beamsville TS and Niagara West MTS both supply Grimsby Power, NPEI, and Hydro One Distribution, while Vineland DS supplies only NPEI. At the time of this IRRP, Grimsby Power estimated the ability to transfer approximately 7 MW of NPEI's forecast load at Beamsville TS to Niagara West MTS. Beyond this amount, the Niagara West MTS station capacity need would arise sooner than already forecast. There is also some remaining capacity (approximately 4 MW) expected at Vineland DS.

[12] All cost estimates, unless otherwise specified, are net present values based on a levelized cash flow analysis rather than capital costs – see Appendix F. In this case, a capital cost estimate of $19M (+/-15%) was provided for Option 2 and $25M - $40M for Option 3.

7.3.2 Non-Wires Options

As explained in Section 7.2.1.1, non-wires options were screened in for additional evaluation for the Beamsville TS and Vineland DS needs.

For Beamsville TS, a number of measures were assessed – such as combinations of incremental targeted CDM with battery storage or gas generation.[13] The most cost-effective non-wires solution portfolio included incremental CDM (approximately 6 MW of additional savings by 2041), plus battery storage assumed to be installed in two phases (2025 and 2038) to match the need profile.[14] For Vineland DS, the incremental CDM potential was also calculated: approximately 2 MW of additional demand savings by 2041.

The net present value ("NPV") of the portfolio of non-wires options for both Beamsville TS and Vineland TS was calculated to be $30M - $57M. The lower cost assumed that the incremental CDM is already system cost-effective based on provincial resource adequacy, whereas the higher cost assumed that the demand savings targeted to these stations would be incremental to the provincial CDM framework. More details on the CDM potential methodology and results are provided in Appendix E.

7.3.3 Recommendation

During the development of the IRRP, the forecasts at Beamsville TS and Niagara West MTS were updated by the impacted LDCs as growth trended higher and new potential customers were identified. By the conclusion of the IRRP, this reinforced the preference for the integrated wires options due to their cost-effectiveness and ability to address the capacity needs at all three stations.

The original scope of the non-wires options that were developed only addressed the Beamsville TS and Vineland DS needs, but were collectively $13M – $40M more expensive than the least expensive wires option. The increased forecast for Niagara West MTS did not impact the wires option of a new 230 kV station in the area – it only increased its cost-effectiveness. Another portfolio of non-wires options sized for Niagara West MTS' final reference forecast capacity need would have increased the non-wires costs further. Reallocating the load forecast on the 115 kV stations to 230 kV supply also helps alleviate the broader Niagara 115 kV sub-system capacity need.

Therefore, due to the cost-effectiveness and ability to meet the multiple needs, the Technical Working Group recommends near-term load transfers to offload Beamsville TS, plus a new 230 kV station supplied from Q23BM and Q25BM. This could be accomplished by expanding the existing Niagara West MTS. The station should be in-service as soon as possible and accommodate at least 57 MW of pre-contingency load in the area by 2041.

It is recommended that after the IRRP, the impacted LDCs coordinate the magnitude and timing of load transfers between the three stations to manage and monitor the Beamsville TS capacity need until the new station is in-service. Moreover, the LDCs and Hydro One should coordinate during the RIP to establish the lead implementer of the new station. Timing, siting, and size of the new

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[13] Based on the unserved energy profile forecast at Beamsville TS, the gas generator option was assumed to be a simple cycle gas turbine facility.

[14] This included an 18 MW, 144 MWh battery storage facility. The Beamsville TS forecast was updated and increased near the end of the IRRP forecast; cost range estimate would only increase with larger battery storage.

transformers should be factored into the decision – in addition to a comprehensive economic comparison that accounts for both the cost of the transformer station and the distribution-level costs that could incur if the station is sited farther west and away from the service territories that are expected to grow.

7.4 Options and Recommendations for Meeting the Crowland TS, Load Security, and Niagara 115 kV Sub-System Needs

The Crowland station capacity and asset replacement needs, as well as the A6C/A7C load security and Niagara 115 kV sub-system capacity needs, share common transmission elements and impact each other. As such, both wires and non-wires options were developed to address these four needs in an integrated fashion.

7.4.1 Transmission Options

Two sets of transmission options were identified – one that largely involves the continued buildout of the 115 kV system in the Niagara Region, and another that expands the 230 kV supply.

Option Set 1 includes:

- New 115 kV station in Welland, supplied by the existing A6C/A7C circuits (to address the Crowland TS capacity need);
- New 230 kV Allanburg bus (to improve supply to the 115 kV sub-system and mitigate the A6C/A7C load security need); and
- Re-building of 115 kV Crowland TS like-for-like (to address the asset replacement need).

Option Set 2 includes:

- Replacement of sections of 115 kV D3A/A3C circuits with approximately 18 km of new 230 kV double-circuit supply lines tapping off Q24HM and Q29HM; and
- The replacement of Crowland TS with a 230 kV station (to address its asset replacement and capacity needs, offload the Niagara 115 kV sub-system, and mitigate the A6C/A7C load security need).

In terms of preliminary capital costs, Option Set 1 was estimated to be approximately $253M - $353M[15] in total, whereas Option Set 2 may cost $128M.[16] Option Set 1 will require a minimum of three years; Option Set 2 will need six years.

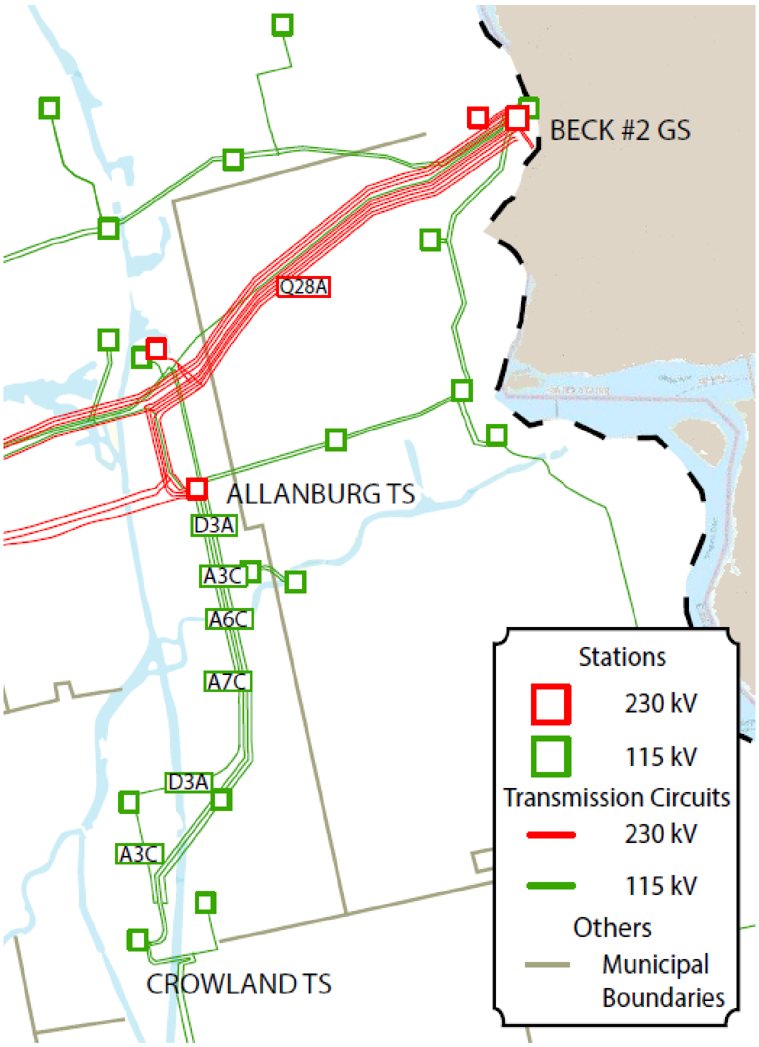
[15] The high end of the cost estimate range for Option Set 1 includes the potential for new 115 kV circuits and other reinforcements if the existing A6C/A7C circuits cannot accommodate the new 115 kV station in Welland.

[16] Capital cost estimates provided by Hydro One during the IRRP were prepared based on preliminary information and intended to provide a ballpark figure to be used strictly for initial options comparison. No engineering or field work was completed as part of the development of these cost allowances and as such, these cost allowances provide no cost guarantee or accuracy range. Costs allocations were derived from previous historical costs/unit costs and were to be used strictly for options comparison; Hydro One may refine and update cost estimates as part of the RIP.

To accommodate the planning forecast, the uprating of an existing 230 kV circuit, Q28A, is also required in addition to either Option Set. The cost and feasibility of this reinforcement is currently being assessed by Hydro One and is estimated to require until at least 2024 to be in-service.

The components of these Option Sets are identified conceptually on the map of Niagara Region's existing transmission system in Figure 22.

Figure 22 | Impacted Areas by the Transmission Options



Under some of the contingencies and conditions expected to limit the 115 kV sub-system LMC, operational measures such as load rejection are permissible according to ORTAC. Therefore, the benefit of a new load rejection scheme was also factored in when assessing the supply capability with each of the wires options described above. It was assumed that this scheme, developed and implemented by Hydro One for the Niagara 115 kV sub-system, could be installed in 2024 or later.[17]

[17] The ultimate in-service date will depend on the complexity of the scheme's design and NPCC approval timelines.

7.4.2 Non-Wires Options

As explained in Section 7.2.1.2 and 7.2.1.4, non-wires options were screened in for additional evaluation for the Crowland TS and 115 kV sub-system supply needs.

For the Crowland TS capacity need alone, incremental targeted CDM, battery storage, and gas generation were all considered either as standalone or integrated options.[18] The most cost-effective non-wires solution portfolio for the Crowland capacity need included incremental CDM (approximately 10 MW of additional savings by 2041), plus a 10 MW/40 MWh battery storage facility installed in two phases (2025 and 2038) to match the need profile. The NPV of this portfolio was calculated to be in the range of $17M - $53M. Similar to what was described for the Beamsville TS non-wires options, this cost range is attributed to the provincial CDM assumptions.[19]

As the Niagara IRRP progressed and the interplay between the Crowland TS needs and the broader Niagara 115 kV supply capability became clearer, a non-wires option was also considered at a high level. An all-generation, 240 MW alternative was sized to compare to the lowest cost transmission option set; 240 MW is the expected increase in the 115 kV sub-system supply capability enabled by Option Set 2 described previously. However, this non-wires option is not a feasible solution due to various factors. While an all-generation option was identified to compare to the wires option on a MW basis, there are significant challenges to implementing and operating a resource to address the multiple, layered, and local needs. For instance, for 240 MW of generation to address both the Crowland TS capacity and replacement needs, as well as the broader 115 kV supply needs, a portion of the generation must be sited on the distribution system to supply customers currently served by Crowland TS and the remaining must be targeted to the region's 115 kV system. There may also be thermal or short circuit limitations to connecting this amount of generation on the distribution system. Moreover, as described in Section 7.2.3, generation is typically not considered a feasible option to solve load security needs.

7.4.3 Recommendation

When comparing the two wires option sets, Option Set 2 is preferred for a number of reasons. It is the more cost-effective option, evaluated at more than $100M less expensive than Option Set 1 (based on capital cost estimates), even though both offer similar 115 kV sub-system supply capability and are sufficient according to the reference planning forecast. Qualitatively, by expanding the 230 kV transmission system, Option Set 2 also offers long-term flexibility to accommodate more load growth in the southern portion of the Niagara Region – particularly along the industrial and commercial hub around the Welland Canal. Option Set 1 provides limited growth options in the area in comparison to Option Set 2, without extensive station expansion at Allanburg TS. Meanwhile, converting the existing 115 kV Crowland TS to 230 kV in Option Set 2 allows the other 115 kV stations in the Niagara Region to accommodate new growth and maximizes the use of existing infrastructure with the available capacity normally utilized by the 115 kV Crowland TS. Triggering the

[18] Based on the unserved energy profile forecast at Crowland TS, the gas generator option was assumed to be a simple cycle gas turbine facility.

[19] Another sensitivity was conducted for the battery storage sizing, resulting in a higher cost range of $25M - $61M. See Appendix D.3 for more details.

reconfiguration is also a time-sensitive opportunity, since Crowland TS is expected to require asset replacement in the near term.[20]

Long-term flexibility can also be considered by comparing the options and their ability to accommodate the high IRRP forecast scenario. According to the reference forecast, approximately 200 MW of extra 115 kV supply capability is required by 2041. As shown in Section 6.3, the high scenario increased this requirement to 340 MW. Both Option Sets 1 and 2 enable the increased capability required for the reference forecast, and neither Option Set precludes a further wires or non-wires option in the long-term. These future actions can include new generation resources or additional 230/115 kV auto-transformation. In contrast, a non-wires option sized precisely to meet the reference need would have less flexibility to accommodate growth that exceeds today's expectations.

Regardless, none of the non-wires options described in Section 7.4.2 can sufficiently address the multiple needs at once. Wires Option Set 2 would cost-effectively resolve the Crowland capacity and replacement needs, the A6C/A7C security issue, and enable other load growth on the 115 kV sub-system. For these reasons, the Technical Working Group recommends the replacement of Crowland TS with a new 230 kV station, supplied by new 230 kV double-circuit lines from Q24HM/Q29HM, as well as the uprating of Q28A. A new load rejection scheme should also be developed to manage the Niagara 115 kV sub-system need. The load forecast should be monitored between regional planning cycles, and there are benefits to targeting incremental CDM to the 115 kV sub-system in order to manage load growth beyond the reference scenario. The technical feasibility and costs of the wires recommendations should be further analyzed in the RIP; the IESO will continue to participate in the RIP Working Group to provide advice and input on this matter.

7.5 Summary of Recommended Actions and Next Steps

The Technical Working Group recommends the actions summarized in Table 5 to meet identified needs in the Niagara IRRP.

Table 5 | Summary of Needs and Recommended Actions

Need(s)	Lead Responsibility	Technical Working Group Recommendation	Expected In-Service Date
• Beamsville TS station capacity	• Grimsby Power • NPEI • Hydro One Distribution	• Coordinate load transfers to offload Beamsville TS to Niagara West MTS in the near-term	• 2023

[20] All final cost estimates have accounted for the asset replacement value for Crowland TS.

Need(s)	Lead Responsibility	Technical Working Group Recommendation	Expected In-Service Date
• Beamsville TS, Niagara West MTS, and Vineland DS station capacity • Niagara 115 kV sub-system supply capacity	• Grimsby Power • NPEI • Hydro One Distribution • Hydro One Transmission	• Initiate development for a new 230 kV station supplied from Q23BM and Q25BM, or an expansion of Niagara West MTS	• 2026-2027
• Beamsville TS, Niagara West MTS, and Vineland DS station capacity	• Grimsby Power • NPEI • Hydro One Distribution	• Monitor load growth between regional planning cycles	• Ongoing
• Beamsville TS and Vineland DS station capacity	• Technical Working Group	• Investigate opportunities to target incremental CDM to Beamsville TS and Vineland DS	• Ongoing
• Crowland TS station capacity and asset replacement • A6C/A7C load security • Niagara 115 kV sub-system supply capacity	• Hydro One Transmission	• Initiate development for the replacement of Crowland TS with a new 230 kV station, supplied by new 230 kV double-circuit lines from Q24HM and Q29HM	• 2028
• Niagara 115 kV sub-system supply capacity	• Hydro One Transmission	• Develop and implement a new 115 kV sub-system load rejection scheme	• 2024
• Niagara 115 kV sub-system supply capacity	• Hydro One Transmission	• Uprate Q28A	• 2024
• Niagara 115 kV sub-system supply capacity	• Technical Working Group	• Monitor load growth between regional planning cycles	• Ongoing

Need(s)	Lead Responsibility	Technical Working Group Recommendation	Expected In-Service Date
• Niagara 115 kV sub-system supply capacity	• Technical Working Group	• Investigate opportunities to target incremental CDM to the 115 kV sub-system	• Ongoing
• Murray TS (T11/T12) station capacity	• NPEI • Hydro One Transmission	• Transfer load in excess of the station limit to Murray TS T13/T14	• 2023
• Carlton TS station capacity	• Alectra	• Monitor load growth between regional planning cycles • Transfer load in excess of the station limit to Bunting TS	• 2028
• Kalar MTS station capacity	• NPEI	• Monitor load growth between regional planning cycles and consider future opportunities for incremental CDM	• 2030

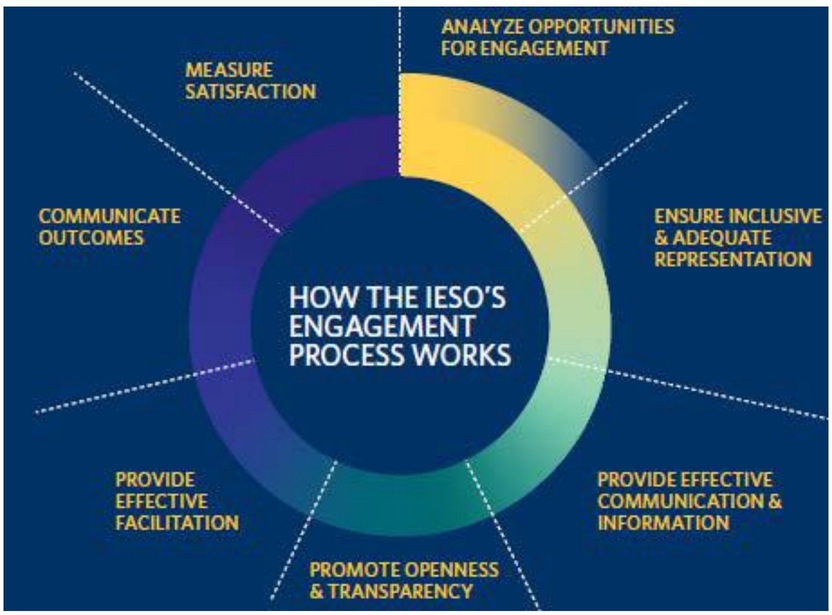
8. Community and Stakeholder Engagement

Engagement is critical in the development of an IRRP. Providing opportunities for input in the regional planning process enables the views and preferences of communities to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles as well as the activities undertaken to date for the Niagara IRRP.

8.1 Engagement Principles

The IESO's engagement principles help ensure that all interested parties are aware of and can contribute to the development of this IRRP. The IESO uses these principles to ensure inclusiveness, sincerity, respect, and fairness in its engagements, striving to build trusting relationships as a result.

Figure 23 | The IESO's Engagement Principles



8.2 Creating an Engagement Approach for Niagara Region

The first step in ensuring that any IRRP reflects the needs of community members and interested stakeholders is to create an engagement plan to ensure that all interested parties understand the scope of the IRRP and are adequately informed about the background and issues in order to provide meaningful input on the development of the IRRP for the region.

Creating the engagement plan for this IRRP involved:

- Targeted discussions to help inform the engagement approach for this planning cycle;
- Communications and other engagement tactics to enable a broad participation, using multiple channels to reach audiences; and

- Identifying specific stakeholders and communities who may have a direct impact in this initiative and that should be targeted for further one-on-one consultation, based on identified and specific needs in the region.

As a result, the engagement plan for this IRRP included:

- A dedicated webpage on the IESO website to post all meeting materials, feedback received and IESO responses to the feedback throughout the engagement process;
- Regular communication with interested communities and stakeholders by email or through the IESO weekly Bulletin;
- Public webinars; and
- Targeted one-on-one outreach with specific communities and stakeholders to ensure that their identified needs are addressed (see Section 8.4).

8.3 Engage Early and Often

The IESO held preliminary discussions to help inform the engagement approach for this second round of planning, and to establish new relationships and dialogue in this region where there has been no active engagement previously. This started with the Scoping Assessment Outcome Report for the Niagara Region. An invitation was sent to targeted municipalities, Indigenous communities, and those with an identified interest in regional issues, to announce the commencement of a new planning cycle and invite interested parties to provide input on the Niagara Region Scoping Assessment Report finalization. A public webinar was held in August 2021 to provide an overview of the regional electricity planning process and seek input on the high-level needs identified and proposed approach. The final Scoping Assessment was posted later in August 2021, identifying the need for a coordinated regional planning approach and an IRRP.

Following finalizing the Scoping Assessment, targeted outreach then began with municipalities in the region to inform early discussions for development of the IRRP, including the IESO's approach to engagement. The launch of a broader engagement initiative followed, with an invitation to IESO subscribers of the Niagara Region to ensure that all interested parties were made aware of this opportunity for input. Three public webinars were held at major stages during the IRRP development to give interested parties an opportunity to hear about its progress and provide comments on key components of the plan. These webinars were attended by a cross-representation of community representatives, businesses, and other stakeholders, and written feedback was collected over a 21-day comment period after each webinar.

The three stages of engagement at which input was invited:

1. The draft engagement plan, electricity demand forecast, and early identified needs – to set the foundation of this planning work.
2. The defined electricity needs for the region and high-level screening of potential options to meet the identified needs.
3. The analysis of options and draft IRRP recommendations.

Comments received during this engagement were primarily focused on:

- Ensuring key areas of growth in specific pockets in the Niagara Region (including the City of Niagara Falls and Town of Fort Erie), have been considered and accounted for in the IRRP work;
- Ensuring there are procedures to alter the implementation of plan recommendations should changes occur in the region; and
- Keeping lines of communication following the plan completion to share information and updates.

Feedback received during the written comment periods for these webinars helped to guide further discussions throughout the development of this IRRP, as well as add due consideration to the final recommendations.

All interested parties were kept informed throughout this engagement initiative via email to Niagara Region subscribers, municipalities, and Indigenous and Métis communities.

Based on the discussions through this engagement initiative, a key priority was to ensure the IRRP and recommended actions aligned with strong forecast growth and development both within specific municipalities and the region more broadly (e.g. future urban expansion and employment areas as outlined in the updated Niagara Region Official Plan). This insight has been valuable to the IESO – it supported an understanding of local growth and an accurate electricity demand forecast, the determination of needs, and the recommendation of solutions to ensure adequate and reliable long-term supply. To that end, ongoing discussions will continue through the IESO's Southwest Regional Electricity Network to keep interested parties engaged in a two-way dialogue on local developments, priorities, and initiatives to prepare for the next planning cycle.

All background information, including engagement presentations, recorded webinars, detailed feedback submissions, and responses to comments received, are available on the IESO's Niagara IRRP engagement webpage.

8.4 Bringing Municipalities to the Table

The IESO held meetings with municipalities to seek input on their planning and to ensure that key local information about growth and development and energy-related initiatives were taken into consideration in the development of this IRRP. At major milestones in the IRRP process, meetings were held with the upper- and lower-tier municipalities in the region to discuss key issues of concern, including forecast regional electricity needs, options for meeting the region's future needs, and broader community engagement. These meetings helped to inform the municipal/community electricity needs and priorities, establish new relationships, and provided opportunities for ongoing dialogue beyond this IRRP process.

Through these discussions valuable feedback was received around strong anticipated growth in major growth centres in the region:

- Strong population growth across the Niagara Region based on 2051 growth projections and in some areas above and beyond the regional forecast (i.e. even higher growth expected in the City of Welland);
- Notable growth in the Town of Lincoln (greenhouses, Secondary Plan areas, potential GO Transit development), along the QEW corridor in Grimsby, and in Thorold;

- Strong economic development around the Welland Canal (e.g. Thorold Multimodal Hub "Niagara Ports");
- Key areas of growth in the City of Niagara Falls within intensification nodes and corridors, projects around the GO Transit Station and the new Niagara South Hospital, wastewater treatment plant, and residential new construction;
- Industrial, commercial, institutional, and residential development in the Town of Fort Erie and Secondary Plan areas; and
- Potential urban boundary expansion in the region totaling 130 hectares of residential and 150 hectares of employment lands.

8.5 Engaging with Indigenous Communities

To raise awareness about the regional planning activities underway and invite participation in the engagement process, regular outreach was made to Indigenous communities within the Niagara Region throughout the development of the plan. This includes the communities of the Mississaugas of the New Credit, Oneida Nation of the Thames and Six Nations of the Grand River (Six Nations Elected Council and Haudenosaunee Confederacy Chiefs Council) and Métis Nation of Ontario Niagara Region Métis Council.

The IESO remains committed to an ongoing, effective dialogue with communities to help shape long-term planning in regions all across Ontario.

9. Conclusion

The Niagara IRRP identifies electricity needs in the region over the 20-year period from 2022 to 2041, recommends a plan to address immediate and near-term needs, and lays out actions to monitor long-term needs. The IESO will continue to participate in the Technical Working Group during the next phase of regional planning, the RIP, to provide input and ensure a coordinated approach.

In the near term, the IRRP recommends load transfers off Beamsville TS and a new or expanded 230 kV station supplied by Q23BM and Q25BM. The IRRP also recommends the implementation of control actions on the Niagara 115 kV sub-system to manage overloads during outage conditions, plus the replacement of Crowland TS with a new 230 kV station supplied by new 230 kV lines from Q24HM and Q29HM. Q28A should be uprated, and a portion of the load at Murray TS (T11/T12) should be transferred to Murray TS (T13/T14). Responsibility for these actions has been assigned to the appropriate members of the Technical Working Group.

In the long term, the IRRP recommends that the Technical Working Group monitor growth in the Niagara 115 kV sub-system, Carlton TS, and Kalar MTS to determine if or when further reinforcements will be needed. This includes monitoring any future community energy planning or electrification trends. Additionally, there are benefits to investigating opportunities to target incremental CDM to the region – particularly to the Beamsville TS/Vineland DS/Niagara West MTS areas and 115 kV sub-system in the near-term, and Kalar MTS in the long-term.

The Technical Working Group will meet at regular intervals to monitor developments and track progress toward plan deliverables. In the event that underlying assumptions change significantly, local plans may be revisited through an amendment, or by initiating a new regional planning cycle sooner than the five-year schedule mandated by the Ontario Energy Board.

Niagara on-the-Lake HYDRO

DISTRIBUTION SYSTEM PLAN APPENDIX C

Highway 55 Project Article

EB-2023-0041

WHAT'S GOING ON HERE? Niagara Stone Road in Virgil

Road is currently receiving upgrades to road capacity, road conditions and other infrastructure improvements

Nick Fearns
Niagara-on-the-Lake Advance
Friday, March 17, 2023

If you have driven through Virgil lately it may have taken you longer than usual.

That is because the Niagara Region, in partnership with the Town of the Niagara-on-the-Lake and Niagara-on-the-Lake Hydro, are reconstructing Niagara Stone Road from Four Mile Creek Road to roughly 200 m north of Line 1.

JUST THE FACTS

The construction contract has a value of $10,930,970 including HST.

Niagara Region is responsible for approx. 79.5 per cent, the Town of Niagara-on-the-Lake is responsible for approximately 14.2 per cent and Niagara-on-the-Lake Hydro is responsible for approximately 6.3 per cent of the construction costs.

Some of the work being completed includes replacement of concrete sidewalks, concrete crosswalks at signalized intersections, parkettes that include bike racks, sitting areas, pedestrian light bollards, and plantings, landscaping and planting beds, decorative roadway lighting and signal poles, a new pedestrian crossover

Converting utilities to underground offers a greater reliability due to the system not being as vulnerable to weather events and new cabling. The improved esthetics also enhances the look of the road corridor.

Road works began the first week of March 2023 along Niagara Stone Road (Regional Road 55) from Four Mile Creek Rd to approx. 200 m north of Line 1.

These road works are estimated to be complete in the fall of 2023.

A previous construction contract was completed in 2017, which covered the section along Niagara Stone Road (Regional Road 55) from Cross Roads School to Concession 6 Road.

Niagara on-the-Lake HYDRO

DISTRIBUTION SYSTEM PLAN APPENDIX D

Asset Management Plan

EB-2023-0041

Niagara-on-the-Lake Hydro
Distribution System
Rotating Asset Management Plan

Executive Summary

Niagara-on-the-Lake Hydro (NOTL Hydro) executes a rotating asset management plan (RAMP) on their electricity distribution infrastructure. NOTL Hydro inspects one third of the distribution system in one of three defined areas every year, and by extension, the entire distribution system is inspected once every three years. This exceeds the requirements of the OEB Distribution System Plan.

Issues that are found during the inspection program are documented and followed up on for repair. Extreme issues, such as leaking oil or badly deteriorated poles are repaired immediately, others are prioritized and scheduled for repair.

Some of the inspection schemes lead into preventive maintenance (PM) programs as well.

Some inspection activities, such as Infrared (IR) testing and dry ice carbon dioxide (CO^2) cleaning, are done annually on select infrastructure.

The following are the NOTL Hydro assets inspected, the frequency of inspection and any associated preventive maintenance. This executive summary lists the activity; details follow in the body of the report.

Asset	Inspection/PM Activity	Inspection/PM Frequency
Transformers (Tx) and Switching Kiosks	1/3 of system every year	Entire system every three years
PM	IR on all equipment inspected	Entire system every three years
	IR on OH Transformers	Entire system annually
	CO^2 cleaning on PMH units	Entire system annually
Switching and Protective Devices	1/3 of system every year	Entire system every three years
PM	Air-Break Switch (ABS) maintenance	Entire system annually
	ABS to Scada-Mate conversion (eval. & execution as required)	Entire system every three years
	Radial tap evaluation, cut-outs	Entire system every three years
	Replace porcelain with polymer	Entire system every three years
Conductors and Cables	1/3 of system every year	Entire system every three years
PM	IR Resting	Entire system annually
Poles/Supports	1/3 of system every year	Entire system every three years
Hardware/Attachments	1/3 of system every year	Entire system every three years
PM	IR Testing	Entire system annually
	Insulator Washing near highways	Annual

Asset	Inspection/PM Activity	Inspection/PM Frequency
Vegetation	1/3 of system every year	Entire system every three years
Civil Infrastructure/Vaults	1/3 of system every year	Entire system every three years
Stations	Annual	All stations inspected annually
Routine Maintenance (RM)	Every other year	Half stations RM annually
PM	Every other year	Half stations PM annually
	Oil testing	All stations annually
	IR testing	All stations monthly
	Power Washing	All stations annually

1. The Distribution System Code

The NOTL HYDRO RAMP exceeds the Ontario Energy Board (OEB) "Distribution System Code" (DSC) Appendix C "Minimum Inspection Requirements", last revised March 1, 2020.

APPENDIX C - MINIMUM INSPECTION REQUIREMENTS

TABLE C-1
Electric Utility System Inspection Cycles
(Maximum Intervals in Years)

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

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

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

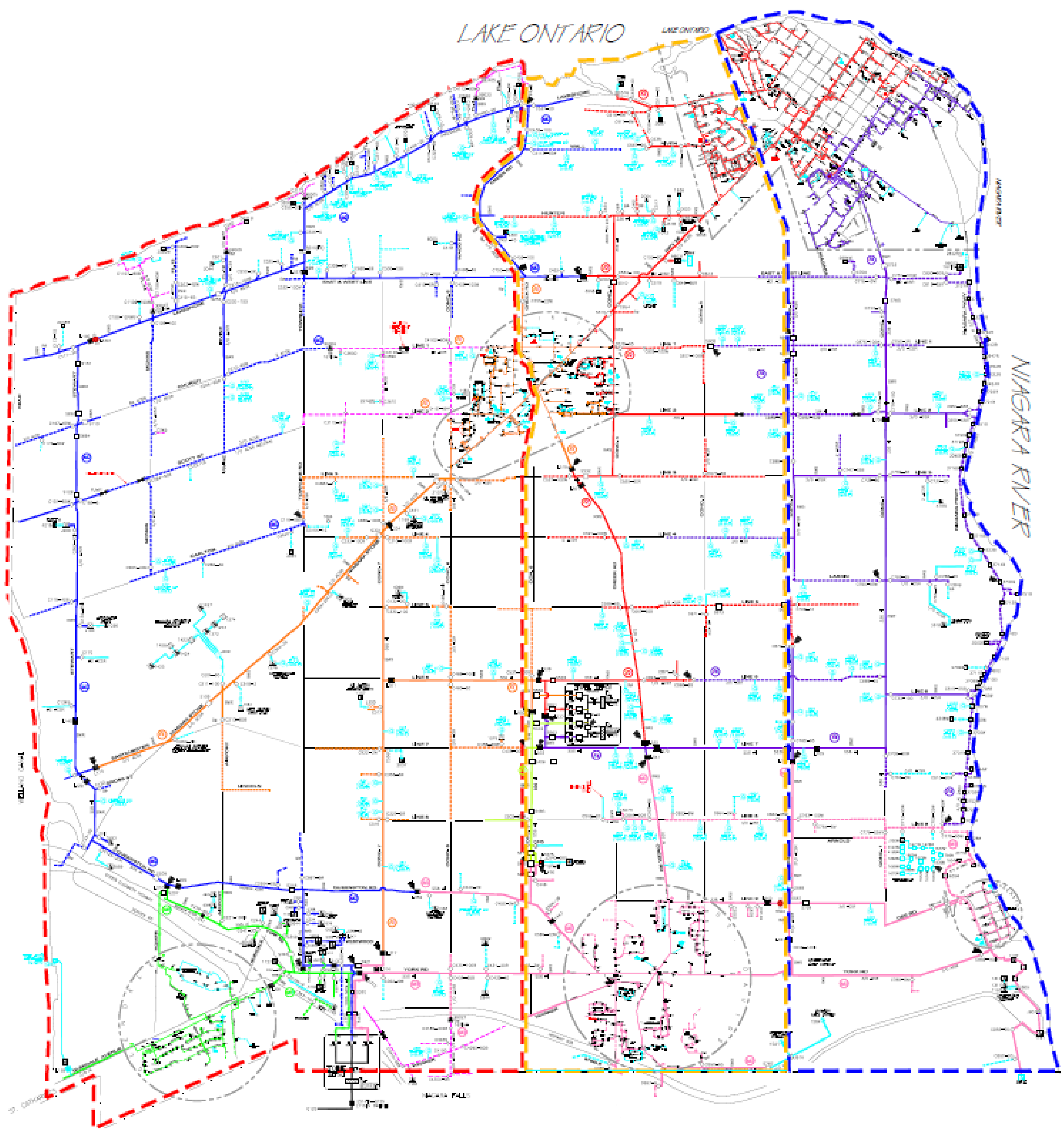
The DSC provides the following definitions that apply to the NOTL HYDRO RAMP:

Patrol Inspection:	Simple visual inspections consist of walking, driving or flying by equipment to identify obvious structural problems and hazards such as leaning power poles, damaged equipment enclosures, and vandalism
Rural:	Those areas that are less populous suburban areas and are outside of a standard metropolitan area. Generally, rural will be defined on a circuit or subcircuit basis by each utility, as areas with a line density of less than 60 customers per kilometer of line. It is recognized that there may be circumstances where the utility might want to treat something as urban though it would otherwise be defined as 'rural' according to this definition.
Urban:	Areas with higher density and, by definition pose safety and reliability consequences to greater numbers of people.

2. The NOTL Hydro RAMP Schedule

The NOTL Hydro inspection schedule is divided into three areas as delineated on Map 1, “NOTL Hydro Inspection Areas”. The map is shown with north pointing straight up, and section 1 is on the west (left, red border) side, section 2 in the middle (orange border), and section three on the east (right, purple border) side. Section 3 will be inspected in 2022, followed by section 1 in 2023, section 2 in 2024, section 3 in 2025, and so on.

Map 1 - NOTL HYDRO Inspection Areas



3. NOTL Hydro Assets

The following is a list of infrastructure identified in the DSC and pertinent to assets owned by NOTL Hydro that forms part of NOTL Hydro's inspection program. The list identifies what is required to be inspected and followed up on with corrective action. Unless otherwise noted, inspection follows a three-year cycle.

3.1 Transformers and Switching Kiosks

- Paint condition and corrosion
- Placement on pad or vault
- Check for lock and penta-bolt in place
- Grading changes
- Access changes (Shrubs, trees, etc.)
- Phase indicators and unit numbers match operating map (where used)
- Leaking oil
- Flashed or cracked insulators
- Contamination/discoloration of bushings
- Evidence of bushing flashover
- Ground lead attachments
- Ground wires on arrestors unattached
- Bird or animal nests
- Vines or brush growth interference
- Pad mounted – lid damage, missing bolts, cabinet damage, public security lock damage

Preventive Maintenance:

- Infrared (IR) testing, annual.
- Dry Ice CO^2 cleaning on PMH units, annual

Distribution transformers and switching kiosks, including switchgear and primary multi-tap junction boxes, are inspected on a three-year cycle in the patrol format. All equipment is Infrared (IR) tested during inspection. Air insulated switchgear (PMH units) are cleaned annually with dry ice carbon dioxide (CO^2). Transformers with leaking oil are addressed immediately upon discovery, as are any other defects that pose potential immediate harm to the general public. Less serious defects are noted, tracked, and dispatched for repair in order of seriousness priority.

3.2 Switching and Protective Devices

- Overhead:
  - Bent, broken bushings and cutouts
  - Damaged lightning arresters, control boxes, current and potential transformers
- Underground/Pad mounted
  - Security and structural condition of enclosure

Preventive Maintenance:

- Air-Break Switch (ABS)
  - Annual for all ABSs
  - Inspection and maintenance done with NOTL HYDRO staff
  - Evaluate and execute as determined: converting ABS to Scada-Mate switches at feeder tie points.

Check all radial taps for fusing and install cut-outs where protective devices are missing.
Replace all porcelain SMU devices with polymer cutouts

Switching and protective devices are inspected on the three-year cycle. Corrective action is prioritized in order of severity. All work on overhead distribution circuits is done by NOTL HYDRO staff. The radial taps in the respective inspection area are inspected to ensure that they are tapped off of the main line through protective polymer fused cut-outs. Those radial taps connected solid to the main line are prioritized to be reconnected through fused cut-outs. Similarly, porcelain switches found in the inspection are identified and scheduled to be replaced with polymer style switches. The exception to the three-year inspection schedule is that all air-break switches throughout the NOTL Hydro system are inspected and maintained every year by NOTL Hydro staff

3.3 Conductors and Cables

Low conductor clearance
Broken/frayed conductors or tie wires
Tree conditions, exposed broken ground conductors
Broken strands, bird caging, and excessive or inadequate sag.
Insulation fraying on secondary especially open wire

Preventive Maintenance:

IR testing is done on the entire NOTL HYDRO system annually followed by corrective action by NOTL HYDRO staff immediately thereafter, as needed.

Conductor and cable inspections follow the three-year cycle. Overhead circuits found to be too low for safe clearance are corrected immediately.

3.4 Poles/Supports

Bent, cracked or broken poles
Excessive surface wear or scaling
Loose, cracked or broken cross arms and brackets
Woodpecker or insect damage, bird nests
Loose or unattached guy wires or stubs
Guy strain insulators pulled apart or broken
Guy guards out of position or missing
Grading changes, or washouts
Indications of burning
Riser Poles: visual check of cable, cable guards, terminators and arrestors
Inspect pole integrity using Polux and associated hardware or other tradition method such as hammer test and visual inspection.
Maintain existing list of identified compromised poles and add found problem poles to list and document on existing map of identified poles. Prioritize in order of criticality.

All poles in the NOTL Hydro system were inspected in 2017-2019. Annual pole replacement activities have been conducted based on the results of these inspections since then. The three-year pole inspection program will resume in 2022.

3.5 Hardware/Attachments

Loose or missing hardware
Insulators unattached from pins
Conductor unattached from insulators
Insulators flashed over or obviously contaminated
Tie wires unraveled
Ground wire broken or removed
Ground wire guards removed or broken
Identify location of areas with porcelain insulators

Preventive Maintenance

IR testing is done on the entire NOTL HYDRO system annually followed by corrective action by NOTL HYDRO staff immediately thereafter.
Insulator washing annually by third party contractor.

Hardware and attachments are inspected on the three-year schedule as part of the pole inspection program. Porcelain insulators will be replaced if present as part of the annual pole replacement program. Insulator washing is conducted annually each spring by a third-party contractor in the vicinity of high-volume highway traffic that creates salt spray and diminishes the insulating qualities of the insulators and may cause tracking and incidence of pole fires if not washed.

3.6 Vegetation

Leaning or broken “danger” trees
Growth into line of “climbing” trees
Unapproved/unsafe occupation or secondary use

Vegetation maintenance is conducted on the three-year cycle. Vegetation is cut back to the 3m limit of approach near primary circuits. Vegetation management is contracted to third party contractors.

3.7 Civil Infrastructure/Vaults

Concrete condition
Locking or closing mechanisms
Vent condition
Corrosion of metal parts
Lifting hooks
Nomenclature

Civil infrastructure is inspected when constructed, and visible above-ground civil infrastructure is inspected on the three-year patrol style cycle. There are rarely ever any emergency repairs required for civil infrastructure in the NOTL Hydro distribution system. Any cracked vaults and eroded concrete conditions found are documented, monitored and prioritized for repair as required.

3.8 Stations

Transformers and Switching Kiosks

Paint condition and corrosion
Placement on pad or vault
Check for lock and penta bolt in place
Leaking oil

Flashed or cracked insulators
Contamination/discoloration of bushings
Evidence of bushing flashover
Ground lead attachments
Ground wires on arrestors unattached
Bird or animal nests

Switching and Protective Devices

Bent, broken bushings and cutouts
Damaged lightning arresters, control boxes, current and potential transformers

Hardware/Attachments

Loose or missing hardware
Insulators unattached from pins
Conductor unattached from insulators
Insulators flashed over or obviously contaminated
Tie wires unraveled
Ground wire broken or removed
Ground wire guards removed or broken

Vegetation and Right of Way:

Accessibility compromised
Grade changes that could expose cable
Leaning or broken "danger" trees in proximity of station
Growth into line of "climbing" trees
Vines or brush growth interference (line or fence clearance)
Bird or animal nests

Preventive Maintenance

Oil analysis
Power wash (York Station)
IR testing
Relay testing
Current Transformer (CT) testing
Sweep Frequency Response Analysis (SFRA) transformer testing
Testing of Substation Transformers
Arrestor testing
Breaker and Protection Testing and Maintenance
General station maintenance

NOTL Hydro staff perform monthly visual inspections at each station. Issues found are documented, prioritized and addressed as required. The visual inspection includes IR testing of bus, conductors, connections and equipment. Station maintenance is done on a two-year cycle. In 2022, NOTL station will undergo preventive maintenance with a third-party contractor, and York station will undergo routine, non-intrusive maintenance by the same contractor. Oil testing and analysis will be conducted annually at each station as part of the third-party routine and preventive maintenance programs.

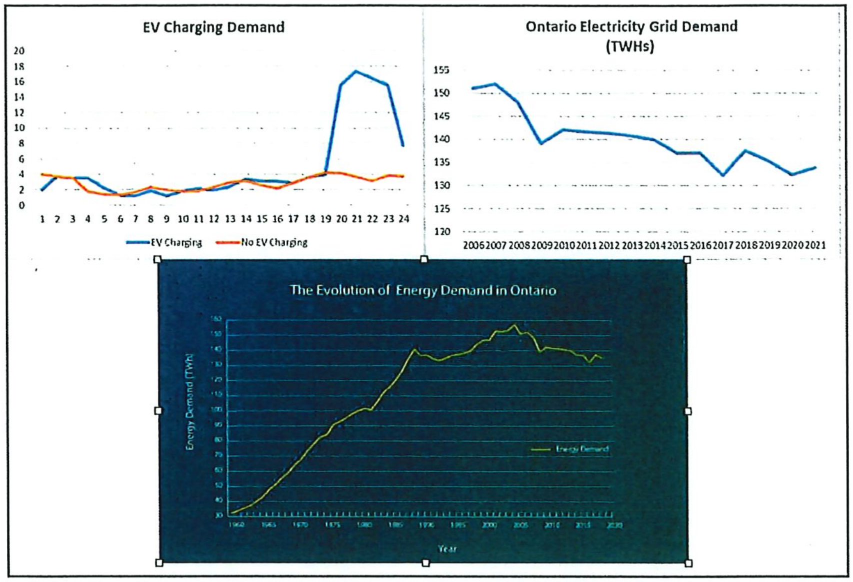
DISTRIBUTION SYSTEM PLAN APPENDIX E

EV Article

EB-2023-0041

NOTL Hydro president lays out impact of electric vehicles

Demand for hydro will grow but should be manageable



Graphs provided by NOTL Hydro president Tim Curtis show the impact the growth in use of electric vehicles will have on hydro demand..

Tim Curtis
Special to The Local

According to the stated objectives of the automobile manufacturers, we are moving towards a world where almost all new cars will be electric vehicles.

GM has a stated goal of all new vehicles being electric by 2035, Toyota has an aim of 70 per cent of all sales being electric by 2030 and hundreds of billions of investment dollars in electric vehicles have been announced by the automobile manufacturers.

There is much about this future world we do not know (it is in the future) but we can predict that most of the power for all these electric vehicles will come from the electricity grid. Based on this, we have analyzed the impact of widespread EV adoption on our local system as well as the provincial grid. There are four specific parts of the system we looked at:

1. The local transformer and upstream distribution system
2. NOTL Hydro's access to the provincial transmission grid
3. The transmission grid itself
4. Provincial generation

Coincident demand

When discussing electricity, it is important to distinguish between how much electricity is used over a period of time (consumption) and how much is used at any one time (demand). Most of the risk is with too much demand, and electric vehicle charging overloading the system at a point in time. For instance, if everybody plugs in their car when they arrive home from work, then what is already the peak demand at around 5 to 6 p.m. will get much worse.

The local transformer and upstream distribution system

Transformers are the green boxes (for underground systems) and grey cans on the poles (for above ground systems) that step down voltage from 16,000 V to the 120/240 V used at most houses. There are over 2,000 of these in NOTL. Each transformer provides power for up to 12 homes. Transformers are sized and installed on the assumption that an average house uses up to around 4 kW of power at any one time.

An electric charger uses much more power than the average household when it is in use. An average level 2 charger can use up to 7 kW. This chart is extreme, as it shows the charging of a Tesla, which has a higher charging demand than most other vehicles. At its peak, the combined demand of the house and charger is over 17 kW. Should you have several electric vehicle chargers operating at the same time, the local transformer could be overloaded. This creates the risk that the transformer could fail, creating a local power outage. Even if NOTL Hydro identifies that a transformer is overloaded, there is the risk that we may not be able to get replacements. Electric utilities will all have this issue, so will all be upgrading their transformers at the same time across North America.

We analyzed a number of scenarios, depending on how many chargers on a transformer were operating at any one time. The results were promising:

1. The number of transformers at risk of overloading was fewer than expected, so should be manageable. One of the fortunate reasons for this is that NOTL Hydro has been oversizing their green pad-mounted transformers to meet potential demand from unrealized electric heating and air conditioning load for many decades.

2. Most of the transformers at risk were the grey pole-mounted ones used for overhead services. This overloading can be corrected by either replacing the transformer with a larger one or adding an additional transformer to the system and rewiring the local connections. As the wiring is all overhead on poles this is much easier than with the underground system.

The upstream distribution system, including low voltage and high voltage wiring, also needs to be considered with increased local load. NOTL Hydro has specified low voltage wire to accommodate 200 amp residential services for decades. Existing 200 amp services are very likely able to accommodate the addition of an electric vehicle charging station in a residence. A service size upgrade may be required for additional loads beyond a single electric vehicle charging station installation.

Similarly, primary high voltage wiring has been sized beyond the installed capacity of the equipment serving the community. In most cases, there is enough room on primary feeders for the additional electric vehicle charging load.

We do ask that if you buy an electric vehicle and install a charging station, please let us know so we can check the local transformer and upgrade it if necessary.

NOTL Hydro access to the provincial grid

As a result of investments over the past 15 years, NOTL Hydro has significant transformation capacity to take power from the provincial grid and convert it to our local voltages. In aggregate we have around 150 MW of transformation capacity and the current peak is around 50 MW. This extra capacity was put in place to provide a redundant source of power for the whole town but is also available to manage future growth like from electric vehicles.

There is another potential source of power to service electric vehicle charging, and that is additional solar power. Since the ending of the provincial contracts, the number of new solar installations in NOTL has been limited, but as the costs of solar continue to fall, that is changing.

Transmission grid

The transmission grid is responsible for bringing power from the various large generators (hydro plants, nuclear power plants, large solar and wind farms) to the local utilities that then distributing the power. The actual demand for power from the transmission grid has been falling since the 2007-2008 recession. It is only now starting to pick up. As a result, only limited new investments in the transmission system have been required. While I have the greatest respect for Hydro One's technical staff, the combination of NIMBYism, multi-year timelines for projects, regulatory procrastination and bureaucratic inertia could make the transmission grid a chokepoint.

NOTL is fed off a 115 kV line that runs from the Beck power plant, through St. Catharines and eventually connects with a 230 kV line. There is currently some excess capacity available on this line, but that can change quickly with growth. The worry is that if NOTL is competing with the rest of Ontario for upgrades to the transmission grid, it might end up lower in the queue.

Provincial generation

NOTL Hydro analyzed the impact of every vehicle in NOTL becoming electric. Our estimate, based on some very high-level assumptions, was that the increase in demand would be 25 per cent. While this is high, it is not extraordinary or unmanageable. Ontario has managed much higher growth in demand for electricity in the past.

I discussed this in more detail in my March 15, 2022 blog at www.notlhydro.com/electric-vehicles-and-electricity-demand/. One of the reasons why the increase in generation needed is not higher is that electric vehicles are much more energy efficient than those with internal combustion engines, which waste a lot of energy, and that is all the excess heat radiating from the engine.

Planning ahead – next steps

NOTL Hydro is confident it can manage the transition to electric vehicles in NOTL. No customer should be worried about their ability to charge a new electric vehicle, though again, we do ask if you could let us know if you have installed an electric vehicle charger so we can check the local infrastructure.

Provincially, there is more of a challenge, not the amount of new electricity, but if it is all wanted at the same time. If the demand for electricity for electric vehicle charging largely happens in the late afternoon or early evening, then there is a real danger the transmission system and/or the generation capacity cannot cope.

The good news is the Ministry of Energy is fully aware of this challenge and is working to try to address it. One of their first steps will be the introduction of new rates later in 2023 that will have very, very low rates at night offset by higher rates in the late afternoon peak times. These new rates are optional, but if you have an electric vehicle you should look into them. Charging your electric vehicle later at night will make it even cheaper to drive.

Beyond that, I am anticipating there will eventually be spirited discussions as to whether electric utilities will be allowed to restrict the charging of vehicles at certain times to prevent overloading the provincial system. This could mean giving the utility access to control, limit or program the customer-owned charger; potentially in return for a discount. Alternatively, it could mean penalties if charging is being done at the peak times or the new optional rates being implemented in 2023 could be imposed. It will all be about managing the demand for EV charging in the least costly manner.

Tim Curtis, president of NOTL Hydro. *(Supplied)*

Niagara on-the-Lake HYDRO

DISTRIBUTION SYSTEM PLAN APPENDIX F

EV Analysis #1

EB-2023-0041

Niagara-on-the-Lake Hydro
Electric Vehicle Impact (part 1)
August 2022

Management was requested to look at the impact on our system if all NOTL residents and businesses converted to electric vehicles (EVs) now. While this is not going to happen; it is a useful analysis.

Staff are currently conducting a detailed review of the system assets, particularly the local transformers, but that analysis will take some time. This paper will look at the potential impact on the overall system load and therefore any impact on the transformer station assets.

Consumption (kwh)
I estimate the residential EV impact if all vehicles switched to be EVs is 40,000,000 kwh per year. Our current annual load is around 225,000,000 kwh so this is only a 18% increase. This is easily managed with our current assets.

This estimate was determined as follows:

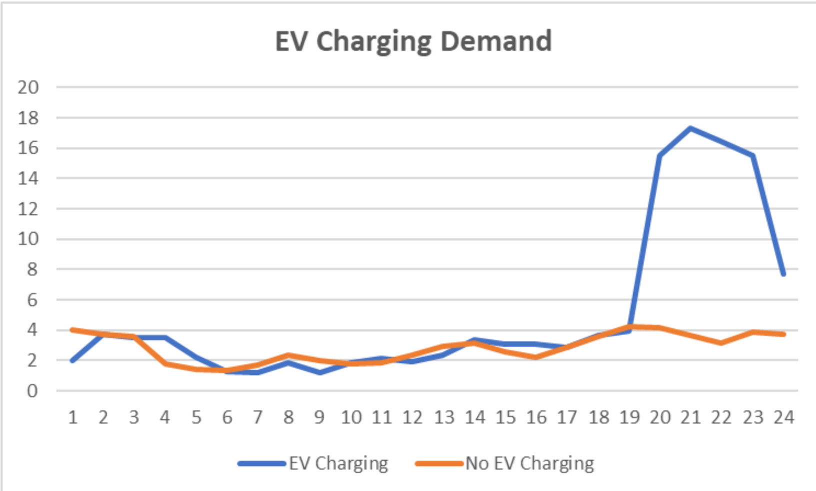
NOTL residences	8,000	
Vehicle per residence	1.5	- Average for Canada (Note 1)
Mileage per vehicle	16,000 km	• Average for Canada
Kwh per km	0.2	
Result	38,400,000	• Note 2
Rounding	40,000,000	

Note 1: This calculates to 12,000 vehicles. A different approach is the population of NOTL is 19,000 and, on average, there are 0.56 cars per person giving 10,640 vehicles.

Notre 2: This works out to around 270 kwh per month per vehicle. This is close to the increase in consumption seen with one customer who purchased a Tesla.

There is no simple way to measure the likely consumption of commercial EVs. Individually, commercial EVs will have higher consumption due to their higher average size and greater use but there are significantly fewer commercial EVs than residential EVs so their overall consumption will be lower. If we assume 50% of the residential consumption then the aggregate additional consumption is 60,000,000 kwh or a 27% increase. Again, this is manageable with our current station assets as, on average, this is an increase in consumption of 7 MW.

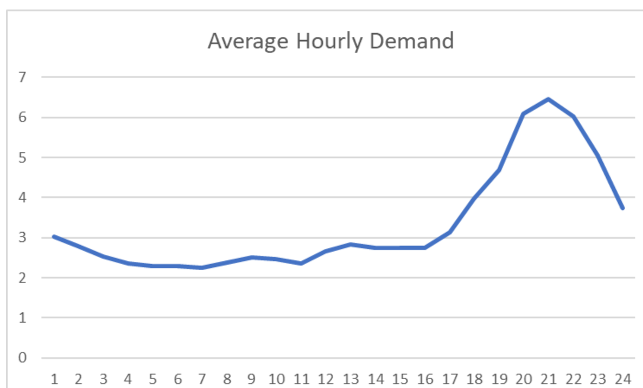
Demand (kW)



The chart shows the impact of one customer charging their Tesla. There is an average increase in demand of 12.5 kW during the charging period. If all 8,000 residential customers were to charge their vehicles in the same manner and at the same time the incremental demand would be 100 MW. Even with our current spare capacity this would be a challenge and that is assuming there are no other additional demands on this capacity such as town growth or new businesses looking for power.

The real challenge with EV charging will therefore not be the size of the additional demand by the timing of it. Fortunately, not every EV will be charged at the same time in this manner.

- EVs do not need to be charged every day. Our Tesla customer charged the EV 71 out of 222 days or every third day on average.
- The incremental demand was also lower on many of the charge days as the car was likely only partially discharged.
- Not every charger has the same level of demand as this one. Most level 2 chargers have 6-7 kW of demand. Tesla chargers have a higher demand.
- The Government of Ontario is introducing a new rate structure in 2023 that will have very low night time rates and higher peak time rates. This is being structured to appeal to EV charging.
- We anticipate that as EVs become more widespread, the Government will introduce programs to encourage EV owners to allow LDCs to have some control over the charging so as to manage the level of demand either provincially or locally.
- NOTL Hydro's current peak is between 4:00 pm – 6:00 PM. This charging is mostly after 6:00 PM so the incremental charge is not on top of peak demand.



NOTL Hydro is currently in an excellent position to absorb the increased demand for electricity. Ongoing investments in the system capacity will ensure this remains the case. These impacts will not be unique to NOTL Hydro. The increases in demand will also impact the transmission grid. Ensuring this grid is also managed in a forward-thinking manner will also be a challenge.

Niagara on-the-Lake HYDRO

DISTRIBUTION SYSTEM PLAN APPENDIX G

EV Analysis #2

EB-2023-0041

Niagara-on-the-Lake Hydro
Transformer Upgrades due to Electric Vehicles
November 2022

To measure the impact of the conversion to Electric Vehicles (EVs) on the local grid, NOTL Hydro performed an analysis on the loading of its transformers. The conclusion from the analysis is that though some upgrades may be needed, these will be manageable in number and will be primarily pole-mounted transformers which will be easier to upgrade.

Initial Loading Analysis
A total of 1,702 transformers were analyzed. These are both pole-mounted and pad-mounted transformers. To analyze the load on a transformer, we use the peak totals of the smart meter loads of all customers connected to a transformer. This analysis was prepared by Savage Data on our behalf.

The key for this analysis is to have the relationship between the meters and the transformers properly documented in the GIS system. A lot of work has been done over the past five years cleaning up this relationship data in the GIS system but more still needs to be done and it is not 100%.

The Savage analysis revealed that 271 of the 1,702 (16%) were loaded at maximum capacity at some point during the year. This can be for one of four reasons:

1. The size (kVa) of the transformer may be misstated in GIS.
2. The listing of the meters connected to the transformer may be incorrect.
3. The transformer may be at capacity or just over capacity for only limited times during the year. This is not an issue and the transformers are built for this.
4. The transformer is overloaded and should be upgraded.

The NOTL Hydro technical team will be checking the individual overloaded transformers from this analysis and either updating the data in GIS or recommending if an upgrade of the transformer is needed. The results of this will have some impact on the results of the EV analysis.

EV Loading Analysis
Three scenarios were analyzed to assess the impact of EVs on the local grid.

In the first scenario, it was assumed that every customer on every meter required a 12 kV charge (a Tesla level charge) at the time of peak charging. Obviously, this is unrealistic but in this scenario 1,345 or 79% of all transformers would be at or over capacity.

In the second scenario, it was assumed that every customer on every meter required a 6 kV charge (a regular level 2 level charge) at the time of peak charging. This could also be considered as half of the customers requiring a 12 kV charge at the peak. In this scenario, 1,046 or 61% of all transformers would be at or over capacity.

Finally, it was assumed that every other customer on every meter required a 6 kV charge (a regular level 2 level charge) at the time of peak charging or an average of 3 kV per customer. In this scenario, 646 or 38% of all transformers would be at or over capacity. Given that 271 or 16% were already showing as at or over capacity, the incremental overloading is 375 transformers or 22%.

Impact
The following is NOTL Hydro's view on the results of this analysis.

1. The numbers at first glance do not seem overwhelming. Given the likely timeline of EV adaptation, the upgrades required can be managed by NOTL Hydro staff.
2. The main challenge will be making sure there are enough transformers in inventory given that all LDCs across North America will have the same challenge. NOTL Hydro will maintain the higher inventory levels it adopted during the pandemic.
3. A scan of the transformers that would be at or over full load indicates that most of them are pole-mounted. These are easier to replace as you have the option of upgrading the transformer or splitting the load across two smaller transformers. This option is not really available for pad-mounted transformers.
4. The analysis showed little or no impact on the larger transformers. These mainly serve commercial customers. If they were installing a large number of chargers in their parking lots they would be analyzing the potential impact as part of the process. The only large transformer showing an impact in the second scenario was Kings Point on Ricardo.
5. It is not expected that much wiring would need to be upgraded though that was not specifically looked at as part of the analysis.
6. All Ontario LDCs will have to be able to offer a new electricity pricing option with very low overnight rates. This is being designed to try to switch EV charging to non-peak times and this would reduce the impact on the local transformers.

For those interested, the following is an article that discussed the focus of our analysis.

Readying the electricity grid for EVs is a challenge these experts say we're ready to handle

Published on 18 November 2022

Author [Mehanaz Yakub]

In the second instalment in *Electric Autonomy Canada's* EV charging discussion series, panelists revealed how smart investments, new technologies and innovative management can help ensure grid readiness for EVs

As the number of electric vehicles on roads goes up, questions about whether Canada's electrical grids will have the capacity to keep up with future power demands are at the forefront of the minds of many industry experts and electricity users alike.

To dive into the challenges and opportunities this situation presents, *Electric Autonomy Canada* this week hosted a panel discussion with experts from Alectra, Natural Resources Canada, Peak Power and Plug'n Drive. It was the second session in a five-part series on public EV charging in Canada that *Electric Autonomy* is holding this November.

The panelists touched on many approaches that can enhance grid resiliency while providing cost advantages to consumers, including expanding the grid infrastructure, adopting time-of-use rates, harnessing battery storage systems and utilizing vehicle-to-grid (V2G) technology.

Challenges with the grid

According to Matthew Sachs, COO at Peak Power, a Toronto-based software and artificial intelligence company that turns energy assets into decentralized electricity sources, the main issue the industry faces with energy grid capacity is being able to meet "instantaneous demand" (i.e. the peak) at any moment.

"The problem facing utilities at every scale around the world is that they have to size all of their infrastructure for the moments of peak demands — so the hottest hours of the year, the coldest hours of the year, plus 15 per cent for reliability," says Sachs.

So even though the utilization rates of most grids in the country are 20 per cent, assuming the status quo approach, the advent of more EVs – one million estimated for just Ontario alone by 2030 – will require construction of even more infrastructure.

Daniel Carr, head of smart cities at Alectra Utilities, which serves several Ontario municipalities west of Toronto, says Alectra anticipates needing 20 per cent more infrastructure than it has currently to handle the rise in peak capacity over the next 20 years.

But building more infrastructure will be expensive. A study in the U.S. found that it will cost US$75-to-US$125 billion to build infrastructure to accommodate the expected 20 million EVs there by 2030. Costs can also be compounded by the fact that most people have a similar daily routine and will plug in their vehicles around the same times, as well as desire fast charging speeds.

What utilities are doing

To reduce the need for new infrastructure and keep costs down, Alectra is looking at new ways of interacting with customers and the introduction of new technologies to lessen the amount of charging that occurs during peak times.

"We want to try and limit the amount of infrastructure we have to build [and] stay more within the infrastructure that we've already got," says Carr. "But I also want to highlight the fact that I think that EVs are a superior technology and a benefit to society; we're getting fewer emissions, we're saving money on fuel, we've been using lower-cost electricity. I think it's okay to spend some of those savings on building up the electricity system so that we can make sure that we've got the capacity there."

Apart from building infrastructure, Alectra is also looking at alternative solutions. For example, the utility spearheaded a time-of-use rate pilot that tested ultra-low pricing for electricity overnight in exchange for higher prices during the day and during peak times. Ontario will be deploying a similar province-wide ultra-low overnight rate structure in May 2023.

"Better planning is also part of this; so being able to really forecast where the demand is going to show up so we can prepare for it because it's not going to be a peanut butter spread evenly across the service territory," says Carr. "There's gonna be hotspots that we're going to want to be prepared for."

Building consumer awareness

When it comes to consumer perspective on grid readiness, Cara Clairman, president and CEO of Plug'n Drive, a non-profit organization that promotes EV adoption, says that consumers are thinking less about whether the grids are ready for EVs and more about grid capacity, if electricity prices will go up and if the electricity they receive is clean.

These questions are already fairly easy to answer, says Clairman. The majority of Canadian provinces run on clean, renewable energy and even in those that don't, EVs are still cleaner to operate over time than combustion vehicles. When it comes to pricing, because electricity is regulated, Clairman is "confident that we're never going to see a giant spike in electricity prices" due to EV uptake.

She also says consumers require more education about the ways they might leverage opportunities between EVs and the grid.

Emerging options such as V2G technology, which enables vehicle owners to get paid by utilities for drawing surplus power from their vehicles, which in turn will help cut grid costs and lower emissions, are not yet on the average consumer's radar, says Clairman.

"I think what we need to do first is help the consumer understand their use of electricity," she says. One way to do that is by giving them price signals and informing them that they can set timers on their chargers to benefit from much lower energy prices depending on the time of day.

"Then when we get to the point where — 'Hey, you know, you could actually earn some money with your EV battery, and here's how' — I think people will respond. I mean, certainly, I see it as a great opportunity."

DISTRIBUTION SYSTEM PLAN APPENDIX H

Underground Customers Open House

EB-2023-0041

Niagara on-the-Lake HYDRO

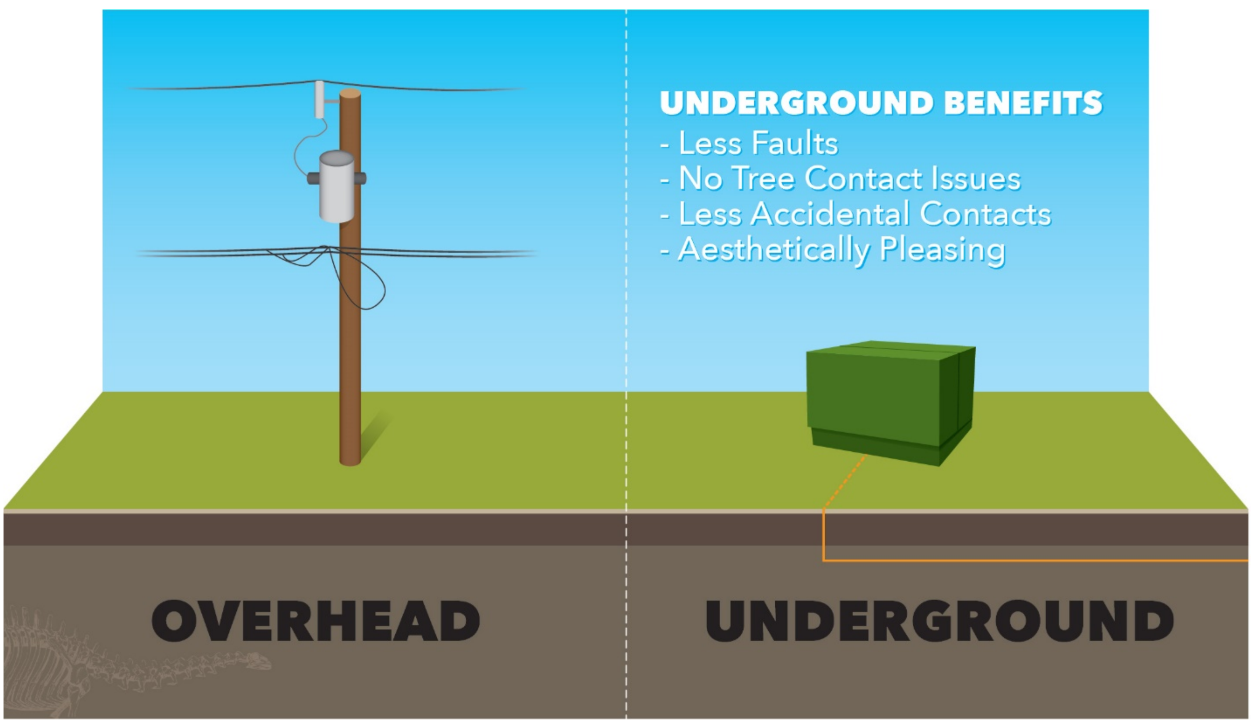
INVITATION

August 7, 2019

Dear Customer:

You are receiving this letter because you are located on a street on which we intend to convert the electrical service from overhead to underground in the foreseeable future. We will be hosting an Open House to discuss our plans, answer questions and get feedback.

Date:	September 24, 2019
Time:	3:00 PM *(doors open at 2:30pm)*
Location:	Mori Room, NOTL Community Centre 8 Anderson Lane, Niagara-on-the-Lake, ON



In particular, we will be presenting a tentative timetable as to when various streets will be converted as well as seeking input as to if residents of certain streets have a strong preference for earlier or later conversions. Other details about the conversion to underground process will also be presented.

8 Henegan Road P.O. Box 460, Virgil, Ontario, L0S 1T0
Phone: (905) 468-4235 Fax: (905) 468-3861

INVITATION

NOTL Hydro has been gradually converting much of the urban areas in NOTL from overhead to underground services for many decades. For those unable to attend the Open House, the presentation and a feedback form will be available on our website www.notlhydro.com on the day of the presentation.

All NOTL Hydro customers are welcome to the Open House.

Please feel free to call with any further questions. We apologize if this was sent to you in error.

Yours truly,

Tim Curtis
President

8 Henegan Road P.O. Box 460, Virgil, Ontario, L0S 1T0
Phone: (905) 468-4235 Fax: (905) 468-3861

DISTRIBUTION SYSTEM PLAN APPENDIX I

Public Notice of PIC
January 2023

Public Works
1815 Sir Isaac Brock Way, PO Box 1042,
Thorold, ON L2V 4T7
Tel: 905-980-6000 Toll-free: 1-800-263-7215
Fax: 905-685-0013
niagararegion.ca

2023-01-06

Notice of Public Information Centre

Contract # 2022-T-122

Regional Road 55 (Niagara Stone Road) Road Reconstruction and Improvements from Four Mile Creek Road to Line 1 in the Town of Niagara-on-the-Lake

The Niagara Region completed a Schedule “C” Municipal Class Environmental Assessment in May 2015, and is now proceeding with the construction. A Public Information Centre is being held to address the forth coming road reconstruction and community improvements in 2023.

Date: **2023-01-25**
Time: **5:00 -7:00p.m.**
Location: **This meeting will be held in the Simpson Room at the Niagara-on-the-Lake Community Centre, 14 Anderson Lane, Niagara-on-the-Lake, ON L0S 1J0.**

A Public Information Centre is being held to inform the public of the planned construction that will include but not be limited to;
Road reconstruction from Four Mile Creek Road to Line 1 Road,

New concrete sidewalks,
New roadway lighting,
Replacement signals at Four Mile Creek Road and Line 1,
Streetscaping and landscaping throughout the road corridor,
Concrete cross walks at the signalized intersections,
Overhead Utility conversions to under ground,
New parkettes and public spaces at Four Mile Creek Road and Niagara Stone Road, Field Road and Niagara Stone Road and Line 1 and Niagara Stone Road.

Further information and updated content on this project can be obtained from the Region's web site using the following:
https://www.niagararegion.ca/projects/niagara-stone-road/default.aspx

For further information, please contact Mike Wilson, A.Sc.T., PMP, Senior Project Manager, Transportation Engineering, Public Works, Niagara Region, 1815 Sir Isaac Brock Way, PO Box 1042, Thorold, ON, L2V 4T7, Michael.wilson@niagararegion.ca, 905-980-6000 ext 3183.

If you require any accommodations for a disability in order to participate in meetings or events, please let us know in advance so that arrangements can be made in a timely manner. Special accessibility accommodations and materials in alternate formats can be arranged by contacting Niagara Region's **Accessibility Advisor** at 905-980-6000 ext. 3252 or **accessibility@niagararegion.ca**.

Personal information collected or submitted in writing at public meetings will be collected, used and disclosed by members of Regional Council and Regional staff in accordance with the **Municipal Freedom of Information and Protection of Privacy Act (MFIPPA)**. Written submissions including names, contact information and reports of public meetings will be made available. Questions about this collection and disclosure should be directed to the Access & Privacy Office at 905-980-6000 ext. 3779 or **FOI@niagararegion.ca**.

Notice first issued 2023-01-09.

DISTRIBUTION SYSTEM PLAN APPENDIX J

Public Notice of PIC
January 2023

EB-2023-0041

IESO response to NOTL REG Investments Plan 2023 – 2027

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 April 5, 2023, Niagara-on-the-Lake Hydro ("NOTL") sent its REG Investments Plan (Plan) to the IESO for comment. The IESO has reviewed NOTL's Plan and reports that it contains no investments specific to connecting REG for the Plan period 2023 – 2027.

The IESO notes that NOTL's service territory is within the Niagara region. The Needs Assessment for Niagara was published by Hydro One Networks Inc on May 24, 2021 indicating further regional planning was required for the region[1]. The IESO's Scoping Assessment Outcome Report outlining the planning approach for the region was published on August 24, 2021[2]. The report determined that an Integrated Regional Resource Plan be undertaken for the Niagara region.

As NOTL has determined it requires no system investments to connect REG over the 2023-2027 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[3].

The IESO appreciates the opportunity provided to review the REG Investments Plan of NOTL and looks forward to working together in further regional planning processes.

[1] Hydro One's Need Assessment, May 24, 2021:
https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/niagara/Documents/2021-Niagara-Region_Needs-Assessment.pdf
[2] IESO's Scoping Assessment, August 24, 2021:
https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/Niagara/niagara-20210824-scoping-assessment-outcome-final.ashx
[3] 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 2B

Capitalization Policy

Policies and Procedures	
	Policy:
	Page: 1 of
	Location: X:\NOTLinc\Policies
	Issued:
IFRS Policy	Issue No.:

1. **Purpose:** To document the company policies for compliance with International Accounting Standard IAS16 as part of future conversion to IFRS accounting requirements.

2. Scope:

Currently, the mandatory date of implementation to IFRS, according to the Accounting Standards Board of Canada, is January 1, 2014[1]. NOTL Hydro has chosen not to change to IFRS before January 1, 2014. Thus, if the mandatory date remains at January 1, 2014, NOTL Hydro's financial statements for the fiscal year 2014 will be in IFRS, with historical results for 2013 stated in both CGAAP and IFRS. NOTL Hydro's 2012 and 2013 financial statements will remain in CGAAP accounting.

However, the Ontario Energy Board, by letter dated July 17, 2012, requires that policies for componentization and depreciation[2] and for capitalization (burdens)[3] for the fiscal year 2013 will be in accordance with IFRS, even though the LDC may remain under CGAAP in 2013, as will be the case for NOTL Hydro. LDCs are permitted to make this accounting change in 2012. However, NOTL Hydro has chosen not to make the change until 2013.

3. Policy: The "Conclusion Documents"[4] in the following pages provide NOTL Hydro's policies in relation to IAS16 standards for:

- Componentization and Depreciation
- Capitalization – Burdens
- Property, Plant and Equipment – Fair Value vs. Carrying Value as Deemed Cost
- Property, Plant and Equipment – Measurement after Recognition
- Property, Plant and Equipment – De-recognition
- Property, Plant and Equipment – Borrowing Costs

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1 This date is sometimes referred to as the "IFRS Changeover Date". The "IFRS Transition Date" is the beginning of the previous year, in this case January 1, 2013 from which date IFRS comparative figures are required for the 2014 financial statements.
2 See 1st item under "Policy"
3 See 2nd item under "Policy"
4 These documents were prepared with the guidance of KPMG on technical IFRS accounting matters.

Prepared by: **Philip Wormwell**	**Approved by:**
Date: December 6, 2012	**Date:**

Conclusion Document

Standard: IAS 16 – Property, Plant and Equipment

Topic: Componentization and Depreciation

Objective:

To document the accounting policy on componentization and depreciation of property, plant and equipment for Niagara-On-The-Lake Hydro Inc. ("the company")

Background:

Each part of an item of property, plant and equipment (PP&E) with a cost that is significant in relation to the total cost of the item shall be depreciated separately.

An entity should allocate the amount initially recognized in respect of an item of PPE to its significant parts to be depreciated separately.

A significant part of an item of PP&E may have a useful life and a depreciation method that are the same as the useful life and the depreciation method of another significant part of that same item. Such parts may be grouped in determining the depreciation charge.

Depreciation is to be computed on a systematic basis over the estimated useful life of the item of PP&E. The depreciable amount of an asset is determined after deducting its residual value. In practice, the residual value of an asset is often insignificant and therefore immaterial in the calculation of the depreciable amount.

The residual value and the useful life of an asset shall be reviewed at least at each financial year-end and, if expectations differ from previous estimates, the change(s) shall be accounted for as a change in an accounting estimate in accordance with **IAS 8** *Accounting Policies, Changes in Accounting Estimates and Errors.*

Depreciation of an asset begins when it is available for use (i.e. when it is in the location and condition necessary for it to be capable of operating in the manner intended by management). Depreciation of an asset ceases at the earlier of the date that the asset is classified as held for sale in accordance with **IFRS 5** and the date that the asset is derecognized.

Considerations:

Significant components of PP&E will be separately accounted under IFRS. Each significant component and the estimated useful lives, for purposes of computing depreciation expense under IFRS, will be set out in Table 1 as attached.

<u>Overhead system</u>

Four components identified – Poles, OH Conductors/Switches, Transformers and OH Secondary Cable.

The company currently has only wood poles and has determined that there are no components of the pole that are material in dollar value or have a significantly different useful life. Therefore, the company has concluded that there is only one component comprised of the fully dressed wood pole. This component includes the standoff brackets and guy wires which are considered immaterial.

In terms of useful life, the Kinetrics report gave a range of 35-75 years, with the typical being 45 year. The company considered the following factors with respect to the useful life of the poles. Mechanical stress and environmental factors are high and medium, respectively. The poles are not overloaded with weight, as the system has the typical length between poles. Historical experience shows the poles are being replaced between 45-50 years. The company has determined a useful life of 45 years is appropriate.

The company currently includes conductor and switches in the same GL account. It has been determined that switches do not make up a significant share of the account. Going forward, it is not expected there will be material amounts of switches added that justifies a separate component. The company also determined that they are not replacing conductor more often than switches or re-closers, which has led to the determination of a single component for these assets. The company has a regular maintenance program on the switches and as a result, failure is not typical.

In terms of useful life, the Kinetrics report gave a range of 50-75 years (typical 60 years) for OH conductors and 30-55 years (typical 45 years) for line switches. The company has determined its conductors fit the typical life span, given historical experience and pole spans being typical (which reduces strain on the conductor). Since switches were determined to be immaterial in this component, a useful life of 60 years is appropriate. Typically, switches are only replaced prior to replacing the conductor, when the switch fails. Failure is not typically seen with the exception of lightning strikes.

Overhead and underground transformers are currently grouped together. Useful lives of the two types of transformers are expected to be similar since the system is not overloaded. There are no plans to remove underground transformers from service prior to 40 years unless they are overloaded. Kinectrics useful life range is 30 to 60 years with typical of 40 years. Electrical loading and mechanical stress are low and environmental factors are considered to be normal. Kinectrics typical useful life is based upon moderate electrical loading. The company's low electrical loading would extend useful life beyond the typical range. Life should be 45 years based upon the utilization factors.

Secondary cable (Services) has been classified into two separate components (underground and overhead) due to the significantly different useful lives based on the type of wire used for each. Overhead wire is PILC (covered wire).

OH secondary cable experience tree wear from rubbing. The cable is insulated, which tends to deteriorate over time. The company's experience has shown this cable does not last longer than about 60 years. A useful life of 60 years is considered appropriate.

<u>TS Stations</u>

Two components identified – Transformers and Other

The company has assessed the different assets that comprise the two TS currently owned. The unique parts are power transformers, stations switch, breakers and switches, relays, bus-bars and steel structures. The company has determined the power transformers are by far the most significant component in the TS stations and should be accounted for as a separate component.

The other components are not considered material and useful lives are not significantly different to warrant any further componentization for the other assets comprising the TS station.

Kinetrics life range for the transformers is 30-60 years with 45 being typical. The company does not have much experience with the life span of this component as the oldest asset is from 1985. Electrical loading and environmental factors do not differ from Kinetrics typical, which is moderate. Typical useful life of 45 years is appropriate.

The other assets component (stations switch, breakers and switches, relays, bus-bars and steel structures) have a life range of between 30 and 60 years with typical being 50 years. The station switches and breakers etc. are regularly maintained and the operational practices of the switches are low to moderate which would suggest a higher useful life than typical. 55 years is considered an appropriate life.

DS Station

The King St. DS Station is expected to be decommissioned in 2013. Based on the expected decommission, the useful life of this asset on January 1, 2013 will be one year.

Underground System

Three Components identified – Underground Cable (Primary) & Devices, Underground Conduit and Secondary Cable (Underground)

The company has determined that underground primary cable and devices represent a single component. The assets in this class have similar useful lives. The Kinetrics report gives useful life ranges of 35-55 years (typical 40 years). The company's assets in this component include both direct buried and in duct, with the majority being in-duct (direct buried has a lower life and only in one or two subdivisions). Mechanical stress, electrical loading, and environmental conditions are considered moderate in the Kinectrics report, but the company has assessed electrical loading as lower. The company has also considered historical experience for these assets. There is currently direct buried cable with a life of 30 years in operation and it is expected that these will last at least 10 more years as no major issues have been encountered at 30 years of life. Based on these factors, the company has assessed these assets with a useful life of 45 years, higher than typical based upon the low electrical loading.

The company has determined that ducts, foundations, vaults and duct banks all form the Underground Conduit component. These assets have similar useful lives. The Kinetrics report gives useful life ranges from 30-85 years for these assets (typical 50-55 years). The company has assessed mechanical stress lower than Kinetrics report (assets are under grass not under roads) which leads to a longer expected life. The company has assessed 65 years as appropriate for these assets.

Secondary cable (Services) has been classified into two separate components (underground and overhead) due to the significantly different useful lives based on the type of wire used for each. Overhead wire is PILC (covered wire).

The Kinectrics report has the useful life of underground secondary cable as a range of 35-60 years (typical 40 years). The company has determined there are no factors that would suggest the useful life is any different from the underground primary cable. As such, a useful life of 45 years is appropriate.

SCADA software: Has been assessed as a single component, since radios are already included under communication equipment. The company is aware this software is updated on an irregular basis (that may exceed annual) but the original firmware may be considered to have a useful life of 8-10 years before it is completely replaced. Therefore a useful life of 10 years has been chosen for this component.

Minor assets

Office Equipment: Has been assessed as a single component as assets have similar useful lives. The current useful life is 10 years, and there are no indications this should change.

Vehicles < 3 tonnes: Single component. Policy is to replace after 5 years, therefore this is the useful life.

Vehicles > 3 tonnes: Single component. Policy is to replace after 10 years, therefore this is the useful life.

Trailers: Single component. Estimated useful life is 15 years based upon planned replacement cycle.

Administrative Buildings: Single component. Kinetrics report gives useful life of 50 – 75 years. The company's administrative building is fairly new. The building was constructed under a low budget (minimum standards) which indicates the maximum useful life is not appropriate. A useful life of 60 years has been determined.

Station Buildings: It has been determined not to separate these assets out from the TS (insignificant in relation to the equipment in the TS station)

Computer Equipment (Hardware): Single component. Policy is replacement every 3 years; therefore the useful life is 3 years.

Computer Equipment (Software): Single component. Policy is replacement every 3 years; therefore the useful life is 3 years. Technological obsolescence limits the life.

Communication Equipment: Single component that includes a computer station that works with the SCADA equipment, towers, radio and phone system. The company does not have any reason as to why this should vary from the rate it is currently being depreciated over, which is 10 years. This component is subject to technological obsolescence so anything higher than 10 years would not be appropriate.

Miscellaneous Equipment (tools and shop): Single component. Based on experience, assets in this class can last 5-10 years, but individually the assets are immaterial. As such, an average life of 8 years is considered appropriate.

Miscellaneous Equipment (stores and warehouse): Single component. The company has assessed at maximum life of 10 years based on Kinetrics report and experience with life of shelving equipment.

Meters: 4 Components were decided

1) Smart Meters: These are material and have a significantly different useful life (no history yet on how long they will last). The company discussed the need to split out into further components (data collectors). It was determined that useful life of data collectors and the meter are similar and therefore no need to break down into further components. The company does not expect useful life to exceed 10 years given problems already encountered with these meters. However, will use same rate as industry (15 years) and assess the appropriateness of this at end of each reporting period.

2) Stranded Meters: Life kept at OEB rate of 25 years.

3) Other Meters: These meters have been lasting 25 years. Technological obsolescence will limit the life of these assets to a certain extent so extending this beyond the 25 years is not appropriate.

4) CT's and PT's: These are material and have a significantly different useful life. Kinetrics report indicates a range of 35-50 years. The company has determined a 40 year life is reasonable for these assets.

Conclusion:

The new levels of componentization and the corresponding useful lives will be applied beginning January 1, 2013[5]. The net book value as deemed cost exemption (available to rate regulated entities) will be applied so that the opening values at January 1, 2013[6] do not need to be restated and therefore, componentization does not need to be applied retroactively.

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[5] *This date assumes the current mandatory IFRS implementation date (or "changeover date") of January 1, 2014, which requires 2013 historical data in 2014 financial statements to be in both CGAAP and IFRS.*
[6] *See Footnote above*

Table 1: Niagara-On-The-Lake Hydro – PP&E Components and Estimated Useful Lives

Component	Previous Component	Proposed Useful Life	Existing Useful Life
Poles	1830 -	45	25
OH Conductors and Switches	1835 -	60	25
Transformers (UG and OH)	1850 -	45	25
Transformers (Substation)	1815-1051 (York) and 1815-1052 (NOTL DS)	45	40
Station Switch, Breakers, Bus-bars	1815-1051 (York) and 1815-1052 (NOTL DS)	55	40
DS Station	1820 -	1 year [i.e. 2013]	25
UG Conductors and Devices	1845 -	45	25
UG Conduit	1840 -	65	25
UG Services	1855-1135 -	45	25
OH Services	1855-1130 -	60	25
SCADA	1980 -	10	15
Office Equipment	1915 -	10	10
Trucks (<3 tonnes)	1930 -7102 -	5	5
Trucks (>3 tonnes)	1930 -7103 -	10	8
Trailers	1930-7104 -	15	5
Administrative Buildings	1908-1030	60	50
PCB Shed	1908-1031	30	30
Computer Hardware	1920 -	3	5
Computer Software	1925 -	3	3
Communication equipment	1955 -	10	10
Miscellaneous Tools	1940 -	8	10
Stores and Warehouse equipment	1935 -	10	10
Stranded Meters	1860 -	25	25
Other Meters	1860 -	25	25
CT/PT	1860 -	40	25
Smart Meters	1860[7]-	15	N/A
Smart Metering – Data Collectors	1860[8]-	15	N/A

[7] *Previously 1555, prior to OEB approval of disposition of the variance account.*
[8] *See footnote 7*

Conclusion Document

Standard: IAS 16 – Property, Plant and Equipment

Topic: Capitalization - Burdens

Objective:

To document the accounting policy on the capitalization of burdens.

Background:

Core Principle

The cost of an item of property, plant and equipment (PP&E) is recognized as an asset if and only if:

a) It is probable that future economic benefits will flow to the company; and
b) The cost of the item can be measured reliably.

The cost of an item of PP&E includes any costs that are directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management.

Certain costs are explicitly prohibited from inclusion as costs of an item of PP&E:

a) Costs of opening a new facility;
b) Costs of introducing a new product or service (including advertising and promotion);
c) Costs of conducting business in a new location or with a new class of customer (including costs of staff training)
d) Administration and other general overhead costs; and,
e) Day-to-day servicing costs.

IAS 16 does not indicate what constitutes an item of PP&E. Judgment is required when applying the core principle.

Directly attributable

The term “directly attributable” is not defined in IAS 16. The specific facts and circumstances surrounding the cost and the ability to demonstrate that the cost is directly attributable to an item of PP&E is critical to establishing whether the cost should be capitalized. The cost must be attributed to a specific item of PP&E at the time it is incurred. The incurrence of that cost should aid directly in the construction effort, making the asset more capable of being used than if the cost had not been incurred.

General and administrative overhead

IFRS does not provide a definition of general and administrative overhead (G&A). 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.

G&A costs typically benefit the organization as a whole or areas of the organization more broadly rather than contributing directly to bringing a physical asset to the location and condition necessary for it to be capable of operating in the manner intended by management. The more the nature of a particular cost strays from being directly attributable to an item of PP&E, then the more likely it is that the cost will be determined to be in the nature of G&A.

Day-to-day servicing costs

Day-to-day servicing costs are defined as costs of labour and consumables and may include the cost of small parts. The purpose of these expenditures is often described as for the “repairs and maintenance” of the item of PP&E.

Feasibility studies and pre-construction activities

Normally, feasibility studies are not capitalized under IFRS as these costs do not always result in asset construction, and therefore may not meet the criteria of providing a future economic benefit. Additionally, the associated costs must be directly attributable to an item of PP&E. Pre-construction activities (such as design work) prior to a decision to go ahead with a capital project do not qualify for capitalization.

Considerations:

Canadian GAAP allowed for capitalization of general and administrative overhead, training costs, etc. while IFRS does not.

The Ontario Energy Board (OEB) requires electricity distributors to be in full compliance with IFRS requirements as applicable to non-regulated enterprises and only where Board authorizes specific alternative treatment for regulatory purposes is alternative treatment acceptable.

Niagara-On-The-Lake Hydro (“the company”) performed a review of the costs currently included in burdens to assess recognition criteria as an item of PP&E under IFRS.

Payroll allocation

Payroll allocation consists of the following benefits paid to employees: health benefits such as drugs, dental/vision, LTD, out of country medical, OMERS, WSIB, Employment insurance, CPP, EHT, and down time (which includes vacation, sick time, bereavement pay). IAS 16 specifically allows for benefits as defined in IAS 19 arising directly from the construction or acquisition of an item of PPE to be included as a directly attributable cost. The payroll allocation is allocated to capital based upon labour dollars charged to capital. Benefits are accumulated in the general ledger for all employees and allocated based upon where the employees charge their time (capital, maintenance, other operating, etc.). The company does not include training costs in payroll burden and downtime due to inclement weather is also not included in payroll burden.

No changes were identified for this burden under IFRS.

The following benefits were considered for inclusion in the burden rate as follows:

Truck allocation

Truck allocation consists of fuel, vehicle maintenance labour, repair parts, licenses and license renewals and amortization. Insurance is currently not included in the burden; however, the company will include insurance costs upon adoption to IFRS. Trucks and company vehicles are used on the job site and are directly related to the construction of an asset as they are required to construct the asset and are dedicated to the asset for a period of time. Truck expenses are allocated to capital based upon the time used on the job site.

With regards to repairs and maintenance costs, the company must decide whether the IFRS standard on this topic precludes capitalization of any repairs and maintenance costs or just specifically the repair and maintenance of the particular item (vehicle) repaired. For example the repairs and maintenance on a truck are not capitalizable to the cost of the truck (IAS 16.12), however an argument can be made that it is capitalizable to the specific capital job the repaired truck was assigned to such as a pole line construction. The company will interpret IAS 16.12 to apply only to repairs and maintenance of an item of PPE. Therefore repairs and maintenance cannot be capitalized to the cost of the item repaired. The company has determined that the repairs and maintenance account (account 91009102) can be included in the burden rate and be capitalized to the cost of a constructed asset when a vehicle is used on the job site for the construction of the asset.

Fuel, amortization (of the truck), truck insurance and license renewals can be capitalized because they are costs required to keep the trucks in running order and are not specifically excluded from capitalization in IAS 16 and they are directly attributable when used to construct an asset and bring it to its intended use. Amortization is currently included in the truck allocation under CGAAP, and the company will continue to include amortization under IFRS.

<u>Stores allocation</u>

The company noted that inventory is not currently recorded at cost. Inventory is recorded at cost plus (cost +10%, which represents the stores burden). This grossed up cost is charged to the specific job when the inventory item is used on the job.

Under IFRS, general and administrative expenses are not capitalized. General and administrative expenses tend to benefit the organization as a whole rather than a single job (or item of PPE) Typically, maintaining stores are more efficient than having parts delivered directly to the job site as they are needed. The company discussed whether stores costs should be capitalized or expensed. The company has structured its operations such that the time needed in stores is actually directly attributable. For example, there is no full time position in stores, but rather when stock is received, it is specifically tracked in the warehouse and segregated for the job for which it is intended. This leads to the conclusion that this time is directly attributable to specific jobs. Further, it would not be difficult for the staff person to track their time to specific jobs if required. The stores burden will continue to be charged to the capital job

Conclusion:

The company will capitalize all costs, including the above burdens, when the cost is directly attributable to bringing the item of PP&E to the location and condition necessary for it to be capable of operating in the manner intended by management.

Any general and administrative costs currently included in the various burden rates, such as training and other administrative expenses, will not be capitalized.

The following changes were made to the capitalization policy as a result of the transition to IFRS.

<u>Payroll allocation</u>

No changes were identified for this allocation.

<u>Truck allocation</u>

Insurance will be capitalized under IFRS.

<u>Stores allocation</u>

No changes were identified for this allocation.

Conclusion Document

Standard: IFRS 1 – Elective Exemption, IAS 16 – Property, Plant and Equipment

Topic: Property, Plant and Equipment – Fair Value vs. Carrying Value as Deemed Cost

Objective:

To determine the policy on initial measurement of property, plant and equipment (PP&E) on the date of transition to IFRS

Background:

Niagara-On-The-Lake Hydro Inc. ("NOTL") may elect to measure an item of PP&E at its fair value on the date of transition to IFRS. The fair value would then represent deemed cost at that date for purposes of subsequent measurement and amortization ("deemed cost election").

An additional IFRS 1 exemption is available to rate regulated entities. The exemption allows an entity to measure an item of PP&E at its previously recorded carrying value (i.e. net book value) on transition to IFRS. As NOTL's operations are rate regulated, they are eligible to apply this exemption.

If an Elective Exemption with respect to PP&E is not taken, NOTL would have to account for PP&E as if the requirements of IAS 16 had always been applied. This would require retrospective restatements of all PP&E balances in accordance with IFRS.

Considerations:

Retroactive restatements will be onerous and impractical as documentation for historical costs are not available.

The fair value exemption is not allowed by the OEB for rate setting purposes.

Fair values are more costly to obtain.

Electing the IFRS 1 exemption for rate regulated entities is more favourable to NOTL. Regulated Net Book Value ("regulated NBV") as at the date of transition to IFRS would be used for rate setting purposes. The OEB requires the use of regulated NBV as the basis for setting the opening rate base values upon transition to IFRS. Therefore, using the carrying value as deemed cost exemption would more closely align financial reporting with the basis in which regulated cash flows and income are determined by the regulator.

Conclusion:

NOTL has concluded that it will elect the IFRS 1 Exemption for rate regulated entities and use net book value as at date of transition to IFRS[9] as deemed cost.

[9] *The transition date is currently January 1, 2013 if the changeover date remains at January 1, 2014.*

Conclusion Document

Standard: IAS 16 – Property, Plant and Equipment

Topic: Property, Plant and Equipment – Measurement after Recognition

Objective:

To determine the policy on measurement of property, plant and equipment (PP&E) after initial recognition

Background:

For all subsequent periods following the initial recognition of an asset, IAS 16 permits a choice of using either the cost model or the revaluation model for valuing PP&E.

Cost Model

After recognition as an asset, an item of PP&E shall be carried at its cost less any accumulated depreciation and any accumulated impairment losses.

Revaluation Model

After recognition as an asset, an item of PP&E whose fair value can be measured reliably shall be carried at a revalued amount, being its fair value at the date of the revaluation less any subsequent accumulated depreciation and subsequent accumulated impairment losses. IAS 16 defines fair value as “the amount for which an asset could be exchanged between knowledgeable, willing parties in an arm’s length transaction.” It also mentions that, if there is no market-based evidence of fair value because of the specialized nature of a particular PP&E item and the item is rarely sold (except as part of a continuing business), an entity may need to estimate fair value using an income or a depreciated replacement cost approach.

Revaluation shall be made with sufficient regularity to ensure that the carrying amount does not differ materially from that which would be determined using fair value at the end of the reporting period. If an item of PP&E is revalued, the entire class of PP&E to which that asset belongs shall be revalued.

Ontario Energy Board

In its report of the Board on Transition to International Financial Reporting Standards, the OEB will require the use of historical acquisition cost as the basis for reporting PP&E for regulatory purposes.

Conclusion:

Niagara-On-The-Lake Hydro Inc. has concluded that it will choose the Cost Model to measure PP&E after initial recognition under IFRS.

Conclusion Document

Standard: IAS 16 – Property, Plant and Equipment

Topic: Property, Plant and Equipment – De-recognition of PP&E

Objective:

To document the accounting policy on de-recognition of property, plant and equipment.

Background:

The carrying amount of an item of property, plant and equipment (PP&E) shall be derecognized:

(a) On disposal; or

(b) When no future economic benefits are expected from its use or disposal (e.g. the item is removed from use).

When a part of an item of PP&E is replaced and that replacement is capitalized under the recognition principle in IAS 16, then the replaced part is derecognized regardless of whether the replaced part has been identified as a separate component and depreciated separately.

The gain or loss arising from the derecognition of an item of PP&E shall be included in profit or loss when the item is derecognized. Gains shall not be classified as revenue, and instead should be presented as other income or expense.

The disposal of an item of PP&E may occur in a variety of ways (e.g. by sale, by entering into a finance lease, by donation, etc.) In determining the date of disposal of an item, an entity applies the criteria in IAS 18 for recognizing revenue from the sale of goods. Under IAS 18.14, revenue from the sale of goods shall be recognized when all the following conditions have been satisfied:

(a) The entity has transferred to the buyer the significant risks and rewards of ownership of the goods

(b) The entity retains neither continuing managerial involvement to the degree usually associated with ownership nor effective control over the goods sold;

(c) The amount of revenue can be measured reliably;

(d) It is probable that the economic benefits associated with the transition will flow to the entity; and

(e) The costs incurred or to be incurred in respect of the transactions can be measure reliably.

The gain or loss arising from derecognizing an item of PP&E shall be determined as the difference between the net disposal proceeds, if any, and the carrying amount of the item.

Considerations:

Currently the pooled method of accounting for capital assets for Utility companies is applied and is an approved method by the Ontario Energy Board ("OEB").

The pooled method of accounting, pools like assets together based on the year of addition as the pooling method assumes that each asset will last, on average, their full useful life.

Under the pooled method there is an assumption that there are assets within the same asset pool which will last longer or shorter than the estimated useful life and therefore, in the end everything balances out on average. However, the assumption does not always hold true, especially if assets are removed from service before the end of their useful life, for example, when a road is widened.

Under the pooled method, if an asset is removed from service prior to the end of its useful life, there is no change to the accounting to remove the asset – it remains in the GL (i.e. it is not derecognized).

Currently, Niagara-On-The-Lake Hydro Inc. ("the company") records their capital assets using the pooled method of accounting and does not derecognize assets removed from service prior to the end of their useful life.

Since the company removes assets from service prior to the end of their useful life from time to time, these removed assets should be derecognized. The company must derecognize the cost of the asset which was removed/disposed. A write-off would be recorded in the amount of the remaining NBV of the asset removed/disposed. Any proceeds on the disposal of the asset would offset the write-off.

In order to properly account for assets that are removed from service in the accounting records, a process needs to be developed which alerts the accounting department when an asset has been removed from service in order to write-off the asset (long-term issue).

Conclusion:

For IFRS purposes a process will need to be developed and implemented which notifies the accounting department of changes which occur in the field which require accounting for the removal of the fixed assets and recording the loss in the income statement.

Conclusion Document

Standard: IAS 23 – Borrowing Costs

Topic: Property, Plant and Equipment – Borrowing Costs

Objective:

To determine the policy on accounting for borrowing costs for property, plant and equipment.

Background:

Borrowing costs are interest and other costs that an entity incurs in connection with the borrowing of funds. A qualifying asset is an asset that necessarily takes a substantial period of time to get ready for its intended use or sale. A substantial period of time is not defined in the IFRS standard. Guidance provided by KPMG suggests that a substantial period of time would be considered to be a period well in excess of 6 months.

For all subsequent periods following the initial recognition of an asset, IAS 16 permits a choice of using either the cost model or the revaluation model for valuing PP&E. Niagara-On-The-Lake Hydro Inc. ("NOTL") has chosen to use the cost model in accordance with the OEB requirements.

IAS 23 requires that borrowing costs be expensed as they are incurred unless they relate to "qualifying assets", in which case they must be capitalized if certain conditions are met. When interest is capitalized, IAS 23 requires the following steps:

- Begin capitalization when borrowing costs and expenditures are incurred and activities to develop a qualifying asset for its intended use are in progress;
- Suspend capitalization when development is interrupted for extended periods; and
- Cease capitalization when a qualifying asset is ready for its intended use or sale and all activities related thereto are complete.

Borrowing costs that are directly attributable to the acquisition, construction, or production of a qualifying asset form part of the cost of that asset. All other borrowing costs are recognized as interest expense.

The borrowing costs capitalized must reflect the weighted average of the actual borrowing costs incurred. The OEB requires the actual interest rate on the debt to be used if the related debt was acquired in an arm's length basis. If the debt is acquired in a non-arm's length basis then the interest rate used cannot exceed the Board's published rates for CWIP for rate setting purposes.

Definitions:

Qualifying asset – NOTL defines a qualifying asset as one that takes in excess of 6 months to construct or get ready for its intended use.

Considerations:

NOTL currently does not have any qualifying assets as the average time frame of constructing an item of PP&E typically does not exceed 6 months.

Conclusion:

Eligible borrowing costs will be capitalized as part of PP&E for all qualifying assets. Interest rate to be used for capitalization will be the actual cost of borrowing when debt is borrowed specifically to obtain the asset or the weighted average cost of borrowing when general borrowings are used to obtain the asset.