EXHIBIT 2

RATE BASE

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RATE BASE

Rate Base Overview

The rate base underlying the revenue requirement sought in this Application has been determined on a basis consistent with Chapter 2 of the Filing Requirements for Electricity Distribution Rate Applications - 2018 Edition for 2019 Rate Applications issued on July 12, 2018 ("Filing Requirement"). In accordance with the Filing Requirements, OPUCN has calculated the rate base as an average of the net capital balances at the beginning and the end of the 2021 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 and the Filing Requirements as issued by the OEB.

The net fixed assets include those distribution assets that are associated with activities that enable the conveyance of electricity for distribution purposes. OPUCN does not have any non-distribution assets. OPUCN's rate base calculation excludes work-in progress as well as inventory held for capital projects.

Controllable expenses include operations, maintenance, billing and collecting, community relations, and administration expenses.

OPUCN has not completed a lead-lag study or equivalent analysis to support a different rate and has submitted this application using the default value of 7.5%.

OPUCN adopted International Financial Reporting Standards ("IFRS") effective January 1, 2012 and has prepared this Application in accordance with the requirements of the OEB for regulatory accounting, reporting and filing. Such requirements include certain modified accounting treatments for regulated utilities reporting under IFRS as specified by the OEB in its Report of the Board: Transition to International Financial Reporting Standards dated July 28, 2009 ("IFRS Report"). Specifically, the OEB requires modified IFRS ("MIFRS") filings and reporting requirements for utilities that have adopted IFRS. OPUCN has incorporated the MIFRS requirement specified in the IFRS Report within the accounting and reporting components of the Application.

OPUCN's 2012 cost of service application, *EB-2011-0073*, was prepared in compliance with the Board's Guidelines for MIFRS transition and there is no requirement for comparative Canadian Generally Accepted Accounting Principles amounts. As a result all balances included in this Application have been determined under MIFRS.

OPUCN has provided a summary of its rate base calculations for the: 2015 to 2019 Board Approved amounts; 2015 to 2019 actual results; forecast 2020 Bridge Year, and 2021 Test Year in Table 2-1 below.

TABLE 2-1 - RATE BASE CONTINUITY SCHEDULE

$000's		2015 Approved	2016 Approved	2017 Approved	2018 Approved	2019 Approved	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Bridge	2021 Test
Fixed Assets													
Gross Fixed Assets (opening balance)		167,213	176,657	184,214	189,607	205,937	167,372	179,026	184,560	189,294	199,644	219,903	233,570
Gross Fixed Assets (closing balance)		176,657	184,214	190,491	205,937	227,445	179,026	184,560	189,294	199,644	219,903	233,570	245,095
Gross Fixed Assets (average)		171,935	180,436	187,353	197,772	216,691	173,199	181,793	186,927	194,469	209,773	226,736	239,332
Accumulated Depreciation (op. balance)		(84,889)	(86,796)	(89,585)	(93,109)	(96,410)	(84,642)	(88,941)	(90,002)	(91,791)	(94,552)	(96,982)	(100,277)
Accumulated Depreciation (clos. balance)		(86,796)	(89,585)	(93,142)	(96,410)	(100,218)	(88,941)	(90,002)	(91,791)	(94,552)	(96,982)	(100,277)	(103,781)
Accumulated Depreciation (average)		(85,842)	(88,190)	(91,363)	(94,759)	(98,314)	(86,792)	(89,471)	(90,896)	(93,172)	(95,767)	(98,629)	(102,029)
Net Fixed Assets (average)	**A**	**86,092**	**92,245**	**95,990**	**103,013**	**118,377**	**86,407**	**92,321**	**96,030**	**101,297**	**114,006**	**128,107**	**137,304**
Working Capital Allowance													
Operations & Maintenance		2,634	2,860	2,999	3,015	2,878	2,797	3,017	2,724	3,154	3,015	3,271	3,168
Billing and Collecting		2,653	2,715	2,780	2,846	2,915	2,170	2,481	2,725	2,478	2,176	2,523	2,573
Community Relations		1,162	1,310	1,338	1,366	1,395	1,192	1,303	1,191	1,268	1,172	1,498	1,553
Admin and General (incl LEAP)		5,632	5,678	5,739	5,837	5,948	5,544	5,608	6,299	6,715	6,543	6,588	6,847
Property Taxes		158	162	165	168	172	128	136	136	136	136	149	152
Total Controllable Expenses		12,240	12,724	13,021	13,234	13,307	11,830	12,545	13,075	13,751	13,042	14,029	14,294
Cost of Power		120,285	120,645	120,890	128,886	129,363	118,112	139,495	106,565	106,625	114,842	118,896	121,274
Working Capital Base		132,525	133,369	133,910	142,120	142,670	129,942	152,040	119,640	120,376	127,884	132,925	135,568
Working Capital Rate %		9.37%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%	7.50%
Working Capital Allowance	**B**	**12,418**	**12,497**	**12,547**	**13,317**	**13,368**	**12,176**	**14,246**	**11,210**	**11,279**	**11,983**	**12,455**	**10,168**
Rate Base	**A + B**	**98,510**	**104,742**	**108,537**	**116,330**	**131,745**	**98,582**	**106,567**	**107,240**	**112,576**	**125,989**	**140,562**	**147,471**

OPUCN's rate base is forecast to be $147.5 million in the 2021 Test Year; $15.7 million higher than the Board-Approved 2019 rate base totaling $131.7 million. This represents an increase of 11.9% over the two year period.

Average net fixed assets increase by $18.9 million while working capital allowance decreases by $3.2 million.

The rate applied to OPUCN's working capital was reduced from 9.37% as approved in OPUCN's last rebasing, to 7.5% in 2021 as per current OEB guidelines. The impact to rate base of the rate reduction on 2021 working capital allowance is approximately $2.5 million. Cost of power has decreased by $8.4 million (6.5% over the period) while controllable expenses increased by $1.0 million or 7.4%. Forecast demand and consumption are 6.0% and 3.6% lower respectively than the Board-Approved amounts in 2019, largely offsetting increases in applicable rates.

FIXED ASSET CONTINUITY STATEMENTS AND RECONCILIATION

OPUCN has provided Fixed Asset Continuity Schedules (Board Appendix 2-BA) for the Historical Actuals 2015 through 2019, the Board-Approved 2019, the Forecast for 2020 Bridge Year and the 2021 Test Year. The opening and closing balances of gross assets and accumulated depreciation used to calculate the fixed asset component of rate base correspond to the respective balances before Work in Progress ('WIP') in the fixed asset continuity statements.

These schedules are provided in Tables 2-2 to 2-9 below and have also been filed in live excel format.

TABLE 2-2 – FIXED ASSETS CONTINUITY SCHEDULE 2015 ACTUAL

			Cost				Accumulated Depreciation				
CCA Class	**OEB Account**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid				$ -				$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	1,635,177	343,765	0	1,978,942	(1,310,482)	(277,766)	0	(1,588,248)	390,694
CEC	1612	Land Rights (Formally known as Account 1906)	0	0	0	0	0	0	0	0	0
N/A	1805	Land	293,875	0	0	293,875	0	0	0	0	293,875
47	1808	Buildings	757,060	0	0	757,060	(402,652)	(100,057)	0	(502,709)	254,351
13	1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0
47	1815	Transformer Station Equipment >50 kV	0	0	0	0	0	0	0	0	0
47	1820	Distribution Station Equipment <50 kV	20,222,771	1,796,637	0	22,019,408	(7,244,493)	(459,317)	0	(7,703,809)	14,315,599
47	1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0
47	1830	Poles, Towers & Fixtures	37,066,586	3,884,554	(85,923)	40,865,217	(13,763,748)	(632,648)	25,386	(14,371,010)	26,494,207
47	1835	Overhead Conductors & Devices	20,172,980	1,411,557	(95,396)	21,489,140	(8,060,508)	(389,630)	59,142	(8,390,996)	13,098,145
47	1840	Underground Conduit	0	0	0	0	0	0	0	0	0
47	1845	Underground Conductors & Devices	42,583,175	3,488,118	(2,400)	46,068,893	(17,997,606)	(717,094)	1,160	(18,713,540)	27,355,353
47	1850	Line Transformers	54,803,906	2,470,741	(16,774)	57,257,873	(30,017,345)	(842,524)	8,270	(30,851,599)	26,406,274
47	1855	Services (Overhead & Underground)	0	0	0	0	0	0	0	0	0
47	1860	Meters	10,994,352	508,381	0	11,502,732	(4,698,586)	(789,729)	0	(5,488,315)	6,014,417
47	1860	Meters (Smart Meters)	0	0	0	0	0	0	0	0	0
N/A	1905	Land	0	0	0	0	0	0	0	0	0
47	1908	Buildings & Fixtures	0	0	0	0	0	0	0	0	0
13	1910	Leasehold Improvements	935,261	113,225	0	1,048,485	(648,874)	(127,539)	0	(776,413)	272,072
8	1915	Office Furniture & Equipment (10 years)				0				0	0
8	1915	Office Furniture & Equipment (5 years)	722,938	11,444	0	734,382	(680,844)	(6,788)	0	(687,632)	46,750
10	1920	Computer Equipment - Hardware	2,601,787	56,032	0	2,657,819	(2,338,763)	(124,182)	0	(2,462,945)	194,874
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	0	0	0	0	0	0	0	0	0
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)				0				0	0
10	1930	Transportation Equipment	4,188,041	500,300	0	4,688,340	(2,447,868)	(288,966)	0	(2,736,834)	1,951,507
8	1935	Stores Equipment	24,516	0	0	24,516	(24,516)	0	0	(24,516)	0
8	1940	Tools, Shop & Garage Equipment	2,398,523	237,357	(24)	2,635,856	(2,045,969)	(140,176)	24	(2,186,121)	449,735
8	1945	Measurement & Testing Equipment	510,303	342,593	0	852,897	(318,938)	(49,014)	0	(367,952)	484,945
8	1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
8	1955	Communications Equipment	418,132	0	0	418,132	(300,459)	(15,854)	0	(316,313)	101,819
8	1955	Communication Equipment (Smart Meters)				0				0	0
8	1960	Miscellaneous Equipment	162,391	13,909	0	176,300	(100,288)	(13,848)	0	(114,137)	62,163
47	1970	Load Management Controls Customer Premises	107,035	0	0	107,035	(107,035)	0	0	(107,035)	0
47	1975	Load Management Controls Utility Premises	1,021,693	0	0	1,021,693	(794,724)	(218,656)	0	(1,013,381)	8,313
47	1980	System Supervisor Equipment	293,582	0	0	293,582	(293,583)	0	0	(293,583)	(1)
47	1985	Miscellaneous Fixed Assets	0	0	0	0	0	0	0	0	0
47	1990	Other Tangible Property	0	0	0	0	0	0	0	0	0
47	1995	Contributions & Grants	(34,542,546)	(3,323,924)	0	(37,866,470)	8,955,095	800,674	0	9,755,769	(28,110,701)
47	2440	Deferred Revenue[5]				0				0	0
		Total PP&E	**167,371,538**	**11,854,688**	**(200,517)**	**179,025,709**	**(84,642,184)**	**(4,393,116)**	**93,982**	**(88,941,318)**	**90,084,391**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**(4,393,116)**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	0
			Net Depreciation	(4,393,116)

TABLE 2-3 – FIXED ASSETS CONTINUITY SCHEDULE 2016 ACTUAL

			Cost				Accumulated Depreciation				
CCA Class	OEB Account	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
	1609	Capital Contributions Paid				$ -				$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	1,978,942	966,353		2,945,295	(1,588,248)	(201,223)		(1,789,471)	1,155,824
CEC	1612	Land Rights (Formally known as Account 1906)				0				0	0
N/A	1805	Land	293,875			293,875				0	293,875
47	1808	Buildings	757,060			757,060	(502,709)	(12,734)		(515,443)	241,617
13	1810	Leasehold Improvements				0				0	0
47	1815	Transformer Station Equipment >50 kV				0				0	0
47	1820	Distribution Station Equipment <50 kV	22,019,408	793,391		22,812,799	(7,703,809)	(528,245)		(8,232,054)	14,580,745
47	1825	Storage Battery Equipment				0				0	0
47	1830	Poles, Towers & Fixtures	40,865,217	2,543,106		43,408,323	(14,371,010)	(716,971)		(15,087,981)	28,320,341
47	1835	Overhead Conductors & Devices	21,489,140	1,074,435		22,563,575	(8,390,996)	(378,472)	(59,142)	(8,828,610)	13,734,965
47	1840	Underground Conduit				0				0	0
47	1845	Underground Conductors & Devices	46,068,893	3,313,949	(3,663,350)	45,719,492	(18,713,540)	(906,245)	3,232,753	(16,387,032)	29,332,460
47	1850	Line Transformers	57,257,873	514,361		57,772,234	(30,851,599)	(934,239)	(8,270)	(31,794,108)	25,978,127
47	1855	Services (Overhead & Underground)				0				0	0
47	1860	Meters	11,502,732	768,829		12,271,561	(5,488,315)	(845,844)		(6,334,160)	5,937,401
47	1860	Meters (Smart Meters)				0				0	0
N/A	1905	Land				0				0	0
47	1908	Buildings & Fixtures				0				0	0
13	1910	Leasehold Improvements	1,048,485	50,601		1,099,086	(776,413)	(91,907)		(868,320)	230,767
8	1915	Office Furniture & Equipment (10 years)				0				0	0
8	1915	Office Furniture & Equipment (5 years)	734,382	15,756		750,138	(687,632)	(7,753)		(695,385)	54,753
10	1920	Computer Equipment - Hardware	2,657,819	74,704		2,732,523	(2,462,945)	(68,580)		(2,531,524)	200,998
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				0				0	0
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)				0				0	0
10	1930	Transportation Equipment	4,688,340	(50,342)		4,637,998	(2,736,834)	(173,451)		(2,910,284)	1,727,714
8	1935	Stores Equipment	24,516			24,516	(24,516)			(24,516)	0
8	1940	Tools, Shop & Garage Equipment	2,635,856	15,129		2,650,985	(2,186,121)	(83,450)	(24)	(2,269,594)	381,391
8	1945	Measurement & Testing Equipment	852,897	67,250		920,147	(367,952)	(39,361)		(407,313)	512,834
8	1950	Power Operated Equipment				0				0	0
8	1955	Communications Equipment	418,132	133,787		551,919	(316,313)	(22,545)		(338,858)	213,061
8	1955	Communication Equipment (Smart Meters)				0				0	0
8	1960	Miscellaneous Equipment	176,300			176,300	(114,137)	(13,031)	93,982	(33,186)	143,114
47	1970	Load Management Controls Customer Premises	107,035			107,035	(107,035)			(107,035)	0
47	1975	Load Management Controls Utility Premises	1,021,693			1,021,693	(1,013,381)	(17,494)		(1,030,875)	(9,182)
47	1980	System Supervisor Equipment	293,582			293,582	(293,582)			(293,582)	0
47	1985	Miscellaneous Fixed Assets				0				0	0
47	1990	Other Tangible Property				0				0	0
47	1995	Contributions & Grants	(37,866,470)	(1,084,162)		(38,950,631)	9,755,769	721,945		10,477,714	(28,472,917)
47	2440	Deferred Revenue[5]				0				0	0
		Total PP&E	**179,025,710**	**9,197,148**	**(3,663,350)**	**184,559,507**	**(88,941,318)**	**(4,319,599)**	**3,259,299**	**(90,001,618)**	**94,557,889**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**(4,319,599)**			

Less: *Fully Allocated Depreciation*

10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	0
			Net Depreciation	(4,319,599)

TABLE 2-4 – FIXED ASSETS CONTINUITY SCHEDULE 2017 ACTUAL

			Cost				Accumulated Depreciation				
CCA Class	OEB Account	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
	1609	Capital Contributions Paid				$ -				$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	2,945,295	(911,725)		2,033,570	(1,789,471)	301,600		(1,487,872)	545,698
CEC	1612	Land Rights (Formally known as Account 1906)	0			0	0			0	0
N/A	1805	Land	293,875			293,875	0			0	293,875
47	1808	Buildings	757,060			757,060	(515,443)	(12,701)		(528,144)	228,916
13	1810	Leasehold Improvements	0			0	0			0	0
47	1815	Transformer Station Equipment >50 kV	0			0	0			0	0
47	1820	Distribution Station Equipment <50 kV	22,812,799	1,147,096		23,959,895	(8,232,054)	(563,973)		(8,796,026)	15,163,869
47	1825	Storage Battery Equipment	0			0	0			0	0
47	1830	Poles, Towers & Fixtures	43,408,323	2,255,915		45,664,238	(15,087,981)	(698,107)		(15,786,088)	29,878,150
47	1835	Overhead Conductors & Devices	22,563,575	842,336		23,405,911	(8,828,610)	(304,921)		(9,133,531)	14,272,380
47	1840	Underground Conduit	0			0	0			0	0
47	1845	Underground Conductors & Devices	45,719,492	1,686,248	(2,837,421)	44,568,319	(16,387,032)	(927,665)	2,268,474	(15,046,223)	29,522,096
47	1850	Line Transformers	57,772,234	1,537,958		59,310,192	(31,794,108)	(852,663)		(32,646,771)	26,663,421
47	1855	Services (Overhead & Underground)	0			0	0			0	0
47	1860	Meters	12,271,561	378,729		12,650,290	(6,334,160)	(980,489)		(7,314,649)	5,335,641
47	1860	Meters (Smart Meters)	0			0	0			0	0
N/A	1905	Land	0			0	0			0	0
47	1908	Buildings & Fixtures	0			0	0			0	0
13	1910	Leasehold Improvements	1,099,086	(1,382)		1,097,705	(868,320)	(110,530)		(978,849)	118,855
8	1915	Office Furniture & Equipment (10 years)	0			0	0			0	0
8	1915	Office Furniture & Equipment (5 years)	750,138	10,649		760,788	(695,385)	(7,702)		(703,087)	57,701
10	1920	Computer Equipment - Hardware	2,732,523	76,501		2,809,023	(2,531,524)	(89,325)		(2,620,850)	188,174
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	0			0	0			0	0
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	0			0	0			0	0
10	1930	Transportation Equipment	4,637,998	503,173	(305,768)	4,835,403	(2,910,284)	(343,394)	305,768	(2,947,910)	1,887,493
8	1935	Stores Equipment	24,516			24,516	(24,516)			(24,516)	0
8	1940	Tools, Shop & Garage Equipment	2,650,985	30,794		2,681,779	(2,269,594)	(222,820)		(2,492,414)	189,365
8	1945	Measurement & Testing Equipment	920,147	135,884		1,056,031	(407,313)	(112,901)		(520,214)	535,817
8	1950	Power Operated Equipment	0			0	0			0	0
8	1955	Communications Equipment	551,919	42,570		594,489	(338,858)	(31,362)		(370,220)	224,269
8	1955	Communication Equipment (Smart Meters)	0			0	0			0	0
8	1960	Miscellaneous Equipment	176,300			176,300	(33,186)	(22,503)		(55,689)	120,611
47	1970	Load Management Controls Customer Premises	107,035			107,035	(107,035)			(107,035)	0
47	1975	Load Management Controls Utility Premises	1,021,693	1,254,834		2,276,527	(1,030,875)	(205,672)		(1,236,547)	1,039,981
47	1980	System Supervisor Equipment	293,582			293,582	(293,582)			(293,582)	0
47	1985	Miscellaneous Fixed Assets	0			0	0			0	0
47	1990	Other Tangible Property	0			0	0			0	0
47	1995	Contributions & Grants	(38,950,631)	(1,112,263)		(40,062,894)	10,477,714	821,397		11,299,111	(28,763,783)
47	2440	Deferred Revenue[5]				0				0	0
		Total PP&E	**184,559,507**	**7,877,316**	**(3,143,189)**	**189,293,635**	**(90,001,618)**	**(4,363,729)**	**2,574,242**	**(91,791,105)**	**97,502,530**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**(4,363,729)**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	0
			Net Depreciation	(4,363,729)

TABLE 2-5 – FIXED ASSETS CONTINUITY SCHEDULE 2018 ACTUAL

			Cost				Accumulated Depreciation				
CCA Class	OEB Account	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
	1609	Capital Contributions Paid				$ -				$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	2,033,570	349,450		2,383,020	(1,487,872)	(210,550)		(1,698,422)	684,598
CEC	1612	Land Rights (Formally known as Account 1906)				0	0			0	0
N/A	1805	Land	293,875			293,875	0			0	293,875
47	1808	Buildings	757,060	4,557,190		5,314,251	(528,144)	(54,043)		(582,188)	4,732,063
13	1810	Leasehold Improvements				0	0			0	0
47	1815	Transformer Station Equipment >50 kV				0	0			0	0
47	1820	Distribution Station Equipment <50 kV	23,959,895	3,562,026		27,521,921	(8,796,026)	(558,702)		(9,354,728)	18,167,193
47	1825	Storage Battery Equipment				0	0			0	0
47	1830	Poles, Towers & Fixtures	45,664,238	236,454		45,900,692	(15,786,088)	(806,817)		(16,592,905)	29,307,787
47	1835	Overhead Conductors & Devices	23,405,911	769,824		24,175,735	(9,133,531)	(351,046)		(9,484,577)	14,691,158
47	1840	Underground Conduit				0	0			0	0
47	1845	Underground Conductors & Devices	44,568,318	3,788,129	(2,372,782)	45,983,665	(15,046,223)	(1,310,794)	1,986,230	(14,370,786)	31,612,879
47	1850	Line Transformers	59,310,192	1,897,603		61,207,796	(32,646,771)	(1,014,368)		(33,661,139)	27,546,657
47	1855	Services (Overhead & Underground)				0	0			0	0
47	1860	Meters	12,650,290	665,231		13,315,521	(7,314,649)	(958,291)		(8,272,940)	5,042,581
47	1860	Meters (Smart Meters)				0	0			0	0
N/A	1905	Land				0	0			0	0
47	1908	Buildings & Fixtures				0	0			0	0
13	1910	Leasehold Improvements	1,097,705			1,097,705	(978,849)	(114,812)		(1,093,661)	4,044
8	1915	Office Furniture & Equipment (10 years)				0	0			0	0
8	1915	Office Furniture & Equipment (5 years)	760,788	24,843		785,630	(703,087)	(10,375)		(713,462)	72,168
10	1920	Computer Equipment - Hardware	2,809,023	425,227		3,234,250	(2,620,850)	(160,864)		(2,781,714)	452,536
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				0	0			0	0
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)				0	0			0	0
10	1930	Transportation Equipment	4,835,403	368,394	(234,407)	4,969,390	(2,947,910)	(349,996)	234,407	(3,063,499)	1,905,891
8	1935	Stores Equipment	24,516			24,516	(24,516)			(24,516)	0
8	1940	Tools, Shop & Garage Equipment	2,681,779	63,786		2,745,565	(2,492,414)	(86,339)		(2,578,754)	166,811
8	1945	Measurement & Testing Equipment	1,056,031	98,920		1,154,950	(520,214)	(112,433)		(632,647)	522,303
8	1950	Power Operated Equipment				0	0			0	0
8	1955	Communications Equipment	594,489	16,798		611,287	(370,220)	(34,330)		(404,550)	206,737
8	1955	Communication Equipment (Smart Meters)				0	0			0	0
8	1960	Miscellaneous Equipment	176,300	11,384		187,684	(55,689)	(8,886)		(64,575)	123,109
47	1970	Load Management Controls Customer Premises	107,035			107,035	(107,035)			(107,035)	0
47	1975	Load Management Controls Utility Premises	2,276,527	30,343		2,306,870	(1,236,547)	(80,947)		(1,317,493)	989,377
47	1980	System Supervisor Equipment	293,582			293,582	(293,582)			(293,582)	0
47	1985	Miscellaneous Fixed Assets				0	0			0	0
47	1990	Other Tangible Property				0	0			0	0
47	1995	Contributions & Grants	(40,062,894)	(3,908,248)		(43,971,142)	11,299,111	1,242,006		12,541,117	(31,430,025)
47	2440	Deferred Revenue[5]				0				0	0
		Total PP&E	**189,293,634**	**12,957,354**	**(2,607,189)**	**199,643,799**	**(91,791,105)**	**(4,981,587)**	**2,220,637**	**(94,552,055)**	**105,091,744**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**(4,981,587)**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	0
			Net Depreciation	(4,981,587)

TABLE 2-6 – FIXED ASSETS CONTINUITY SCHEDULE 2019 ACTUAL

			Cost				Accumulated Depreciation				
CCA Class	OEB Account	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
	1609	Capital Contributions Paid	0	4,136,705	0	4,136,705		(82,734)	0	(82,734)	4,053,971
12	1611	Computer Software (Formally known as Account 1925)	2,383,020	175,658	(210,454)	2,348,223	(1,698,422)	(200,199)	210,454	(1,688,167)	660,057
CEC	1612	Land Rights (Formally known as Account 1906)	0	0	0	0	0	0	0	0	0
N/A	1805	Land	293,875	0	0	293,875	0	0	0	0	293,875
47	1808	Buildings	5,314,251	396,754	0	5,711,005	(582,188)	(69,905)	0	(652,093)	5,058,912
13	1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0
47	1815	Transformer Station Equipment >50 kV	0	0	0	0	0	0	0	0	0
47	1820	Distribution Station Equipment <50 kV	27,521,921	(52,040)	(423,685)	27,046,197	(9,354,728)	(572,635)	403,178	(9,524,185)	17,522,012
47	1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0
47	1830	Poles, Towers & Fixtures	45,900,692	7,579,626	(3,158,733)	50,321,585	(16,592,905)	(866,269)	2,418,834	(15,040,340)	35,281,245
47	1835	Overhead Conductors & Devices	24,175,735	2,494,435	(978,589)	25,691,581	(9,484,577)	(324,491)	718,546	(9,090,521)	16,601,060
47	1840	Underground Conduit	0		0	0	0	0	0	0	0
47	1845	Underground Conductors & Devices	45,983,665	8,146,716	4,074,276	58,204,657	(14,370,786)	(1,389,602)	(3,135,484)	(18,895,872)	39,308,785
47	1850	Line Transformers	61,207,796	4,594,038	(1,612,391)	64,189,443	(33,661,139)	(1,152,831)	1,580,261	(33,233,709)	30,955,734
47	1855	Services (Overhead & Underground)	0	0	0	0	0	0	0	0	0
47	1860	Meters	13,315,521	1,071,723	(626,093)	13,761,150	(8,272,940)	(1,003,435)	503,513	(8,772,862)	4,988,288
47	1860	Meters (Smart Meters)		0	0	0	0	0	0	0	0
N/A	1905	Land	0	0	0	0	0	0	0	0	0
47	1908	Buildings & Fixtures	0	0	0	0	0	0	0	0	0
13	1910	Leasehold Improvements	1,097,705	0	0	1,097,705	(1,093,661)	(37,631)	0	(1,131,292)	(33,588)
8	1915	Office Furniture & Equipment (10 years)				0	0			0	0
8	1915	Office Furniture & Equipment (5 years)	785,630	17,506	(3,007)	800,129	(713,462)	(12,057)	13,100	(712,419)	87,710
10	1920	Computer Equipment - Hardware	3,234,250	148,154	(298,177)	3,084,226	(2,781,714)	(192,826)	298,177	(2,676,363)	407,864
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		0	0	0	0	0	0	0	0
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)				0	0			0	0
10	1930	Transportation Equipment	4,969,390	340,672	(203,843)	5,106,219	(3,063,499)	(382,527)	203,843	(3,242,183)	1,864,036
8	1935	Stores Equipment	24,516	6,251	0	30,767	(24,516)	(446)	0	(24,962)	5,804
8	1940	Tools, Shop & Garage Equipment	2,745,564	105,949	(58,471)	2,793,042	(2,578,754)	(155,002)	58,447	(2,675,308)	117,734
8	1945	Measurement & Testing Equipment	1,154,950	158,594	0	1,313,545	(632,647)	(133,621)	0	(766,268)	547,276
8	1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
8	1955	Communications Equipment	611,287	0	0	611,287	(404,550)	(35,170)	0	(439,720)	171,567
8	1955	Communication Equipment (Smart Meters)				0	0			0	0
8	1960	Miscellaneous Equipment	187,684	55,314	0	242,998	(64,575)	(40,977)	0	(105,552)	137,445
47	1970	Load Management Controls Customer Premises	107,035	0	0	107,035	(107,035)	0	0	(107,035)	0
47	1975	Load Management Controls Utility Premises	2,306,870	59,364	0	2,366,234	(1,317,493)	(183,189)	0	(1,500,683)	865,551
47	1980	System Supervisor Equipment	293,582	0	0	293,582	(293,582)	0	0	(293,582)	0
47	1985	Miscellaneous Fixed Assets	0	0	0	0	0	0	0	0	0
47	1990	Other Tangible Property	0	0	0	0	0	0	0	0	0
47	1995	Contributions & Grants	(43,971,142)	(6,198,919)	521,445	(49,648,616)	12,541,117	1,228,234	(95,264)	13,674,087	(35,974,529)
47	2440	Deferred Revenue[5]				0				0	0
		Total PP&E	**199,643,798**	**23,236,499**	**(2,977,723)**	**219,902,574**	**(94,552,055)**	**(5,607,313)**	**3,177,606**	**(96,981,763)**	**122,920,811**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**(5,607,313)**			

Less: *Fully Allocated Depreciation*

10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	0
			Net Depreciation	(5,607,313)

TABLE 2-7 – FIXED ASSETS CONTINUITY SCHEDULE 2019 BOARD-APPROVED

			Cost				Accumulated Depreciation				
CCA Class	OEB Account	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
	1609	Capital Contributions Paid				0				0	0
12	1611	Computer Software (Formally known as Account 1925)	3,195,250	194,233	(812)	3,388,671	(3,078,426)	(232,570)	406	(3,310,590)	78,081
CEC	1612	Land Rights (Formally known as Account 1906)	0	0	0	0	0	0	0	0	0
N/A	1805	Land	293,875	0	0	293,875	0	0	0	0	293,875
47	1808	Buildings	2,507,060	0	0	2,507,060	(466,760)	(40,158)	0	(506,918)	2,000,142
13	1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0
47	1815	Transformer Station Equipment >50 kV	0	0	0	0	0	0	0	0	0
47	1820	Distribution Station Equipment <50 kV	26,655,386	4,753,284	(299,094)	31,109,576	(8,726,463)	(661,932)	265,673	(9,122,722)	21,986,854
47	1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0
47	1830	Poles, Towers & Fixtures	51,035,813	2,846,613	(604,238)	53,278,188	(14,070,616)	(946,438)	471,046	(14,546,008)	38,732,179
47	1835	Overhead Conductors & Devices	26,433,656	7,077,691	(323,126)	33,188,221	(8,339,189)	(578,039)	254,678	(8,662,549)	24,525,672
47	1840	Underground Conduit	0	0	0	0	0	0	0	0	0
47	1845	Underground Conductors & Devices	52,875,735	8,006,065	(533,250)	60,348,550	(19,671,182)	(1,195,468)	450,645	(20,416,005)	39,932,545
47	1850	Line Transformers	56,674,650	464,855	(113,758)	57,025,748	(33,040,737)	(831,687)	92,271	(33,780,153)	23,245,594
47	1855	Services (Overhead & Underground)	0	0	0	0	0	0	0	0	0
47	1860	Meters	5,501,673	602,560	(78,166)	6,026,067	(7,280,978)	(985,424)	39,338	(8,227,064)	(2,200,996)
47	1860	Meters (Smart Meters)	7,733,934	0	0	7,733,934	(747,565)	0	0	(747,565)	6,986,369
N/A	1905	Land	0	0	0	0	0	0	0	0	0
47	1908	Buildings & Fixtures	0	0	0	0	0	0	0	0	0
13	1910	Leasehold Improvements	1,362,760	45,000	0	1,407,760	(1,237,724)	(126,000)	0	(1,363,724)	44,036
8	1915	Office Furniture & Equipment (10 years)		0	0	0			0	0	0
8	1915	Office Furniture & Equipment (5 years)	770,439	5,000	0	775,439	(724,582)	(12,214)	0	(736,796)	38,644
10	1920	Computer Equipment - Hardware	3,266,797	99,160	(1,112)	3,364,846	(3,043,076)	(178,667)	556	(3,221,187)	143,659
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	129,776	0	0	129,776	(74,955)	0	0	(74,955)	54,821
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	0	0	0	0	0	0	0	0	0
10	1930	Transportation Equipment	5,653,040	170,000	0	5,823,040	(3,767,056)	(384,165)	0	(4,151,221)	1,671,819
8	1935	Stores Equipment	24,516	0	0	24,516	(24,516)	0	0	(24,516)	0
8	1940	Tools, Shop & Garage Equipment	2,972,450	150,004	(12,555)	3,109,899	(2,563,116)	(145,273)	10,325	(2,698,064)	411,835
8	1945	Measurement & Testing Equipment	778,175	132,584	(539)	910,219	(413,563)	(54,752)	472	(467,843)	442,376
8	1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
8	1955	Communications Equipment	450,083	31,950	0	482,033	(365,475)	(20,647)	0	(386,122)	95,911
8	1955	Communication Equipment (Smart Meters)	0	0	0	0	0	0	0	0	0
8	1960	Miscellaneous Equipment	162,391	0	0	162,391	(136,705)	(6,286)	0	(142,992)	19,399
47	1970	Load Management Controls Customer Premises	107,035	0	0	107,035	(107,034)	0	0	(107,034)	0
47	1975	Load Management Controls Utility Premises	1,021,693	0	0	1,021,693	(900,030)	0	0	(900,030)	121,664
47	1980	System Supervisor Equipment	293,582	0	0	293,582	(293,583)	0	0	(293,583)	(1)
47	1985	Miscellaneous Fixed Assets	0	0	0	0	0	0	0	0	0
47	1990	Other Tangible Property	0	0	0	0	0	0	0	0	0
47	1995	Contributions & Grants	(43,078,548)	(1,105,000)	0	(44,183,548)	12,630,590	1,006,399	0	13,636,988	(30,546,560)
47	2440	Deferred Revenue[5]				0				0	0
		Total PP&E	**206,821,223**	**23,474,000**	**(1,966,649)**	**228,328,574**	**(96,442,742)**	**(5,393,321)**	**1,585,409**	**(100,250,654)**	**128,077,920**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**(5,393,321)**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	0
			Net Depreciation	(5,393,321)

TABLE 2-8 – FIXED ASSETS CONTINUITY SCHEDULE 2020 BRIDGE YEAR

			Cost				Accumulated Depreciation				
CCA Class	**OEB Account**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	4,136,705	0	0	4,136,705	(82,734)	(82,734)	0	(165,468)	3,971,237
12	1611	Computer Software (Formally known as Account 1925)	2,348,223	300,000	0	2,648,223	(1,688,167)	(367,627)	0	(2,055,793)	592,430
CEC	1612	Land Rights (Formally known as Account 1906)	0	0	0	0	0	0	0	0	0
N/A	1805	Land	293,875	0	0	293,875	0	0	0	0	293,875
47	1808	Buildings	5,711,005	325,000	0	6,036,005	(652,093)	(106,628)	0	(758,721)	5,277,284
13	1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0
47	1815	Transformer Station Equipment >50 kV	0	0	0	0	0	0	0	0	0
47	1820	Distribution Station Equipment <50 kV	27,046,197	139,600	(125,000)	27,060,797	(9,524,185)	(604,774)	113,125	(10,015,834)	17,044,963
47	1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0
47	1830	Poles, Towers & Fixtures	50,321,585	3,969,164	(750,000)	53,540,749	(15,040,340)	(934,581)	678,750	(15,296,170)	38,244,579
47	1835	Overhead Conductors & Devices	25,691,581	2,426,871	(950,000)	27,168,452	(9,090,521)	(460,170)	859,750	(8,690,941)	18,477,511
47	1840	Underground Conduit	0	0	0	0	0	0	0	0	0
47	1845	Underground Conductors & Devices	58,204,657	4,162,075	(750,000)	61,616,733	(18,895,872)	(1,319,592)	678,750	(19,536,715)	42,080,018
47	1850	Line Transformers	64,189,443	4,228,100	(100,000)	68,317,543	(33,233,709)	(1,134,921)	90,500	(34,278,130)	34,039,413
47	1855	Services (Overhead & Underground)	0	0	0	0	0	0	0	0	0
47	1860	Meters	13,761,150	412,500	(200,000)	13,973,650	(8,772,862)	(860,581)	181,000	(9,452,443)	4,521,207
47	1860	Meters (Smart Meters)	0	480,900	0	480,900	0	0	0	0	480,900
N/A	1905	Land	0	0	0	0	0	0	0	0	0
47	1908	Buildings & Fixtures	0		0	0	0	0	0	0	0
13	1910	Leasehold Improvements	1,097,705	280,000	0	1,377,705	(1,131,292)	(76,925)	0	(1,208,218)	169,487
8	1915	Office Furniture & Equipment (10 years)		0	0	0	0	0	0	0	0
8	1915	Office Furniture & Equipment (5 years)	800,129	0	0	800,129	(712,419)	0	0	(712,419)	87,710
10	1920	Computer Equipment - Hardware	3,084,226	971,500	0	4,055,726	(2,676,363)	(342,132)	0	(3,018,494)	1,037,232
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	0	0	0	0	0	0	0	0	0
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	0	0	0	0	0	0	0	0	0
10	1930	Transportation Equipment	5,106,219	545,000	(50,000)	5,601,219	(3,242,183)	(416,998)	45,250	(3,613,931)	1,987,288
8	1935	Stores Equipment	30,767	60,000	0	90,767	(24,962)	(20,887)	0	(45,849)	44,917
8	1940	Tools, Shop & Garage Equipment	2,793,042	0	0	2,793,042	(2,675,308)	(85,858)	0	(2,761,166)	31,876
8	1945	Measurement & Testing Equipment	1,313,545	0	0	1,313,545	(766,268)	(51,078)	0	(817,347)	496,198
8	1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
8	1955	Communications Equipment	611,287	250,000	0	861,287	(439,720)	(47,170)	0	(486,890)	374,397
8	1955	Communication Equipment (Smart Meters)	0	0	0	0	0	0	0	0	0
8	1960	Miscellaneous Equipment	242,998	0	0	242,998	(105,552)	0	0	(105,552)	137,445
47	1970	Load Management Controls Customer Premises	107,035	0	0	107,035	(107,035)	0	0	(107,035)	0
47	1975	Load Management Controls Utility Premises	2,366,234	0	0	2,366,234	(1,500,683)	(164,721)	0	(1,665,404)	700,830
47	1980	System Supervisor Equipment	293,582	0	0	293,582	(293,582)	0	0	(293,582)	0
47	1985	Miscellaneous Fixed Assets	0	0	0	0	0	0	0	0	0
47	1990	Other Tangible Property	0	0	0	0	0	0	0	0	0
47	1995	Contributions & Grants	(49,648,616)		0	(49,648,616)	13,674,087	1,113,271	0	14,787,358	(34,861,258)
47	2440	Deferred Revenue[5]	0	(1,958,057)		(1,958,057)	0	21,756	0	21,756	(1,936,301)
		Total PP&E	**219,902,574**	**16,592,654**	**(2,925,000)**	**233,570,228**	**(96,981,763)**	**(5,942,352)**	**2,647,125**	**(100,276,990)**	**133,293,239**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**(5,942,352)**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	21,756
			Net Depreciation	(5,964,108)

TABLE 2-9 – FIXED ASSETS CONTINUITY SCHEDULE 2021 TEST YEAR

			Cost				Accumulated Depreciation				
CCA Class	OEB Account	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
	1609	Capital Contributions Paid	4,136,705		0	4,136,705	(165,468)	(82,734)	0	(248,202)	3,888,502
12	1611	Computer Software (Formally known as Account 1925)	2,648,223	200,000	0	2,848,223	(2,055,793)	(232,891)	0	(2,288,684)	559,539
CEC	1612	Land Rights (Formally known as Account 1906)	0	0	0	0	0	0	0	0	0
N/A	1805	Land	293,875	0	0	293,875	0	0	0	0	293,875
47	1808	Buildings	6,036,005	100,000	0	6,136,005	(758,721)	(109,429)	0	(868,150)	5,267,855
13	1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0
47	1815	Transformer Station Equipment >50 kV	0	0	0	0	0	0	0	0	0
47	1820	Distribution Station Equipment <50 kV	27,060,797	1,880,300	(125,000)	28,816,097	(10,015,834)	(628,741)	113,125	(10,531,450)	18,284,646
47	1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0
47	1830	Poles, Towers & Fixtures	53,540,749	2,709,830	(750,000)	55,500,579	(15,296,170)	(1,007,784)	678,750	(15,625,204)	39,875,375
47	1835	Overhead Conductors & Devices	27,168,452	2,274,548	(950,000)	28,492,999	(8,690,941)	(509,195)	859,750	(8,340,386)	20,152,613
47	1840	Underground Conduit	0	0	0	0	0	0	0	0	0
47	1845	Underground Conductors & Devices	61,616,733	4,028,875	(750,000)	64,895,608	(19,536,715)	(1,327,104)	678,750	(20,185,069)	44,710,539
47	1850	Line Transformers	68,317,543	2,431,968	(100,000)	70,649,511	(34,278,130)	(1,220,213)	90,500	(35,407,843)	35,241,669
47	1855	Services (Overhead & Underground)	0	0	0	0	0	0	0	0	0
47	1860	Meters	13,973,650	303,300	(200,000)	14,076,950	(9,452,443)	(707,907)	181,000	(9,979,351)	4,097,600
47	1860	Meters (Smart Meters)	480,900	371,700	0	852,600	0	0	0	0	852,600
N/A	1905	Land	0	0	0	0	0	0	0	0	0
47	1908	Buildings & Fixtures	0		0	0	0	0	0	0	0
13	1910	Leasehold Improvements	1,377,705	100,000	0	1,477,705	(1,208,218)	(132,360)	0	(1,340,578)	137,127
8	1915	Office Furniture & Equipment (10 years)		0	0	0		0	0	0	0
8	1915	Office Furniture & Equipment (5 years)	800,129	0	0	800,129	(712,419)	0	0	(712,419)	87,710
10	1920	Computer Equipment - Hardware	4,055,726	1,412,000	0	5,467,726	(3,018,494)	(576,275)	0	(3,594,769)	1,872,957
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	0	0	0	0	0	0	0	0	0
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	0	0	0	0	0	0	0	0	0
10	1930	Transportation Equipment	5,601,219	530,000	(50,000)	6,081,219	(3,613,931)	(419,194)	45,250	(3,987,875)	2,093,344
8	1935	Stores Equipment	90,767	0	0	90,767	(45,849)	(26,887)	0	(72,736)	18,030
8	1940	Tools, Shop & Garage Equipment	2,793,042	0	0	2,793,042	(2,761,166)	(73,011)	0	(2,834,177)	(41,135)
8	1945	Measurement & Testing Equipment	1,313,545	0	0	1,313,545	(817,347)	(42,872)	0	(860,219)	453,326
8	1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
8	1955	Communications Equipment	861,287	150,000	0	1,011,287	(486,890)	(67,070)	0	(553,960)	457,327
8	1955	Communication Equipment (Smart Meters)	0	0	0	0	0	0	0	0	0
8	1960	Miscellaneous Equipment	242,998	0	0	242,998	(105,552)	0	0	(105,552)	137,445
47	1970	Load Management Controls Customer Premises	107,035	0	0	107,035	(107,035)	0	0	(107,035)	0
47	1975	Load Management Controls Utility Premises	2,366,234	0	0	2,366,234	(1,665,404)	(169,674)	0	(1,835,078)	531,156
47	1980	System Supervisor Equipment	293,582	0	0	293,582	(293,582)	0	0	(293,582)	0
47	1985	Miscellaneous Fixed Assets	0	0	0	0	0	0	0	0	0
47	1990	Other Tangible Property	0	0	0	0	0	0	0	0	0
47	1995	Contributions & Grants	(49,648,616)		0	(49,648,616)	14,787,358	1,116,345	0	15,903,703	(33,744,913)
47	2440	Deferred Revenue[5]	(1,958,057)	(2,043,057)		(4,001,113)	21,756	66,213	0	87,969	(3,913,144)
		Total PP&E	**233,570,228**	**14,449,464**	**(2,925,000)**	**245,094,693**	**(100,276,990)**	**(6,150,784)**	**2,647,125**	**(103,780,649)**	**141,314,044**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**(6,150,784)**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	66,213
			Net Depreciation	(6,216,997)

RATE BASE VARIANCE ANALYSIS

Variances in Year Over Year Rate Base

Tables 2-10 illustrates the variances from year to year for each rate base component for the years 2016 through 2021, followed by a brief narrative of the changes. Fuller details related to capital expenditures are contained in the gross assets variance analysis later in this exhibit.

TABLE 2-10 - VARIANCES IN YEAR OVER YEAR RATE BASE

$000's		2016 Actual Vs. 2015 Actual	2017 Actual Vs. 2016 Actual	2018 Actual Vs. 2017 Actual	2019 Actual Vs. 2018 Actual	2020 Bridge Vs. 2019 Actual	2021 Test Vs 2020 Bridge
Fixed Assets							
Gross Fixed Assets (opening balance)		11,654	5,534	4,734	10,350	20,259	13,668
Gross Fixed Assets (closing balance)		5,534	4,734	10,350	20,259	13,668	11,524
Gross Fixed Assets (average)		8,594	5,134	7,542	15,304	16,963	12,596
Accumulated Depreciation (op. balance)		(4,299)	(1,060)	(1,789)	(2,761)	(2,430)	(3,295)
Accumulated Depreciation (clos. balance)		(1,060)	(1,789)	(2,761)	(2,430)	(3,295)	(3,504)
Accumulated Depreciation (average)		(2,680)	(1,425)	(2,275)	(2,595)	(2,862)	(3,399)
Net Fixed Assets (average)	A	**5,914**	**3,709**	**5,267**	**12,709**	**14,101**	**9,197**
Working Capital Allowance							
Operations & Maintenance		221	(293)	430	(139)	256	(102)
Billing and Collecting		311	244	(246)	(302)	347	50
Community Relations		111	(112)	77	(97)	326	56
Admin and General (incl LEAP)		64	691	416	(171)	45	259
Property Taxes		8	0	0	0	13	3
Total Controllable Expenses		715	529	676	(709)	987	266
Cost of Power		21,383	(32,929)	60	8,217	3,787	2,373
Working Capital Base		22,098	(32,400)	736	7,508	4,774	2,638
Working Capital Rate %		9.37%	9.37%	9.37%	9.37%	9.37%	7.50%
Working Capital Allowance	B	**2,071**	**(3,036)**	**69**	**703**	**447**	**(2,283)**
Rate Base	A + B	**7,985**	**673**	**5,336**	**13,413**	**14,548**	**6,914**

2016 Actual versus 2015 Actual ($000's)

The increase in 2016 was driven by net capital additions of $9,197 and an increase in working capital allowance of $2,071. The change in working capital reflects an unexpectedly large increase in cost of power of $21,383 and an increase of $710, or 6.0%, in controllable expenses. The principal drivers for the increase in controllable expenses were $354 higher bad debt expense and lower labour allocations to capital work. The increase in net capital additions is driven by the change in gross assets, explanations for which can be seen later in this exhibit in Tables 2-16 to 2-21 and accompanying variance analysis.

2017 Actual versus 2016 Actual ($000's)

The increase in 2017 of $373 was driven by an increase in average net fixed assets of $3,709 (net capital additions of $7,877) mostly offset by a decrease in working capital allowance of $3,036. The change in working capital reflects a normalisation of cost of power from 2016 of $32,929 and an increase of $529, or 4.2%, in controllable expenses.

2018 Actual versus 2017 Actual ($000's)

The increase in 2018 of $5,336 was driven by an increase in average net fixed assets of $5,267 (net capital additions of $12,957) and an increase in working capital allowance of $69.

2019 Actual versus 2018 Actual ($000's)

The increase in 2019 was driven by an increase in average net fixed assets of $12,709 (net capital additions of $23,236) and a decrease in working capital allowance of $703. The change in working capital reflects an increase in cost of power of $8,217 and a decrease of $709, or 7.7%, in controllable expenses. The principal drivers for the decrease in controllable expenses were $190 lower bad debt expense, labour turnover, and higher labour allocations to capital work.

2020 Bridge Year versus 2019 Actual ($000's)

The increase in 2020 is driven by an increase in average net fixed assets of $14,101 (net capital additions of $16,593) and an increase in working capital allowance of $447. The change in working capital reflects an increase in cost of power of $3,787 and an increase of $987, or 7.6%, in controllable expenses. The principal drivers for the increase in controllable expenses are labour replacements and new hires, and lower labour allocations to capital and CDM type work.

2021 Test Year versus 2020 Bridge Year ($000's)

The increase in 2021 is driven by an increase in average net fixed assets of $9,197 (net capital additions of $14,449) and a decrease in working capital allowance of $2,283. The change in working capital reflects the change to the Board mandated working capital allowance rate of 7.5% in the absence of a lead-lag study. The 7.5% rate replaces the previous OPUCN Board approved rate of 9.37%, and drives a reduction in the 2021 working capital allowance of $2,520.

Variances in Actual to Approved Rate Base

Tables 2-11 illustrates the variances in actuals to Board Approved amounts for each rate base component for the years 2015 through 2019, followed by a brief narrative of the changes. Fuller details related to capital expenditures are contained in the gross assets variance analysis later in this exhibit.

TABLE 2-11 - VARIANCES IN ACTUAL TO APPROVED RATE BASE 2015-2019

$000's		2015 Actual Vs. 2015 Approved	2016 Actual Vs. 2016 Approved	2017 Actual Vs. 2017 Approved	2018 Actual Vs. 2018 Approved	2019 Actual Vs. 2019 Approved	2021 Test Vs. 2019 Approved
Fixed Assets							
Gross Fixed Assets (opening balance)		159	2,369	345	(314)	(6,293)	27,633
Gross Fixed Assets (closing balance)		2,369	345	(1,198)	(6,293)	(7,542)	17,650
Gross Fixed Assets (average)		1,264	1,357	(426)	(3,304)	(6,918)	22,642
Accumulated Depreciation (op. balance)		247	(2,146)	(417)	1,318	1,858	(3,867)
Accumulated Depreciation (clos. balance)		(2,146)	(417)	1,351	1,858	3,236	(3,563)
Accumulated Depreciation (average)		(949)	(1,281)	467	1,588	2,547	(3,715)
Net Fixed Assets (average)	**A**	**314**	**76**	**41**	**(1,716)**	**(4,371)**	**18,926**
Working Capital Allowance							
Operations & Maintenance		162	158	(275)	139	137	291
Billing and Collecting		(483)	(234)	(55)	(368)	(738)	(341)
Community Relations		30	(7)	(147)	(98)	(224)	158
Admin and General (incl LEAP)		(88)	(70)	560	877	596	899
Property Taxes		(31)	(26)	(29)	(33)	(36)	(20)
Total Controllable Expenses		(410)	(179)	54	517	(266)	987
Cost of Power		(2,173)	18,850	(14,324)	(22,261)	(14,521)	(8,361)
Working Capital Base		(2,582)	18,671	(14,270)	(21,744)	(14,787)	(7,375)
Working Capital Rate %		9.37%	9.37%	9.37%	9.37%	9.37%	9.37%
Working Capital Allowance	**B**	**(242)**	**1,749**	**(1,337)**	**(2,037)**	**(1,386)**	**(3,221)**
Rate Base	**A + B**	**72**	**1,825**	**(1,296)**	**(3,753)**	**(5,756)**	**15,705**

2015 Actual Comparison to 2015 Board-Approved Rate Base ($000's)

The 2015 actual variance to 2015 approved of $72, below the materiality threshold of $100 used in this application.

2016 Actual Comparison to 2016 Board-Approved Rate Base ($000's)

The actual rate base of $106,567 in 2016 was higher than the Board-Approved 2016 amount by $1,825 due primarily to an unexpectedly large increase in cost of power of $18,850, accounting for $1,766 of the increase.

2017 Actual Comparison to 2017 Board-Approved Rate Base ($000's)

The actual rate base of $107,240 in 2017 was lower than the Board-Approved 2017 amount by $1,296 due primarily to $14,324 lower than forecast cost of power, accounting for $1,342 of the decrease.

2018 Actual Comparison to 2018 Board-Approved Rate Base ($000's)

The actual rate base of $112,576 in 2018 was lower than the Board-Approved 2018 amount by $3,753 due to lower than forecast average net fixed assets of $1,716 and $2,037 lower than forecast working capital allowance. Actual capital expenditures of $12,957 were $5,487 lower than forecast. The variance in working capital allowance is driven primarily by $22,261 lower than forecast cost of power.

2019 Actual Comparison to 2019 Board-Approved Rate Base ($000's)

The actual rate base of $125,989 in 2019 was lower than the Board-Approved 2019 amount by $5,756 due to lower than forecast average net fixed assets of $4,371 and $1,386 lower than forecast working capital allowance. Actual capital expenditures of $23,236 were in line with forecast, the variance due mainly to the $5,487 lower than forecast capital spend in 2018. The variance in working capital allowance is driven primarily by $14,521 lower than forecast cost of power.

2021 Test Year Comparison to 2019 Board-Approved Rate Base ($000's)

The forecast rate base of $125,989 in 2021 is higher than the Board-Approved 2019 amount by $15,705 due to an increase in average net fixed assets of $18,926 partially offset by $3,221 lower working capital allowance. Combined capital expenditures of $31,042 drive the increase in average net fixed assets, while the reduction to 7.5% from 9.37% in the working capital allowance rate drives a reduction in working capital allowance of $2,530.

ALLOWANCE FOR WORKING CAPITAL

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

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

b) The filing of a lead/lag study.

OPUCN has opted to use the rate of 7.5% for calculating the Working Capital Allowance as per the 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) multiplied by the default value of 7.5%. OPUCN is proposing a working capital allowance of $10,147,185 as shown in Table 2-12 below.

TABLE 2-12 - ALLOWANCE FOR WORKING CAPITAL

Working Capital Allowance $000's	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2019 Approved	2020 Bridge	2021 Test
Operations & Maintenance	2,797	3,017	2,724	3,154	3,015	2,878	3,271	3,168
Billing and Collecting	2,170	2,481	2,725	2,478	2,176	2,915	2,523	2,573
Community Relations	1,192	1,303	1,191	1,268	1,172	1,395	1,498	1,553
Admin and General (incl LEAP)	5,544	5,608	6,299	6,715	6,543	5,948	6,588	6,847
Property Taxes	128	136	136	136	136	172	149	152
Total Controllable Expenses	**11,830**	**12,545**	**13,075**	**13,751**	**13,042**	**13,307**	**14,029**	**14,294**
Cost of Power	118,112	139,495	106,565	106,625	114,842	129,363	118,629	121,274
Working Capital Base	**129,942**	**152,040**	**119,640**	**120,376**	**127,884**	**142,670**	**132,658**	**135,568**
Working Capital Rate %	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%	7.50%
Working Capital Allowance	**12,176**	**14,246**	**11,210**	**11,279**	**11,983**	**13,368**	**12,430**	**10,168**

OPUCN has not previously been directed by the Board to undertake a lead/lag study.

Cost of Power

OPUCN has calculated cost of power (COP) for the 2020 Bridge Year and 2021 Test Year in support of its rate base calculation, using the load forecast, which is discussed in detail in Exhibit 3 – Operating Revenue.

OPUCN confirms that the Cost of Power (COP) is determined by a split between the Regulated Price Plan (RPP) and non-RPP customers based on actual data, use of most current RPP prices established for the May 1, 2019 to April 30, 2020 period, and use of the most recent approved Uniform Transmission Rates (UTRs), Smart Metering Entity charge and regulatory charges. A summary of the Total COP expenses is shown in Table 2-13 below.

TABLE 2-13 – COST OF POWER SUMMARY

Cost of Power $000's	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2019 Approved	2020 Bridge	2021 Test
4705 Power Purchased	72,163	81,045	63,308	64,829	59,003	61,707	61,674	68,619
4707 Global Adjustment	28,304	38,377	26,841	24,611	38,318	47,296	39,084	37,688
4708 Charges - WMS	4,159	5,227	3,155	3,069	3,436	4,544	3,505	3,333
4714 Charges - NW	6,745	7,301	6,560	6,539	6,631	7,788	6,763	6,177
4716 Charges - CN	6,276	7,071	6,232	7,297	7,104	7,471	7,246	5,186
4751 Smart Metering Entity Charge	465	473	470	281	351	558	358	273
Total	**118,112**	**139,495**	**106,565**	**106,625**	**114,842**	**129,363**	**118,629**	**121,274**

OPUCN's wholesale market participant (WMP) customers have been excluded from the calculation of electricity and global adjustment costs, as they transact directly with the Independent Electricity System Operator (IESO) for the purchase of electricity. WMP customers are included in the calculation of the retail transmission costs.

In accordance with the Filing Requirements, the commodity price estimate used to calculate COP was determined using a split between RPP and non-RPP Class A and Class B customers based on 2019 actual data and uses the most current RPP price. Non-RPP consumption data has been further split between customers eligible for the Global Adjustment (GA) modifier vs. non-eligible. The RPP and non-RPP prices were obtained from the “Regulated Price Plan Prices and the Global Adjustment Modifier for the Period

May 1, 2019 to April 30, 2020" and the "Regulated Price Plan Cost Supply Report May 1, 2019 – April 30, 2020". The GA modifier was applied to eligible customers and a weighted average commodity price was determined using the 2019 actual split between RPP, eligible non-RPP and non-eligible non-RPP customers. Table 2-14 below shows the calculation of the RPP and non-RPP forecast supply costs for 2021 (Appendix 2-Za).

TABLE 2-14 – COMMODITY EXPENSE CALCULATION (APPENDIX 2-ZA)

Step 1: **2021 Forecasted Commodity Prices**

Forecasted Commodity Prices	Table 1: Average RPP Supply Cost Summary*		non-RPP	RPP
HOEP ($/MWh)	Load-Weighted Price for RPP Consumers		$20.09	$20.09
Global Adjustment ($/MWh)	Impact of the Global Adjustment		$106.94	$106.94
Adjustments ($/MWh)				$1.00
TOTAL ($/MWh)	Average Supply Cost for RPP Consumers			**$128.03**

Step 2: **Commodity Expense**
(volumes for the bridge and test year are loss adjusted)

Commodity

Customer Class Name	UoM	Revenue USA #	Expense USA #	2021 Test Year Class A Non-RPP Volume**		Class B Non-RPP Volume**	Class B RPP Volume**	Average HOEP	Average RPP Rate	Amount
Residential	kWh	4006	4705	-		14,591,747	481,903,320	$ 0.02009	$ 0.12803	$61,991,230
GS < 50 KW	kWh	4010	4705	-		19,610,270	109,095,925	$ 0.02009	$ 0.12803	$14,361,522
GS 50 to 999 KW	kWh	4015	4705	9,245,104		213,064,122	105,726,242	$ 0.02009	$ 0.12803	$18,002,323
GS 1000 to 4999 KW	kWh	4015	4705	42,028,615		34,437,097	-	$ 0.02009	$ 0.12803	$1,536,196
Large User	kWh	4015	4705	38,878,939		-	-	$ 0.02009	$ 0.12803	$781,078
Unmetered	kWh	4010	4705	-		-	2,506,367	$ 0.02009	$ 0.12803	$320,890
Sentinel	kWh	4025	4705	-		-	24,360	$ 0.02009	$ 0.12803	$3,119
Street Lighting	kWh	4025	4705	-		4,555,628	-	$ 0.02009	$ 0.12803	$91,523
	kWh	4025	4705					$ 0.02009	$ 0.12803	$0
TOTAL				**90,152,658**		**286,258,864**	**699,256,215**			**$97,087,881**

Class A - non-RPP Global Adjustment

Customer	UoM	Revenue	Expense	2021 Amount	kWh Volume				Hist. Avg GA/kWh ***	Amount
GS 50 to 999 KW	kWh	4015	4707	$ 708,756	9,245,104				$ 0.0767	$708,756
GS 1000 to 4999 KW	kWh	4015	4707	$ 3,316,005	42,028,615				$ 0.0789	$3,316,005
Large User	kWh	4015	4707		38,878,939				$ 0.0785	
				4,024,760	90,152,658					**$4,024,760**

Class B - non-RPP Global Adjustment

Customer Class Name	UoM	Revenue USA #	Expense USA #	2021		Class B Non-RPP Volume			GA Rate/kWh	Amount
Residential	kWh	4006	4707			14,591,747			$ 0.10694	$1,560,441
GS < 50 KW	kWh	4010	4707			19,610,270			$ 0.10694	$2,097,122
GS 50 to 999 KW	kWh	4015	4707			213,064,122			$ 0.10694	$22,785,077
GS 1000 to 4999 KW	kWh	4015	4707			34,437,097			$ 0.10694	$3,682,703
Large User	kWh	4015	4707			0			$ 0.10694	$0
Unmetered	kWh	4010	4707			0			$ 0.10694	$0
Sentinel	kWh	4025	4707			0			$ 0.10694	$0
Street Lighting	kWh	4025	4707						$ 0.10694	$0
Total Volume						**281,703,236**				
TOTAL										**$30,125,344**

*Regulated Price Plan Prices for the Period November 1, 2019 – October 31, 2020
** Enter 2020 load forecast data by class based on the most recent 12-month historic Class A and Class B RPP/Non-RPP proportions
*** Based on average $ GA per kWh billed to class A customers for most recent 12-month historical year.

OPUCN understands 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. OPUCN has used the most recent approved Uniform Transmission Rates (UTRs), Smart Metering Entity charge and regulatory charges. Table 2-15 below shows the detailed calculation of the forecast cost of power for 2021 (Appendix 2-Zb).

TABLE 2-15 – COMMODITY EXPENSE CALCULATION (APPENDIX 2-ZB)

		2021 Test Year	RPP		2021 Test Year	non-RPP		Total
Electricity Commodity	Units	Volume	Rate	$	Volume	Rate	$	$
Class per Load Forecast				-				
Residential	kWh	481,903,320		61,698,082	14,591,747		293,148	
GS < 50 KW	kWh	109,095,925		13,967,551	19,610,270		393,970	
GS 50 to 999 KW	kWh*	105,726,242		13,536,131	222,309,226		4,466,192	
GS 1000 to 4999 KW	kWh*	0		-	76,465,711		1,536,196	
Large User	kWh	0		-	38,878,939		781,078	
Unmetered	kWh	2,506,367		320,890	0		-	
Sentinel	kWh	24,360		3,119	0		-	
Street Lighting	kWh	0		-	4,555,628		91,523	
SUB-TOTAL		699,256,215		89,525,773	376,411,522		7,562,107	$ 97,087,881

Global Adjustment non-RPP	Units							
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh			0			1,560,441	
GS < 50 KW	kWh			0			2,097,122	
GS 50 to 999 KW	kWh*			0			23,493,833	
GS 1000 to 4999 KW	kWh*			0			6,998,708	
Large User	kWh			0			3,050,245	
Unmetered	kWh			0			-	
Sentinel	kWh			0			487,179	
Street Lighting	kWh			0			-	
SUB-TOTAL		0		0			37,687,528	$ 37,687,528

Transmission - Network								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	481,903,320	$ 0.0073	3,517,894	14,591,747	$ 0.0073	106,520	
GS < 50 KW	kWh	109,095,925	$ 0.0068	741,852	19,610,270	$ 0.0068	133,350	
GS 50 to 999 KW	kW	116,261	$ 2.4777	288,060	244,461	$ 2.4777	605,700	
GS 50 to 999 KW - interval metered	kW	149,867	$ 3.1758	475,946	315,122	$ 3.1758	1,000,766	
GS 1000 to 4999 KW	kW	-	$ 3.1758	-	182,480	$ 3.1758	579,520	
Large User	kW	-	$ 3.3839	-	86,319	$ 3.3839	292,096	
Unmetered	kWh	2,506,367	$ 0.0068	17,043	-	$ 0.0068	-	
Sentinel	kW	81	$ 1.7090	138	-	$ 1.7090	-	
Street Lighting	kW	-	$ 1.6801	-	12,698	$ 1.6801	21,334	
SUB-TOTAL				5,040,934			2,739,285	7,780,218

Transmission - Connection								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	481,903,320	$ 0.0066	3,180,562	14,591,747	$ 0.0066	96,306	
GS < 50 KW	kWh	109,095,925	$ 0.0061	665,485	19,610,270	$ 0.0061	119,623	
GS 50 to 999 KW	kW	116,261	$ 2.1429	249,136	244,461	$ 2.1429	523,855	
GS 50 to 999 KW - interval metered	kW	-	$ 2.7221	-	315,122	$ 2.7221	857,795	
GS 1000 to 4999 KW	kW	-	$ 2.7221	-	182,480	$ 2.7221	496,729	
Large User	kW	-	$ 2.9701	-	86,319	$ 2.9701	256,377	
Unmetered	kWh	2,506,367	$ 0.0061	15,289	-	$ 0.0061	-	
Sentinel	kW	81	$ 2.5155	203	-	$ 2.5155	-	
Street Lighting	kW	-	$ 2.4729	-	12,698	$ 2.4729	31,400	
SUB-TOTAL				4,110,674			2,382,084	6,492,758

TABLE 2-15 (CONTINUED) - COMMODITY EXPENSE CALCULATION (APPENDIX 2-ZB)

		2021 Test Year	RPP		2021 Test Year	non-RPP		Total
Wholesale Market Service								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	481,903,320	$ 0.0034	1,638,471	14,591,747	$ 0.0034	49,612	
GS < 50 KW	kWh	109,095,925	$ 0.0034	370,926	19,610,270	$ 0.0034	66,675	
GS 50 to 999 KW	kWh	105,726,242	$ 0.0034	359,469	222,309,226	$ 0.0034	755,851	
GS 1000 to 4999 KW	kWh	-	$ 0.0034	-	76,465,711	$ 0.0034	259,983	
Large User	kWh	-	$ 0.0034	-	38,878,939	$ 0.0030	116,637	
Unmetered	kWh	2,506,367	$ 0.0034	8,522	-	$ 0.0034	-	
Sentinel	kWh	24,360	$ 0.0034	83	-	$ 0.0034	-	
Street Lighting	kWh	-	$ 0.0034	-	4,555,628	$ 0.0034	15,489	
SUB-TOTAL				2,377,471			1,264,248	3,641,719

Class A CBR								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh			-			-	
GS < 50 KW	kWh			-			-	
GS 50 to 999 KW	kWh			-	9,245,104	$ 0.0002	1,929	
GS 1000 to 4999 KW	kWh			-	42,028,615	$ 0.0002	9,697	
Large User	kWh			-	38,878,939	$ 0.0002	8,836	
Unmetered	kWh			-			-	
Sentinel	kWh			-			-	
Street Lighting	kWh			-			-	
SUB-TOTAL				-			20,461	20,461

RRRP								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	481,903,320	$ 0.0005	240,952	14,591,747	$ 0.0005	7,296	
GS < 50 KW	kWh	109,095,925	$ 0.0005	54,548	19,610,270	$ 0.0005	9,805	
GS 50 to 999 KW	kWh	105,726,242	$ 0.0005	52,863	222,309,226	$ 0.0005	111,155	
GS 1000 to 4999 KW	kWh	-	$ 0.0005	-	76,465,711	$ 0.0005	38,233	
Large User	kWh	-	$ 0.0005	-	38,878,939	$ 0.0005	19,439	
Unmetered	kWh	2,506,367	$ 0.0005	1,253	-	$ 0.0005	-	
Sentinel	kWh	24,360	$ 0.0005	12	-	$ 0.0005	-	
Street Lighting	kWh	-	$ 0.0005	-	4,555,628	$ 0.0005	2,278	
SUB-TOTAL				349,628			188,206	537,834

Smart Meter Entity Charge								
Class per Load Forecast		Customers	Rate	$	Customers	Rate	$	Total
Residential		54,538	0.57	373,042	1,651	0.57	941	
GS < 50 KW		3,619	0.57	24,752	650	0.57	371	
Seasonal				-				
SUB-TOTAL				397,794			1,312	399,106
SUB- TOTAL				101,802,275			51,845,231	153,647,506
ORECA CREDIT	31.80%			(32,373,123)			0	(32,373,123)
TOTAL				**69,429,151**			**51,845,231**	**121,274,382**

***The ORECA Credit of 31.8% will only apply to RPP proportion of the listed components. Impacts on distribution charges are excluded for the purpose of calculating the cost of power

**** Class A CBR: use the average CBR per kWh, similar to how the Class A GA cost is calculated

2021 Test Year - CoP	
4705 -Power Purchased	$ 97,087,881
4707- Global Adjustment	$ 37,687,528
4708-Charges-WMS	$ 4,200,014
4714-Charges-NW	$ 7,780,218
4716-Charges-CN	$ 6,492,758
4750-Charges-LV	$ -
4751-IESO SME	$ 399,106
Misc A/R or A/P	$ (32,373,123)
TOTAL	**$ 121,274,382**

GROSS ASSETS – PROPERTY, PLANT, AND EQUIPMENT AND ACCUMULATED DEPRECIATION

Overview

In support of its rate base calculation, OPUCN has attached the information required in the Chapter 2 Filing Requirements for Gross Assets, Accumulated Depreciation and Working Capital.

Gross Assets – By Function

OPUCN's Gross Assets are divided into four principal categories (distribution plant general plant, intangible plant, and capital contributions) as illustrated in Table 2-16.

Distribution assets are the wires, poles, meters and transformers used to distribute electricity through OPUCN's service territory. These assets are recorded to OEB accounts 1805 - 1860.

General Plant investments are the assets used by staff to plan, maintain and build the distribution system. It consists of OEB account 1920 – 1980, and includes trucks, computer software and hardware.

Intangible plant, USoA account 1609, relates to contributions made to Hydro One for a new transformer station just east of the City of Oshawa.

Contributions and Grants consist of the contributed capital or deferred revenue that OPUCN has received from developers and others as per the Distribution System Code.

OPUCN has not applied for any ACM or ICM adjustments as part of a previous IRM Application. All opening and closing balances agree to required filing Appendix 2-BA which is filed in live Excel format and included in this exhibit in Tables 2-2 through 2-9.

Table 2-16 provides a summary of Gross Assets for 2015 through 2019 Actual results, 2015 through 2019 Board-Approved amounts; forecast 2020 Bridge Year; and 2021 Test Year:

TABLE 2-16 - GROSS ASSETS BY FUNCTION

Gross Assets	Actual 2015	Actual 2016	Actual 2017	Actual 2018	Actual 2019	Bridge 2020	Test 2021
Distribution Plant	201,302,685	206,698,007	211,707,486	224,811,161	246,317,198	259,866,409	271,191,930
General Plant	15,589,494	16,812,132	17,649,043	18,803,780	19,097,287	21,173,787	23,415,787
Intangible Plant	0	0	0	0	4,136,705	4,136,705	4,136,705
Capital Contributions	(37,866,470)	(38,950,631)	(40,062,894)	(43,971,142)	(49,648,616)	(51,606,672)	(53,649,729)
Gross Asset less Capital Contributions	179,025,709	184,559,507	189,293,635	199,643,799	219,902,574	233,570,228	245,094,693
Gross Assets	Approved 2015	Approved 2016	Approved 2017	Approved 2018	Approved 2019	Bridge 2020	Test 2021
Distribution Plant	200,427,352	208,208,417	214,650,025	231,074,544	252,918,981	259,866,409	271,191,930
General Plant	15,683,050	16,914,608	17,824,892	18,825,227	19,593,141	21,173,787	23,415,787
Intangible Plant	0	0	0	0	0	4,136,705	4,136,705
Capital Contributions	(39,453,548)	(40,908,548)	(41,983,548)	(43,078,548)	(44,183,548)	(51,606,672)	(53,649,729)
Gross Asset less Capital Contributions	176,656,853	184,214,478	190,491,369	206,821,223	228,328,574	233,570,228	245,094,693

Gross Assets – Detailed Breakdown

Section 2.5.1.2 of the Board's Filing Requirements requires that Applicants provide a detailed breakdown by major plant account for each functionalized plant item. OPUCN has included a breakdown of each major plant account according to the Board's USofA in Tables 2-17 through 2-25 in compliance with this requirement. The tables cover Historical and Board-Approved years for 2015 through 2019, the 2020 Bridge Year, and the 2021 Test Year.

TABLE 2-17 - GROSS ASSETS DETAILED BREAKDOWN 2015-2018

Description	USA	2015 Actual	2016 Actual	Variance 2016 Actual v 2015 Actual	2017 Actual	Variance 2017 Actual v 2016 Actual	2018 Actual	Variance 2018 Actual v 2017 Actual
Land	1805	293,875	293,875	0	293,875	0	293,875	0
Buildings	1808	757,060	757,060	0	757,060	0	5,314,251	4,557,190
Leasehold Improvements	1910	1,048,485	1,099,086	50,601	1,097,705	(1,382)	1,097,705	0
Land and Buildings sub-total		**2,099,421**	**2,150,022**	**50,601**	**2,148,641**	**(1,382)**	**6,705,831**	**4,557,190**
Distribution Station Equipment	**1820**	**22,019,408**	**22,812,799**	**793,391**	**23,959,895**	**1,147,096**	**27,521,921**	**3,562,026**
Poles, Towers & Fixtures	1830	40,865,217	43,408,323	2,543,106	45,664,238	2,255,915	45,900,692	236,454
Overhead Conductors & Devices	1835	21,489,140	22,563,575	1,074,435	23,405,911	842,336	24,175,735	769,824
Underground Conductors & Devices	1845	46,068,893	45,719,492	(349,400)	44,568,319	(1,151,173)	45,983,665	1,415,346
Poles and Wires sub-total		**108,423,250**	**111,691,390**	**3,268,140**	**113,638,468**	**1,947,078**	**116,060,092**	**2,421,624**
Line Transformers	**1850**	**57,257,873**	**57,772,234**	**514,361**	**59,310,192**	**1,537,958**	**61,207,796**	**1,897,603**
Meters	**1860**	**11,502,732**	**12,271,561**	**768,829**	**12,650,290**	**378,729**	**13,315,521**	**665,231**
Computer Equipment - Hardware	1920	2,657,819	2,732,523	74,704	2,809,023	76,501	3,234,250	425,227
Computer Software (Formally 1925)	1611	1,978,942	2,945,295	966,353	2,033,570	(911,725)	2,383,020	349,450
IT Assets sub-total		**4,636,761**	**5,677,818**	**1,041,057**	**4,842,593**	**(835,224)**	**5,617,270**	**774,677**
Office Furniture & Equipment	1915	734,382	750,138	15,756	760,788	10,649	785,630	24,843
Transportation Equipment	1930	4,688,340	4,637,998	(50,342)	4,835,403	197,405	4,969,390	133,987
Stores Equipment	1935	24,516	24,516	0	24,516	0	24,516	0
Tools, Shop & Garage Equipment	1940	2,635,856	2,650,985	15,129	2,681,779	30,794	2,745,565	63,786
Measurement & Testing Equipment	1945	852,897	920,147	67,250	1,056,031	135,884	1,154,950	98,920
Communications Equipment	1955	418,132	551,919	133,787	594,489	42,570	611,287	16,798
Miscellaneous Equipment	1960	176,300	176,300	0	176,300	0	187,684	11,384
Load Management Controls Customer Premises	1970	107,035	107,035	0	107,035	0	107,035	0
Load Management Controls Utility Premises	1975	1,021,693	1,021,693	0	2,276,527	1,254,834	2,306,870	30,343
System Supervisor Equipment	1980	293,582	293,582	0	293,582	0	293,582	0
Equipment sub-total		**10,952,734**	**11,134,314**	**181,580**	**12,806,449**	**1,672,135**	**13,186,510**	**380,061**
Capital Contributions Paid	**1609**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Gross Assets Total		**216,892,179**	**223,510,139**	**6,617,960**	**229,356,528**	**5,846,390**	**243,614,941**	**14,258,412**
Contributions & Grants	1995	(37,866,470)	(38,950,631)	(1,084,161)	(40,062,894)	(1,112,263)	(43,971,142)	(3,908,248)
Deferred Revenue[5]	2440	0	0	0	0	0	0	0
Gross Assets Less Capital Contributions		**179,025,709**	**184,559,507**	**5,533,798**	**189,293,635**	**4,734,127**	**199,643,799**	**10,350,164**

TABLE 2-18 - GROSS ASSETS DETAILED BREAKDOWN 2019-2021

Description	USA	2019 Actual	Variance 2019 Actual v 2018 Actual	2020 Bridge	Variance 2020 Bridge v 2019 Actual	2021 Test	Variance 2021 Test v 2020 Bridge
Land	1805	293,875	0	293,875	0	293,875	0
Buildings	1808	5,711,005	396,754	6,036,005	325,000	6,136,005	100,000
Leasehold Improvements	1910	1,097,705	0	1,377,705	280,000	1,477,705	100,000
Land and Buildings sub-total		**7,102,585**	**396,754**	**7,707,585**	**605,000**	**7,907,585**	**200,000**
Distribution Station Equipment	**1820**	**27,046,197**	**(475,725)**	**27,060,797**	**14,600**	**28,816,097**	**1,755,300**
Poles, Towers & Fixtures	1830	50,321,585	4,420,892	53,540,749	3,219,164	55,500,579	1,959,830
Overhead Conductors & Devices	1835	25,691,581	1,515,846	27,168,452	1,476,871	28,492,999	1,324,548
Underground Conductors & Devices	1845	58,204,657	12,220,992	61,616,733	3,412,075	64,895,608	3,278,875
Poles and Wires sub-total		**134,217,823**	**18,157,731**	**142,325,934**	**8,108,111**	**148,889,187**	**6,563,253**
Line Transformers	**1850**	**64,189,443**	**2,981,648**	**68,317,543**	**4,128,100**	**70,649,511**	**2,331,968**
Meters	**1860**	**13,761,150**	**445,630**	**14,454,550**	**693,400**	**14,929,550**	**475,000**
Computer Equipment - Hardware	1920	3,084,226	(150,024)	4,055,726	971,500	5,467,726	1,412,000
Computer Software (Formally 1925)	1611	2,348,223	(34,796)	2,648,223	300,000	2,848,223	200,000
IT Assets sub-total		**5,432,450**	**(184,820)**	**6,703,950**	**1,271,500**	**8,315,950**	**1,612,000**
Office Furniture & Equipment	1915	800,129	14,499	800,129	0	800,129	0
Transportation Equipment	1930	5,106,219	136,829	5,601,219	495,000	6,081,219	480,000
Stores Equipment	1935	30,767	6,251	90,767	60,000	90,767	0
Tools, Shop & Garage Equipment	1940	2,793,042	47,477	2,793,042	0	2,793,042	0
Measurement & Testing Equipment	1945	1,313,545	158,594	1,313,545	0	1,313,545	0
Communications Equipment	1955	611,287	0	861,287	250,000	1,011,287	150,000
Miscellaneous Equipment	1960	242,998	55,314	242,998	0	242,998	0
Load Management Controls Customer Premises	1970	107,035	0	107,035	0	107,035	0
Load Management Controls Utility Premises	1975	2,366,234	59,364	2,366,234	0	2,366,234	0
System Supervisor Equipment	1980	293,582	0	293,582	0	293,582	0
Equipment sub-total		**13,664,838**	**478,327**	**14,469,838**	**805,000**	**15,099,838**	**630,000**
Capital Contributions Paid	**1609**	**4,136,705**	**4,136,705**	**4,136,705**	**0**	**4,136,705**	**0**
Gross Assets Total		**269,551,190**	**25,936,249**	**285,176,901**	**15,625,711**	**298,744,422**	**13,567,521**
Contributions & Grants	1995	(49,648,616)	(5,677,474)	(49,648,616)	0	(49,648,616)	0
Deferred Revenue[5]	2440	0	0	(1,958,057)	(1,958,057)	(4,001,113)	(2,043,057)
Gross Assets Less Capital Contributions		**219,902,574**	**20,258,775**	**233,570,228**	**13,667,654**	**245,094,693**	**11,524,464**

TABLE 2-19 - GROSS ASSETS DETAILED BREAKDOWN 2015-2016 APPROVED VS. ACTUALS

Description	USA	2015 Approved	2015 Actual	Variance 2015 Actual v 2015 Approved	2016 Approved	2016 Actual	Variance 2016 Actual v 2016 Approved
Land	1805	135,152	293,875	158,723	135,152	293,875	158,723
Buildings	1808	757,060	757,060	0	757,060	757,060	0
Leasehold Improvements	1910	1,182,760	1,048,485	(134,275)	1,272,760	1,099,086	(173,674)
Land and Buildings sub-total		**2,074,973**	**2,099,421**	**24,448**	**2,164,973**	**2,150,022**	**(14,951)**
Distribution Station Equipment	**1820**	**21,270,629**	**22,019,408**	**748,779**	**22,845,800**	**22,812,799**	**(33,001)**
Poles, Towers & Fixtures	1830	42,138,099	40,865,217	(1,272,882)	44,136,953	43,408,323	(728,630)
Overhead Conductors & Devices	1835	22,706,790	21,489,140	(1,217,650)	23,871,237	22,563,575	(1,307,662)
Underground Conductors & Devices	1845	45,399,656	46,068,893	669,237	47,512,818	45,719,492	(1,793,326)
Poles and Wires sub-total		**110,244,545**	**108,423,250**	**(1,821,295)**	**115,521,008**	**111,691,390**	**(3,829,618)**
Line Transformers	**1850**	**55,324,047**	**57,257,873**	**1,933,827**	**55,640,871**	**57,772,234**	**2,131,363**
Meters	**1860**	**11,513,158**	**11,502,732**	**(10,426)**	**12,035,764**	**12,271,561**	**235,797**
Computer Equipment - Hardware	1920	2,866,964	2,657,819	(209,145)	3,039,369	2,732,523	(306,846)
Computer Software (Formally 1925)	1611	2,373,768	1,978,942	(394,826)	2,818,794	2,945,295	126,501
IT Assets sub-total		**5,240,732**	**4,636,761**	**(603,971)**	**5,858,162**	**5,677,818**	**(180,345)**
Office Furniture & Equipment	1915	750,439	734,382	(16,057)	760,439	750,138	(10,301)
Transportation Equipment	1930	4,608,040	4,688,340	80,300	5,023,040	4,637,998	(385,042)
Stores Equipment	1935	24,516	24,516	0	24,516	24,516	0
Tools, Shop & Garage Equipment	1940	2,537,637	2,635,856	98,219	2,668,094	2,650,985	(17,108)
Measurement & Testing Equipment	1945	518,851	852,897	334,045	577,523	920,147	342,624
Communications Equipment	1955	418,133	418,132	(0)	418,133	551,919	133,787
Miscellaneous Equipment	1960	162,391	176,300	13,909	162,391	176,300	13,909
Load Management Controls Customer Premises	1970	107,035	107,035	0	107,035	107,035	0
Load Management Controls Utility Premises	1975	1,021,693	1,021,693	0	1,021,693	1,021,693	0
System Supervisor Equipment	1980	293,582	293,582	0	293,582	293,582	0
Equipment sub-total		**10,442,318**	**10,952,734**	**510,416**	**11,056,446**	**11,134,314**	**77,868**
Capital Contributions Paid	**1609**	**0**	**0**	**0**	**0**	**0**	**0**
Gross Assets Total		**216,110,402**	**216,892,179**	**781,777**	**225,123,026**	**223,510,139**	**(1,612,887)**
Contributions & Grants	1995	(39,453,548)	(37,866,470)	1,587,078	(40,908,548)	(38,950,631)	1,957,917
Deferred Revenue[5]	2440	0	0	0	0	0	0
Gross Assets Less Capital Contributions		**176,656,853**	**179,025,709**	**2,368,856**	**184,214,478**	**184,559,507**	**345,030**

TABLE 2-20 - GROSS ASSETS DETAILED BREAKDOWN 2017-2018 APPROVED VS. ACTUALS

Description	USA	2017 Approved	2017 Actual	Variance 2017 Actual v 2017 Approved	2018 Approved	2018 Actual	Variance 2018 Actual v 2018 Approved
Land	1805	135,152	293,875	158,723	293,875	293,875	0
Buildings	1808	757,060	757,060	0	2,507,060	5,314,251	2,807,190
Leasehold Improvements	1910	1,317,760	1,097,705	(220,056)	1,362,760	1,097,705	(265,056)
Land and Buildings sub-total		**2,209,973**	**2,148,641**	**(61,333)**	**4,163,696**	**6,705,831**	**2,542,134**
Distribution Station Equipment	**1820**	**23,226,598**	**23,959,895**	**733,297**	**26,655,386**	**27,521,921**	**866,535**
Poles, Towers & Fixtures	1830	48,696,860	45,664,238	(3,032,622)	51,035,813	45,900,692	(5,135,120)
Overhead Conductors & Devices	1835	24,285,216	23,405,911	(879,305)	26,433,656	24,175,735	(2,257,921)
Underground Conductors & Devices	1845	47,204,142	44,568,319	(2,635,823)	52,875,735	45,983,665	(6,892,070)
Poles and Wires sub-total		**120,186,218**	**113,638,468**	**(6,547,750)**	**130,345,203**	**116,060,092**	**(14,285,111)**
Line Transformers	**1850**	**56,316,134**	**59,310,192**	**2,994,058**	**56,674,650**	**61,207,796**	**4,533,145**
Meters	**1860**	**12,711,102**	**12,650,290**	**(60,812)**	**13,235,608**	**13,315,521**	**79,913**
Computer Equipment - Hardware	1920	3,136,524	2,809,023	(327,501)	3,396,573	3,234,250	(162,323)
Computer Software (Formally 1925)	1611	2,953,829	2,033,570	(920,259)	3,195,250	2,383,020	(812,230)
IT Assets sub-total		**6,090,353**	**4,842,593**	**(1,247,760)**	**6,591,823**	**5,617,270**	**(974,553)**
Office Furniture & Equipment	1915	765,439	760,788	(4,652)	770,439	785,630	15,191
Transportation Equipment	1930	5,463,040	4,835,403	(627,638)	5,653,040	4,969,390	(683,650)
Stores Equipment	1935	24,516	24,516	0	24,516	24,516	0
Tools, Shop & Garage Equipment	1940	2,832,719	2,681,779	(150,939)	2,972,450	2,745,565	(226,885)
Measurement & Testing Equipment	1945	645,991	1,056,031	410,040	778,175	1,154,950	376,776
Communications Equipment	1955	418,133	594,489	176,357	450,083	611,287	161,205
Miscellaneous Equipment	1960	162,391	176,300	13,909	162,391	187,684	25,293
Load Management Controls Customer Premises	1970	107,035	107,035	0	107,035	107,035	0
Load Management Controls Utility Premises	1975	1,021,693	2,276,527	1,254,834	1,021,693	2,306,870	1,285,177
System Supervisor Equipment	1980	293,582	293,582	0	293,582	293,582	0
Equipment sub-total		**11,734,539**	**12,806,449**	**1,071,911**	**12,233,404**	**13,186,510**	**953,106**
Capital Contributions Paid	**1609**	**0**	**0**	**0**	**0**	**0**	**0**
Gross Assets Total		**232,474,917**	**229,356,528**	**(3,118,388)**	**249,899,771**	**243,614,941**	**(6,284,830)**
Contributions & Grants	1995	(41,983,548)	(40,062,894)	1,920,654	(43,078,548)	(43,971,142)	(892,594)
Deferred Revenue[5]	2440	0	0	0	0	0	0
Gross Assets Less Capital Contributions		**190,491,369**	**189,293,635**	**(1,197,734)**	**206,821,223**	**199,643,799**	**(7,177,424)**

TABLE 2-21 - GROSS ASSETS DETAILED BREAKDOWN 2019 APPROVED VS. ACTUALS AND 2021 TEST YEAR

Description	USA	2019 Approved	2019 Actual	Variance 2019 Actual v 2019 Approved	2019 Approved	2021 Test Year	Variance 2021 Test v 2019 Approved
Land	1805	293,875	293,875	0	293,875	293,875	0
Buildings	1808	2,507,060	5,711,005	3,203,944	2,507,060	6,136,005	3,628,944
Leasehold Improvements	1910	1,407,760	1,097,705	(310,056)	1,407,760	1,477,705	69,944
Land and Buildings sub-total		**4,208,696**	**7,102,585**	**2,893,888**	**4,208,696**	**7,907,585**	**3,698,888**
Distribution Station Equipment	**1820**	**31,109,576**	**27,046,197**	**(4,063,380)**	**31,109,576**	**28,816,097**	**(2,293,480)**
Poles, Towers & Fixtures	1830	53,278,188	50,321,585	(2,956,603)	53,278,188	55,500,579	2,222,391
Overhead Conductors & Devices	1835	33,188,221	25,691,581	(7,496,640)	33,188,221	28,492,999	(4,695,222)
Underground Conductors & Devices	1845	60,348,550	58,204,657	(2,143,893)	60,348,550	64,895,608	4,547,058
Poles and Wires sub-total		**146,814,959**	**134,217,823**	**(12,597,136)**	**146,814,959**	**148,889,187**	**2,074,228**
Line Transformers	**1850**	**57,025,748**	**64,189,443**	**7,163,696**	**57,025,748**	**70,649,511**	**13,623,764**
Meters	**1860**	**13,760,001**	**13,761,150**	**1,149**	**13,760,001**	**14,929,550**	**1,169,549**
Computer Equipment - Hardware	1920	3,494,621	3,084,226	(410,395)	3,494,621	5,467,726	1,973,105
Computer Software (Formally 1925)	1611	3,388,671	2,348,223	(1,040,448)	3,388,671	2,848,223	(540,448)
IT Assets sub-total		**6,883,293**	**5,432,450**	**(1,450,843)**	**6,883,293**	**8,315,950**	**1,432,657**
Office Furniture & Equipment	1915	775,439	800,129	24,690	775,439	800,129	24,690
Transportation Equipment	1930	5,823,040	5,106,219	(716,821)	5,823,040	6,081,219	258,179
Stores Equipment	1935	24,516	30,767	6,251	24,516	90,767	66,251
Tools, Shop & Garage Equipment	1940	3,109,899	2,793,042	(316,857)	3,109,899	2,793,042	(316,857)
Measurement & Testing Equipment	1945	910,219	1,313,545	403,325	910,219	1,313,545	403,325
Communications Equipment	1955	482,033	611,287	129,255	482,033	1,011,287	529,255
Miscellaneous Equipment	1960	162,391	242,998	80,607	162,391	242,998	80,607
Load Management Controls Customer Premises	1970	107,035	107,035	0	107,035	107,035	0
Load Management Controls Utility Premises	1975	1,021,693	2,366,234	1,344,540	1,021,693	2,366,234	1,344,540
System Supervisor Equipment	1980	293,582	293,582	0	293,582	293,582	0
Equipment sub-total		**12,709,848**	**13,664,838**	**954,989**	**12,709,848**	**15,099,838**	**2,389,989**
Capital Contributions Paid	**1609**	**0**	**4,136,705**	**4,136,705**	**0**	**4,136,705**	**4,136,705**
Gross Assets Total		**272,512,122**	**269,551,190**	**(2,960,932)**	**272,512,122**	**298,744,422**	**26,232,300**
Contributions & Grants	1995	(44,183,548)	(49,648,616)	(5,465,068)	(44,183,548)	(49,648,616)	(5,465,068)
Deferred Revenue[5]	2440	0	0	0	0	(4,001,113)	(4,001,113)
Gross Assets Less Capital Contributions		**228,328,574**	**219,902,574**	**(8,426,000)**	**228,328,574**	**245,094,693**	**16,766,119**

VARIANCE ANALYSIS ON GROSS ASSETS

2016 Actual vs. 2015 Actual

Total gross assets in 2016 increased by $10.4M over 2015 made up of $9.2M in additions partially offset by $3.7M in disposals, principally old assets nearing or at end of life replaced through asset renewal projects. Project specific details are included in the capital expenditures variance analysis later in this exhibit.

The principal drivers of the net increase are:

- $2.6M in planned overhead and underground line renewals,
- $1.1M in reactive/emergency plant replacement,
- $1.0M in IT assets, principally OMS implementation and enhancements,
- $1.4M in third party relocations, and
- $(1.1)M in capital contributions received.

2017 Actual vs. 2016 Actual

Total gross assets in 2017 increased by $4.7M over 2016 made up of $7.8M in additions partially offset by $3.1M in disposals, principally old assets nearing or at end of life replaced through asset renewal projects. Project specific details are included in the capital expenditures variance analysis later in this exhibit.

The principal drivers of the net increase are:

- $2.4M in planned overhead and underground line renewals,
- $1.2M in reactive/emergency plant replacement,
- $1.0M in station renewal projects,
- $0.4M related to pole replacement program, and
- $(1.1)M in capital contributions received.

2018 Actual vs. 2017 Actual

Total gross assets in 2018 increased by $10.3M over 2017 made up of $13.0M in additions partially offset by $2.6M in disposals, principally old assets nearing or at end of life replaced through asset renewal projects. Project specific details are included in the capital expenditures variance analysis later in this exhibit.

The principal drivers of the net increase are:

- $7.6M related to new substation construction (MS9)
- $2.3M in planned overhead and underground line renewals,
- $1.0M in reactive/emergency plant replacement,
- $0.8M in IT assets, principally ODS replacement and general IT infrastructure upgrades,
- $0.5M in station renewal projects,
- $0.5M in downtown area underground self-healing grid
- $0.2M related to pole replacement program, and
- $(3.9)M in capital contributions received.

2019 Actual vs. 2018 Actual

Total gross assets in 2019 increased by $20.3M over 2018 made up of $23.2M in additions partially offset by $3.0M in disposals, principally old assets nearing or at end of life replaced through asset renewal projects. Project specific details are included in the capital expenditures variance analysis later in this exhibit.

The principal drivers of the net increase are:

- $7.5M related to new substation feeders (MS9)
- $4.1M contribution to new Hydro One TS (Enfield),
- $3.8M in planned overhead and underground line renewals,

- $1.7M in reactive/emergency plant replacement,
- $2.7M in expansions and connections,
- $1.4M in third party relocations,,
- $0.3M related to pole replacement program, and
- $(6.2)M in capital contributions received.

Forecast 2020 Bridge Year vs. 2019 Actual

Total gross assets in 2020 are forecast to increase by $13.7M over 2019 made up of $16.6M in additions partially offset by $2.9M in disposals, principally old assets nearing or at end of life replaced through asset renewal projects. Project specific details are included in the capital expenditures variance analysis later in this exhibit.

The principal drivers of the net increase are:

- $4.7M in planned overhead and underground line renewals and $,
- $1.2M in reactive/emergency plant replacement,
- $1.9M in expansions and connections,
- $1.0M related to substation transformer replacement (MS10),
- $1.1M in third party relocations,
- $1.1M related to feeders for new Hydro One TS and new substation (MS9),
- $0.5M for porcelain switch and insulator replacement program,
- $0.5M for voltage monitoring (grid monitoring and automation)
- $1.4M in IT assets, principally operational technology (GIS,OMS,ODS,SCADA) and general IT infrastructure upgrades,
- $1.1M in fleet renewal ($0.5M) and facilities projects,
- $0.4M related to pole replacement program, and

- $(2.0)M in capital contributions received.

Forecast 2021 Test Year vs. 2020 Bridge Year

Total gross assets in 2021 are forecast to increase by $11.5M over 2020 made up of $14.5M in additions partially offset by $2.9M in disposals, principally old assets nearing or at end of life replaced through asset renewal projects. Project specific details are included in the capital expenditures variance analysis later in this exhibit.

The principal drivers of the net increase are:

- $3.3M in planned overhead and underground line renewals and $,
- $1.1M in reactive/emergency plant replacement,
- $1.9M in expansions and connections,
- $1.8M related to substation transformer replacement program,
- $1.4M in third party relocations,
- $0.6M for porcelain switch and insulator replacement program,
- $0.5M for voltage monitoring (grid monitoring and automation)
- $1.5M in IT assets, principally acquisition of Customer Information System ($0.7M),
- $0.6M in fleet renewal ($0.5M) and facilities projects,
- $0.4M related to pole replacement program, and
- $(2.0)M in capital contributions received.

2015 Actual vs. 2015 Board-Approved

Total gross assets in 2015 increased by $2.4M more than Board–Approved forecast. Gross additions were $0.5M lower than approved, however gross disposals were lower by $2.7M. On a net book value basis, disposals were just $0.3M lower than approved.

The principal drivers of the $0.5M lower than approved spend are:

- $1.5M lower than planned relocation projects due to changes in scope and timing,
- $0.6M underspend due to delay in OMS implementation project, completed in 2016,
- $0.5M underspend due to delayed (to 2016) of neutral reactor project,

Partially offset by:

- $0.9M higher spend related to system connection and expansion work, many of which are multi-year projects difficult to forecast precisely by year,
- $0.6M higher than planned spend on overhead line renewal, mainly remediation work and completion of work planned in previous years, and
- $0.3M higher than planned reactive/emergency asset replacement.

2016 Actual vs. 2016 Board-Approved

Total gross assets in 2016 were $0.3M more than Board–Approved forecast. Gross additions were $0.6M lower than approved, however gross disposals were higher by $1.6M. The overall $0.3M higher than Board–Approved forecast for total gross assets is made up of the $2.4M 2015 variance carried forward less the $0.6M underspend in 2016, less the $1.6M higher than planned disposals in 2016.

The principal drivers of the $0.6M lower than approved spend are:

- $0.7M lower overhead line renewal as two large projects deferred to future years (Rossland Rd E and Bloor/Oliver to MS11),

- $0.5M underspend due to deferral to 2017 of 44kV breaker replacement program,
- $0.4M underspend related to lower than planned cost of neutral reactor project,

Partially offset by:

- $1.0M higher spend related to OMS implementation project due to activity deferred from 2015.

2017 Actual vs. 2017 Board-Approved

Total gross assets in 2017 were $1.2M lower than Board–Approved forecast. Gross additions were $0.2M higher than approved, and gross disposals were higher by $1.7M. The overall $1.2M lower than Board–Approved forecast for total gross assets is made up of the $0.3M 2016 variance carried forward plus the $0.2M higher spend in 2017, less the $1.7M higher than planned disposals in 2017.

2018 Actual vs. 2018 Board-Approved

Total gross assets in 2018 were $7.2M lower than Board–Approved forecast. Gross additions were $5.5M lower than approved, and gross disposals were higher by $0.5M. The overall $7.2M lower than Board–Approved forecast for total gross assets is made up of the $1.2M 2016 variance carried forward plus the $5.5M underspend in 2018 and $0.5M higher than planned disposals in 2018.

The principal drivers of the $5.5M lower than approved spend are:

- $2.2M lower than planned spend related to new MS9 substation, a combination of delayed timing and overall lower cost of related distribution feeders,
- $1.9M lower than planned relocation projects due to changes in scope and timing,
- $1.4M lower overhead line renewal with two large projects totalling $1.0M deferred to 2019,
- $1.0M lower than planned system connection and expansion work, many of which are multi-year projects difficult to forecast precisely by year,

Partially offset by:

- $1.0M in smaller net favourable variances, driven mainly by changes in timing of work.

2019 Actual vs. 2019 Board-Approved

Total gross assets in 2019 were $8.4M less than Board–Approved forecast. Gross additions were $0.2M lower than approved, and gross disposals were higher by $1.0M. The overall $8.4M lower than Board–Approved forecast for total gross assets is made up of the $7.2M 2018 variance carried forward plus the $0.2M underspend in 2019 and $1.0M higher than planned disposals in 2019.

The principal drivers of the $0.2M lower than approved spend are:

- $3.8M lower than planned spend related to new distribution feeders and egress for new MS9 substation and new Enfield TS, $1.0M of which deferred to 2020,
- $1.0M planned station transformer replacements deferred to 2020,

Partially offset by:

- $1.9M higher than planned system connection and expansion work, many of which are multi-year projects difficult to forecast precisely by year,
- $0.6.M higher than planned relocation projects due to changes in scope and timing,
- $0.9M higher overhead line renewal with two large projects totalling $1.0M deferred from 2018,
- $0.8.M higher than planned reactive/emergency plant replacement projects.

RECONCILIATION OF DEPRECIATION EXPENSE TO CONTINUITY STATEMENTS

OPUCN confirms that the depreciation expense as shown in Exhibit 4 is the same as shown in the continuity statements and no reconciliation is required.

CAPITAL EXPENDITURES

OPUCN has prepared a Distribution System Plan (DSP) in accordance with the OEB's Chapter 5 Consolidated Distribution System Plan Filing Requirements in support of its 2021 Test Year Cost of Service Application. OPUCN's Distribution System Plan (DSP) is attached as Appendix 2-1 to this Exhibit.

The key elements that drive the size and mix of capital investments needed to achieve the planning objectives are investments in the four investment categories, condition assessment, reliability performance, customer and load growth, grid modernization and cybersecurity.

OPUCN's historical capital expenditure from 2015 through 2019 has an average annual expenditure of approximately $13.0M primarily driven by System Access and System Service requirements in order to address the forecasted customer and load growth within the service territory. This prompted OPUCN to invest in ensuring that the transmission and distribution system does not have any constraints and that sufficient capacity and infrastructure are available to connect customers.

During the forecast years from 2021 to 2025, the planned capital expenditure has shifted to System Renewal and System Service requirements to improve system reliability and mitigate customer outage impacts. This can be achieved through the required replacement of end of Typical Useful Life (TUL) or high failure risk assets and grid modernization to make the distribution system more responsive in monitoring and locating power outages. This will also provide customers with timely information to enable consumption-related decision-making.

OPUCN's historical and forecast capital expenditure summary is provided in Table 2-22 below. This table provides an overall summary of capital expenditures for the past five historical years, the 2020 Bridge Year and the 2021 Test Year, and the forecast years 2022 through 2025 as per the DSP. Capital expenditures are categorised into one of four investment categories: System Access, System Renewal, System Service and General Plant.

TABLE 2-22 - APPENDIX 2-AB CAPITAL EXPENDITURE SUMMARY

CATEGORY	Historical Period (previous plan[1] & actual)											
	2015			2016			2017			2018		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var
	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access	8,595	6,236	-27.4%	3,740	3,207	-14.3%	3,150	1,793	-43.1%	3,435	3,438	0.1%
System Renewal	5,943	7,233	21.7%	4,932	4,193	-15.0%	4,472	5,475	22.4%	4,761	3,779	-20.6%
System Service	1,068	722	-32.4%	1,380	1,192	-13.6%	420	941	124.1%	10,455	8,514	-18.6%
General Plant	1,675	988	-41.0%	1,180	1,448	22.7%	755	874	15.7%	889	1,299	46.1%
Total Expenditure	**17,281**	**15,179**	**-12.2%**	**11,232**	**10,040**	**-10.6%**	**8,797**	**9,083**	**3.3%**	**19,540**	**17,030**	**-12.8%**
Capital Contributions	(4,911)	(3,324)	-32.3%	(1,455)	(843)	-42.1%	(1,075)	(1,207)	12.3%	(1,095)	(4,073)	271.9%
Net Capital Expenditures	**12,370**	**11,855**	**-4.2%**	**9,777**	**9,197**	**-5.9%**	**7,722**	**7,876**	**2.0%**	**18,445**	**12,957**	**-29.8%**

CATEGORY	Historical (cont'd)			Forecast Period (planned)							
	2019			2020			2021	2022	2023	2024	2025
	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000	$ '000	$ '000	$ '000	$ '000
System Access	3,455	10,318	198.6%	5,790	1,637	-71.7%	5,911	4,895	4,499	4,629	4,645
System Renewal	4,851	6,524	34.5%	8,129	3,939	-51.5%	7,498	9,311	8,797	8,884	8,818
System Service	15,763	11,621	-26.3%	2,508	1,146	-54.3%	1,109	799	1,383	886	995
General Plant	510	704	38.1%	2,124	223	-89.5%	1,975	851	794	875	713
Total Expenditure	**24,579**	**29,168**	**18.7%**	**18,551**	**6,945**	**-62.6%**	**16,493**	**15,856**	**15,473**	**15,274**	**15,171**
Capital Contributions	(1,105)	(5,931)	436.7%	(1,958)	(411)	-79.0%	(2,043)	(1,692)	(1,555)	(1,600)	(1,606)
Net Capital Expenditures	**23,474**	**23,237**	**-1.0%**	**16,593**	**6,534**	**-60.6%**	**14,449**	**14,164**	**13,918**	**13,674**	**13,565**

Specific investment category spending requirements include:

- System Access driven by customer connection needs, third-party infrastructure needs requiring mandatory utility relocation, and mandated revenue metering and service obligations;
- System Renewal investments required to replace end of TUL assets, assets in deteriorating condition including high failure risk assets and/or asset failure;
- System Service investments such as operational technologies and grid modernization;
- General Plant investments to meet the facilities, fleet, office systems and IT needs including the acquisition of the Customer Information System (CIS).

OPUCN's forecast period expenditures represent a consistent average total budget envelope across the planning period, balancing annual variations in anticipated mandatory System Access work and other mandatory projects with changes in the other three investment categories. The utility can usually pace and prioritize with a greater degree of control – thus facilitating the overall smoothness and predictability of rate changes over the plan timeline.

The capital investment plan was developed to ensure that the system has sufficient resilience and flexibility to achieve a safe and reliable distribution system performance.

CAPITAL EXPENDITURES BY PROJECT

The following tables and narrative analysis summarize OPUCN's capital expenditures on a project specific basis for: 2015-2019 on an actual basis; the 2020 Bridge Year; and the 2021 Test Year on a forecast basis.

A summary of OPUCN's capital projects by year is provided in Table 2-23 below, also filed in excel format with Chapter 2 Appendices, Appendix 2-AA.

TABLE 2-23 - APPENDIX 2-AA CAPITAL PROJECTS

Projects	2015	2016	2017	2018	2019	2020 Bridge Year	2021 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
System Access							
Expansions	774,110	(318,665)	928,874	(47,919)	1,891,799	1,662,014	1,662,014
Connections	307,045	567,800	(393,553)	(420,820)	620,238	231,550	231,550
Revenue Metering	433,622	549,305	247,460	530,591	453,066	223,000	223,000
MIST Metering	79,367	144,012	116,088	101,585	207,537		
Remote Disconnect/Reconnect Metering	78,174	54,328	(35,063)				
Third Party Relocations	1,397,286	1,397,544	(186,995)	(791,200)	1,704,083	1,110,000	1,365,000
AMI System Upgrade						605,000	386,600
Sub-Total System Access	**3,069,603**	**2,394,324**	**676,810**	**(627,763)**	**4,876,723**	**3,831,564**	**3,868,164**
System Renewal							
Reactive/ Emergency Plant Replacement	1,097,162	1,141,696	1,228,047	1,010,143	1,664,882	1,190,000	1,111,800
Overhead Line Renewal	2,872,934	1,394,679	1,746,845	1,134,682	2,978,280	3,142,190	1,981,000
Underground Line Renewal	756,602	1,195,360	696,087	1,121,338	870,483	1,545,000	1,353,500
Station Renewal	144,227	111,102	964,478	470,407			
MS14 Metalclad Switchgear Replacment	1,632,383						
Pole Replacement Program			423,444	213,793	250,775	400,000	400,000
Porcelain Switch and Insulator Replacement Program						550,000	550,000
Vault Transformenr Replacement Program						162,000	162,000
44kV Quick Sleeve Replacement Program						100,000	100,000
Relay replacement Program						40,000	40,000
MS10 T2 Replacement						1,000,000	
Municipal Substation Switchgear Replacement Program							1,800,000
Sub-Total System Renewal	**6,503,308**	**3,842,837**	**5,058,901**	**3,950,363**	**5,764,419**	**8,129,190**	**7,498,300**
System Service							
Downtown Automation	712,331	498,801					
Downtown UG Self-Healing Grid				531,433			
OH Automated Self Healing Switches			646,329	261,496	3,593	50,000	200,000
Neutral Reactors		692,153	206,432	11,590			
Distribution System Supply Optimization		24,167	37,343	40,652	68,588		
Smart Fault Indicators	9,774	238	51,143	28,217	24,704		
Non-electric Fence					245,251		
MS9 Substation Construction				7,600,859	(281,342)		
Enfield Contribution to HONI					4,136,705		
MS9 and Enfield Feeders					7,455,780	1,140,400	
Operational Technology (GIS,OMS,ODS,SCADA)						257,500	267,500
Smart Grid						335,000	350,000
Municipal Substation Transformer Monitoring and Telemetry						150,000	150,000
Repair, Improvements and Upgrades of OT and Smart Grid Infrastructure						25,000	41,000
Ground Grid Upgrades						100,000	100,000
Voltage Monitoring (Grid Monitoring and Automation)						450,000	
Sub-Total System Service	**722,105**	**1,215,358**	**941,246**	**8,474,247**	**11,653,279**	**2,507,900**	**1,108,500**
General Plant							
Fleet	460,652	132,338	503,173	368,394	340,672	545,000	530,000
Facilities	108,415	218,640	49,309	110,787	106,367	565,000	100,000
Major Tools & Equipment	54,338	51,358		126,810	62,006	100,000	100,000
Office IT & Equipment Upgrades	104,672	79,976	187,535	282,572	126,791	87,000	89,000
Operational Technology (GIS, MAS)	8,071		81,907	9,018	41,620		
OMS Implementation and Enhancements	251,533	1,000,607	51,933				
ODS Replacement and Enhancement				360,507	59,515		
Back-up Control Room and Associated IT Infrastructure						200,000	
Back-Up Generator Replacement						205,000	
Information Technology General						282,000	419,500
Customer Self-Serve Online Portal (Green Button Dashboard)						140,000	
Customer Information System (CIS) Acquisition							736,000
Sub-Total General Plant	**987,680**	**1,482,919**	**873,857**	**1,258,089**	**736,972**	**2,124,000**	**1,974,500**
Miscellaneous	572,215	261,250	325,518	(97,827)	204,922	0	0
Total	**11,854,911**	**9,196,688**	**7,876,332**	**12,957,109**	**23,236,315**	**16,592,654**	**14,449,464**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets (input as negative)	0	0	0	0	0	0	0
Total	**11,854,911**	**9,196,688**	**7,876,332**	**12,957,109**	**23,236,315**	**16,592,654**	**14,449,464**

VARIANCE ANALYSIS ON CAPITAL EXPENDITURES

2016 Actual vs. 2015 Actual

OPUCN's total actual capital expenditures in 2016 was $9.2M or $2.7M lower than 2015 total expenditures, as indicated in Table 2-24 below. This is mainly due to switchgear replacement at MS14 in 2015 of $1.6M along with $1.4M lower overhead line renewal in 2016.

TABLE 2-24 - 2016 ACTUAL VS 2015 ACTUAL CAPITAL EXPENDITURES ($000S)

CATEGORY	2016 Actual	2015 Actual	Variance	
	$ '000	*$ '000*	*$ '000*	%
System Access	3,207	6,236	3,029	94.5%
System Renewal	4,193	7,233	3,040	72.5%
System Service	1,192	722	(470)	(39.4)%
General Plant	1,448	988	(460)	(31.8)%
Total Expenditure	**10,040**	**15,179**	**5,139**	**51.2%**
Capital Contributions	(843)	(3,324)	(2,481)	294.3%
Net Capital Expenditures	**9,197**	**11,855**	**2,658**	**28.9%**

<u>System Access</u>

Gross System Access expenditures decreased in 2016 by $3.0M compared with 2015 mainly due to a larger number of connection and expansion projects closing in 2015. On a net basis, after capital contributions, 2016 spend is $0.7M lower.

<u>System Renewal</u>

2016 Total System Renewal expenditures of $4.2M represents an decrease of $3.0M over 2015, On a net basis, after capital contributions, 2016 spend is $2.7M lower. The decrease is mainly due to switchgear replacement at MS14 in 2015 of $1.6M along with $1.4M lower overhead line renewal in 2016. The 2015 amount included unplanned expenditure of $0.7M related to remediation work and completion of work planned in previous years.

<u>System Service</u>

The year over year increase in System Service expenditures of $0.5M is due mainly to $0.7M related to the start of the Neutral Reactor Project, partially offset by a $0.2M decline in expenditures on the Oshawa downtown automation project, a multi-phase project to modernize and automate monitoring and control of downtown vaults.

<u>General Plant</u>

2016 Total General Plant expenditures of $1.4M was an increase of $0.5M over 2015 due to $0.8M higher than 2015 expenditure on the OMS implementation and enhancement project partially offset by $0.3M lower investment in fleet.

2017 Actual vs. 2016 Actual

OPUCN's total actual capital expenditures in 2017 was $7.9M or $1.3M lower than 2016 total expenditures, as indicated in Table 2-25 below.

TABLE 2-25 - 2017 ACTUAL VS 2016 ACTUAL CAPITAL EXPENDITURES ($000S)

CATEGORY	2017 Actual	2016 Actual	Variance	
	$ '000	*$ '000*	*$ '000*	%
System Access	1,793	3,207	1,414	78.9%
System Renewal	5,475	4,193	(1,283)	(23.4)%
System Service	941	1,192	251	26.7%
General Plant	874	1,448	574	65.7%
Total Expenditure	**9,083**	**10,040**	**956**	**10.5%**
Capital Contributions	(1,207)	(843)	364	(30.2)%
Net Capital Expenditures	**7,876**	**9,197**	**1,320**	**16.8%**

<u>System Access</u>

System Access expenditures decreased in 2016, net of capital contributions, by $1.7M compared with 2016. Lower third party relocation expenditures ($1.4M) and lower connection project expenditures ($0.9M) were partially offset by higher expansion project costs of $1.2M.

System Renewal

Total System Renewal expenditures of $5.5M represents an increase of $1.3M over 2016, On a net basis, after capital contributions, 2017 spend is $1.2M higher. The increase is mainly due to 2017 expenditures of $1.0M on the 44kV Circuit Breaker Replacement Program and $0.4M on the pole replacement program started in 2017.

System Service

The year over year decrease in System Service expenditures of $0.3M is due mainly to decreases of $0.5M and $0.5M respectively for the Downtown Automation project and the Neutral Reactor Project, partially offset by a $0.6M increase in expenditures on the Overhead Automated Self Healing Switch project.

General Plant

Total General Plant expenditures of $0.9M was a decrease of $0.6M over 2016 due to $0.9M lower than 2016 expenditure on the OMS Implementation and Enhancement project partially offset by $0.4M higher expenditures on fleet.

2018 Actual vs. 2017 Actual

OPUCN’s total actual capital expenditure in 2018 was $13.0M or $5.1M higher than 2017 total expenditures, as indicated in Table 2-26 below. The increase is mainly due to $7.6M in costs related to the construction of the MS9 municipal substation in 2018 partially offset by lower net (after capital contributions) expenditures on system access and renewal projects.

TABLE 2-26 - 2018 ACTUAL VS 2017 ACTUAL CAPITAL EXPENDITURES ($000S)

CATEGORY	2018 Actual	2017 Actual	Variance	
	$ '000	*$ '000*	*$ '000*	%
System Access	3,438	1,793	(1,645)	(47.9)%
System Renewal	3,779	5,475	1,697	44.9%
System Service	8,514	941	(7,573)	(88.9)%
General Plant	1,299	874	(425)	(32.7)%
Total Expenditure	**17,030**	**9,083**	**(7,946)**	**(46.7)%**
Capital Contributions	(4,073)	(1,207)	2,866	(70.4)%
Net Capital Expenditures	**12,957**	**7,876**	**(5,081)**	**(39.2)%**

<u>System Access</u>

System Access expenditures decreased in 2018, net of capital contributions, by $1.3M compared with 2017 mainly due to fewer expansion ($1.0M) and third party relocation projects ($0.6M) closing in 2017, partially offset by an increase of $0.3M in revenue metering activity.

<u>System Renewal</u>

System Renewal expenditures of $3.8M represents an decrease of $1.7M over 2017, On a net basis, after capital contributions, 2018 spend is $1.1M lower. The decrease is due mainly to decreases related to the 44kV Circuit Breaker Replacement Program ($0.5M), the pole replacement program ($0.2M), overhead line renewal projects ($0.6M), and $0.2M less reactive/emergency activity in 2018. An increase in underground line renewal projects of $0.4M partially offsets these decreases.

<u>System Service</u>

The year over year increase in System Service expenditures of $7.6M is due mainly to $7.6M related to the construction of the MS9 municipal substation in 2018. Other year over year variances include $0.5M expenditure on the Downtown Self Healing UG vaults (smart grid) project, offset by year over year reductions in spend on the Overhead Automated Self Healing Switches project ($0.4M) and the Neutral Reactors project ($0.2M).

General Plant

Total General Plant expenditures of $1.3M was an increase of $0.4M over 2017 due to $0.4M expenditure on the ODS ODS Replacement and Enhancement project.

2019 Actual vs. 2018 Actual

OPUCN’s total actual capital expenditure in 2019 was $23.2M or $10.3M higher than 2018 total expenditures, as indicated in Table 2-27 below.

TABLE 2-27 - 2019 ACTUAL VS 2018 ACTUAL CAPITAL EXPENDITURES ($000S)

CATEGORY	2019 Actual	2018 Actual	Variance	
	$ '000	*$ '000*	*$ '000*	%
System Access	10,318	3,438	(6,880)	(66.7)%
System Renewal	6,524	3,779	(2,746)	(42.1)%
System Service	11,621	8,514	(3,107)	(26.7)%
General Plant	704	1,299	594	84.3%
Total Expenditure	**29,168**	**17,030**	**(12,138)**	**(41.6)%**
Capital Contributions	(5,931)	(4,073)	1,858	(31.3)%
Net Capital Expenditures	**23,237**	**12,957**	**(10,280)**	**(44.2)%**

System Access

System Access expenditures increased in 2019, net of capital contributions, by $5.5M compared with 2018. Expansions, net of capital contributions, were higher by $1.9M. Third party relocations were higher in 2019 by $2.5M and customer connections were higher by $1.0M.

System Renewal

System Renewal expenditures of $6.5M represents an increase of $2.7M over 2018, On a net basis, after capital contributions, 2019 spend is $1.8M higher. The increase is mainly due to year over year increases in overhead line renewal projects ($1.8M) and reactive/emergency plant replacement ($0.7M), partially offset by decreases related to the 44kV Circuit Breaker Replacement Program ($0.5M) and $0.3M lower underground line renewal in 2019.

<u>System Service</u>

The year over year increase in System Service expenditures of $3.1M is due mainly to the $4.1M contribution to Hydro One for the new Enfield TS. The reduction in 2019 related to the $7.6M spend on MS9 construction costs in 2018 is offset by expenditures of $7.5M in 2019 related to MS9 and Enfield feeders. Other year over year reductions include $0.5M and $0.3M related to the Downtown Self Healing UG vaults (smart grid) project and the Overhead Automated Self Healing Switches project respectively.

<u>General Plant</u>

General Plant expenditures of $0.7M was a decrease of $0.6M over 2018 due mainly to $0.3M lower than 2018 expenditure on the ODS Replacement and Enhancement project and $0.2M related to IT server additions in 2018.

2020 Bridge Year vs. 2019 Actual

OPUCN's total forecast capital expenditure in 2020 $16.6M or $6.6M lower than 2019 total expenditures, as indicated in Table 2-28 below. This is mainly due to $9.1M lower system service costs in 2019 related to the new MS9 and Enfield TS.

TABLE 2-28 – 2020 BRIDGE YEAR VS 2019 ACTUAL CAPITAL EXPENDITURES ($000S)

CATEGORY	2020 Bridge Year	2019 Actual	Variance	
	$ '000	*$ '000*	*$ '000*	%
System Access	5,790	10,318	4,528	78.2%
System Renewal	8,129	6,524	(1,605)	(19.7)%
System Service	2,508	11,621	9,113	363.3%
General Plant	2,124	704	(1,420)	(66.8)%
Total Expenditure	**18,551**	**29,168**	**10,617**	**57.2%**
Capital Contributions	(1,958)	(5,931)	(3,973)	202.9%
Net Capital Expenditures	**16,593**	**23,237**	**6,644**	**40.0%**

System Access

2020 System Access expenditures forecast of $5.8M are $4.5M lower than 2019. Net of capital contributions, the year over year reduction is $1.0M. 2020 forecast includes an increase of $0.6M related to updating the Advanced Metering Infrastructure (AMI) System, offset by year over year reductions related to MIST and revenue metering ($0.5M), expansions and connections ($0.6M), and third party relocations ($0.6M).

System Renewal

2020 forecast System Renewal expenditures of $8.1M represents an increase of $1.6M over 2019. On a net basis, after capital contributions, 2020 spend is $2.4M higher. The increase is mainly due to $1.0M for the replacement of a MS transformer and legacy lead cable at MS10, $0.8M related to overhead and underground line renewal, and $0.6M related to the Porcelain Switch and Insulator Replacement.

System Service

The year over year forecast decrease in System Service expenditures of $9.1M is due mainly to a net decrease of $10.2M in costs related to the new MS9 and Enfield TS. Increases in year over year spend include $0.5M related to the Voltage Monitoring project, $0.3M smart grid investments, $.3M in operational technology systems (ODS, OMS, GIS, SCADA).

General Plant

2020 forecast General Plant expenditures of $2.1M are an increase of $1.4M over 2019. The increase is driven by $0.5M in upgrades to facilities, $0.2M in fleet additions, $0.4M related to control room backup infrastructure and a replacement backup generator, and $0.4M in IT infrastructure projects including a Customer Self-Serve Online Portal (Green Button Dashboard).

2021 Test Year vs. 2020 Bridge Year

OPUCN's total forecast capital expenditures in 2021 is $14.4M or $2.1M lower than 2020 forecast total expenditures, as indicated in Table 2-29 below.

TABLE 2-29 - 2021 TEST YEAR VS 2020 BRIDGE YEAR CAPITAL EXPENDITURES ($000S)

CATEGORY	2021 Test Year	2020 Bridge Year	Variance	
	$ '000	*$ '000*	*$ '000*	*%*
System Access	5,911	5,790	(121)	(2.0)%
System Renewal	7,498	8,129	632	8.4%
System Service	1,109	2,508	1,399	126.1%
General Plant	1,975	2,124	149	7.5%
Total Expenditure	**16,493**	**18,551**	**2,059**	**12.5%**
Capital Contributions	(2,043)	(1,958)	85	(4.2)%
Net Capital Expenditures	**14,449**	**16,593**	**2,144**	**14.8%**

<u>System Access</u>

System Access forecast expenditures in 2021 of $5.9M are in line with 2020 forecast, with no significant variances forecast.

<u>System Renewal</u>

2021 System Renewal expenditures of $7.5M represents a decrease of $0.6M over 2020 forecast. The decrease is due to year over year reductions related to the replacement of a MS transformer and legacy lead cable at MS10 ($1.0M) and lower overhead/ underground line renewal ($1.4M), partially offset by $1.8M in expenditure on the Municipal Substation Switchgear Replacement Program.

<u>System Service</u>

The year over year decrease in System Service expenditures of $1.4M is due mainly to a net decrease of $1.1M in costs related to feeders for the new MS9 and Enfield TS along with $0.5M related to the Voltage Monitoring spend in 2020, partially offset by lower expenditures from the Overhead Automated Self Healing Switches program ($0.2M).

<u>General Plant</u>

2021 forecast General Plant expenditures of $2.0M is a decrease of $0.1M over 2020. This decrease is made up of reductions in facilities projects ($0.5M), spend in 2020 related to control room backup infrastructure and a replacement backup generator ($0.4M), customer self-serve portal investment in 2020 ($0.1M), partially offset by the cost of acquiring a customer information system ($0.7M).

2015 Actual vs. 2015 Board-Approved

OPUCN's total actual capital expenditures in 2015 was $11.9M or $0.5M lower than 2015 Board-Approved total expenditures, as indicated in Table 2-30 below. This is mainly due to switchgear replacement at MS14 in 2015 of $1.6M along with $1.4M lower overhead line renewal in 2016.

TABLE 2-30 – 2015 ACTUAL VS 2015 BOARD-APPROVED CAPITAL EXPENDITURES ($000S)

CATEGORY	2015 Approved	2015 Actual	Variance	
	$ '000	*$ '000*	*$ '000*	%
System Access	8,595	6,236	(2,359)	(27.4)%
System Renewal	5,943	7,233	1,290	21.7%
System Service	1,068	722	(346)	(32.4)%
General Plant	1,675	988	(687)	(41.0)%
Total Expenditure	**17,281**	**15,179**	**(2,102)**	**(12.2)%**
Capital Contributions	(4,911)	(3,324)	1,587	(32.3)%
Net Capital Expenditures	**12,370**	**11,855**	**(515)**	**(4.2)%**

<u>System Access</u>

System Access expenditures of $6.2M in 2015 were $2.4M lower than Board-Approved. Net of capital contributions, 2015 was by $0.6M lower. The principal reason for the variance were delays around construction projects related to the Highway 407 extension.

<u>System Renewal</u>

2015 System Renewal expenditures of $7.2M were $1.3M higher than Board-Approved. On a net basis, after capital contributions, 2015 spend is $1.3M lower. The increase is due to higher than forecast cost of switchgear replacement at MS14 ($0.4M), higher than planned overhead and underground renewal projects ($0.5M), and higher reactive capital projects ($0.3M).

<u>System Service</u>

System Service expenditures of $0.7M were $0.3M lower than Board-Approved due mainly to $0.5M related to the deferral of the Neutral Reactor Project to 2016, partially offset by a $0.1M underspend in the Oshawa downtown automation project, a multi-phase project to modernize and automate monitoring and control of downtown vaults.

<u>General Plant</u>

General Plant expenditures of $1.0M were $0.7M lower than Board-Approved due mainly to $0.6M lower than planned expenditure on the OMS Implementation and Enhancement project.

2016 Actual vs. 2016 Board-Approved

OPUCN's total actual capital expenditures in 2016 were $9.2M or $0.6M lower than 2016 Board-Approved total expenditures, as indicated in Table 2-31 below.

TABLE 2-31 – 2016 ACTUAL VS 2016 BOARD-APPROVED CAPITAL EXPENDITURES ($000S)

CATEGORY	2016 Approved	2016 Actual	Variance	
	$ '000	*$ '000*	*$ '000*	%
System Access	3,740	3,207	(533)	(14.3)%
System Renewal	4,932	4,193	(739)	(15.0)%
System Service	1,380	1,192	(188)	(13.6)%
General Plant	1,180	1,448	268	22.7%
Total Expenditure	**11,232**	**10,040**	**(1,192)**	**(10.6)%**
Capital Contributions	(1,455)	(843)	612	(42.1)%
Net Capital Expenditures	**9,777**	**9,197**	**(580)**	**(5.9)%**

System Access

System Access expenditures of $3.2M in 2016 were $0.5M lower than Board-Approved. Net of capital contributions, 2016 was by $0.2M higher. The principal reason for the variance was $0.1M higher revenue metering expenditures.

System Renewal

2016 System Renewal expenditures of $4.2M were $0.7M lower than Board-Approved. On a net basis, after capital contributions, 2016 spend was $0.9M lower. The underspend is due mainly to lower than planned overhead and underground renewal projects ($0.6M) and deferred expenditures of $0.5M on the 44kV Circuit Breaker Replacement Program, partially offset by higher than planned reactive capital projects ($0.3M).

System Service

System Service expenditures of $1.2M were $0.2M lower than Board-Approved due mainly to lower than planned spend in 2016 on the Neutral Reactors project ($0.4M) and the deferred expenditures of $0.3M related to the Downtown Self Healing UG vaults (smart grid) project. These underspends were partially offset by $0.5M in expenditures related to the Oshawa downtown automation project, originally planned for 2015.

General Plant

General Plant expenditures of $1.4M were $0.3M higher than Board-Approved due mainly to $0.9M higher than planned expenditure on the OMS Implementation and Enhancement project, partially offset by planned ODS replacement cost ($0.4M) deferred to 2018 and lower than planned fleet, facilities and IT expenditures.

2017 Actual vs. 2017 Board-Approved

OPUCN’s total actual capital expenditure in 2017 was $7.9M or $0.2M higher than 2017 Board-Approved total expenditures, as indicated in Table 2-32 below.

TABLE 2-32 – 2017 ACTUAL VS 2017 BOARD-APPROVED CAPITAL EXPENDITURES ($000S)

CATEGORY	2017 Approved	2017 Actual	Variance	
	$ '000	*$ '000*	*$ '000*	%
System Access	3,150	1,793	(1,357)	(43.1)%
System Renewal	4,472	5,475	1,003	22.4%
System Service	420	941	521	124.1%
General Plant	755	874	119	15.7%
Total Expenditure	**8,797**	**9,083**	**286**	**3.3%**
Capital Contributions	(1,075)	(1,207)	(132)	12.3%
Net Capital Expenditures	**7,722**	**7,876**	**154**	**2.0%**

<u>System Access</u>

System Access expenditures of $1.8M in 2017 were $1.4M lower than Board-Approved. The principal reason for the variance was $1.3M lower than planned third party driven relocations and $0.4M lower than planned metering projects, partially offset by $0.4M higher than planned connections and expansions.

<u>System Renewal</u>

System Renewal expenditures of $5.5M were $1.0M higher than Board-Approved. On a net basis, after capital contributions, 2018 spend was $0.9M higher. The overspend is due mainly to $0.5M on the 44kV Circuit Breaker Replacement Program originally planned for 2016 and $0.4M higher than planned reactive capital projects.

<u>System Service</u>

System Service expenditures of $0.9M were $0.5M higher than Board-Approved due mainly to $0.2M spend on the Neutral Reactors project originally planned in 2016 and $0.3M higher than planned spend in 2017 on the Overhead Automated Self Healing Switch project. This was originally planned over 2017 and 2018 with $0.3M budgeted in 2018.

General Plant

General Plant expenditures of $0.9M were $0.1M higher than Board-Approved due mainly to $0.1M higher than planned expenditure on the fleet investments. This variance offsets prior year underspend.

2018 Actual vs. 2018 Board-Approved

OPUCN's total actual capital expenditure in 2018 was $13.0M or $5.5M lower than 2018 Board-Approved total expenditures, as indicated in Table 2-33 below.

TABLE 2-33 – 2018 ACTUAL VS 2018 BOARD-APPROVED CAPITAL EXPENDITURES ($000S)

CATEGORY	2018 Approved	2018 Actual	Variance	
	$ '000	*$ '000*	*$ '000*	%
System Access	3,435	3,438	3	0.1%
System Renewal	4,761	3,779	(982)	(20.6)%
System Service	10,455	8,514	(1,941)	(18.6)%
General Plant	889	1,299	410	46.1%
Total Expenditure	**19,540**	**17,030**	**(2,510)**	**(12.8)%**
Capital Contributions	(1,095)	(4,073)	(2,978)	271.9%
Net Capital Expenditures	**18,445**	**12,957**	**(5,488)**	**(29.8)%**

System Access

System Access expenditures of $3.4M in 2018 were in line with Board-Approved amount of $3.4M. Net of capital contributions, 2018 was by $2.9M lower. The principal reason for the variance was $1.9M lower than planned third party relocations and $1.0M lower than planned connections/expansions.

System Renewal

2018 System Renewal expenditures of $3.8M were $1.0M lower than Board-Approved. The underspend is due mainly to one subdivision (Riverside North & South) forecast at $1.0M delayed until 2019.

<u>System Service</u>

System Service expenditures of $8.5M were $0.4M higher than Board-Approved due mainly to delayed spend in 2018 of $2.8M on the planned MS9 feeders partially offset by $0.6M higher than planned spend on MS9 construction and $0.1M related to the Overhead Automated Self Healing Switch project project.

<u>General Plant</u>

General Plant expenditures of $1.3M were $0.4M higher than Board-Approved due mainly to $0.4M expenditure on the ODS Replacement and Enhancement project originally planned for 2016.

2019 Actual vs. 2019 Board-Approved

OPUCN's total actual capital expenditures in 2015 was $23.2M or $0.2M lower than 2019 Board-Approved total expenditures, as indicated in Table 2-34 below.

TABLE 2-34 – 2019 ACTUAL VS 2019 BOARD-APPROVED CAPITAL EXPENDITURES ($000S)

CATEGORY	2019 Approved	2019 Actual	Variance	
	$ '000	*$ '000*	*$ '000*	%
System Access	3,455	10,318	6,863	198.6%
System Renewal	4,851	6,524	1,673	34.5%
System Service	15,763	11,621	(4,142)	(26.3)%
General Plant	510	704	194	38.1%
Total Expenditure	**24,579**	**29,168**	**4,589**	**18.7%**
Capital Contributions	(1,105)	(5,931)	(4,826)	436.7%
Net Capital Expenditures	**23,474**	**23,237**	**(237)**	**(1.0)%**

<u>System Access</u>

System Access expenditures of $10.3M in 2019 were $6.9M higher than Board-Approved. Net of capital contributions, 2019 was by $2.5M higher. The principal reason for the variance was $1.9M higher than planned connections/subdivisions and $0.6M higher than planned third party relocations.

System Renewal

2019 System Renewal expenditures of $6.5M were $1.7M higher than Board-Approved. On a net basis, after capital contributions, 2016 spend was $1.2M higher. The overspend is due mainly to $$1.1M higher than planned overhead projects and $0.8M higher than planned reactive capital projects partially offset by $1.0M related to the deferral to 2020 of the MS Transformer Replacement project. Of the planned overhead variance, $0.7M relates to the Riverside subdivision originally budgeted in 2018 at $1.0M.

System Service

System Service expenditures of $11.6M were $4.1M lower than Board-Approved due mainly to $3.8M lower than planned spend in 2019 on the feeder systems for MS9 and Enfield TS ($1.1M deferred to 2020), and $0.2M related to the deferred Voltage Monitoring project.

General Plant

General Plant expenditures of $0.7M were $0.2M higher than Board-Approved due mainly to $0.2M higher than originally planned expenditure on fleet.

COSTS OF ELIGIBLE INVESTMENTS FOR DISTRIBUTORS

OPUCN has no investments eligible for rate protection as described in section 79.1 of the Ontario Energy Board Act, 1998 (OEB Act) and O.Reg. 330/09 under the OEB Act.

NEW POLICY OPTIONS FOR THE FUNDING OF CAPITAL

OPUCN is not proposing any qualifying ACM capital projects in this cost of service rate application. OPUCN has no approved ACM or ICM from a previous Price Cap IR application.

CAPITALIZATION POLICY

OPUCN's rebasing in 2012 (EB-2011-0073) was completed based on MIFRS and included appropriate changes to its capitalization policy to exclude from capital any costs which are not directly attributable to an item of PP&E, as part of the transition to MIFRS. This capitalization policy under MIFRS is consistent with IFRS, which OPUCN formally adopted for financial reporting purposes on January 1, 2015. This application does not include any further changes to capitalization policies.

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

Material Costs

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

Labour Costs

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

Third Party Contract Costs

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

Fleet Costs

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

CAPITALIZATION OF OVERHEAD

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

Payroll Burden

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

The payroll burden rate used in OPUCN's last rebasing in 2015 (EB-2014-0101) was 63%. The labour burden rate is recalculated each year in order to incorporate any changes to benefit and other directly attributable costs. An updated actuarial valuation of the Post Retirements Benefit liability is done every year end, and is incorporated into the calculation. December 31, 2018 analysis resulted in a small reduction in the labour burden rate from 63.0% to 60% for 2019. The 60% rate is included in each of the years 2020 through 2021 in this application.

OPUCN has completed Appendix 2-D which provides a summary of the overhead costs before capitalization, and the actual OM&A amounts capitalized. Table 2-35 below is a summary of Appendix 2-D.

TABLE 2-35– APPENDIX 2-D OVERHEAD EXPENSE

OM&A Before Capitalization ($000's)	2017 Historical Year	2018 Historical Year	2019 Historical Year	2020 Bridge Year	2021 Test Year
Corporate	2,855	3,009	3,059	2,810	3,101
General & Administrative	2,116	2,351	2,283	2,543	2,512
Customer Service	3,135	2,991	2,586	3,100	3,162
Facilities	1,292	1,394	1,476	1,435	1,466
Operations & Metering	7,331	8,209	7,662	8,234	8,229
Property Taxes	136	136	136	149	152
Total OM&A Before Capitalization (B)	16,865	18,089	17,201	18,271	18,621

Capitalized OM&A ($000's)	2017 Historical Year	2018 Historical Year	2019 Historical Year	2020 Bridge Year	2021 Test Year	Directly Attributable? (Yes/No)	Explanation for Change in Overhead Capitalized
employee benefits	2,997	3,429	3,288	3,353	3,420	Yes	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
initial delivery and handling costs	198	227	217	222	226	Yes	
vehicle and related costs	597	683	654	668	681	Yes	
Total Capitalized OM&A (A)	3,792	4,338	4,159	4,242	4,327		

% of Capitalized OM&A (=A/B)	22%	24%	24%	23%	23%		

SERVICE QUALITY AND RELIABILITY PERFORMANCE

Service Quality Indicators

OPUCN tracks its performance on the OEB's Electricity Service Quality Requirements (ESQR). The OEB's *Distribution System Code* sets the minimum service quality requirements that a distributor must meet in carrying out its obligations to distribute electricity under its license and the *Ontario Energy Board Act, 1998*.

As required by the OEB, OPUCN records and submits these performance measures which are compared with the OEB's established expected ESQR levels, to evaluate OPUCN's performance in appointment scheduling, service accessibility and emergency response.

Table 2-36 below summarizes OPUCN last 5 years of reported ESQRs.

While achieving or exceeding all ESQR metrics since 2015, one area of focus for OPUCN has been answering customer calls and providing information relevant to customers' enquiries. OPUCN has and continues to enhance its IVR and CIS systems and leverage the integration of this with its Outage Management System (OMS) to provide faster response and better information to customers, internal and external stakeholders.

TABLE 2-36–SERVICE QUALITY INDICATORS (ESQR) (FROM APPENDIX 2-G)

Indicator	OEB Minimum Standard	2015	2016	2017	2018	2019
Low Voltage Connections	90.0%	95.4%	92.6%	99.5%	99.8%	100.0%
High Voltage Connections	90.0%	100.0%	0.0%	0.0%	0.0%	0.0%
Telephone Accessibility	65.0%	70.2%	73.7%	90.5%	90.1%	94.1%
Appointments Met	90.0%	99.6%	100.0%	98.5%	100.0%	100.0%
Written Response to Enquires	80.0%	100.0%	99.5%	99.9%	100.0%	100.0%
Emergency Urban Response	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Emergency Rural Response	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Telephone Call Abandon Rate	10.0%	1.8%	1.3%	0.4%	0.4%	0.2%
Appointment Scheduling	90.0%	100.0%	100.0%	92.8%	97.5%	92.5%
Rescheduling a Missed Appointment	100.0%	0.0%	0.0%	100.0%	100.0%	100.0%
Reconnection Performance Standard	85.0%	100.0%	100.0%	99.8%	100.0%	100.0%

Reliability Indicators

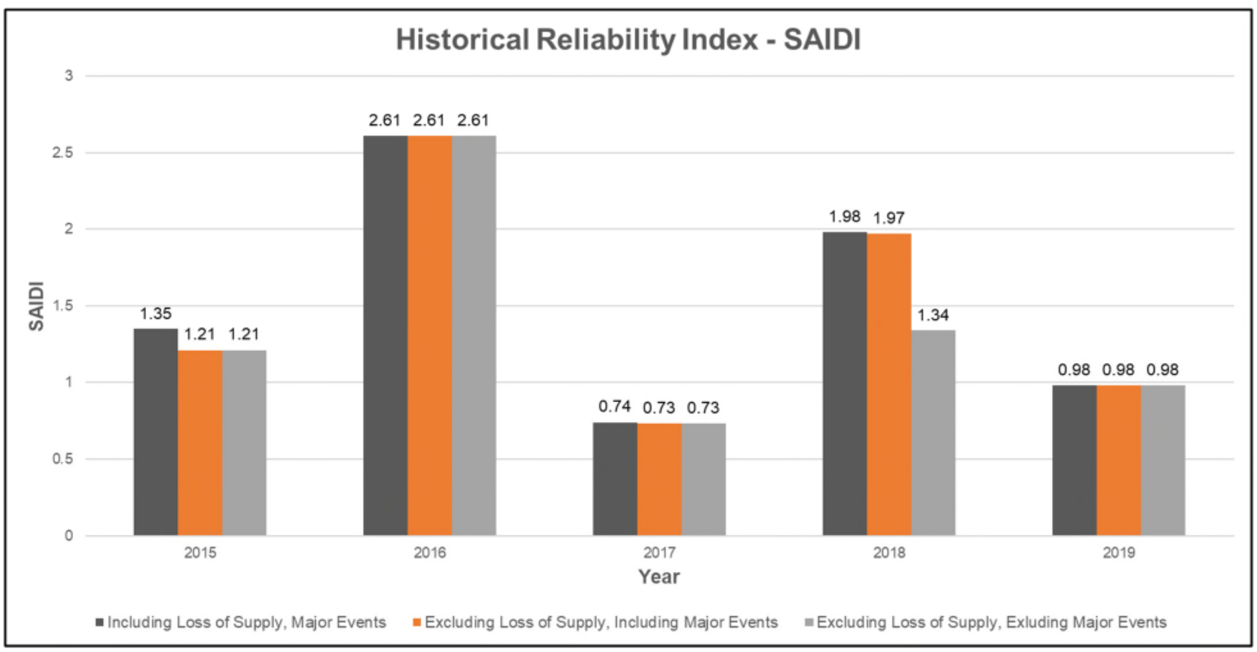
OPUCN tracks and reports to the OEB, the System Average Interruption Duration Index ("SAIDI"), System Average Interruption Frequency Index ("SAIFI"). Table 2-37 below summarizes OPUCN last 5 years of reported SAIDI and SAIFI.

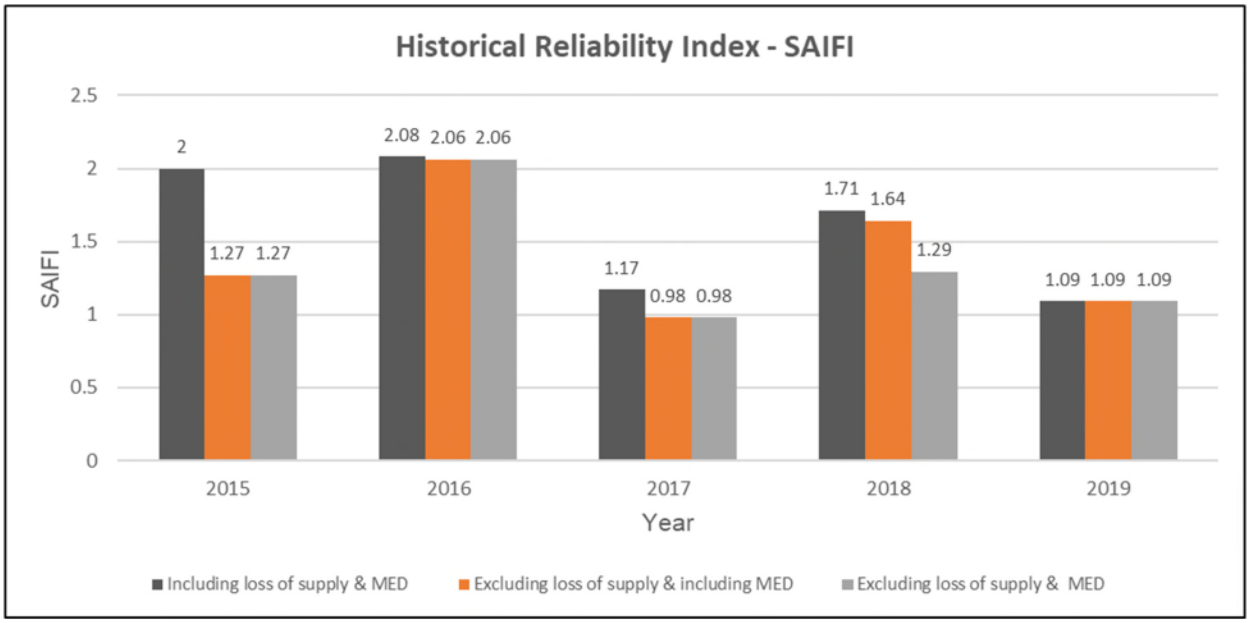
TABLE 2-37–REPORTED SERVICE RELIABILITY INDICATORS (FROM APPENDIX 2-G)

Index	Including outages caused by loss of supply					5 Year Average
	2015	**2016**	**2017**	**2018**	**2019**	
SAIDI	1.350	2.610	0.750	1.960	0.980	1.530
SAIFI	2.010	2.080	1.180	1.710	1.090	1.614

Index	Excluding outages caused by loss of supply					5 Year Average
	2015	**2016**	**2017**	**2018**	**2019**	
SAIDI	1.210	2.610	0.730	1.950	0.980	1.496
SAIFI	1.270	2.060	0.980	1.640	1.090	1.408

Index	Excluding Major Event Days					5 Year Average
	2015	**2016**	**2017**	**2018**	**2019**	
SAIDI	1.210	2.610	0.730	1.340	0.980	1.374
SAIFI	1.280	2.060	0.980	1.290	1.090	1.338





OPUCN experienced variations in both SAIDI and SAIFI during the historic period from 2015 to 2019 with up to 2.61 in SAIDI and 2.06 in SAIFI in 2016 excluding loss of supply and MED. Service reliability performance were underperforming in 2016 compared to the previous 5-year rolling average SAIDI target of 1.45 and SAIFI target of 1.36 primarily due to outages affecting majority of our customer base. OPUCN experienced an outage in 2016 that resulted from a 44kV quick sleeve failure causing a switch to open resulting in approximately 37,000 customers to experience an outage lasting 6 hours. The outage occurred in the evening after work hours and crews had to be called in to make the necessary repairs. In order to address this type of outage in the future, a “44kV Quick Sleeve Replacement Program” has been included in the capital investment plan. This project will replace existing quick sleeves with permanent sleeves on the 44kV primary overhead conductor lines that will provide better reliability during the period of 2020-2022.

In 2018, OPUCN experienced one Major Event on May 4th. A major windstorm impacted OPUCN’s service territory resulting in numerous sustained and momentary outages. Abnormal high winds/microburst caused 13 poles to snap and break resulting in the loss of two 44kV feeders. Multiple high winds also caused trees to be uprooted and limbs to crash, debris in the air caused two additional 44kV feeders to be removed from service. This event interrupted power to 20,580 customers and caused 35,673 customer-hours of interruptions. The storm impacted 7 distribution feeders and it took approximately 3 hours to restore power to the 90% of the customers impacted. Table 2-38 below summarizes Major Events over the past 5 years.

TABLE 2-38 - MAJOR EVENT DETAILS (2015-2019)

Major Event Details	2015	2016	2017	2018	2019
Number of Interruptions	-	-	-	**7**	-
6-Adverse Weather	-	-	-	7	-
Number of Customer Interruptions	-	-	-	**20,580**	-
6-Adverse Weather	-	-	-	20,580	-
Number of Customer Hours Interruptions	-	-	-	**35,673**	-
6-Adverse Weather	-	-	-	35,673	-

Refer to Section 5.2.3.c of the Distribution System Plan for a detailed discussion with respect to System Reliability.

APPENDIX 2-1 – DISTRIBUTION SYSTEM PLAN

Oshawa PUC Networks Inc.

Distribution System Plan

Historical Period: 2015-2020
Forecast Period: 2021-2025

July 2020

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5.2 Distribution System Plan

5.2.1 Distribution System Plan Overview

This section provides a high-level overview of the information filed in the DSP, including key elements of the DSP, an overview of how projects address customer's preferences, sources of expected cost efficiencies, the period covered by the DSP, the vintage of the information, an indication of important changes to OPUCN's Asset Management (AM) processes, and aspects of the DSP that are contingent on the outcome of ongoing activities or future events.

5.2.1.a Key Elements of the DSP

The key elements that drive the size and mix of capital investments needed to achieve the planning objectives are investments in the four investment categories, condition assessment, reliability performance, customer and load growth, grid modernization and cybersecurity. Table 1 provides OPUCN's net historical and forecasted capital expenditures by investment category and system operations and maintenance (O&M) costs over the period of 2015 to 2025. Note that 2020 are budgetary expenditures.

Category	Historical Period ($'000)						Forecasted Period ($'000)				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
System Access	6,236	3,207	1,793	3,438	10,318	5,790	5,911	5,016	4,662	4,767	4,772
System Renewal	7,233	4,193	5,475	3,779	6,524	8,129	7,498	9,311	8,797	8,884	8,818
System Service	722	1,192	941	8,514	11,621	2,508	1,109	799	1,383	886	995
General Plant	988	1,448	874	1,299	704	2,124	1,975	851	794	875	713
Total Gross	**15,179**	**10,040**	**9,083**	**17,030**	**29,168**	**18,551**	**16,493**	**15,977**	**15,636**	**15,411**	**15,299**
Contributions	(3,324)	(843)	(1,207)	(4,073)	(5,931)	(1,958)	(2,043)	(1,813)	(1,718)	(1,738)	(1,733)
Total Net	**11,855**	**9,197**	**7,876**	**12,957**	**23,236**	**16,593**	**14,449**	**14,164**	**13,918**	**13,673**	**13,566**
System O&M	2,797	3,017	2,724	3,154	3,015	3,271	3,168	3,232	3,296	3,362	3,430

Table 1: Historical and Forecasted Capital Expenditure and System O&M

OPUCN's historical capital expenditure from 2015 through 2019 has an average annual expenditure of approximately $13,024K primarily driven by System Access and System Service requirements in order to address the forecasted customer and load growth within the service territory. This prompted OPUCN to invest in ensuring that the transmission and distribution system does not have any constraints and that sufficient capacity and infrastructure are available to connect customers.

During the forecast years from 2021 to 2025, the planned capital expenditure has shifted to System Renewal and System Service requirements to improve system reliability and mitigate customer outage impacts in response to customer feedback. This can be achieved through the required replacement of equipment at the end of Typical Useful Life (TUL) or high failure risk assets and grid modernization to make the distribution system more responsive in monitoring and locating power outages. This will also provide customers with timely information to enable consumption-related decision-making.

Specific investment category spending requirements include:

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

- System Renewal investments required to replace end of TUL assets, assets in deteriorating condition including high failure risk assets and/or asset failure;

- System Service investments such as operational technologies and grid modernization;
- General Plant investments to meet the facilities, fleet, office systems and IT needs including the acquisition of the Customer Information System (CIS).

OPUCN forecast period expenditures represent a consistent average total budget envelope across the planning period, balancing annual variations in anticipated mandatory System Access work and other mandatory projects with changes in the other three investment categories. The utility can usually pace and prioritize with a greater degree of control – thus facilitating the overall smoothness and predictability of rate changes over the plan timeline.

The capital investment plan was developed to ensure that the system has sufficient resilience and flexibility to achieve a safe and reliable distribution system performance. Additional key elements are described in the following:

Condition Assessment

OPUCN has identified a need to proactively manage the replacement of assets that are at, or near, end of TUL and in “poor” or “very poor” condition. An Asset Condition Assessment (ACA) located in Appendix B was completed in 2019 by METSCO Energy Solutions Inc. (METSCO), an independent consultant, assessing the condition of the classes of distribution and station assets owned by OPUCN. This condition-based assessment report identifies critical or poor condition assets that need to be replaced to avoid risk of in service failure that would cause unacceptable customer impacts. The report provides a proposed replacement plan which also considers the TUL of an asset with due consideration for assets that represent a high risk of failure. Line renewal and replacement programs covering a multiyear period have been developed to deal with key assets at end of TUL or assets in “poor” or “very poor” condition. Replacement plans ensure that planning objectives related to reliability, customer satisfaction and operating cost control are achieved.

Identified assets requiring replacement are captured under System Renewal investments. These investments are generally assets requiring replacement due to condition and risk. If the investments are not completed at an optimal time there is an inherent risk of outages due to equipment failure which would affect current reliability performance. OPUCN’s objective is to ensure that the future distribution system is designed to deliver reliable power desired by customers and to minimize the lifetime cost by considering preventative maintenance, life-extending refurbishment, and end-of life replacement. The System Renewal spending is paced throughout the forecast period to accommodate annual spending variances in the other investment categories to maintain overall consistent budget envelope spending. OPUCN’s continued investment in replacement programs should maintain current reliability performance and mitigate risk of significant asset failures.

Reliability Performance

Improving and maintaining a level of reliability performance is one of the key elements of this DSP which is in line with OPUCN’s AM objectives. OPUCN experienced variations in both SAIDI and SAIFI during the historic period from 2015 to 2019 where service reliability levels were underperforming in certain years as compared to the SAIDI and SAIFI target.
One of the main contributing factors to unreliability was equipment failures which represents on average 36% of SAIDI and 30% of SAIFI over the past 5 years. The equipment has been identified in the ACA and includes a significant amount aging infrastructure built using standards and construction material available at the time of initial construction. Furthermore, particular

attention in the ACA was given to equipment presenting highest reliability risks, such as substation assets. To address identified reliability concerns, OPUCN intends to focus on paced System Renewal investments and specific System Service investments to bring the reliability indices in line with the expectations of both OPUCN's customers and the OEB. This focus is supported by OPUCN's customer feedback results obtain during the rate application process. Customers predominantly stressed the need for reliable service, and therefore OPUCN is focusing on those capital investments that produce reliable and consistent energy. These investments will help continue reducing number of system outages and will provide opportunities for improved efficiencies.

Customer and Load Growth

Based on OPUCN's consultations with the City of Oshawa and Durham Region, OPUCN expects its customer base to continue to increase over the next five years. This growth rate was predicted in the previous DSP but due to some delay in developments, the growth rate will also affect this planning period. OPUCN's consultations and forecast confirm, on average, a projected annual customer connection growth rate of approximately 1.4%, which is slightly lower than annual customer growth rate from 2015 through 2019 but still higher than historical level. The projected rate of customer connection growth is supported by the increase in issued building permits and evidence of several major residential and commercial real estate developments currently in planning and construction stages.

The City of Oshawa published a 2019 total building permit value of approximately $400 million with industrial development driving economic growth in 2019. Based on the current development information from the City of Oshawa, OPUCN has projected customer connection growth of additional 12,755 residential units by 2029.

The demonstrated increase in large residential subdivisions and commercial developments, especially along the extended 407 corridor and Kedron II planning area, has led OPUCN to coordinate the building of new substations including a new OPUCN distribution substation, MS9, and Hydro One Networks Inc. (Hydro One) owned Transmission Station (TS), Enfield TS to address ongoing and future customer load requirements. These projects have been completed in the previous planning cycle and no additional feeder projects were identified as of yet in the forecast period, however, "Connections" and "Expansions" capital expenditure may be impacted as a result of the customer load growth.

Grid Modernization and Cybersecurity

Grid modernization will continue to advance as OPUCN continues to invest in activities such as communication infrastructure, metering, distribution system monitoring, automated switches, Operational Technology (OT) and Information Technology (IT) systems to meet reliability performance expectations and cybersecurity requirements. Given the current technology available, customers are now expecting electrical utilities to minimize service disruptions and better manage outage duration, impact and communications. OPUCN plans to continue and accelerate System Service investments including installation of grid modernizing devices and equipment to allow remote automated switching and fault isolation to reduce restoration time and outage impact on customers. OPUCN will update its IT systems to the latest system version and ensure that all systems and equipment that will be in place are compliant with the cybersecurity framework and requirements. Advanced technology with intelligent devices and management systems will also enable OPUCN to operate a "smarter grid" that will have better visibility and operational flexibility.

Customer Service

Customer service enhancement is one of the key elements of this DSP aimed at addressing customer preferences in providing several secure communication channels to meet the need to improve the customer experience. After carefully assessing customer feedback describing desired communication services OPUCN investigated potential solutions that would meet our customers' needs. OPUCN selected a Customer Self-Serve Online Portal that has existed in the electrical industry already and has been proven to be reliable, intuitive, and easy to use to meets our customers' requests. The new portal will allow customers the ability to log into a secure portal to view balances, due dates, bills as well as smart meter activity and predicted bill statistics. Customers can self-select communication preferences by method and reason and manage their own privacy settings. The new portal will be directly connected to OPUCN's current website and will be seamless to the customer to navigate from one to the other. OPUCN will continue to invest in this type of General Plant project that will enhance customer experience and improve business efficiencies and effectiveness including the in-house acquisition of a Customer Information System (CIS). Acquiring a CIS and hosting in-house will allow OPUCN full control of the system and configurations, mitigating the risk of being heavily reliant on a third party vendor.

5.2.1.b Customer Preferences Overview

OPUCN conducts customer surveys approximately every two years targeting residential and small commercial customers. Beginning in 2014, with the help of an external consultant, Utility*PULSE*, OPUCN augmented their regular telephone-based Customer Satisfaction survey with supplemental questions to help gain insights into, or deal with, issues customers care about. The outcomes of these engagement sessions provide a list of customer preferences that is being factored in the AM process in order to maintain a sustainable, reliable and cost efficient distribution system that meets or exceeds customer expectations. Please refer to Table 2 that provides customer preferences by priorities.

Results shows that 95% of the respondents support continuously improving the safety and reliability of the electricity network, 95% remain focused on keeping costs low, and 92% support looking for ways to use technology to safeguard the electricity network or get more out of the equipment. These preferences are consistent with most surveys in finding a balance between keeping costs low and having reliable service. The goal of OPUCN is to invest in projects or programs that will improve the safety and reliability of the distribution system. In order to optimize cost, the capital expenditure plan leverages the AM process to ensure spending levels are appropriately smoothed to match customer expectations with respect to efficiently balancing the risk of unplanned outages with costs.

As an OPUCN customer could you tell us how important each of the following items is to you?			
Top 2 boxes 'Very + Somewhat important'	**OPUCN 2019**	**OPUCN 2018**	**OPUCN 2014**
Continuously improve the safety and reliability of the electricity network	95%	91%	86%
Remain focused on keeping costs low	95%		
Reduce response times to outages	94%	86%	80%
Look for ways to use technology to safeguard the electricity network or get more out of the equipment	92%	91%	
Provide good jobs in the community	91%		
Improve customer service	88%		
Invest in green energy technologies (energy storage, electric vehicles, etc.)	88%		
Invest in smart grid technologies (system automation)	88%	83%	75%
Invest in projects to reduce the environmental impact of the utility's operations	88%	76%	
Improve communications for billing and outages	87%	50%	
Educate the public as it relates to electricity safety	84%	73%	
Investing more in tree trimming to help reduce the number of outages		78%	68%
Provide more self-serve options on the website	78%	44%	40%
Provide sponsorships to support local programs and events	76%	48%	45%
Develop a smartphone application to allow you to view your electricity use and pay your bill	75%	50%	37%
Burying Overhead wires		64%	62%
Make better use of social media such as twitter	62%	29%	33%

Table 2: Customer Preferences and Priorities

Overall, there is a strong support for OPUCN's proposed capital investment plan. Appendix C contains the detailed results from OPUCN's efforts in engaging with the customer in identifying their needs and preferences including a full summary of OPUCN's Engagement and a report on Taking A.I.M. Survey results.

5.2.1.c Anticipated Sources of Cost Savings

OPUCN's planning and investment processes follow Good Utility Practices that are communicated through the DSP which includes adherence to the OEB's Distribution System Code (DSC) that sets out minimum performance standards for electricity distribution systems in Ontario, and minimum inspection requirements for distribution equipment. The following practices and activities are expected to produce cost savings over the forecast period:

- Proactive or planned replacement of vital distribution system assets exhibiting poor condition or high risk assets reduces reactive maintenance costs and improves service to the customer, resulting in fewer and shorter outages, which in turn has a beneficial impact on the cost of outages to customers. The timing of replacing assets is also established according to economic end of TUL.
- Using economy of scale and when possible, capital investments in the same area are

identified and assets are grouped together to form a program that will provide the most cost-effective solution. An example of this is renewing an entire subdivision in one year as opposed to individual streets over many years provides the optimal design and minimizes construction costs by reducing crew/equipment mobilization activities and by streamlining project planning and work execution. Savings are built into the forecast amounts.

- Continued maintenance and update of OT systems including, but not limited to, the Outage Management System (OMS) and Supervisory Control and Data Acquisition (SCADA) will improve situational awareness by having reliable data during outage events. This allows OPUCN to respond quickly and efficiently to outage events by restoring electricity service to affected customers more quickly than is currently possible.
- Improved use of the Geographic Information System (GIS) to capture and access the distribution system asset information is expected to aid in cost control. By providing the most up-to-date data to engineering and operations department more accurate long-term and short-term decision-making can take place.
- A new web based estimating and job management tool, Quadra, is currently being utilized by OPUCN that provides improved estimation when used for proposing overhead and underground line renewal projects. This enables better estimation and improves the forecasted capital expenditures.
- Utility relocation projects and other underground and overhead reconstruction projects described in this DSP are coordinated with regional and municipal roadway construction schedules to ensure that the potential scope and timelines are optimized. The anticipated savings are built into the forecast amounts.
- Prudent investment in distribution automation such as remote controlled and self-healing switches, monitoring equipment and smart grid devices as part of grid modernization are expected to improve situational awareness, shorten response time, reduce truck rolls, and outage restoration times.
- OPUCN’s new Computerized Maintenance Management Software (CMMS) will optimize the asset condition inspection and maintenance schedule which provides a better understanding of each asset’s stage in its lifecycle and will lead to more cost-effective decisions with respect to maintenance, refurbishment and replacement decisions. This recent application software will be adopted by OPUCN starting in 2020.

5.2.1.d Period Covered by DSP

The duration of this DSP covers eleven years comprising of a six-year historical period of 2015 to 2020, where 2020 is the Bridge Year, and a five-year forecast period of 2021 to 2025, where 2021 is the Test Year.

5.2.1.e Vintage of the Information

ACA described in Section 5.3 Asset Management Process was finalized on April 2019 using asset data compiled as of December 31, 2017.

Unless otherwise noted, all information contained in the DSP is current as of December 31, 2019.

5.2.1.f Important Changes to Asset Management Process

Supporting documentation used in the AM process in this DSP is consistent with the previous DSP (i.e. ACA, Grid Modernization Plan, Regional Planning, etc); however, there are significant improvements and changes in the data and methodology utilized including the following:

Enhanced Asset Data Quality

- In addition to service age, visual inspection and maintenance records, OPUCN incorporated transformer loading information, pole testing data, updated GIS information providing location and attributes of assets during ACA.
- Reclosers, smart switches, elbows and padmounted switchgears are additional assets included in the ACA.
- OEB's Asset Depreciation Study has been used as a reference in determining the TUL of each asset in developing replacement plan.

Improved Analytic Tools

- Reliable outage data from the OMS are now utilized which provides better and accurate information during an outage event. This also assists engineering and operations in analyzing outage cause and reliability impacts that drive the AM process.
- In determining the System Renewal investment plan for overhead and underground, OPUCN utilizes a GIS application software, GeoMedia, in creating a heat map that would determine "hot spots" representing assets that are in "poor" or "very poor" condition. Using this information, these assets are grouped together to optimize design in forming a planned overhead or underground line renewal program.
- A new web based estimating and job management tool, Quadra, is currently being utilized by OPUCN that provides improved estimation when used for proposing overhead and underground line renewal projects. This provides better estimation and improves the forecasted capital expenditures.
- PI System is a data historian used by OPUCN to determine loading of in-field transformers. The information collected is used in condition assessments and identification of transformers that are critically overloaded.
- Kinetiq is a software platform providing loading and generation information that is used in OPUCN's capacity assessments. Results of the assessments are used in Regional Planning and identifying wired and non-wired solutions on a distribution level.

Process Change

In the previous DSP, OPUCN assessed investments based on risk probability and risk consequences. Higher consequence and probability projects receive a higher implementation priority. In this DSP, OPUCN further improved the process used to support the level of investments and prioritization of investments. Investments for all categories are also prioritized based on meeting AM objectives and mandatory project requirements. Furthermore, investments within the same categories are prioritized based on ACA for System Renewal investments or Grid Modernization Plan priority assessment for System Service investments. The capital investment plan must also remain within the total budget envelope across the planning period where each investment can be assessed for any change requirements and risk associated with the change. This facilitates the overall smoothness and predictability of rate changes over the plan timeline.

Investment Category Assignment Change

OT related projects including upgrades to OMS, Operational Data Store (ODS) and GIS have been relocated from the General Plant investment category to the System Service investment category. These projects have been identified as operational and design systems projects that meet the operational objectives of OPUCN.

5.2.1.g DSP Contingencies

There are certain aspects of this DSP that are contingent upon the ongoing and future activities in the OPUCN service territory including the following:

Customer Connections and Expansions

OPUCN forecasts a growth rate in service connections of approximately 1.4% annually over the five-year period. As a result, OPUCN's capital investment plan includes projects related to customer connections and expansions, including new revenue metering requirements. These investments and their timing are contingent on the advancement of the developments anticipated by the planning authorities consulted and the reality of homes and commercial units being constructed and sold. Variances in connection timing/quantity over the period of the DSP will also impact actual connections and related System Access expenditures.

Road Authority Driven Utility Relocation

The Region of Durham and City of Oshawa carry out road resurfacing and other types of roadway improvements on an annual basis and OPUCN receives requests for utility relocations. Historically, although high-level plans are identified, actual implementation does not materialize precisely as planned. This type of expenditure is mandatory and is driven by the Region and the City schedules. OPUCN can only include in its DSP the locations and high-level designs identified by these regional and municipal agencies. Actual annual expenditures and contributions will be dependent on final designs and work schedules.

True-Up Costs for Enfield TS

In order to address the overloading condition of neighbouring TSs and load growth, it was identified in the previous Regional Planning process to build a new TS, Enfield TS. This Hydro One TS was put into service on March 2019 and serves as a third point of supply for OPUCN. A Connection Cost Recovery Agreement (CCRA) was established between OPUCN and Hydro One in May, 2017 for this project and the initial capital contribution was calculated based on a load forecast (guaranteed load) at that time. However, if the forecasted load does not materialize from 2020 to 2025, additional capital contribution may be applied during the true-up periods (5^{th} – 2024, 10^{th} – 2029 and 15^{th} – 2034 anniversary of the in-service date). OPUCN has not included any additional capital contributions in the capital investment plan, as this information is contingent upon future load growth and weather conditions. OPUCN will opt to apply for an Incremental Capital Module (ICM) rate application if required at an opportune time.

Future Distribution Infrastructure Requirements

The General Motors (GM) plant in Oshawa is currently being supplied directly by Hydro One from Oshawa GM TS but as a result of GM shutting down its production, existing buildings and land may be repurposed in the future that would require electric supply service from OPUCN. OPUCN will require additional distribution and/or substation infrastructure in order to provide the service requirements of future customers occupying the repurposed building and land. This requirement is contingent upon future City planning activities and development. OPUCN will opt to apply for an ICM rate application if this will be required.

5.2.1.h Grid Modernization, Distributed Energy Resources & Climate Change Adaptation

There are a number of projects OPUCN will be implementing to meet the goals of Ontario's 2017 Long Term Energy Plan. OPUCN will be focusing on using innovation to meet future goals, empowering consumers with access to data and tools, and reducing carbon usage in operations.

Municipal Substation Network Cybersecurity Upgrade

Data for the smart grid is sent through OPUCN's communication infrastructure between sensors, switches, the control room and other devices. OPUCN will be improving the OT cybersecurity through security measures as indicated in "OEB's Cybersecurity Framework." Not only will this increase cybersecurity but also improve data bandwidth and reduce communication latencies for OT devices and other smart grid devices. This project looks to "invest in innovative solutions that make their systems more efficient, reliable, and cost-effective" (refer to Long Term Energy Plan, Chapter 3, Summary) and "ensure cyber security is being addressed in the electricity system and that there is appropriate regulatory oversight to mitigate cyber risks and threats" (refer to 2017 Long Term Energy Plan, *Chapter 4*, Cyber Security).

GIS, OMS, ODS Software Update

OPUCN will be updating existing GIS, OMS, ODS software to current packages, and align with Microsoft upgrades to maintain security of the system. OPUCN will be upgrading existing powerful software to extend functionality to analyze data and use information to make the network more efficient and reliable. This project looks to "invest in innovative solutions that make their systems more efficient, reliable, and cost-effective" (refer to Long Term Energy Plan, Chapter 3, Summary).

Advanced Metering Infrastructure (AMI) System Update

OPUCN will be replacing all failed smart meters that are currently in service with the next generation of meters. The replacement program includes upgrading the AMI data collector units and communication to provide faster and more reliable data transmission. These upgrades along with Green Button Dashboard and ODS software update will provide customers with near real-time consumption data access. This project is directly linked to Ontario's 2017 Long Term Energy Plan in providing choice through information, tools and access to energy data (refer to 2017 Long Term Energy Plan, Chapter 5, Providing Choice Through Information, Tools and Access to Energy Data).

Customer Self-Serve Online Portal (Green Button Dashboard)

OPUCN will implement an enhanced self-service tool that will allow customers the ability to log into a secure portal to view balances, due dates, bills as well as smart meter activity and predicted bill statistics. The software has the ability to provide current alerts based on customer settings including bill/usage thresholds, high usage and other configurable options. This project is directly linked to Ontario's 2017 Long Term Energy Plan in providing choice through information, tools and access to energy data (refer to 2017 Long Term Energy Plan, Chapter 5, Providing Choice Through Information, Tools and Access to Energy Data).

Deployment of Centralized Automation Controller, Smart Fault Indicators, Lateral Reclosers & IEDs

A Centralized Automation Controller will be installed to enable Fault Locating, Isolation and System Restoration (FLISR) across multiple Intelligent Electronic Devices (IED) and remote switches. The Centralized Automation Controller will leverage on a powerful software platform to analyze data from IEDs and remote switches to perform fast automatic outage restoration. IEDs will be used to extend visibility of the electrical distribution system. This project looks to "invest in innovative solutions that make their systems more efficient, reliable, and cost-effective" (refer to Long Term Energy Plan, Chapter 3, Summary).

Municipal Substation Transformer Monitoring and Telemetry

OPUCN will be installing transformer monitoring systems which detect the amount of dissolved gasses in the Municipal Substation (MS) power transformers to determine its real-time condition. Based on the amount of dissolved gasses and associated information, the probability of transformer failure can also be assessed. This project looks into using new technology in grid modernization to extend the use of sensors to reduce truck rolls (carbon footprint) to perform oil sampling and provide greater visibility on probability of failure of Municipal Substation transformers. This project looks to "invest in innovative solutions that make their systems more efficient, reliable, and cost-effective" (see Long Term Energy Plan, Chapter 3, Summary).

Expansion of Overhead Automated Switching & SCADA Operated 44kV Overhead Switches

Automated switches will be installed replacing existing manual switches. Automated switches will have FLISR capabilities that will make the system more efficient and reliable. Both automated switches and remote 44kV operated switches will reduce truck rolls, reducing carbon footprint in operations. This project looks to "invest in innovative solutions that make their systems more efficient, reliable, and cost-effective" (refer to Long Term Energy Plan, Chapter 3, Summary).

Municipal Substation Battery and Battery Charger Replacement

OPUCN will be installing battery condition monitoring systems as the batteries and battery chargers are renewed. The control operators will be able to determine the real-time condition of the batteries and the information gathered can be used to assess associated probability of failure. This project looks into using new technology in grid modernization to extend the use of sensors to reduce truck rolls (carbon footprint) to perform corrective maintenance and provide greater visibility on the probability of failure of MS back-up control power. This project looks to "invest in innovative solutions that make their systems more efficient, reliable, and cost-effective" (refer to Long Term Energy Plan, Chapter 3, Summary).

5.2.2 Coordinated Planning with Third Parties

The following outlines how OPUCN has coordinated construction planning with customers, developers, municipal and provincial governments, Hydro One, other Local Distribution Companies (LDC) through Regional Planning process and the Independent Electricity System Operator (IESO). This DSP is informed using engagement with all of these major stakeholders. This section will also explain the types of consultation, the role of OPUCN, indicate the participants involved, and identifies the final deliverables of the planning activity, if any.

As part of the requirements to demonstrate and document OPUCN's coordinated planning during the development of this DSP, the details of the formal engagements with the following major third parties are described below:

- Customer Engagement;
- Regional Planning with Hydro One and other LDCs;
- Regional and Municipal Government consultation;
- Metrolinx consultation; and
- Renewable Energy Generation (REG) planning with the IESO.

Customer Engagement

OPUCN seeks regular feedback from its customers to ensure that their overall experience is positive and to receive any constructive suggestions on areas where OPUCN could improve. These consultations include:

- Surveys;
- Website interaction;
- Community meetings and events; and
- Construction notice communication.

OPUCN conducts customer surveys targeting residential and small commercial customers approximately every two years. As referred to in Section 5.2.1.b, UtilityPULSE assisted OPUCN in augmenting a telephone-based customer satisfaction survey that helped gain insights into, or deal with issues customers care about.

OPUCN posts on its website a listing of its capital investment projects and the vegetation control areas for the coming year. OPUCN has posted its planned System Renewal capital projects up to 2022. This allows OPUCN customers to review the proposed projects and submit their concerns or questions to OPUCN. Any customer feedback or concerns are reviewed, and responses provided accordingly.

OPUCN hosted several in-person initiatives including open houses, information sessions and a virtual telephone town hall to educate and inform customers about the rate application process and the DSP. OPUCN's senior executive team hosted all of the in-person outreach and customers were able to have open interactive dialogue with the team. Participants had the opportunity to provide feedback on the DSP and request contact from OPUCN to further discuss questions or concerns.

OPUCN took efforts to engage the local contractor and developer community with the goal to keep them up-to-date on safety, incentives and opportunities. OPUCN created a dedicated webpage "Contractor's Corner" for developers and contractors to find guidelines, specifications, and service applications. Centralizing the information simplified the contractor's process and streamlined the service application process. In 2018, OPUCN hosted Contractor Safety Day and their first Developer Information Conference to review connection processes. Compared to 2018, attendance doubled at the 2019 Contractor Safety Day where the team was able to expand by educating contractors on how to safely work around OPUCN's infrastructure.

OPUCN provides advance notice to customers advising them of upcoming overhead or underground rebuilds in their area or neighbourhood, including any planned outages. Any questions or concerns (for example, the location of the proposed poles or pad-mount type transformers) are normally resolved directly with the customers.

OPUCN continues to meet with its major customers (e.g. Ontario Tech University, Lakeridge Health Centre, Oshawa Center, etc.) and key developers (e.g. Tribute Homes, Panatonni Development Company, Sorbora, Podium Development), to provide ongoing updates, account related consultation, and service related consultation on their project plans and future developments.

Overall, the outcomes of these engagement sessions provide information on customer preferences that is being factored in the DSP and embedded within OPUCN's AM objectives in order to maintain a sustainable, reliable and cost efficient distribution system that meets or exceeds customer expectations. Appendix C contains the detailed results from OPUCN's efforts in engaging with the customers in identifying their needs and preferences, including a full summary of OPUCN's Customer Engagement and a report on Taking A.I.M. Survey results.

Regional Planning with Hydro One and other LDCs

The purpose of the regional planning process is to assess and identify electrical infrastructure needs in the region. OPUCN is part of the GTA East region (refer to Figure 1) which includes municipalities of Oshawa, Clarington, Pickering, Ajax and Whitby supplied by OPUCN, Elexicon Energy Inc. and Hydro One. OPUCN participated in the Needs Assessment (NA) meetings initiated and led by Hydro One to determine if Regional Planning including Regional Infrastructure Plan (RIP) or Integrated Regional Resource Plan (IRRP) are required. Upon submission of the updated load forecast and LDCs' planning information, the NA report was completed and published on August 15th, 2019. The report concluded that the capacity needs identified in the previous planning cycle have already been addressed or will be addressed by Enfield TS and Seaton MTS. This was further supported by the RIP report published on February 29th, 2020 and shown in Appendix D. No additional regional coordination is required at this time, however, the following asset replacements were recommended:

- Cherrywood TS – 230kV and 500kV Breaker Replacement (Multi-Phase Projects)
- Cherrywood TS – LV DESN Switchyard Refurbishment
- Wilson TS – T1/T2 Replacement and Switchyard Refurbishment

The anticipated impact of the above projects on OPUCN's distribution system is an increased reliability and power transfer capability at the transmission level. The cost associated with these projects do not have any direct implication on OPUCN's DSP investments as these costs will be incurred by Hydro One.

Figure 1: Map of GTA East Planning Region (Source: IESO)

The Planning Status Letter is also attached in Appendix E, which further describes in the detail the plan for the GTA East region. Please also refer to Appendix D for OPUCN's submitted load forecast, NA report and RIP report.

Regional and Municipal Governments Consultation

To assist OPUCN with its asset management and system capacity planning, OPUCN attends a quarterly Oshawa Municipal Services Coordination Committee (OMSCC) meeting (refer to Appendix F showing a sample agenda of the meeting) initiated by the City of Oshawa. Attendees of this meeting include the Durham Region (Region), the City of Oshawa (City), Enbridge Gas, telecommunication companies including Rogers Communications and Bell, and any other relevant utility operating within city limits. OPUCN and other members of the OMSCC are subject to providing to the OMSCC detailed updates of all current and future construction plans during every meeting. Where relocation projects are identified, additional detailed utility coordination meetings are held as required by the driver of the project. Due to the detail that these meetings require, they are kept separate from the OMSCC.

OPUCN monitors the Region and City construction work schedules in order to, where possible, co-ordinate its own work and project completion schedules with those of the Region and the City in order to avoid conflicts and unnecessary inconvenience to customers, especially businesses in the downtown area, and to minimize costs where possible.

Utility relocation projects and other underground and overhead reconstruction projects described in this DSP were developed directly through the consideration of regional and municipal roadway construction schedules. By attending the OMSCC meetings, OPUCN was able to have visibility into the potential scope and timeline of upcoming utility relocation projects to effectively plan its work for the forecast period.

Metrolinx Consultations

Metrolinx plans to undertake rail reconstruction along its Lakeshore East line from Oshawa to Bowmanville. Indicated in the Public Meeting #1 Notice in Appendix G, the proposed changes could include new track realignment, new or adjusted crossings, and additional stations or refinements to station design. These activities could impact OPUCN in several ways, including:

- Any new stations planned in the OPUCN service territory will require servicing and possible plant relocation;
- Track realignment and new or adjusted crossings will require plant relocations or reconstruction to meet minimum clearance requirements.

There has been no new information from Metrolinx since detailed planning has not commenced. Therefore, the specific future cost impacts have not been identified in this DSP because they are unknown with no specific planning year. If these investments materialize during this planning period, OPUCN will assess if there are any cost impacts at the time of request and will opt to apply for an ICM rate application if required at a future time.

Renewable Energy Generation (REG) Consultation

OPUCN has initiated the REG consultation and prepared the REG investment plan (see Appendix H) with the primary purpose of sharing information with IESO and coordination of REG connections. The REG investment plan was submitted to IESO for review on February 6th, 2020. An IESO response (see Appendix I) was provided to OPUCN on February 24th, 2020 confirming that the plan is consistent with the regional planning work in the GTA East Region in which no immediate needs were identified to warrant REG investments.

Further, no capacity requirements or system constraints were identified for the OPUCN distribution system to accommodate the potential connection of REGs, and therefore, OPUCN is not proposing any immediate planned capital expansions or enhancement investments related to these connections for this planning period. The IESO has acknowledged that this is consistent with the IESO's information regarding REG applications to date and the regional planning process.

5.2.3 Performance Measurement for Continuous Improvement

5.2.3.b Appendix 5-A

The following provides unit cost metrics for capital expenditures and O&M per customer, kilometer of line, and peak capacity. Note that 1-Year in the following Table 3 refers to 2019 and 5-Year refers to the period 2015-2019. The year 2020, which is by definition is within the historical period, was omitted from this analysis as the actual data for this year was not available.

Appendix 5-A
Metrics

Metric Category	Metric	Measures	
		1 Year	5 Year Average
Cost	**Total Cost per Customer[1]**	$ 442	$ 276
	Total Cost per km of Line[2]	$ 25,984	$ 16,305
	Total Cost per MW[3]	$ 146,899	$ 85,970
CAPEX	**Total CAPEX per Customer**	$ 391	$ 225
	Total CAPEX per km of Line	$ 23,000	$ 13,297
O&M	**Total O&M per Customer**	$ 51	$ 51
	Total O&M per km of Line	$ 2,984	$ 3,009

Notes to the Table:

1 The Total Cost per Customer is the sum of a distributor's capital and O&M costs divided by the total number of customers that the distributor serves.
2 The Total Cost per km of Line is the sum of a distributor's capital and O&M costs divided by the total number of kilometers of line that the distributor
3 The Total Cost per MW is the sum of the distributor's capital and O&M costs divided by the total peak MW that the distributor serves.

Explanatory Notes on Adverse Deviations (complete only if applicable)

Metric Name: **Total Cost per KM of Line and per Customer**

2019 cost per customer is higher than the five year average due to the growth in capital cost (new municipal substation)
2019 cost per circuit km of line is higher than the five year average for same reason as noted above. Much higher capital spent in 2019 compared to 2015

Metric Name: **Total CAPEX per KM of Line, per Customer, and per MW peak**

2019 values for Capex per customer and per km of line exceed the average as 2019 included substation build. See explanation above

Metric Name: **Total O&M per KM of Line and per Customer**

O&M costs in 2019 reflect the 5 year average. Little movement.

Table 3: Appendix 5-A

The following describes the methods and measures (metrics) used to monitor distribution system planning process performance including a description of the purpose, form and motivation. The performance measures used by OPUCN are aligned with OEB requirements for continuous improvement and are divided into three general groups:

1. Customer Oriented Performance
2. Cost Efficiency and Effectiveness
3. Asset and/or System Operations Performance

The performance measures included on the scorecard have an established minimum level of performance expected to be achieved. The scorecard is also used to continuously improve AM and capital planning process. OPUCN's current performance state is represented by OPUCN's official scorecard results as published by OEB. The scorecard is designed to track and show OPUCN's performance results over time and helps to clearly benchmark its performance and improvement against other utilities and best practices.

Each metric provided in the table and subsections below, influences OPUCN's decision making to achieve the best performance for its customers. The following sections address performance metrics as published by the OEB in the performance scorecard. Additionally, each performance measure has OPUCN's target on delivering the target within this DSP. OPUCN's scorecard published in 2019 is shown in Appendix J.

Performance Outcomes	Measure	Driver	Metric	OPUCN Target	OEB Targets
Customer oriented Performance	Service Quality	Regulatory/ Consumer	New Residential/Small Business Services Connected on Time	100% in 2 days	90% in 5 days
			Scheduled Appointments Met on Time	100%	90%
			Telephone Calls Answered on Time	>92%	65%
			Written Response to Enquiries	100% in 1 business day	98%
	Customer Satisfaction	Customer	First Contact Resolution	Less than 2% of qualifying calls	n/a
			Billing Accuracy	>98%	>98%
			Customer Satisfaction Survey	>90%	n/a
	System Reliability	Regulatory/ Customer	SAIDI	Previous 5-year rolling average	Historic 5-year 2010-2014 average (1.18)
			SAIFI	Previous 5-year rolling average	Historic 5-year 2010-2014 average (1.06)
Cost efficiency and effectiveness	Cost Control	Regulatory/ Customer/ Corporate	Efficiency Assessment	Group 2	n/a
	Distribution System Plan Implementation Progress	Corporate/ Regulatory	Program Delivery Cost	Within 5% of budget	n/a
Asset/system operations performance	Safety	Regulatory/ Corporate	Level of Public Awareness	>80%	n/a
			Level of Compliance with Ontario Regulation 22/04	0 NC; 0 NI	C
			Serious Electrical Incident Index	0	0
			Lost Time Injuries	0	n/a
	Distribution Losses	Corporate	Line Losses	<5%	n/a

Table 4: OPUCN Performance Measures and Targets

5.2.3.1 Customer Oriented Performance

Service Quality

5.2.3.a Methods and Measures

The DSC sets the minimum service quality requirements that an LDC must meet in carrying out its obligations to distribute electricity under its license and under the Energy Competition Act, 1998. As required by the OEB, OPUCN records and submits all performance measures, which are compared with the OEB's established levels to evaluate customer service quality. The performance metrics are described below.

New Residential/Small Business Services Connected on Time

A connection for a new service request for a low-voltage (less than 750 V) service must be completed within five (5) business days from the day on which all applicable service conditions are satisfied, or at such a later date as agreed by the customer and the LDC.

Scheduled Appointments Met on Time

When an appointment is either requested by a customer/representative or required by an LDC with a customer/representative, the LDC must offer to schedule the appointment during the LDC's regular hours of operation within a window that is no greater than four (4) hours. The LDC must then arrive for the appointment within the scheduled timeframe. This includes underground locate requests.

Telephone Calls Answered on Time

The OEB requires that qualified incoming calls to an LDC's customer care telephone number must be answered within the thirty-second time period as established below:

1. For qualified incoming calls that are transferred to the LDC's Interactive Voice Response (IVR) system, the thirty (30) seconds shall be counted from the time the customer selects to speak to a customer service representative.
2. In all other cases, the thirty (30) seconds shall be counted from the first ring to the call center queue.

Written Response to Enquiries

A written response to a qualified enquiry shall be sent by an LDC within ten (10) business days.

5.2.3.c Historical Performance

OPUCN sets targets that exceed OEB targets and has consistently exceeded the OEB mandated threshold for service quality as part of the customer focus section of the OEB scorecard as per Table 5. This is reflected in the level of customer satisfaction within OPUCN's service territory. OPUCN's customer service representatives respond to a varying number of phone calls and email requests per year. Answering more than 90% of calls within the 30 second window as prescribed by the OEB. The overall answer rate is well above the industry targets and is indicative of OPUCN's dedication to be an organization focused on customer service.

Table 5 presents the measures for tracking OPUCN's performance in the service quality category.

Measures	2015	2016	2017	2018	2019
New Residential/Small Business Services Connected on Time	95.40%	92.60%	99.47%	99.78%	100.00%
Scheduled Appointments Met on Time	99.60%	100.00%	98.53%	100.00%	100.00%
Telephone Calls Answered on Time	70.20%	73.70%	90.52%	90.10%	94.20%
Written Response to Enquiries	100.00%	99.00%	99.91%	100.00%	100.00%

Table 5: Performance Measures – Service Quality

5.2.3.d Effect of Historical Performance on DSP

OPUCN has exceeded the industry targets for each service quality measure. OPUCN continues to strive to better serve the customer with the highest standards of excellence; and plans General Plant investments that focus on improved and reliable customer service including acquiring a Customer Information System (CIS) that will be hosted in-house, along with an up-to-date customer self-service online portal software.

<u>Customer Satisfaction</u>

5.2.3.a Methods and Measures

OPUCN measures and reports on Customer Satisfaction measures which include: First Contact Resolution, Billing Accuracy and Customer Satisfaction Survey Results. OPUCN uses the OEB Targets for the billing accuracy measure, and has set its own targets for first contact resolution and customer satisfaction.

First Contact Resolution

OPUCN tracks calls where customers' questions were not resolved during their initial call and required a follow-up phone call, or were escalated to a Team Leader, Supervisor or Manager. Out of all incoming qualifying calls, OPUCN targets that less than 2% will not be resolved on first contact.

Billing Accuracy

The DSC sets the minimum service quality requirements that an LDC must meet. This service quality requirement must be met at least 98% of the time on a yearly basis.

Customer Satisfaction Survey

OPUCN undertakes a customer satisfaction survey on a biannual basis to obtain feedback on the overall value of service offered to customers. The latest such survey took place in 2018.

Customers (residential and commercial) are engaged to provide high level feedback on their perceptions of OPUCN's performance and where they think OPUCN could improve service.

This information is extremely useful to help guide future investment planning that will maintain or improve customer satisfaction. OPUCN's target is that greater than >90% of customers are fairly satisfied or very satisfied with their experience with OPUCN.

5.2.3.c Historical Performance

OPUCN has exceeded its target for customer satisfaction as part of the customer focus section of the scorecard and ensures that corporate and AM objectives are aligned with OEB performance outcomes. OPUCN takes efforts to ensure involvement of their customers in discussions to understand their preferences and concerns. Various methods of communication such as telephone or online surveys and telephone or in person public town hall style meetings were used to engage customers.

Measures	2015	2016	2017	2018	2019
First Contact Resolution	0.27%	0.82%	0.48%	0.18%	0.49%
Billing Accuracy	99.93%	100.00%	99.94%	100.00%	99.66%
Customer Satisfaction Survey Results	93.00%	92.00%	92.00%	95.00%	94.60%

Table 6: Performance Measures – Customer Satisfaction

First contact resolutions are measured based on how many interactions required escalation or further investigation in order to be resolved.

Billing accuracy continues to be strong for OPUCN. Historically we run well above the OEB target of 98%. OPUCN has validation points instilled at every point in the billing process to ensure bills are generated accurately.

The Customer Satisfaction Survey results are a combination of the detailed bi-annual telephone survey conducted by UtilityPulse and the customer service “instant” automated survey that customers opt into participating in prior to the beginning of their call in the Customer Service Centre.

5.2.3.d Effect of Historical Performance on DSP

OPUCN conducts telephone customer service satisfaction surveys on a biannual basis and offers their customers an instant survey to evaluate their recent interaction. Surveys show that the customers are very satisfied with OPUCN’s performance and they trust OPUCN. OPUCN reviews the survey results to ensure their plan is still on track and meeting customer’s needs. In general, customer perceptions and attitudes (i.e. reliability, communication preferences) obtained from survey information has been a consideration in the development of the DSP and OPUCN’s overall planning process.

<u>System Reliability</u>

5.2.3.a Methods and Measures

System reliability is an indicator of quality of electricity supply received by the customer. System reliability and performance is monitored via a variety of weekly, monthly, annual and on-demand reports generated by the SCADA system and the OMS.
The reliability of supply is primarily measured by internationally accepted indices SAIDI and SAIFI as defined in the OEB’s Electricity Reporting & Record Keeping Requirements dated May 3, 2016.

SAIDI (System Average Interruption Duration Index)

SAIDI is the length of outage customers experience in the year on average, expressed as hours per customer per year. It is calculated by dividing the total customer hours of sustained interruptions over a given year by the average number of customers served.

SAIFI (System Average Interruption Frequency Index)

SAIFI is the number of interruptions each customer experiences in the year on average, expressed as the number of interruptions per year per customer. It is calculated by dividing the total number of sustained customer interruptions over a given year by the average number of customers. An interruption is considered sustained if it lasts for at least one minute.

Loss of Supply (LOS) outages occur due to problems associated with assets owned by another party other than OPUCN or the bulk electricity supply system. OPUCN tracks SAIDI and SAIFI including and excluding LOS.

Major Events or Major Event Days (MEDs) are calculated using the IEEE Std 1366-2012 methodology. Major Event is defined and confirmed by assessing whether interruption was beyond the control of OPUCN (i.e. force majeure or LOS) and whether the interruption was unforeseeable, unpredictable, unpreventable, or unavoidable.

When a pattern of recurring failures emerges, the Engineering Department is asked to investigate and develop a strategy for improving reliability. Surveys and day-to-day customer feedback indicate that the existing level of service reliability is not, and has not been, a critical issue raised by the public in the OPUCN service area but remains a priority. OPUCN continues to work proactively to monitor the reliability to ensure it does not adversely affect the customers in the service area. The previous 5-year rolling average for SAIDI and SAIFI (excluding LOS and MEDs) are used as default targets for reliability performance expectations in the current year.

5.2.3.c Historical Performance

A summary of service reliability data for the historical period (2015-2019) is provided below in Table 7 and Figure 2 to Figure 3. The summary provides data with respect to three conditions:

- All interruptions
- All interruptions, Excluding “Loss of Supply” and
- All interruptions, Excluding “Loss of Supply” and “Major Events”

Year	SAIDI	SAIFI
All Interruptions		
2015	1.35	2.00
2016	2.61	2.08
2017	0.74	1.17
2018	1.98	1.71
2019	0.98	1.08
5 Year Rolling Average	1.53	1.61
All Interruptions, Excluding Loss of Supply		
2015	1.21	1.27
2016	2.61	2.06
2017	0.73	0.98
2018	1.97	1.64
2019	0.98	1.08
5 Year Rolling Average	1.50	1.41
All Interruptions, Excluding Loss of Supply and Major Events		
2015	1.21	1.27
2016	2.61	2.06
2017	0.73	0.98
2018	1.36	1.29
2019	0.98	1.08
5 Year Rolling Average	1.38	1.34

Table 7: OPUCN Service Reliability Statistics

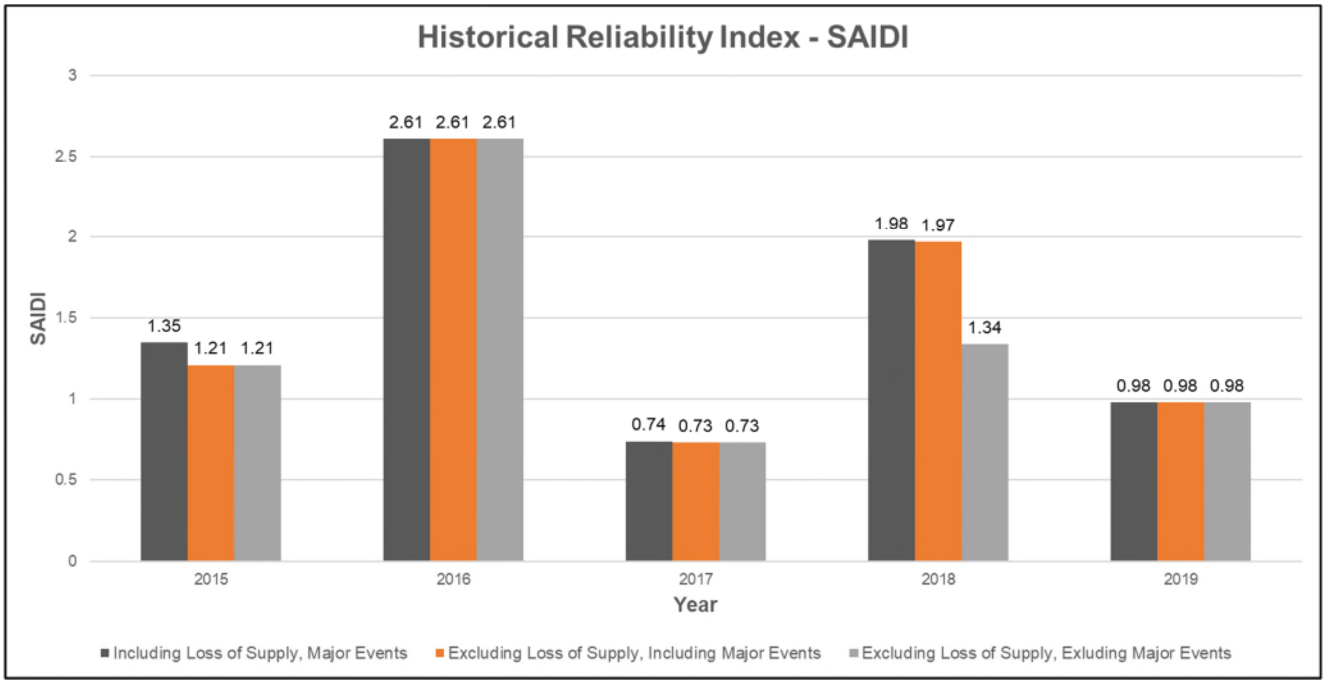


Figure 2: OPUCN Performance Measure – SAIDI

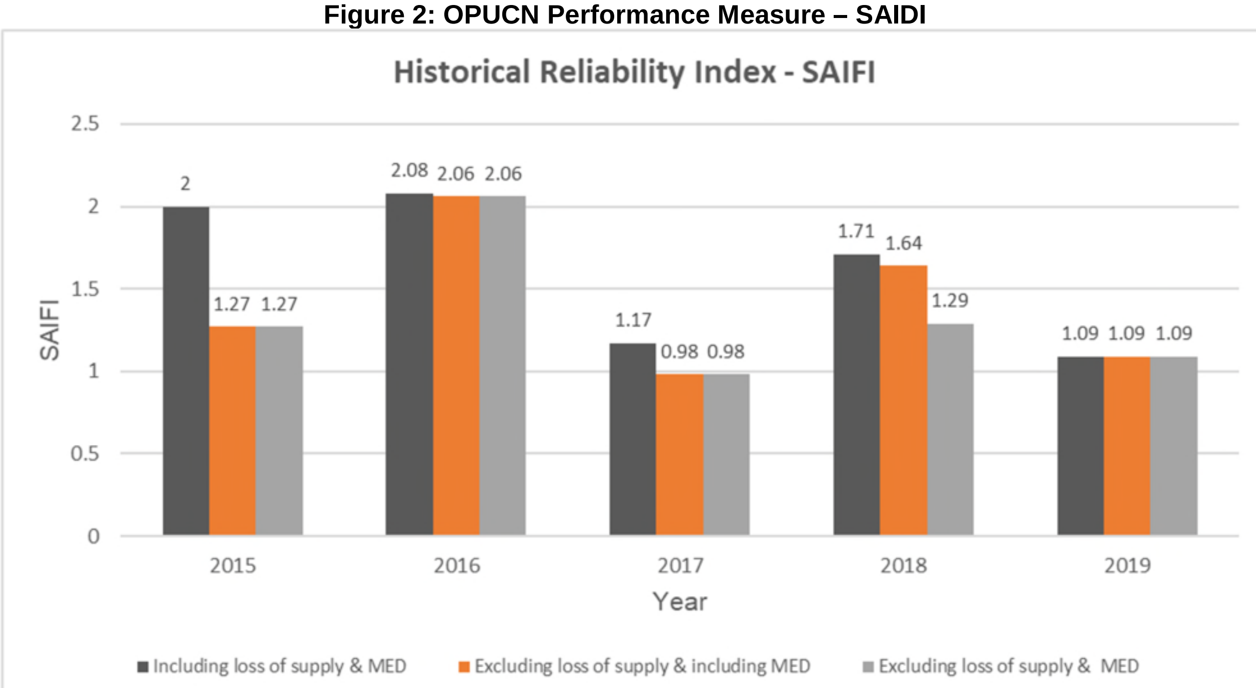


Figure 3: OPUCN Performance Measure – SAIFI

OPUCN experienced variations in both SAIDI and SAIFI during the historic period from 2015 to 2019 with up to 2.61 in SAIDI and 2.06 in SAIFI in 2016 excluding loss of supply and MED. Service reliability performance were underperforming in 2016 compared to the previous 5-year rolling average SAIDI target of 1.45 and SAIFI target of 1.36 primarily due to outages affecting majority of our customer base. OPUCN experienced an outage in 2016 that resulted from a 44kV quick sleeve failure causing a switch to open resulting in approximately 37,000 customers to experience an outage lasting 6 hours. The outage occurred in the evening after work hours and crews had to be called in to make the necessary repairs. In order to address this type of outage in the future, a “44kV Quick Sleeve Replacement Program” has been included in the capital investment plan from 2020-2022. This project will replace existing quick sleeves with permanent sleeves on the 44kV primary overhead conductor lines which will provide better reliability.

In 2018, OPUCN experienced one Major Event on May 4th

- A major windstorm impacted OPUCN’s service territory resulting in numerous sustained and momentary outages. Abnormal high winds/microburst caused 13 poles to snap and break resulting in the loss of two 44kV feeders. Multiple high winds also caused trees to be uprooted and limbs to crash, debris in the air caused two additional 44kV feeders to be removed from service. This event interrupted power to 20,580 customers and caused 35,673 customer-hours of interruptions. The storm impacted 7 distribution feeders and it took approximately 3 hours to restore power to the 90% of the customers impacted.

Major Event Details	2015	2016	2017	2018	2019
Number of Interruptions	-	-	-	**7**	-
6-Adverse Weather	-	-	-	7	-
Number of Customer Interruptions	-	-	-	**20,580**	-
6-Adverse Weather	-	-	-	20,580	-
Number of Customer Hours Interruptions	-	-	-	**35,673**	-
6-Adverse Weather	-	-	-	35,673	-

Table 8: Major Event Details (2015-2019)

The following sections and figures provide the breakdown of historical outages for the years 2015-2019 regarding the number of outages, number of customers interrupted and number of customer hour interruptions. Tracking outage performance by cause code provides valuable information on specific outages that need to be addressed to improve reliability.

Table 9 presents the count of interruptions broken down by the cause codes excluding major events.

Cause Code	2015	2016	2017	2018	2019	Total Outages	Percent Share
0-Unknown/Other	12	23	13	19	17	84	4.21%
1-Scheduled Outage	3	109	269	246	485	1112	55.71%
2-Loss of Supply	3	2	1	1	-	7	0.35%
3-Tree Contacts	9	8	15	15	9	56	2.81%
4-Lightning	-	1	1	3	1	6	0.30%
5-Defective Equipment	75	76	79	88	56	374	18.74%
6-Adverse Weather	7	3	5	13	2	30	1.50%
7-Adverse Environment	-	-	2	7	6	15	0.75%
8-Human Element	2	4	4	5	4	19	0.95%
9-Foreign Interference	60	65	50	59	59	293	14.68%
Total	**171**	**291**	**439**	**456**	**639**	**1,996**	**100%**

Table 9: Number of Interruptions by Cause (2015-2019) – Excluding MEDs

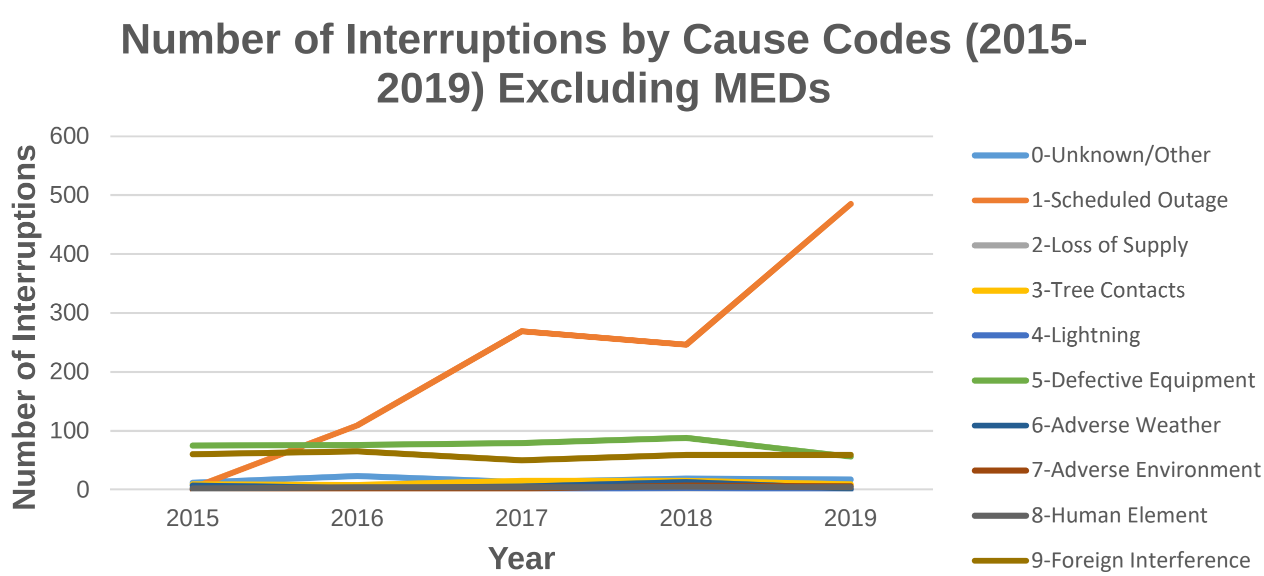


Figure 4: Number of Interruptions by Cause (2015-2019) – Excluding MEDs

The total number of interruptions over the historical period vary from a low 171 to a high of 639 and showing an increasing trend within the period. This represents an average of 0.5 to 1.8 interruptions per day. Scheduled outages show an overall increasing trend as well. This is primarily due to planned outages that were undertaken to accommodate capital overhead and underground rebuild programs. This cause code accounts for the largest number of interruptions (55.71%). However, *Scheduled Outages* is not the largest contributor to number of customers interrupted. This is primarily due to pre-planned outages so that the number of customers impacted is minimal. Scheduled outages are also necessary for OPUCN to safely and effectively maintain and renew the distribution system equipment along with reducing the safety hazard for the workers working around energized circuits. Scheduled outages prevent unexpected system failures that could cause unplanned emergency outages that are often longer and more disruptive.

Although service interruptions due to the *Unknown/Other* cause codes have frequently occurred over the historical period, they typically do not impact OPUCN's reliability performance. By definition, there is inherent uncertainty as to why an outage occurred in the first place. However, it is generally accepted that the likely outage cause is either related to trees contacting the lines and burning away and/or interference from wildlife.

The number of outages associated with *Loss of Supply* is extremely small due to the N-1 redundancy built into the transmission supply system and OPUCN owned MSs. The number of customers impacted by a LOS outage is always the greatest because of the customer count associated with a transformer station versus a feeder or distribution equipment. These outages are mitigated in coordination with Hydro One to reduce the occurrences of operating transformer stations in a non-redundant mode.

The number of outages caused by *Tree Contacts* show a varying trend over the historical period. Tree contact outages are mitigated through effective tree trimming programs to maintain line clearance standards. OPUCN operates a three-year tree trimming cycle to clear trees on primary feeder routes in its service territory. While tree trimming programs help to mitigate outages caused by tree contacts, there are events beyond OPUCN's control that normally occur, such as high winds and freezing rain that can result in trees falling and coming in contact with power lines despite being trimmed to acceptable standards.

The number of outages caused by *Defective Equipment* shows an overall increasing trend over the historical period as a result of being able to capture secondary outages when the OMS was commissioned in 2016. However, it can be inferred from Figure 4 that the number of outages caused by defective equipment including secondary outages has improved in 2019 when compared to 2018. This category is also responsible for the second highest number of outages among the cause code categories. These outages are mitigated through effective maintenance programs and renewal programs.

The number of outages caused by *Adverse Weather* shows an increasing trend in 2018. The increase in 2018 is primarily due to an ice storm that impacted the region on April 15th, 2018. OPUCN also experienced a major event due to the abnormal high winds/microburst on May 4th, 2018 resulting in numerous sustained and momentary outages as a result of the multiple high winds on overhead power lines and trees. This event interrupted power to 20,580 customers and caused 35,673 customer-hours of outage time. In comparison, there were no major storms in 2015, 2016, 2017 and 2019 and weather-related incidents including tree contacts caused significantly fewer power interruptions. These types of outages are unpredictable and difficult to mitigate. Over the 2020-2025 period, OPUCN plans to invest in the overhead line renewal and asset renewal for distribution system hardening. These investments will increase overall system reliability and resiliency in adverse weather conditions.

The number of outages caused by *Adverse Environment* are consistently small and typically do not impact OPUCN's reliability performance while *Human Element* outages show a consistently stable trend during the period of 2015-2019.

Foreign Interference outages is primarily due to motor vehicle accidents and animal contacts. Some of these outages (such as animal contact) are mitigated through installation of non-electric fence at the outdoor MSs and increased use of animal barriers. Other foreign interference outages (e.g. motor vehicle accidents) are more difficult to mitigate but are being tracked.

Customers Interrupted (CI) and Customer Hours Interrupted (CHI)

The number of CI is a measure of the number of customers impacted by the number of interruptions. CHI is a measure of outage duration and the number of customers impacted. The tables and figures below provide the historical values and trends for both CI and CHI.

Cause Code	2015	2016	2017	2018	2019	Total Customers Interrupted	Percent Share
0-Unknown/Other	614	2,930	2,014	8,839	1,316	15,713	3.55%
1-Scheduled Outage	217	2,107	5,422	6,745	4,586	19,077	4.31%
2-Loss of Supply	41,116	1,176	11,218	4,297	-	57,807	13.06%
3-Tree Contacts	3,012	245	3,171	9,153	3,365	18,946	4.28%
4-Lightning	-	57	8,186	1,186	172	9,601	2.17%
5-Defective Equipment	28,414	48,976	12,479	19,873	22,052	131,794	29.77%
6-Adverse Weather	6,429	2,663	260	791	99	10,242	2.31%
7-Adverse Environment	-	-	78	3,436	2,314	5,828	1.32%
8-Human Element	2,561	35,621	11,755	3,477	14,695	68,109	15.38%
9-Foreign Interference	30,062	25,165	12,924	21,542	15,906	105,599	23.85%
Total	**112,425**	**118,940**	**67,507**	**79,339**	**64,505**	**442,716**	**100%**

Table 10: # of Customer Interruptions by Interruption Cause (2015-2019) Excluding MEDs

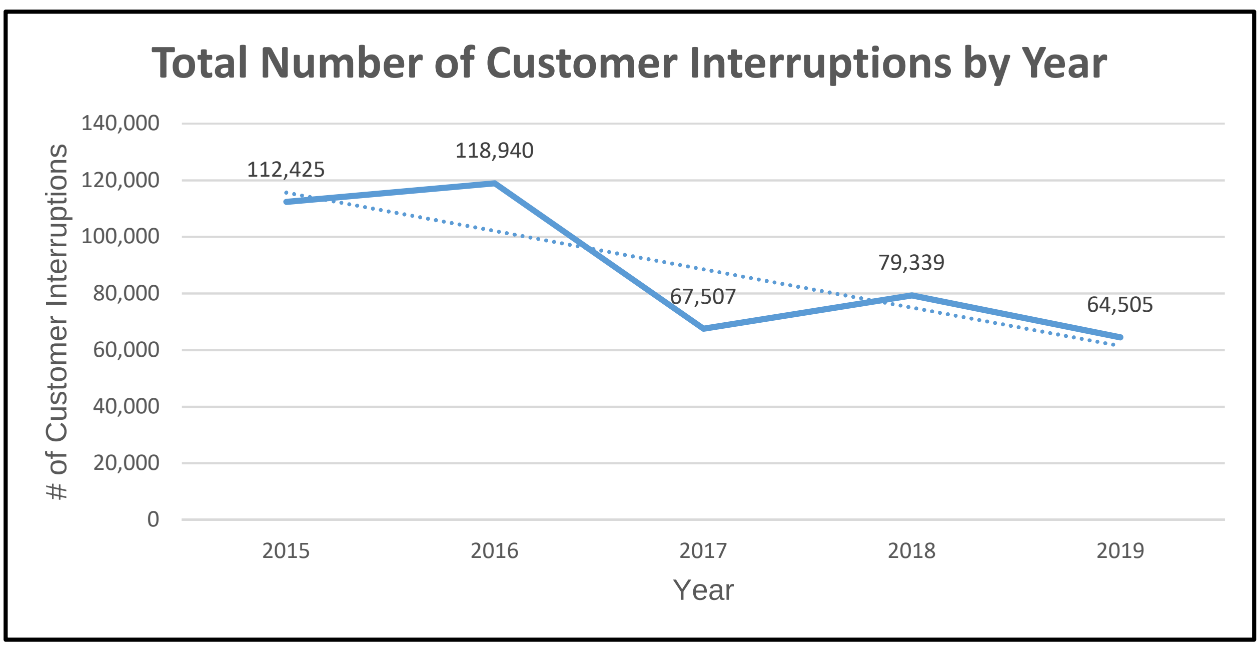


Figure 5: Total Number of Customer Interruptions (2015-2019) Excluding MEDs

Cause Code	**2015**	**2016**	**2017**	**2018**	**2019**	**Total Customer-Hours Interrupted**	**Percent Share**
0-Unknown/Other	1,040	2,780	1,287	12,867	568	18,542	4.58%
1-Scheduled Outage	428	3,543	6,062	4,527	5,212	19,772	4.89%
2-Loss of Supply	7,569	21	1,122	716	-	9,428	2.33%
3-Tree Contacts	3,364	680	3,953	12,261	7,174	27,433	6.78%
4-Lightning	-	152	2,245	127	487	3,011	0.74%
5-Defective Equipment	27,378	64,591	17,000	23,744	17,773	150,486	37.20%
6-Adverse Weather	10,621	3,774	1,158	4,737	225	20,515	5.07%
7-Adverse Environment	-	-	42	2,919	3,079	6,039	1.49%
8-Human Element	1,192	55,165	237	628	4,682	61,904	15.30%
9-Foreign Interference	23,930	18,419	9,687	16,347	19,046	87,430	21.61%
Total	**75,522**	**149,126**	**42,793**	**78,873**	**58,245**	**404,560**	**100%**

Table 11: # of Customer-Hours of Interruptions by Interruption Cause (2015-2019) Excl. MEDs

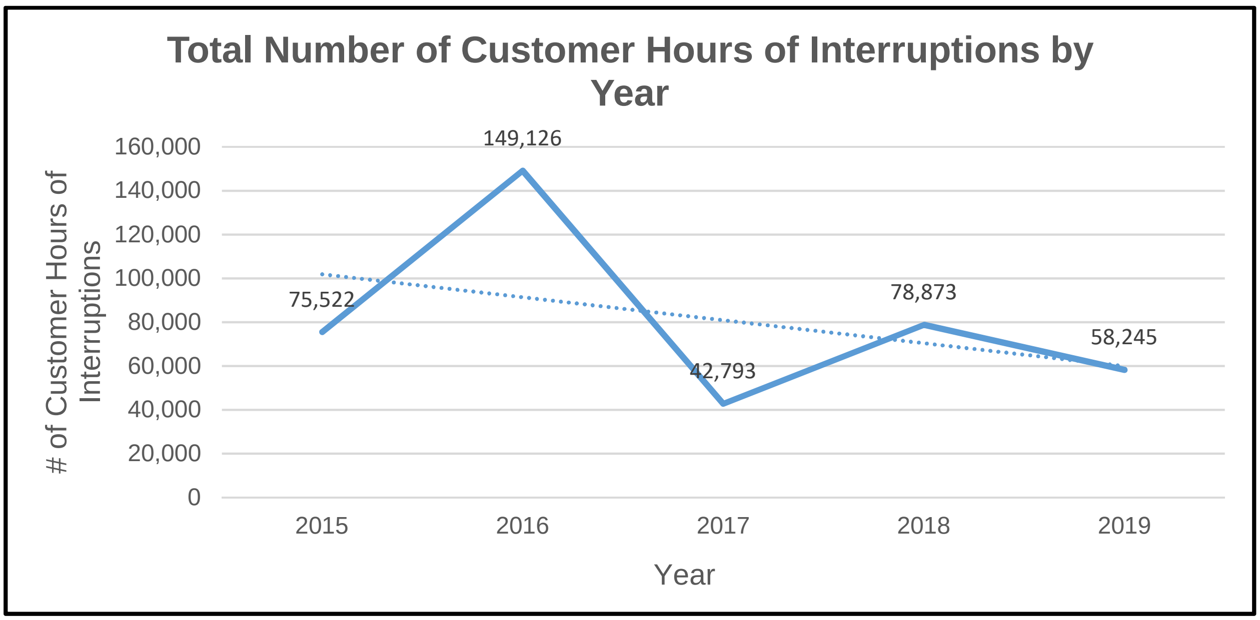


Figure 6: Total Number of Customer Hours of Interruptions (2015-2019) Excluding MEDs

Defective Equipment is the largest contributor to CI and as observed in the table above, it is also the largest contributor to CHI. CHI due to defective equipment shows a decreasing trend over the historical period. However, from 2015 to 2016 there was a significant increase (97%) in CHI. The increase in CHI in 2016 is primarily due to one large outage caused by a quick sleeve failure which opened a switch which resulted in 37,000 customers experiencing an outage lasting 6 hours. The outage occurred in the evening after work hours and crews had to be called in to make the necessary repairs. These outages are mitigated through effective maintenance programs and replacement and renewal programs. OPUCN replaces defective equipment in the system to ensure a continued reliable supply of electricity to its customers. OPUCN's maintenance and inspection program has been an effective means of replacing infrastructure at end of life. OPUCN intends to address the assets that are in poor condition through its System Renewal programs.

Foreign Interference is the second largest contributor to CI and CHI over the historical period. Interruptions due to foreign interference such as animals, vehicles, dig-ins, customer equipment, other utilities, vandalism, sabotage, and foreign objects, are typically beyond the control of OPUCN. OPUCN has implemented programs such as non-electric fence installation at MSs and installing animal guards to reduce the incidents of animal contacts. OPUCN also actively encourages customers, contractors and residents to participate in its "Call Before You Dig" program to identify underground plant.

5.2.3.d Effect of Historical Performance on DSP

OPUCN uses SAIDI and SAIFI reliability indices to determine the system reliability performance and maintain control over capital and maintenance spending. Additionally, tracking system reliability performance by cause code aids OPUCN in identifying investments. The investment described in the DSP would allow us to maintain or in some cases improve existing system reliability performance. To improve the SAIDI and SAIFI trends, OPUCN plans System Renewal and System Service projects that will focus on shortening both duration and frequency of outages that customers experience.

OPUCN has implemented and identified several programs to reduce the number of controllable outages. These programs include:

- Planned renewal at the end of TUL assets such as poles, conductors, cables, distribution transformers and station assets
- Planned replacement of faulty porcelain switches, porcelain insulators and 44kV quick sleeves
- Design and construction of distribution circuits to meet CSA standards
- Pole testing
- Proactive vegetation management
- Installation of animal barriers to control the outages due to wild life
- Installation of "smart grid" devices such as 44kV remote operated switch, intellirupter switches, IEDs, etc.

5.2.3.2 Cost Efficiency and Effectiveness

<u>Cost Control</u>

5.2.3.a Methods and Measures

Efficiency Assessment

The OEB has ranked all Ontario LDCs in one of five efficiency groups (1 – 5) with Group 1 being deemed the most efficient and Group 5 being deemed the least efficient.

5.2.3.c Historical Performance

OPUCN is currently ranked in Group 2 with respect to Efficiency Assessment (stretch factor = 0.15%). OPUCN has been in Group 2 for the last 5 years. Group 2 LDC is defined as having actual costs between 10% and 25% lower than predicted costs. OPUCN's goal is to sustain or improve current efficiencies, and remain a cost-effective utility.

5.2.3.d Effect of Historical Performance on DSP

Going forward, OPUCN intends to continue to implement productivity and efficiency improvements to help offset some of the costs associated with distribution system enhancements, while maintaining the reliability and quality of its distribution system.

Distribution System Plan Implementation Progress

5.2.3.a Methods and Measures

OPUCN will be monitoring its execution of the projects and programs included in the DSP. On a semi-annual basis, OPUCN will review actual capital expenditures to date and will forecast total expenditures to year end. Where forecast to year end is materially greater than the budget, OPUCN will review projects and determine if they can be deferred to a later date or reduce their scope. Mandatory projects for a given year are typically not subjected to deferral.

Program Delivery Cost

On an annual basis, OPUCN will calculate for that year, and on a cumulative basis for the five years of the DSP, its actual capital spending compared to the approved capital budget. OPUCN's target for this measure is that DSP actual spending to be within 5% of approved DSP capital budget.

5.2.3.c Historical Performance

The historical results are based on OPUCN's 2015-2018 DSP as filed with the OEB.

Measure	2015	2016	2017	2018	2019
Program Delivery Cost	99%	97%	101.3%	70.2%	99.0%

Table 12: Program Delivery Cost Measure

OPUCN spent 70.2% of its OEB approved capital budget for 2018 and was under budget for the year primarily due to the deferral and reallocation of projects to subsequent years. This in turn increased OPUCN spent in 2019. OPUCN completed construction of MS9 in 2018, however, construction continued on Hydro One's Enfield TS and associated distribution feeders in 2019-2020. Substation build is typically a multiyear program that added complexity to the program delivery cost.

5.2.3.d Effect of Historical Performance on DSP

The 2021 to 2025 DSP has been prepared in consideration that program spending must be achievable with the resources that are available (i.e. suppliers/material, design services, municipal approvals, contract labour, vehicles, etc.) in a timely manner. Programs are expected to be completed in the period(s) they are budgeted. Annual DSP spending exceeding a designated threshold of +/- 5% will require a detailed variance explanation. DSP investment planning has been set up to design, issue and construct reasonable amount of work that can be achieved within the forecast period.

5.2.3.3 Asset and/or System Operations Performance

Safety

5.2.3.a Methods and Measures

The OEB stated that the public safety metric will have the following components and will be included on the LDCs' annual scorecards:

a) Component A - Public Awareness of Electrical Safety
b) Component B - Compliance with Ontario Regulation 22/04
c) Component C - Serious Electrical Incident Index

Public Awareness of Electrical Safety

Component A, Public Awareness of Electrical Safety, measures the level of awareness of key electrical safety precautions among the public within the electricity LDC's service territory, and the degree of effectiveness for LDC's activities on preventing electrical accidents. OPUCN targets a public awareness index score of greater than 80%.

The survey is conducted by a third-party consultant every two years, and adheres to the methodology and implementation as directed by the OEB, as published in their November 25, 2015 "Scorecard Methodology and Implementation Guide."

Survey results are based on a telephone survey (Random Digit Dialing) among 400+ Members of the General Public, 18 years of age or older, residing within OPUCN's geographic service territory. The data is statistically weighted according to Canadian census figures for age, gender and region.

Compliance with Ontario Regulation 22/04

Ontario Regulation 22/04 - *Electrical Distribution Safety* establishes objective based electrical safety requirements for the design, construction, and maintenance of electrical distribution systems owned by licensed LDCs. Specifically, the regulation requires the approval of equipment, plans, specifications and inspection of construction before they are put into service.

The definitions of a C, NI and NC score, as categorized by the ESA, are provided in the following Table 13.

Score	Definition
C	Compliant - Fully or substantially meeting the requirements of Regulation 22/04.
NI	Needs Improvement - A failure to comply with part of Regulation 22/04; or - Non-pervasive failure to comply with adequate, established procedures for complying with Regulation 22/04
NC	Non-Compliance - A failure to comply with a substantial part of Regulation 22/04; or - Continuing failure to comply with a previously identified Needs Improvement item.

Table 13: Ontario Regulation 22/04 Compliance Definition

Serious Electrical Incident Index

*S*erious Electrical Incident Index measures the number of non-occupational (general public) serious electrical incidents involving LDC-owned assets.

OPUCN's target is to remain in compliance in all categories being audited.

5.2.3.c Historical Performance

OPUCN has a strong commitment to safety, health & wellness, and public safety measures and is in compliance with Ontario Regulation 22/04. The table below highlights OPUCN's historical performance for each of the three components. Level of Compliance with O.Reg. 22/04 for 2019 has not been completed as of the DSP writing and has been deferred due to the COVID-19 event.

Measures	2015	2016	2017	2018	2019
Level of Public Awareness	85.00%	85.00%	85.00%	85.00%	83.00%
Level of Compliance with O.Reg. 22/04	C	C	C	C	TBD
Serious Electrical Incident Index	0.000	0.000	0.000	0.000	0.000

Table 14: Performance Measures – Safety

OPUCN has been fully compliant with Ontario Regulation 22/04 during the historical period, achieving a score of C. OPUCN's continued achievement of compliance is due to our strong commitment to safety, and adherence to standards and company procedures & policies.

OPUCN achieved a score of 0.000 for the Serious Electrical Incident Index per 1,000 km of line during the historical period. OPUCN takes public safety in the vicinity of its distribution equipment very seriously, and regularly carries out activities to take prompt corrective action where potential public safety issues are identified. OPUCN promotes public safety messages through bill inserts, web and social media.

5.2.3.d Effect of Historical Performance on DSP

OPUCN continues to promote education, awareness, application of safe work practices and compliance with O.Reg. 22/04 and as such safety continues to play a key role in project prioritization. Ensuring a safe environment for workers and the public has been taken into consideration in the development of the DSP and OPUCN's AM and capital expenditure planning processes.

OPUCN also put measures in place to reduce and eliminate serious electrical incident that are within its control and has identified a number of pole line rebuild projects that will eliminate some of the hazards such as 44kV quick sleeve replacements.

<u>Distribution Losses</u>

5.2.3.a Methods and Measures

OPUCN system losses are monitored annually. System design and operation is managed such that system losses are maintained within OEB thresholds, as defined in the "OEB Practices Relating to Management of System Losses." Losses are monitored to ensure that the OEB 5% threshold is not exceeded.

5.2.3.c Historical Performance

OPUCN system losses over the historical period are shown below:

Year	2015	2016	2017	2018	2019
Distribution Losses	4.68%	3.59%	3.29%	4.38%	4.23%

Table 15: OPUCN System Losses

Losses are trending in the 3.29% – 4.68% range over the historical period and are within the OEB 5% threshold.

5.2.3.d Effect of Historical Performance on DSP

Existing performance is within performance targets and as such, there is no specific impact on the DSP. In this DSP, OPUCN has adopted a performance target of the maximum of the previous 5-year rolling average.

5.2.4 Realized Efficiencies due to Smart Meters

The installation of smart meters provides OPUCN and its customers an operational advantage in maintaining its service while simultaneously improving upon it. These operational advantages include:

- The process of issuing a timely, accurate bill to our customers has been improved. With smart metering, inaccurate bills have been eliminated and bill discrepancies are now easily dealt with at first call.
- Reduce labour costs during the customer account "move in/move out" process as rolling trucks to the field to obtain final meter readings is no longer required.
- Remote disconnect meters installed at locations where it was difficult to access or had repeat requirements to disconnect and reconnect a customer, this would help in reducing truck rolls to these locations.
- Detecting abnormal operating conditions such as customers who have illegally reconnected themselves after having been disconnected.
- Customer panel upgrades where electricians have changed the service panel size without notifying OPUCN, this would have an impact on the transformer size and cabling to the customer's home.
- "Last Gasp" functionality of the meters is utilized in the OMS to identify extent of outages and devices that operated. The OMS predicts outage from smart meters to automatically dispatch predicted outages through SMS to an on-call crew without a system operator being called in, eliminating the need to have a 24/7 "manned" control room in an age where power supply is required 24/7, OPUCN dispatched 634 SMS messages to line crews in 2019.
- Customer communications is evident on May 4, 2018 when over 23,000 users visited OPUCN's outage website during the windstorm. OPUCN called over 18,000 customers in the affected area within 35 minutes of detecting all outages by using the OMS and an IVR auto dialer to inform each customer that we were aware of the power outage and that we are working to restore power. We informed each customer to check OPUCN outage map for an update. The OMS was updated in near real time by outage messages from meters during this event.
- AMI data in the OMS is used to monitor transformer loading which assists engineering in determining transformer health allowing OPUCN to plan appropriate areas requiring an upgrade prior to the transformer failing due to accelerated degradation or aging. Effective planning reduces the overall cost impact experienced by customers. Transformer loading data is also used to monitor existing services and to assist with transformer sizing in design for new or additional services. Smart meters provide more

detailed energy use for customers throughout the day. This enables customers to proactively manage their energy consumption. System Operators ping meters to diagnose power related issues without dispatching a crew.

5.3 Asset Management Process

This section describes in detail OPUCN's AM process and the direct links between the process and expenditure that comprise the capital investment plan covered by this DSP.

5.3.1 Asset Management Process Overview

5.3.1.a Asset Management Objectives

OPUCN AM objectives were developed and implemented to align with the corporate mission, vision and corporate objectives. OPUCN mission and vision are summarized in the following:

Corporate Mission:

"We earn the trust of our customers every day by delivering safe, sustainable, reliable energy our customers value at a competitive rate."

Corporate Vision:

"Meeting the evolving needs of our customers as a leading enabler of integrated critical energy and communications infrastructure."

The main outcome is to build a safe, sustainable and reliable infrastructure to service the needs of the community while complying with regulatory obligations and license conditions. OPUCN infrastructure investment decisions are guided by the AM objectives that are based on OPUCN corporate objectives to achieve optimal performance of its assets at a reasonable cost with due regard for safety, system reliability, and customer service expectations. OPUCN corporate objectives that forms the basis of the AM objectives are:

Corporate Objectives:

- Modernize our infrastructure and enhance public safety
- Enhance our business, regulatory and finance processes
- Enhance the customer experience
- Invest in our people
- Demonstrate environmental stewardship and community involvement

These corporate objectives were developed to align with Renewed Regulatory Framework for Electricity (RRFE) outcomes and are embedded within the key elements driving this DSP. The relationship between RRFE outcomes, corporate objectives and AM objectives including the strategy to achieve the AM goals and objectives are shown in Table 16.

RRFE Outcomes	Corporate Objectives	Asset Management Objectives	Strategy to Achieve AM Objectives
Customer Focus	Enhance the Customer Experience	Provide more relevant, real time, accurate and useful information and tools Improve interaction response and resolution times Transition from reactive to proactive customer relationship	Engage customers and incorporate needs and preferences into solutions Invest in tools, processes and systems that improve interaction times and eliminate unnecessary interactions
Operational Effectiveness	Modernization our Infrastructure and Enhance Public Safety	Maintain or improve: Reliability Safety Security Minimize operational costs Optimize asset usage	Renew/ upgrade assets before failure with equipment/ designs that are safer and will improve reliability, optimize usage and have better value (cost vs benefit)
Public Policy Responsiveness	Demonstrate Environmental Stewardship and Community Involvement	Mitigate environmental risk Ensure investments are sustainable in the long term Address public policy, social and community needs Assist in the advancement of economic development	Seek investments that protect the environment and are sustainable long term Engage local governments and communities to help address social and economic needs
Financial Performance	Enhance our Business, Regulatory and Finance Processes Invest in our People	Ensure that costs are reasonable and controllable Improve business effectiveness Improve business efficiency	Assess costs to ensure they are reasonable and controllable Seek investments that improve business effectiveness (doing the right thing to achieve objectives) and efficiency (doing the right things with minimal waste)

Table 16: RRFE Outcomes – Corporate Objectives – Asset Management Objectives Relationship

OPUCN utilizes AM objectives presented in Table 16 for qualitatively prioritizing each capital investment. Priorities for investment were classified as either low, medium or high depending on how many of the AM objectives they were expected to address. For example, substation transformer replacement will meet operational and environmental objectives, which also address safety, reliability, and financial objectives. Therefore, the investment was categorized as high priority. This prioritization methodology is currently an approach that will be further developed to be more systematic/objective to be able to:

- Define risk impacts on AM objectives;
- Identify the optimal risk mitigation alternative through an evaluation of available options

Investment Category	Type(s)	AM Objective Ranking
System Access	Mandatory	Mandatory – High
System Service	Mandatory and Discretionary	Mandatory – High (i.e. Capacity Upgrade) Discretionary – Low/Med/High (i.e. Smart Grid Upgrade)
System Renewal	Mandatory and Discretionary	Mandatory – High (i.e. ACA Results) Discretionary – Low/Med/High (i.e. Advancement for Scheduling Efficiencies)
General Plant	Mandatory and Discretionary	Mandatory – High (i.e. Condition Assessment) Discretionary – Low/Med/High (i.e. Facilities Upgrades)

Table 17: Capital Investment Classification Using Asset Management Objectives

An integral part of achieving the objectives are inspection, maintenance and replacement programs, to ensure system performance is sustained during the entire asset service life. This ensures a continual and consistent focus on delivering services that balances risk and long-term costs.

5.3.1.b Components of the Asset Management Process

OPUCN's capital investment plan is designed to achieve the AM objectives and in order to develop this, the following data sets are utilized in the process:

- Asset Register – Asset information pertaining to physical and electrical attributes of each asset including type, location, service age, installation date, length, conductor size, equipment ratings, etc. resides in the transformer database, pole database and GIS.

- Asset Condition Assessment – ACA was completed in 2019 assessing the condition of the classes of distribution and station assets owned by OPUCN as shown below (refer to Appendix B). This report identifies critical or poor condition assets that need to be replaced to manage reliability of supply to customers. Asset categories included in the ACA are listed below.

  Distribution Assets

  - Poles – poles are a form of support for overhead distribution feeders and low voltage secondary lines.
  - Overhead Primary Conductors – overhead conductors along with structures that support them constitute overhead lines or feeders that distribute electrical energy to customers from the MS or TS
  - Underground Primary Cables – underground cables are mainly used in urban areas where it is either impossible or extremely difficult to build overhead lines due to aesthetic, legal, environmental and safety reasons
  - Distribution Transformers – distribution transformers change primary distribution voltages to secondary voltages such as 120/240V, 120/208V or 347/600V for use in residential and commercial applications
  - Primary & Smart Switches – the primary function of switches is to allow for isolation of line sections or equipment for maintenance, safety or other operating requirements. The operating mechanism can be either a manual gang operating linkage or remote.
  - Switchgears – switchgear is used for protection and switching in the underground distribution system. The switching assemblies can be classified into air insulated, SF6 or solid dielectric load break switches and vacuum fault interrupters.
  - Cut-Out Arrestors – cut-out arrestor consists of a fuse and a switch to manually disconnect the circuit. The fuse is designed to open the circuit in an over current event.
  - Elbows – elbow is a connector use for connecting underground cable to transformers, switchgear and junctions equipped with loadbreak bushings
  - Reclosers – reclosers are light duty circuit breakers equipped with control units designed for breaking and making fault current.
  - Vaults & Manholes – vaults and manholes permit installation of transformers, switchgear or other equipment

  Substation Assets

  - Substation Transformers – substation transformers are employed in MS to step down transmission voltage to distribution voltage levels
  - Substation Switchgear – substation switchgear comprises the enclosure, the circuit breakers and the associated protection and control devices used for protection and switching of distribution system circuits
  - Circuit Breakers – circuit breakers are automated switching devices that can make, carry and interrupt electrical currents under normal and abnormal conditions
  - Relays & RTUs – Protection relays work to detect faults and isolate the system by triggering the opening and closing of the circuit breakers. RTUs collect digital and analog data from equipment, exchange information to the master system, and perform control functions on field devices. They are typically comprised of

the following: power supply, CPU, I/O Modules, housing and chassis, communications interface, and software

- Battery & Battery Chargers – battery and battery chargers are components of the substation direct current (DC) systems and are the critical supply for station protection and control equipment and other auxiliary devices such as transformer cooling
- Ground Grids – ground grid is part of the overall design of a substation that provide means to dissipate electric currents into the earth
- Fences & Buildings – fences & buildings are structures use to keep the substation secure.

- TUL of Assets – OEB Asset Depreciation Study has been used as reference in determining the TUL of each asset.
- Asset Capacity Utilization and Constraint Assessment – Asset capacity utilization and constraint assessment are determined from a local capacity planning (load forecasting), REG planning and Regional Planning perspective considering systems constraints and future loading requirements. Refer to Section 5.4.3.d.
- Historical Performance Data – Information on equipment failures and outages are captured including maintenance and operational inspection and test reports. Inspection data assist in identifying and confirming potential equipment hazards and critical assets in need of repair or replacement. Power outage incident reports are also used to capture information on root cause, duration, fault location and restoration time.
- Reliability Analysis – Reliability based failure analysis are used including but not limited to, technological obsolescence, primary cable fault analysis, remaining pole strength and condition and persistent asset failures (i.e. outages caused by porcelain insulator).
- Grid Modernization Plan – OPUCN engaged METSCO to assess current distribution system status and develop a Grid Modernization Plan (refer to Appendix K). This report outlines several initiatives that would help OPUCN implement a “smarter grid” to increase efficiencies in its system operations, avoid or shorten system outages, provide system visibility, and provide service value to its customers. /
- Customer Engagement Results – Customer needs and preferences are identified through customer engagement platforms such as customer survey. The results are available in Appendix C.
- Regional and Municipal Requests – Coordinated infrastructure planning efforts with third party including City of Oshawa and Region of Durham.
- Regional Infrastructure Plan (Refer to Appendix D)
- REG Plan and IESO Response (Refer to Appendix H and Appendix I)
- Operational Requirements – Requirements that may not be directly part of the distribution system including IT, tools, fleet and facilities
- Regulatory, Public Policy and Government Directives

The relationship between the components of the AM process used to prepare a capital investment plan is shown in Figure 7.

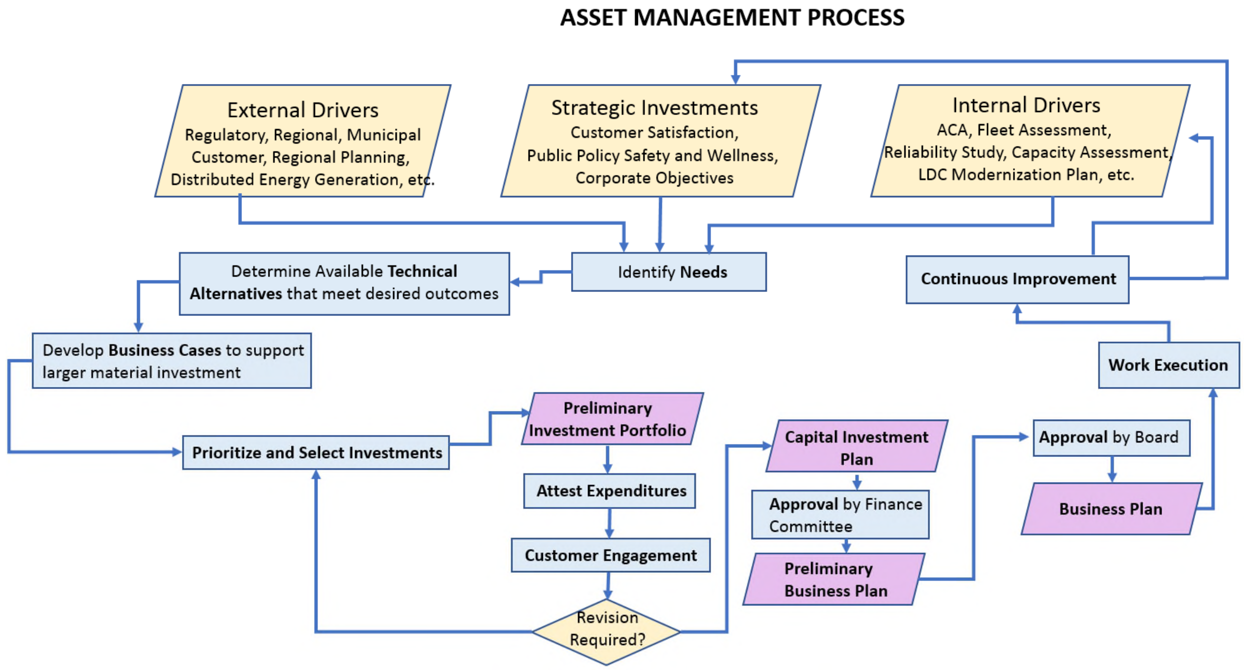


Figure 7: Asset Management Process

OPUCN's AM process begins with identifying the needs based on inputs and drivers which can be either internal, external or driven by strategic investments identified above. Information collected from these investment drivers will determine the initial investments portfolio and are classified into four categories, as defined in OEB's Chapter 5 filing requirements: System Access, System Renewal, System Service and General Plant.

Available technical alternatives to meet desired outcomes are considered and developed that can range from "do nothing" to proceeding with a different solutions to address identified needs. Example of such solutions could be repair vs replacement and considerations are governed by OPUCN's AM strategy and the asset lifecycle policy. Where needs are mandatory such as System Access projects, alternatives are not considered except for the timing of implementation.

Mandatory capital projects are automatically included as per the scheduled need. There is normally little flexibility to defer these projects. In general, mandatory projects are defined as:

- System Access investments that facilitate modifications to the distribution system infrastructure to allow connection of new load or generation customers and to relocate distribution system infrastructure installed in public right-of-way to accommodate municipal road reconstruction projects. System Access investments are mandatory and therefore, receive the highest priority in the overall investment envelope:
  - New/modified customer service connections
  - Road authority driven utility relocation projects
  - Mandated service obligations

- System Renewal investments that are reactive in nature in addressing assets that failed, assets identified in ACA that are in critical condition or assets posing any safety concerns:
    - Emergency plant replacement
    - Safety related projects
    - ACA recommended replacement programs

- System Service investments that addresses capacity requirements
- General Plant investments that are reactive in nature or projects that have been identified in the Building Condition Assessment (BCA) provided in Appendix L that is essential in supporting business needs or addressing safety concerns.

In developing alternatives, a number of considerations are taken into account. These considerations include: OPUCN's AM objectives, strategies, costs, bill impacts (rate mitigation), resource availability, and financial stability.

A list of capital investments is produced as the output of this step and investment justification is compiled for the projects along with more detailed business cases or narratives for the larger material investments proposed.

OPUCN does not have any formal analytical tools and methods used for risk management at this time but will be reviewing a quantitative risk assessment methodology in the future, however, prioritization and selection of capital investments is completed by determining the AM objectives achieved by each project. Projects that provide the greatest benefit and highest level of risk mitigation in accordance with the AM objectives will receive a higher prioritization ranking and preference for inclusion in the proposed capital investment plan. This approach is mostly relevant to System Renewal projects where proactive replacement is considered but was also adopted for System Service and General Plant projects.

An important step in the investment prioritization process is the ACA where an asset Health Index (HI) framework is formulated. An ACA is used to produce the HI, which is a quantified condition score of a given asset's condition and is related to the probability of failure. The HI score is calculated using asset age, test data, inspection and historical performance data (as applicable). This procedure allowed separation of the assets in “very good”, “good” and “fair” condition bands that require minimal risk mitigation from those in “poor” and “very poor” condition. For assets determined to be in “poor” or “very poor” condition, consequences of asset failures were assessed and those requiring renewal/rehabilitation were ranked in order of priority, with highest risk of failure being assigned the highest priority.

Since a significantly large part of OPUCN's infrastructure assets have been determined to be in “poor” or “very poor” condition, prioritization of investments in the System Renewal category required a risk assessment approach, which is described in Section 5.3.3 in detail.

For System Service investments and some General Plant investments, prioritization within these categories are developed and assessed for their ability to achieve the desired benefits and/or system driver impact on: customer choice; enabling of disruptive technology such as REG, Electric Vehicle (EV) and battery storage; reliability improvement; regulatory compliance; and/or cost improvement. A summary of the impact scores and projects are provided in Sections 8 and 9 of the Grid Modernization Plan (Appendix K).

After completing the initial assessment stage, the preliminary investment portfolio is tested against OPUCN total capital and operating funds which determines financial capability and rate impacts. In addition to this, customer engagement sessions were also held to receive feedback and determine customer preferences for service quality level and rate increase, which assisted in shaping the preliminary investment portfolio by putting emphasis on projects that addresses customer needs. The customer needs are reflected in the AM objectives.

If revision is required, each discretionary project proposed undergoes a further scoping and risk assessment to determine any synergies and optimization. This may also indicate that to optimize system performance or distribution requirements, the budget may require funding adjustment. A discretionary project change assessment (DPCA) form is completed if there is a modification (refer to Appendix M for an example of a DPCA form), scope reduction or cancellation required for discretionary projects which will be ultimately approved by a member of the senior management team. The overarching objective of this exercise is to meet the criteria and requirements of the capital and operating budget under an overall spending envelope while optimizing system performance and meeting customer needs.

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

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

Continuous improvement is the final step in the AM process. The performance measures included on the scorecard have an established minimum level of performance expected to be achieved which is also used to continuously improve AM and capital planning process.

5.3.2 Overview of Assets Managed

5.3.2.a Key Features of the Distribution Service Area

OPUCN owns and operates a distribution network that currently serves approximately 60,000 customers in the City of Oshawa located in the Regional Municipality of Durham (Refer to Figure 8 for Service Area Map). The service territory of OPUCN covers 145.5 square kilometres consisting of 49.1 square kilometres of rural service area and 96.4 square kilometres of urban service area. OPUCN’s system has a total of 1,010 circuit km with a split of 54% and 46% between overhead to underground systems respectively.

OPUCN service territory lies on the Lake Ontario shoreline and similar to all of Southern Ontario, this area has a humid continental climate with moderate seasonal temperate differences. Temperature extremes can reach to -40˚C during winter and +40˚C in summer, however, the average weather temperature can vary from -15˚C to +25 ˚C. Oshawa is located within the CSA heavy loading area as described in CSA 22.3 No. 1-15 Overhead Systems. Accordingly, the corresponding CSA referenced heavy loading conditions of radial thickness of ice; horizontal wind loading and temperature are accounted for in-line designs when preparing this DSP.

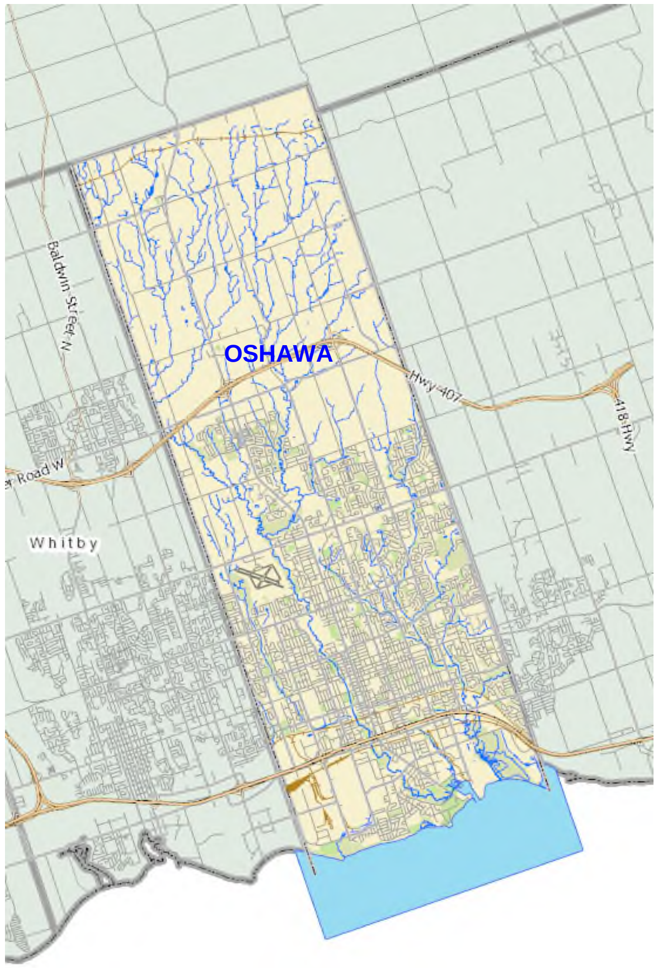


Figure 8: OPUCN Service Territory

According to the information gathered from the City and Region regarding demographics, the estimated population of the City of Oshawa is currently at 172,434 and has grew by 14% between 2008 and 2018. It is expected that the population will grow by 16% in 10 years due to an increasing development in Oshawa. With 2.7% Gross Domestic Product (GDP) growth, Oshawa is considered to be one of the fastest growing economies of 2018 in Canada. It is forecasted that the GDP will stabilize in 2020, following a gain of 1.8% in 2019 and will quickly resume in 2021 at a projected rate of 2.2%. Based on this projections, OPUCN has considered this growth within connection and expansion programs which also triggers utility relocation as a result of municipally driven road widening. A diagram of the upcoming residential subdivision development (circled in red) is shown in Figure 9. Note that the colored areas of the map represent the City Site Plan Application status which can change over time.

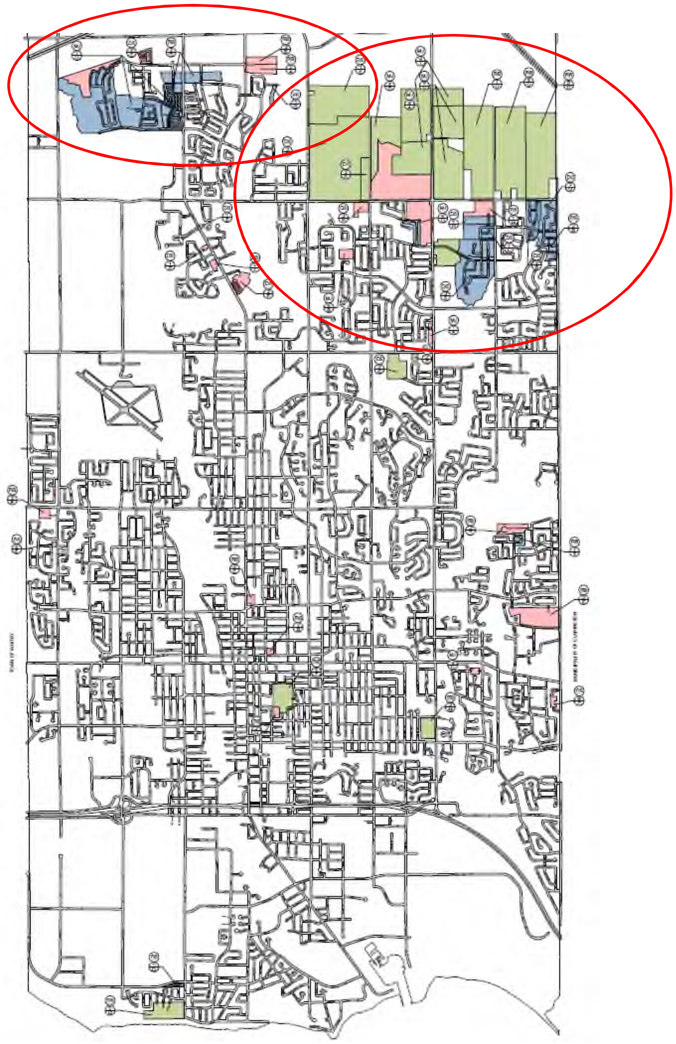


Figure 9: Residential Subdivision Development Activity Map

5.3.2.b Summary Description of the System Configuration

OPUCN is supplied from three Hydro One owned TSs at 44kV which includes Wilson TS, Thornton TS and Enfield TS. The demarcation point between Hydro One and OPUCN starts at the 44kV feeders leaving the TSs where eight 44kV feeders from Wilson TS, four 44kV feeders from Thornton TS and two 44kV feeders from Enfield TS are used to supply 9 of OPUCN's MSs. Figure 10 below provides the approximate geographic locations of Hydro One owned transmission stations and OPUCN owned distribution substations within OPUCN service territory.

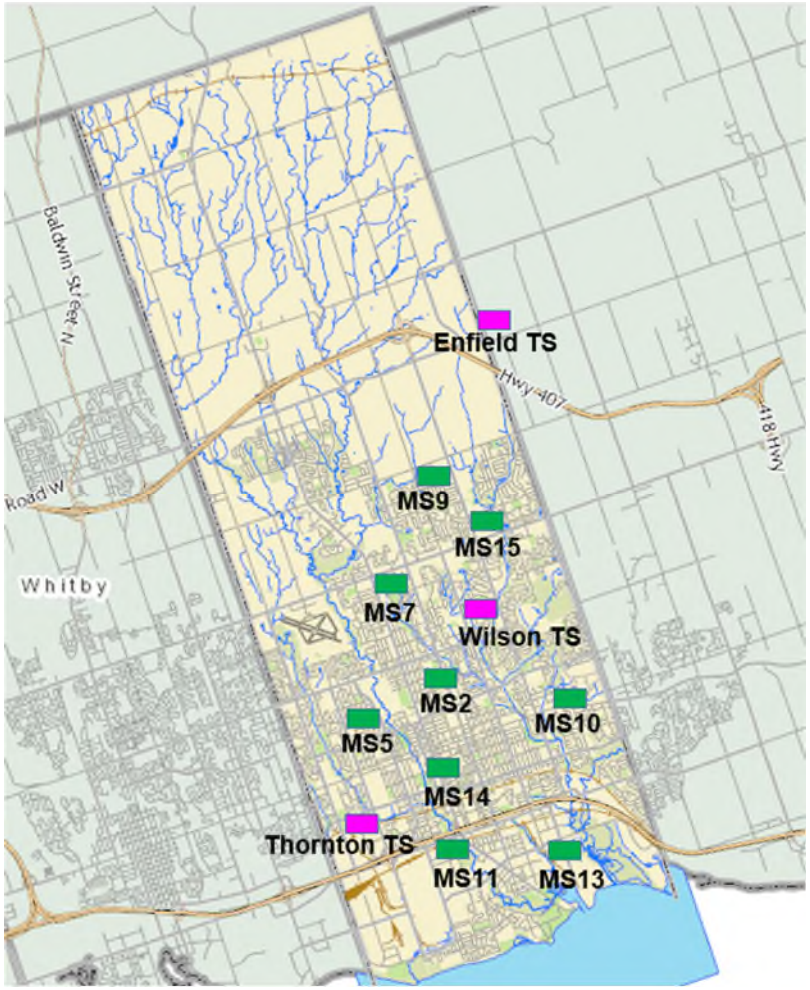


Figure 10: HONI Transmission Station and OPUCN Municipal Substation Locations

The following figures show the 44kV and 13.8kV single line diagram of OPUCN distribution system network where approximately 12% are 44kV and 88% are 13.8kV. Figure 11 also provides the interconnection between HONI TS and OPUCN MS.

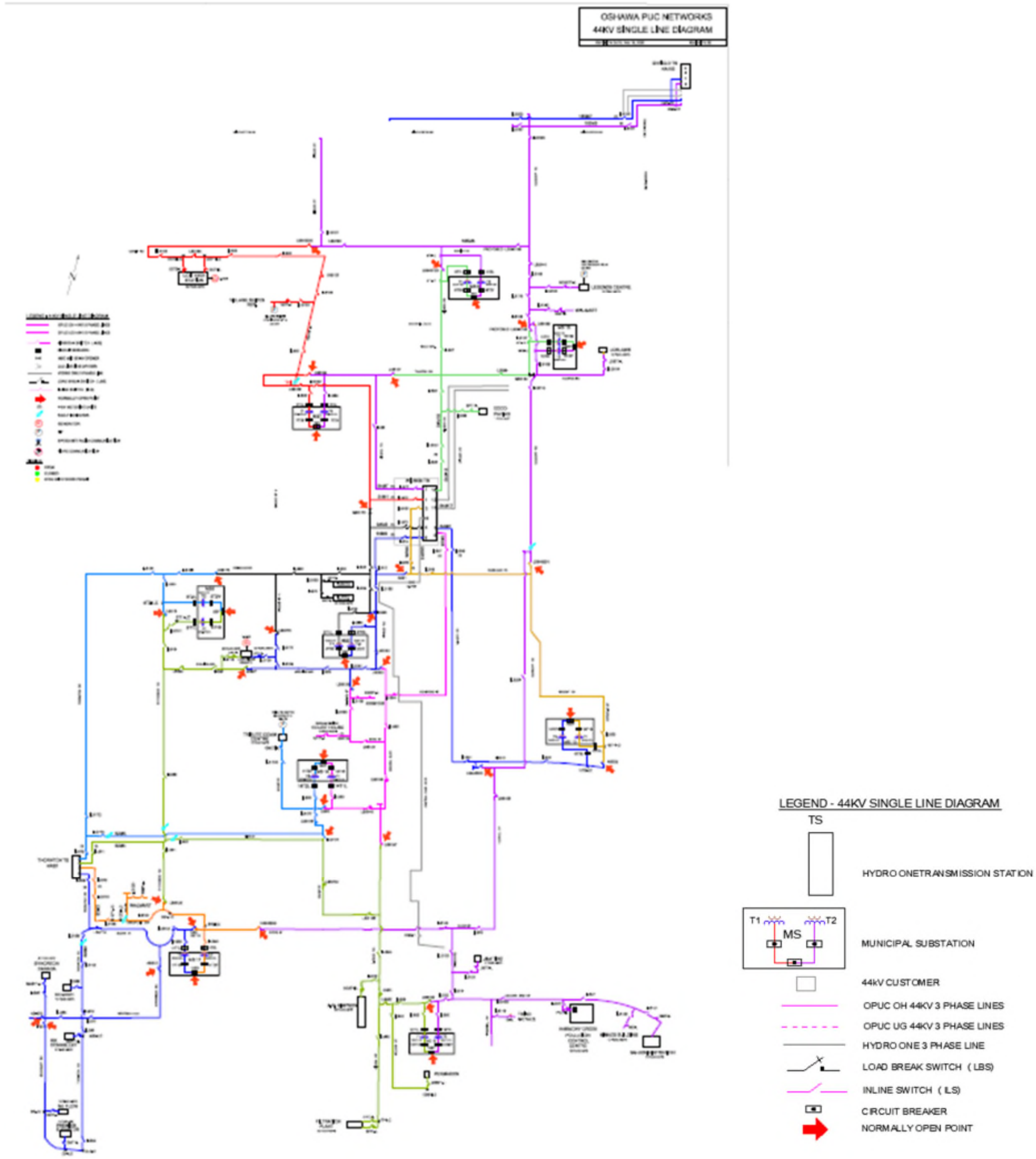


Figure 11: OPUCN 44kV Single Line Diagram

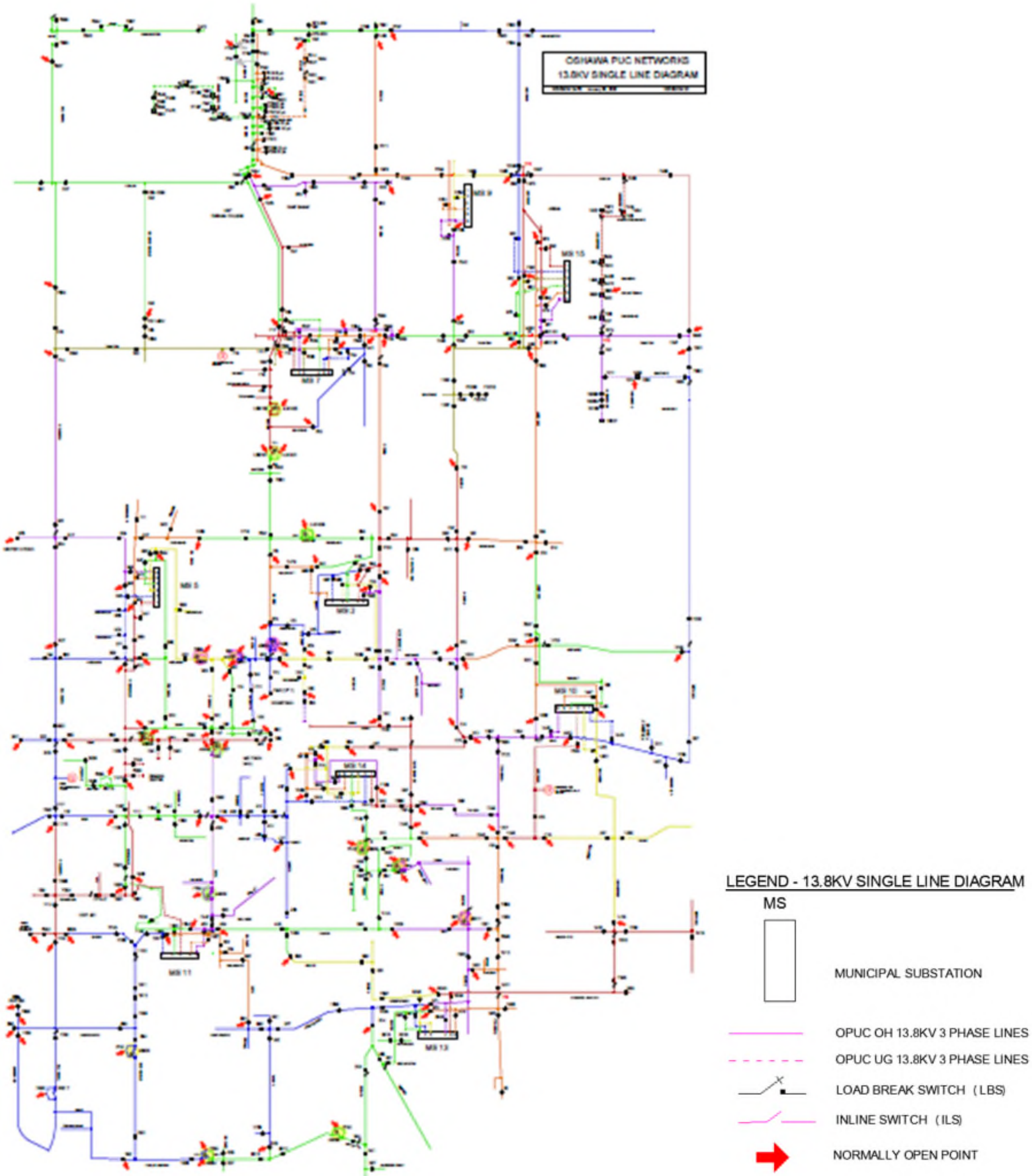


Figure 12: OPUCN 13.8kV Single Line Diagram

All OPUCN MSs are equipped with two transformers stepping the voltage down from 44kV to 13.8kV where each are protected by a 44kV circuit breaker. Each of the MSs also has a medium voltage switchgear that contains two transformer breakers and one bus tie breaker between two 13.8kV buses that are each equipped with 13.8kV circuit breakers to protect outgoing 13.8kV feeders. A summary of the substation transformer capacity and associated number of feeders for each distribution substation is provided in Table 18.

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

Table 18: OPUCN Distribution Substation Ratings

OPUCN operates a primary "loop distribution" system, which offers flexibility in switching operations to minimize outage durations, and distributes electricity through 14 x 44kV primary feeders and up to 54 x 13.8kV distribution primary feeders. The primary distribution network consists of approximately 547 km of overhead primary lines and 463 km of underground primary cables, which provides supply to distribution type transformers that step down to the following secondary voltage levels in order to supply customers:

1. 120/240V, 1-ph circuits to serve residential or small commercial customers;
2. 120/208V, 3-ph circuits to serve commercial customers; and
3. 347/600V, 3-ph circuits to serve commercial and industrial customers.

The following Table 19 provides the number and length of circuits by primary voltage level:

Primary Voltage	Number of Circuits	Overhead System (km)	Underground System (km)
44kV	14	119	3
13.8kV	54	428	460

Table 19: Number and Length of Circuits by Primary Voltage Level

5.3.2.c Asset Demographics and Asset Condition Assessment

The ACA was prepared in April 2019 to assess the condition of assets in-service by determining health indices using available condition data (refer to Appendix B for the full ACA report). This ACA provides demographic and asset condition information on fixed assets employed in OPUCN's MSs, overhead and underground systems, and does not include the newly energized MS9 substation assets as this substation was energized in the last quarter of 2018.

The ACA report documents the condition of all major assets in units of health indices and provides ranking of assets in designations rated "very good", "good", "fair", "poor" and "very poor". In determining the health indices of assets, all available information relevant to the assets' health, including age, results of visual inspections and results of diagnostic testing when available, have been utilized. Figure 13 and Table 20 present the asset demographics and summary results of the ACA.

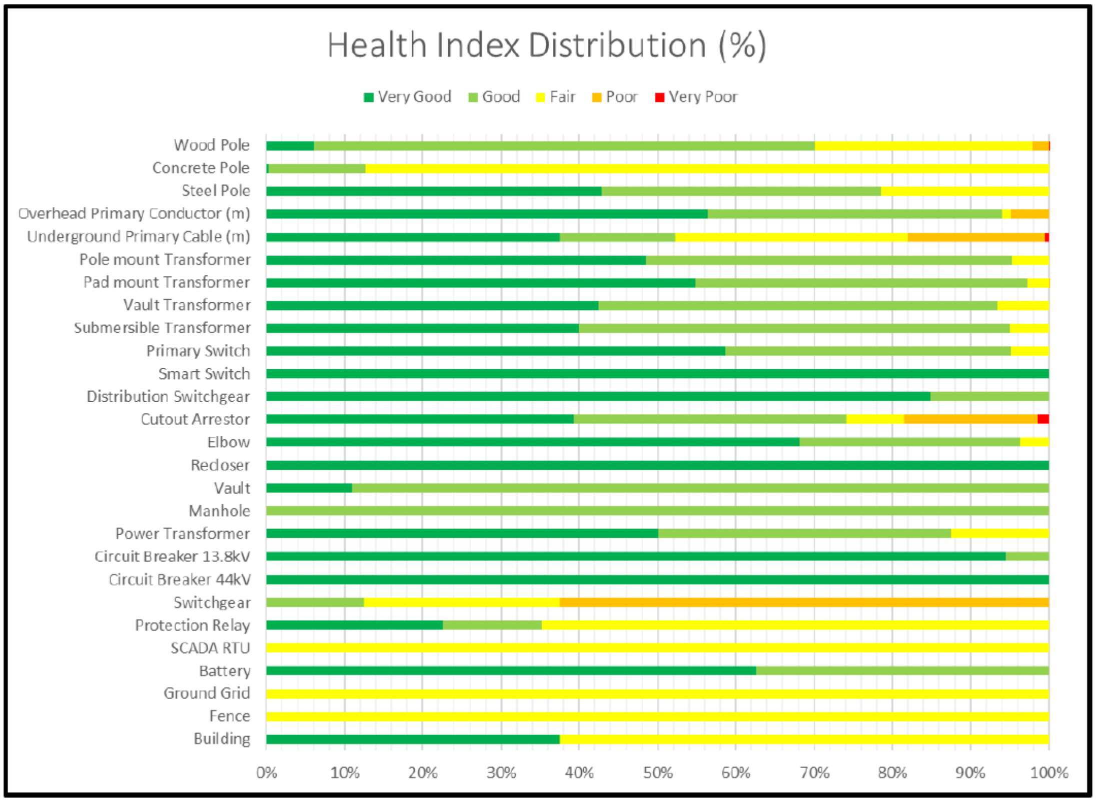


Figure 13: OPUCN Health Index Distribution for Major Assets

Asset Category	Pop.	Health Index Distribution					Avg. Health Index
		Very Good	Good	Fair	Poor	Very Poor	
Wood Pole	9,570	6%	64%	28%	2%	0%	73%
Concrete Pole	869	0%	12%	87%	0%	0%	66%
Steel Pole	14	43%	36%	21%	0%	0%	72%
Overhead Primary Conductor (m)	519,869	56%	38%	1%	5%	0%	86%
Underground Primary Cable (m)	460,325	37%	15%	30%	18%	0%	69%
Pole mount Transformer	2,513	49%	47%	5%	0%	0%	84%
Pad mount Transformer	3,765	55%	42%	3%	0%	0%	85%
Vault Transformer	394	42%	51%	7%	0%	0%	84%
Submersible Transformer	20	40%	55%	5%	0%	0%	83%
Primary Switch	1,001	59%	36%	5%	0%	0%	87%
Smart Switch	15	100%	0%	0%	0%	0%	100%
Distribution Switchgear	33	85%	15%	0%	0%	0%	96%
Cutout Arrestor	2,830	39%	35%	7%	17%	1%	80%
Elbow	7,192	68%	28%	4%	0%	0%	90%
Recloser	4	100%	0%	0%	0%	0%	0%
Vault	146	11%	89%	0%	0%	0%	84%
Manhole	120	0%	100%	0%	0%	0%	83%
Power Transformer	16	50%	38%	13%	0%	0%	83%
Circuit Breaker 13.8kV	72	94%	6%	0%	0%	0%	96%
Circuit Breaker 44kV	16	100%	0%	0%	0%	0%	100%
Switchgear	8	0%	13%	25%	63%	0%	43%
Protection Relay	71	23%	13%	65%	0%	0%	75%
SCADA RTU	8	0%	0%	100%	0%	0%	60%
Battery	8	63%	38%	0%	0%	0%	89%
Ground Grid	16	0%	0%	100%	0%	0%	67%
Fence	8	0%	0%	100%	0%	0%	60%
Building	8	38%	0%	63%	0%	0%	75%

Table 20: ACA Overall Results

Based on the summary results, the MS switchgear presents the lowest average HI overall followed by MS components such as the ground grid, fence and SCADA RTU. Cutout arrestors (porcelain switch), underground primary cable and wood pole exhibits a level of “poor” “very poor” condition in its asset base. Porcelain insulators are not part of this list, however, it was identified that this type of insulator is also in “very poor” condition due to repeated failures resulting in reliability issues experienced by OPUCN. The remaining assets exhibit a condition of degradation pattern that requires periodic system renewal to mitigate additional failure risks of assets. The ACA report also provides a recommended replacement plan being used as a preliminary baseline for OPUCN to identify how many assets should be replaced to maintain the overall system health.

Substation Assets

MS transformers and MS switchgear complete with protection and control equipment as well as substation structural infrastructure are the most critical components, essential to safe and reliable operation of the MS. Section 3.2 of the ACA in Appendix B indicates the age demographic and existing condition of substation assets in OPUCN’s MS.

The key role of the OPUCN MSs is to step down 44kV to 13.8kV safely and reliably. As per ACA, OPUCN currently has 16 MS transformers (not including 2 new MS transformers from MS9), where 5 are close to 40 years of in-service age. These MS transformers will reach or exceed the end of its TUL during this planning cycle. 13% of the MS transformers are also in “fair” condition but it is expected that these transformers will be in “poor” and “very poor” condition by 2023-2025 which would require replacement. Most of the MS switchgears are also in “poor” condition with service age over the maximum useful life accounting for 63% of the total

MS switchgear assets. MS switchgear is a critical asset with a high risk of impact to safety and reliability and the replacement of these assets should be prioritized. Other station assets were also identified in “fair” or “good” condition with in-service age close to its TUL including 25% of protection relays, all of SCADA RTUs, 63% of substation batteries and 38% of substation battery chargers. These station assets are expected to be in “poor” or “very poor” condition or obsolete in the next 5 years and will be considered for replacement to maintain safety and reliability.

Ground grids are in “fair” condition, but ground grid upgrades must be considered to bring existing station grounding to current standards based on a full ground grid study completed in 2019 (refer to Appendix N for the ground grid study completed for one of the MS). The ground grid work is propose to be completed in 2021.

Distribution Assets

Distribution assets are comprised of overhead (OH) and underground (UG) systems with poles, conductors, cables, distribution transformers and other protective devices being the primary assets in this group. Section 3.1 of the ACA in Appendix B indicates the age demographic and existing condition of assets in the overhead and underground distribution systems. Poles, OH conductors and UG cables along with other distribution components that are in “poor” or “very poor” condition or approaching the of end of its TUL can experience degradation of strength and pose a high risk of failure. Planned rebuild for both OH and UG systems for these assets will be required to mitigate any inherent risks.

<u>Poles</u>

Based on pole testing and inspection results completed in 2017, there are about 10,453 poles employed by OPUCN of which 9,570 are wood poles, 869 are concrete poles and 14 are steel poles. The condition of the poles is indicated in Sections 3.1.1 and 3.1.2 of the ACA and presents poles that are in “poor” or in “very poor condition.” It can also be inferred that a significant number of poles have reached or exceeded the end of its TUL and should be considered for renewal. The ACA proposed recommendation is to replace approximately 330 poles annually which can be addressed under an OH line renewal and pole replacement programs.

<u>Overhead Primary Conductor</u>

OPUCN owns approximately 547km of primary overhead conductors across its distribution system to date. These conductors are rarely tested as distribution lines normally outlive the poles and are not usually on the critical path to determine the end of life for a line section. However, small primary conductors such as #4AWG or #6AWG are susceptible to frequent breakdowns and have low tensile strength including conductors that are too small for line loads resulting in suboptimal system operation due to high line losses. Sleeves used to splice overhead primary conductor lines were also considered as quick sleeves that are employed by OPUCN may not last the entire life of the OH primary conductors and must be replaced to mitigate the risk of lines falling from an energized line. Section 3.1.3 of the ACA identifies that there are approximately 5% of OH primary conductors that are in “”poor” and “very poor” condition.

<u>Underground Primary Cable</u>

The UG distribution system at OPUCN employs approximately 463km of underground primary cables. As shown on Section 3.1.4 of the ACA, approximately 6-12% of the UG primary cable have reached or exceeded the TUL during the forecast period. It is important to note that the majority of these were installed on a direct buried configuration that is more susceptible to failure and has a larger impact on reliability when compared to cables installed in duct.

The XLPE cables utilized by OPUCN have a TUL of 25 years, and although the underground primary cables are not experiencing wide spread failures, unplanned failures are a risk and could significantly impact reliability. OPUCN is also prioritizing the replacements of these underground circuits based on the number of failures experienced and assessed as part of its primary underground cable fault analysis. In order to mitigate the risk of UG primary cable faults, UG line renewal program is being proposed.

Distribution Transformers

Based on Section 3.1.5 of the ACA, OPUCN employs about 6,692 number of distribution transformers of which 3,765 are padmount transformers, 2,513 are pole-mount transformers, 20 are submersible transformers and 394 are vault transformers. Only one distribution transformer have been identified in "poor" or in "very poor" condition, however, OPUCN employs "run-to-failure" strategy for distribution transformers, due to the relatively low impact of transformer failures on reliability. The only exception to this is with vault transformers located in either customer-owned vault or OPUCN-owned vault due to safety risk and customer impact when these type of transformers fail. Furthermore, when transformers with serious deficiencies are identified through inspections, these are immediately replaced.

Switches, Reclosers and Switchgears

OPUCN`s distribution system is well equipped for disconnecting, isolating, load-breaking, and fault interrupting to provide isolation during power interruptions. A majority of the switches and switchgears are pole-mounted which also includes smart switches. There are no switches, reclosers or switchgears identified in "poor" or in "very poor" condition, however, Sections 3.1.6, 3.1.7 and 3.1.10 of the ACA shows that there are about 48 primary switches that have reached or exceeded the end of its TUL. Switches are generally replaced during reconstruction of a feeder and associated costs are included within OPUCN's line renewal program. Asset condition and TUL are also considered when upgrading switches to "smart" switches.

Cut-Out Arrestors

OPUCN employs approximately 2,830 cut-out arrestors or cut-out switches and 3,083 transformer cut-outs in its distribution system. The asset service age was calculated based on current record and best available information for cut-out arrestors, however, there is no age data available for transformer cut-outs and therefore, has been excluded from the figures in Section 3.1.8 of the ACA. This asset type is typically replaced during OH line renewal projects, however, OPUCN had been experiencing repeated failures of porcelain fused switches and insulators which has impacted reliability. Some failures have resulted in electrical failure of the insulation, while in other cases the insulator has cracked and broken resulting in pole fires. Although no serious accident has occurred so far, the failing cut-outs do present a risk of injury to public or utility employees and have an impact on system reliability.

In 2013-2014, OPUCN adopted a systematic program under which porcelain switches and porcelain insulators are being systematically replaced with polymer type units to address safety risks and improve overall reliability. The replacement continued as part of overhead rebuild projects. However, the previous program was not able to address all porcelain switches and porcelain insulators and a new program is being proposed in this planning period to completely replace these type of cut-out switches and insulators and further mitigate equipment failures.

Elbows

Elbows are typically part of pad-mount transformer and switchgear installations and characteristically have the same TUL as the pad-mount transformers and switchgear. There are no elbows identified as “poor” or “very poor” condition in Section 3.1.9 of the ACA, however, elbows will be typically replaced at the same time the pad-mount transformer and switchgear is replaced or during underground line renewal.

Vaults and Manholes

Underground vaults and manholes are utilized by OPUCN mostly in the downtown core. These assets are deemed critical as they are being used for various functions including cable pull-boxes and placement for vault transformers. No vaults or manholes were identified as “poor” or “very poor” condition in Section 3.1.11 of the ACA, however, some of these vaults and manholes are more than 50 years old and should be inspected regularly with maintenance being carried out on an as required basis.

5.3.2.d Capacity Assessment of Existing System

For system planning purposes, sufficient distribution system capacity must be planned to meet peak load requirements. OPUCN can utilize its allocated capacity from Hydro One Transmission Stations (TS) as indicated in Table 21. The capacity utilization is determined by the 10-day limited time rating (LTR) for each individual TS and compared against OPUCN peak loading.

Hydro One TS Name	Allocated Capacity (MVA)	2019 Peak Load (MVA)	Capacity Utilization
Wilson TS	171.9	132.6	77.1%
Thornton TS	85.0	82.3	96.8%
Enfield TS	96.4	12.2	12.7%

Table 21: Transmission Station Capacity Utilization

Although Wilson TS and Thornton TS are within its allocated capacity, Wilson TS has exceeded its normal supply capacity in the past due to weather and load growth and Thornton TS is almost at its capacity. Enfield TS, a newly built Hydro One owned TS, was installed and energized in 2019 to relieve the TSs from overloading as well as to meet the new load growth in Oshawa. Feeder rebuild plans are currently under construction and expected to be completed in 2020 to accommodate the permanent transfer of load from Wilson TS and Thornton TS to Enfield TS. The load transfer will alleviate any capacity constraints from the 2 TSs and will optimize the capacity utilization between the three Hydro One points of supply.

OPUCN MSs are planned and configured to be loaded to up to 100% of their normal or base rating. These substations are designed with a primary “loop distribution” system to allow for the MS to be backed up from one or more adjacent MSs. This configuration offers flexibility in switching operations to minimize outage durations and maintain reliability of the distribution system. Table 22 below provides the capacity utilization at each MS. It should be noted that the information in the table below represents the non-coincidental station peak loading. Temporary load transfer can also affect the station load during facilitation of a planned or emergency work.

OPUCN MS	Normal Capacity (MVA)	2019 Peak Load (MVA)	Capacity Utilization
MS2	50	33.2	66.4%
MS5	50	40.7	81.4%
MS7	40	45.1	112.8%
MS9	50	0.0	0.0%
MS10	45	32.6	72.4%
MS11	50	36.1	72.2%
MS13	50	26.6	53.2%
MS14	40	21.3	53.3%
MS15	40	23.6	59.0%

Table 22: Municipal Substation Capacity Utilization

As per Table 22, most of the MS operates well within the normal station rating except for MS7 where the MS was loaded above its normal rating and surpassed the first level cooling (ONAN: Oil Natural Air Natural). This loading condition is a result of the developments in north Oshawa where MS7 is situated. A plan has already been in placed to transfer load to the newly built MS9 to alleviate the system capacity constraints and supply future distribution capacity requirements in this developing area.

Table 23 provides the feeder capacity information on both 44kV and 13.8kV distribution network. The planning capacity will be limited to 400A on 44kV feeders, and 300A on 13.8kV feeders to ensure that adequate feeder transfer capability exists and to withstand load transfers in case of supply breaker or main feeder failure, however, some feeders are peaking over these values primarily due to temporary load transfer. Although the planning capacity was exceeded, the feeder peak loading is still within the feeder design capacity of 600A and will be further optimized with the introduction of new MS9 and Enfield TS feeders. Note that the data represented in this table are non-coincidental loads.

Feeder	Planning Capacity (Amps)	2019 Peak Load (Amps)	Capacity Utilization
Thornton TS			
52M2	400	182	45.5%
52M3	400	492	123.0%
52M4	400	494	123.5%
52M5	400	434	108.5%
Wilson TS			
54M1	400	317	79.3%
54M2	400	219	54.8%
54M3	400	382	95.5%
54M4	400	239	59.8%
54M5	400	275	68.8%
54M6	400	295	73.8%
54M7	400	453	113.3%
54M18	400	340	85.0%
Enfield TS			
165M7	400	0	0%
165M8	400	160	40.0%
MS Feeders			
2F1	300	90	30.0%
2F2	300	241	80.3%
2F3	300	182	60.7%
2F4	300	304	101.3%
2F5	300	349	116.3%
2F6	300	221	73.7%
5F1	300	417	139.0%
5F2	300	278	92.7%
5F3	300	229	76.3%
5F4	300	194	64.7%
5F5	300	165	55.0%
5F6	300	420	140.0%
7F1	300	405	135.0%
7F2	300	415	138.3%
7F3	300	198	66.0%
7F4	300	426	142.0%
7F5	300	262	87.3%
7F6	300	179	59.7%
9F1	300	0	0.0%
9F2	300	0	0.0%
9F3	300	0	0.0%
9F4	300	0	0.0%
9F5	300	0	0.0%
9F6	300	0	0.0%
10F1	300	238	79.3%
10F2	300	139	46.3%
10F3	300	131	43.7%
10F4	300	261	87.0%
10F5	300	130	43.3%
10F6	300	466	155.3%
11F1	300	327	109.0%
11F2	300	356	118.7%
11F3	300	3	1.0%

11F4	300	77	25.7%
11F5	300	313	104.3%
11F6	300	436	145.3%
13F1	300	306	102.0%
13F2	300	234	78.0%
13F3	300	78	26.0%
13F4	300	128	42.7%
13F5	300	152	50.7%
13F6	300	215	71.7%
14F1	300	186	62.0%
14F2	300	211	70.3%
14F3	300	117	39.0%
14F4	300	190	63.3%
14F5	300	117	39.0%
14F6	300	71	23.7%
15F1	300	149	49.7%
15F2	300	84	28.0%
15F3	300	128	42.7%
15F4	300	196	65.3%
15F5	300	195	65.0%
15F6	300	235	78.3%

Table 23: Distribution Feeder Capacity Utilization

Identification of asset capacity is critical to ensure that the distribution system will be able to withstand current and future loading requirements as well as operate the distribution system safely and reliably. The previous tables provide information regarding capacity requirements that have been addressed following the completion of Enfield TS and MS9. This alleviates the overloading condition in OPUCN's distribution system. No capacity requirements or constraints have been identified for this planning period, however, capital feeder programs related to Enfield TS and MS9 are expected to be completed by 2020 in order to fully utilize the available capacity from these new substations.

5.3.3. Asset Lifecycle Optimization Policies and Practices

5.3.3.a Asset Replacement Policies and Prioritization

OPUCN's policy for asset lifecycle optimization is to achieve optimal system and operating performance while ensuring safety and system reliability to meet customer needs and expectations in line with the following key objectives:

- Maintain and ensure safety, reliability and resiliency of distribution system infrastructure
- Improve operational efficiency
- Modernize infrastructure and enhance public safety

In order to achieve these, OPUCN focuses on sustaining the assets so that they can perform reliably and safely, while improving cost effectiveness. The decisions involving investment into fixed assets play a major role in determining the optimal performance of a distribution system. A majority of the investments in fixed assets are triggered by either declining performance in the areas of supply system reliability, power quality or safety; or increasing operating and maintenance costs associated with aging assets; or anticipated growth in demand requiring capacity upgrades. In all cases, investments that are either too high or made too far in advance of the actual system need may result in non-optimal operation. On the other hand, investment not made on time when warranted by the system needs raise the risk of performance targets not being achieved and would result in non-optimal operation. Optimal operation of the distribution system is achieved when “right sized” investments into renewal and replacement (capital investments) and into asset repair, rehabilitation and preventative maintenance are planned and implemented based on a “just-in-time” approach.

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

OPUCN considers different parameters including, but not limited to, asset condition, asset depreciation, asset functionality, loading, applicable standards, safety issues and failure risks in prioritizing System Renewal investments and to assess if the asset should be refurbished, replaced, run-to-failure or require no action. The ACA considers the parameters when assessing an asset and the results provide the number of assets that need to be replaced. Hot spots are identified in a heat map as shown in Appendix O where condition of assets are “poor” or “very poor” and where applicable, the assets are grouped together to optimize design in forming an overhead or underground rebuild plan. The results of the ACA and heat map are utilized to create a planned capital renewal program and prioritize investments over the next 5 years.

If the assessment of an asset does not require any further action, do-nothing approach can be implemented until a future inspection indicates otherwise. If additional action is required, OPUCN follows the refurbishment standard practices to address the asset and take corrective actions. For example, a pole line in poor condition can be refurbished by replacing certain assets in the pole line that are in “poor” or “very poor” condition, thus extending the life of the pole line or pace the rebuild of the whole pole line. Additionally, in order to further pace investments and to prevent a vicious cycle of deferring System Renewal investments, OPUCN includes assets in its renewal plan that are within 1-5 years of needing to be replaced.

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

Proactive Replacement

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

Major assets that require significant effort to replace and have long lead times for material or asset delivery are replaced based on the results of the ACA. This proactive replacement allows

OPUCN to modernize the asset and size the asset based on system requirements. This also avoids service failures that may cause major outage impacts or safety risks to customers. The following assets are assessed for proactive replacement:

- Substation Transformers
- Substation Switchgears
- Substation Breakers
- Substation Battery and Battery Charger
- Protection & Control Assets
- Load Break Switches
- Switchgears
- Distribution Poles
- Vault Transformers – distribution transformers on a customer vault or supplying high density areas including downtown Oshawa
- Underground Cable – cables with high risk failures and customer impact

Reactive Replacement

Assets that are quick to replace and low risk, do not require large capital investments and do not cause significant customer outages are “run-to-failure” and replaced or refurbished on an emergency basis. The maintenance activities for these assets are performed in a reactive mode and the scope of repairs is limited to rectifying deficiencies found during safety inspections. The replacement is typically completed on a like-for-like approach which does not necessarily provide opportunities to upgrade the asset using current technology or planned capacity increase. For example, OPUCN employs “run-to-failure” strategy for distribution transformers, due to the relatively low impact of distribution transformer failures on reliability. However, when transformers with serious deficiencies are identified through inspections, these are immediately replaced.

The assets considered under reactive replacement are typically assessed with visual inspection at a minimum and includes the following

- Distribution Transformers
- Pole Line Hardware
- Metering Assets

Maintenance Planning Criteria and Assumptions

Proper maintenance is essential in maintaining system reliability and the functional integrity of the distribution system. It improves distribution system efficiency and prevents unnecessary or unexpected service disruptions, which optimize expenditures. In order to realize these benefits, OPUCN has established a maintenance program that will keep the asset in its top operational condition to mitigate the risk of unexpected power outages, asset damage, and high cost of repair or replacement in an emergency condition. This program has been divided into two categories: Reactive Maintenance (Unplanned) and Routine System Operations and Maintenance (Planned). Reactive maintenance will require immediate action and is urgent due to its unplanned nature, whereas, routine maintenance is scheduled according to issues identified through inspections, testing or trouble reports. Reactive and routine maintenance are further subdivided into systems, which are either substation, overhead system or underground system.

Reactive Maintenance

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

<u>Routine System Operations and Maintenance</u>

Preventative maintenance is scheduled or performed in response to problems identified in inspection, testing and/or trouble reports. The asset is repaired or replaced prior to a failure. Testing may be performed to predict the asset condition.

OPUCN complies with or exceeds the minimum inspection requirements set out in the OEB's Appendix C of the DSC, which specifies inspection, and maintenance of distribution system assets. Manufacturer's recommendations and best industry practices are also considered in determining the scope of maintenance. Routine System maintenance is completed on an as required basis while the frequency of OPUCN system inspection and preventative maintenance activities are as follows and included in OPUCN's Maintenance Plan in Appendix P:

1. Visual inspections on both OH and UG systems including civil infrastructures and customer owned substations are completed on a 3-year cycle through a distribution system patrol according to geographic zones, completing 1/3 of the distribution system annually as shown in Figure 14. Visual inspections on all distribution automation devices are to be completed annually to ensure the control and communication devices continue to function in the absence of AC power. This will also include load checks on the batteries and their chargers. Results of the inspection are used in the ACA and allows OPUCN to capture and identify any asset deficiencies in the field that requires repair or replacement either through a maintenance or capital program.

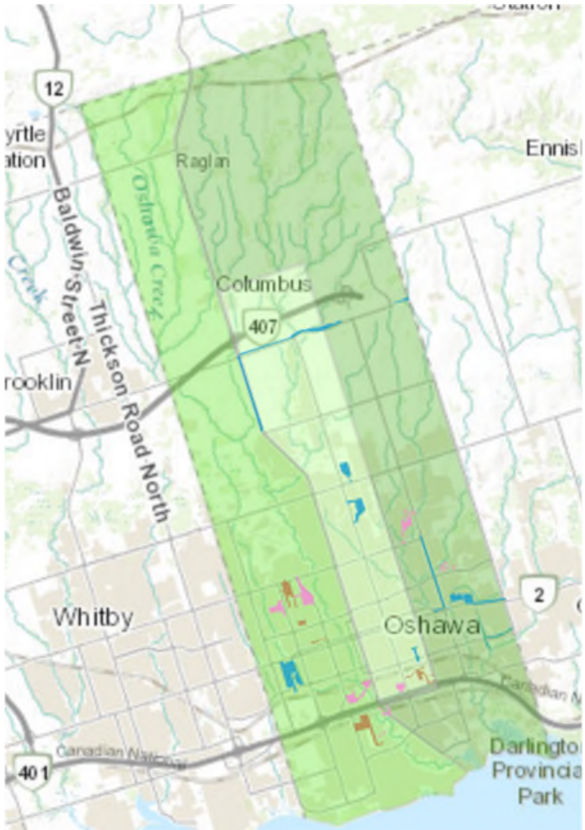


Figure 14: OPUCN Geographic Zones

2. Infrared scanning of all critical assets including overhead primary lines, distribution transformers, substation asset, terminators, connectors, etc. is carried out annually to identify any anomalies caused by overheating and may be attributed to poor connections, overloading or defective equipment. Infrared scanning allows for corrective measures to be taken before the assets fail that can cause power outages. In order to ensure that all anomaly locations are identified, OPUCN schedules the inspection during summer when system load is higher. A third party collects the data and summarizes all defects locations, level of severity and proposed recommended action. Any repairs or replacements required are completed within a reasonable timeline depending on the level of severity, with highest severity completed immediately.

3. Switch maintenance includes maintenance on all load break switches, air break switches and in-line (solid blade) switches are completed on a 3-year cycle. These switches are used on the distribution system to reconfigure overhead circuits on load as required to ensure sufficient supply to the customers during routine and emergency switching. Proper operation of these switches will shorten the outage restoration time resulting in the improvement of system reliability.

   The maintenance is coordinated through the control room operator due to system loading considerations and the capability to take a switch out of service, when required. The switch and the manual operating device will be cleaned, lubricated, aligned and adjusted. Any defective components will be replaced as required. Other deficiencies are reported and documented for follow-up repairs.

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

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

5. Vegetation management or tree trimming is carried out on a 3-year cycle according to geographic zones, completing 1/3 of the distribution system annually as shown in Figure 14. The objective of this program is to minimize tree contact interruptions and mitigate reliability risks and safety hazards. OPUCN contracted forestry crew are required to trim trees within 3m of primary conductors and 1.5m of secondary conductors as a minimum and must follow the regulatory and industry standards in maintaining clearances from power lines and equipment. As required, third parties inspect power lines for tree limbs or vegetation growing too close to the lines or at risk of falling into the lines, outside of planned cycle.

The following provides a summary of the frequency of system inspection and maintenance for OH and UG systems.

System	Activity	Frequency
Overhead System	Visual Inspection	3-year cycle, Annually for distribution automation
	Infrared Scanning	Annually
	Switch Maintenance	3-year cycle
	Pole Testing	5-year cycle (20 years+)
	Vegetation Management	3-year cycle
Underground System	Visual Inspection	3-year cycle, Annually for distribution automation
	Infrared Scanning	Annually

Table 24: Frequency of Overhead and Underground System Inspection and Maintenance

Similar to overhead and underground systems, OPUCN performs a comprehensive system inspection and maintenance for substation assets which also includes visual inspection and infrared scanning as well as MS components maintenance. Some critical assets installed at MSs are monitored through the SCADA system and all data collected during inspection are used for condition assessment and allows OPUCN to capture and identify any asset deficiencies in order to develop a corrective action plan. The following maintenance activity and frequency are being performed in the substation.

1. Visually inspect all MS components including circuit breakers, substation transformers

and cooling fans, cable terminators, switchgear, station service transformers, batteries, battery chargers, lighting, heating, ventilation, drains, doors, locks, fences, safety equipment, fire extinguishers, eye-wash stations, and all associated devices used to provide protection, control, metering and monitoring of the station

2. Maintain DC systems by checking and testing voltage of each cell and the total battery voltage and perform load testing on the batteries once a year
3. Test and maintain the mechanical and electrical features of the protection control system.
4. Collect oil samples from transformers and tap changer compartments and send samples for oil testing and Dissolved Gas in Oil Analysis (DGA). Review test results to determine if further action/testing is required
5. Perform detailed testing every three years on the transformer including, but not limited to: turn ratio, doble, winding resistance, core ground, power dissipation factor, dielectric absorption, excitation current, cooling system, bushings, alarms and trip mechanism
6. Complete on-load tap changer maintenance
7. Check, clean and lubricate switchgear, ventilation and fan
8. Conduct infrared scanning on all high voltage substation component

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

Table 25: Frequency of Substation Inspection and Maintenance

OPUCN is in the process of improving substation maintenance by transitioning to the maintenance activities as prescribed in the ANSI/NETA MTS-2015. The maintenance activities and frequency of those activities exceeds the minimum requirements by the OEB and are in the process of being finalized. These plans will provide guidance on more comprehensive maintenance on the MSs to prolong asset life and ensure all equipment is operating as designed.

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

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

5.3.3.b Asset Lifecycle Risk Management Policies and Practices

OPUCN's policy is to achieve optimal system and operating performance while ensuring safety and system reliability to meet customer needs and expectations in line with the key objectives as outlined in the introduction of 5.3.3.a:

- Maintain and ensure safety, reliability and resiliency of distribution system infrastructure
- Improve operational efficiency
- Modernize infrastructure and enhance public safety

This policy will minimize risks while maintaining an optimal system and ensuring the safety and system reliability of the critical distribution system infrastructure. This is achieved by utilizing the best AM strategies in managing risks which includes detailed inspection and testing, standard maintenance of assets and applying proper corrective actions for each asset based on risk and analysis. In doing so, the risk associated with each asset can be mitigated and the prioritization of investments can be optimized over a period of time.

Prioritization of capital investments is established by considering the level of risks associated with the asset investment. Mandatory investments are considered high priority and are included in the capital investment plan. Investments with highest level of risk mitigation and greatest benefit including major assets are prioritized compared to low level risk assets. For example, critical asset investments such as replacement of substation transformer or substation switchgear are considered high priority as it can negatively impact significant portions of the distribution system should it fail compared to a distribution transformer replacement program that have local impact. OH and UG renewal investments are also prioritized against each other within their respected program condition ("poor" or "very poor") and criticality of the area, e.g. supplying critical customers like hospitals or municipal government buildings.

The results and outcomes of the following analyses are used to evaluate risk for the capital investment plan:

- ACA
- Historical Reliability Analysis
- Operations & Maintenance Data
- Equipment Failure Analysis
- Equipment Loading

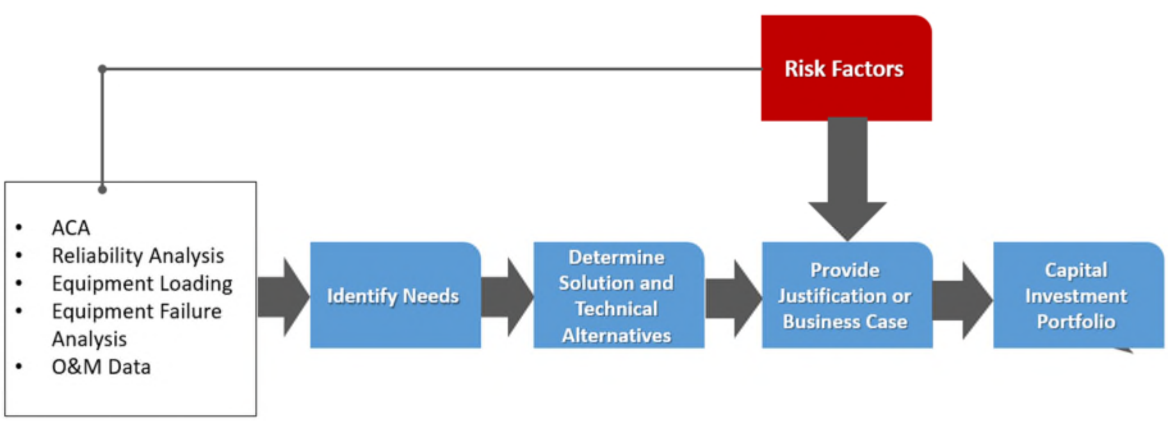


Figure 15: Asset Lifecycle Risk Management Process

Risk factors are utilized based on its impact on the capital investment and analyzed during the justification process. Investments with highest level of risk mitigation are prioritized compared to low level risk assets.

5.3.4 System Capability Assessment for Renewable Energy Generation

This section provides information on the capability of OPUCN's distribution system to accommodate REG. A summary of the REG forecast and information on identifying constraints are also identified.

5.3.4.a Renewable Generators Over 10kW

As of December 31st, 2019, OPUCN's distribution system has the following renewable energy installations (REG) with capacity totaling to 3942.5kW under the FIT, microFIT and net-metering program:

- 334 micro-FIT solar photovoltaic (PV) installations with micro-FIT generation capacity of 2644.39kW;
- 6 FIT solar photovoltaic (PV) installation with FIT generation capacity of 940.0 kW;
- 38 net-metering solar photovoltaic (PV) installation with net-metering generation capacity of 358.1kW;

Additionally, the following generation projects are connected onto OPUCN's distribution system with capacity totaling to 4550 kW:

- 1 Combined Heat and Power (CHP) system with generation capacity of 1600kW
- 1 microgrid system consisting of 2400kW CHP, 500kW battery energy storage system and 50kW solar photovoltaic (PV) installation – 2950kW total generation capacity

In total, there are 11 FIT, net-metering, CHP and microgrid generation connections that are over 10kW which is summarized in Table 26.

Project Type	# of Connected REGs	Generation Capacity (kW)
FIT	6	940.0
Net-Metering	3	166.8
CHP	1	1600.0
Microgrid	1	2950.0
Total	11	5656.8

Table 26: Summary of Generation Connections (>10kW)

5.3.4.b Renewable Energy Generation Forecast

Since the IESO ceased accepting new applications under the FIT and microFIT programs, OPUCN has observed a significant decline in the number of generation connections. Applications are now limited to net-metering, load displacement, CHP and microgrid projects including a potential 3 small generation installations with proposed total generation of 1539.6kW and 1 micro-embedded generation installations with proposed total generation of 7.7kW with a total capacity of 1.55MW proposed to be connected to OPUCN's distribution system during the planning period.

A summary of anticipated REG connections is provided in Table 27:

Feeder	Project Type	# of Proposed Connection	Total Capacity (kW)
44kV Distribution Network			
54M1	Load Displacement	1	439.6
54M18	CHP	1	600.0
13.8kV Distribution Network			
11F2	Net-Metering	1	500.0
13F1	Net-Metering	1	7.7
	Total	5	1547.3

Table 27: List of Proposed Generation Connections

5.3.4.c Capacity Available

The estimated remaining substation capacity for both Hydro One TSs and OPUCN MSs is shown in Table 28 and Table 29. All of the identified substations have sufficient short circuit capacity and thermal capacity to accommodate proposed REG connections. It is also important to note that based on historical generation connections, majority of REG projects are inverter-based or small CHP with insignificant fault contribution to the distribution system. OPUCN does not anticipate that future generation connections during this planning period will reach the capacity limits.

Station Name	Voltage (kV)	Available Short Circuit Capacity (MVA)	Available Thermal Capacity (MW)
Thornton TS	44	346.0	98.2
Wilson TS	44	538.0	218.4
Enfield TS	44	254.6	91.9

Table 28: Hydro One Transmission Station Capacity (Refer to Appendix Q: Sections of Hydro One list of Station Capacity, Dec 19, 2019)

Distribution Substation Transformer		Voltage (kV)	Available Short Circuit Capacity (MVA)	Available Thermal Capacity (MW)
MS2	**T1**	13.8	101.9	25.7
	T2	13.8	101.7	26.3
MS5	**T1**	13.8	103.4	26.2
	T2	13.8	108.2	20.8
MS7	**T1**	13.8	97.3	21.4
	T2	13.8	97.2	21.3
MS9	**T1**	13.8	119.8	25.0
	T2	13.8	128.9	25.0
MS10	**T1**	13.8	82.5	25.5
	T2	13.8	118.5	20.8
MS11	**T1**	13.8	100.1	25.7
	T2	13.8	102.5	25.8
MS13	**T1**	13.8	112.5	26.2
	T2	13.8	108.8	26.0
MS14	**T1**	13.8	97.4	21.1
	T2	13.8	104.4	20.8
MS15	**T1**	13.8	101.5	25.7
	T2	13.8	98.4	26.2

Note: The acceptable thermal capacity limit at a TS or MS is established by adding together 60% of maximum MVA rating of the single transformer and the minimum station load.

Table 29: OPUCN Municipal Substation Capacity

5.3.4.d Constraints – Distribution and Upstream

Based on the available capacity identified in the previous section, there are no constraints identified and there is sufficient capacity in both OPUCN's distribution system and Hydro One's TS to accommodate the potential connection of future REGs. OPUCN does not anticipate any requirement for immediate investments as a result of this for this planning period. This will be further monitored as future proposed REGs are identified.

5.3.4.e Constraints – Embedded Distribution

OPUCN does not have any embedded distributors and does not have any constraints to identify in this section.

5.4 Capital Expenditure Plan

This section describes OPUCN's five-year capital expenditure plan over the forecast period, including a summary of the plan, an overview of OPUCN's capital expenditure planning process, a summary of capital expenditures, and justification of capital expenditures.

OPUCN's DSP includes information on prospective investments over a five-year forecast period (2021– 2025) as well as planned and actual information on investments over the historical period (2015– 2020). Table 30 summarizes the historical and forecast periods covered by this DSP:

Historical Period					Bridge Year	Test Year	Forecast Period			
2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025

Table 30: Historical and Forecast Periods

5.4.a Customer Engagement

OPUCN conducts customer surveys approximately every two years targeting residential and small commercial customers. Beginning in 2014, with the help of an external consultant, Utility*PULSE*, OPUCN augmented their regular telephone-based Customer Satisfaction survey with supplemental questions to help gain insights into, or deal with, issues customers care about. For example, the 2014 telephone survey asked 405 OPUCN customers to prioritize investments for ten operational issues. In 2017, 400 interviewees were asked to identify the importance of 10 items as they relate to online access to various items, and in 2018, 402 interviewees were asked to prioritize 12 operational planning items. These results were measured against feedback given in 2019's online Taking A.I.M. Survey shown in Appendix C. Additionally, OPUCN complimented the survey activity with several in-person initiatives. Open houses, information sessions and a virtual telephone town hall were conducted to educate and inform customers about the rate application process and potential costs. All of the in-person outreach was hosted by OPUCN's senior executive team and customers were able to have open interactive dialogue.

Customer Engagement Activity	Methodology	Customers Engaged
Customer Engagement Surveys (2014, 2017, 2018)	Telephone	**1,207**
Taking A.I.M. (Applied Insights Methodology) Survey – 2019	Online	**1,240**
Public Open House (Nov 2017, May 2018, Nov 2018)	In-person	**275**
Virtual Telephone Town Hall (Oct 2019)	Telephone (Live)	**9,798**
Four separate information sessions (Nov-Dec 2019)	In-person	**50**
Total number of customers who participated in the engagement:		**12, 570**

Table 31: Customer Engagement Activities

Findings from OPUCN's Customer Engagement activities show 6% of online survey respondents will not support any increase for any reason. However, 41% of online survey customer respondents would support all of OPUCN's recommendations or more than their recommendations. The findings also illustrate that OPUCN is a well-respected company (83% online (2019), 85% telephone (2018)), who is trusted and trustworthy (86% online (2019), 90% telephone (2018)) and who is seen as an organization that spends money prudently (82% telephone (2018)). The data from the online Taking A.I.M. Survey with information for CoS and DSP also shows that the majority of the respondents support OPUCN's recommendations as they relate to System Renewal, System Service, General Plant, and Facility investments.

Base: Total Respondents 1,240	Support OP's recommendations #	Support OP's recommendations %
General Plant	713	58.3%
New Facility	912	73.5%
System Renewal	763	61.6%
System Service	739	59.6%

Table 32: Customer Survey Respondents

Copies of Taking A.I.M. Survey Report and OPUCN Engagement Summary Report are filed along with the preliminary capital investment plan. Overall, 85% of OPUCN's customers are very satisfied or fairly satisfied with OPUCN. In terms of priorities, 95% support continuously improving the safety and reliability of the electricity network, and 95% support remaining focused on keeping costs low and 92% support looking for ways to use technology to safeguard the electricity network or get more out of the equipment. These results support OPUCN's focus on System Renewal and System Service investments.

OPUCN posts on its website a listing of its capital investment projects for the upcoming years as well an online outage map to reference during power outages. OPUCN has posted its proposed capital projects for 2020-2022. This allows OPUCN's customers to review the upcoming projects and submit their concerns or questions to OPUCN. Any customer feedback or concerns are reviewed and responses provided accordingly. 77% of survey participants have indicated that they would like to see an outage notification system that automatically sends you a message by phone call, email or text within the next 5 years. OPUCN currently has a telephone notification system in place.

OPUCN also provides advanced notices to customers at each stage of a renewal project advising them of upcoming overhead or underground plant rebuilds in their area or neighborhood, including any planned outages. Any questions or concerns (for example location of the proposed poles or pad-mount type transformers) are normally resolved directly with the customer.

OPUCN hosts open houses and information sessions to share plans of upcoming projects, customer service updates and safety related information. OPUCN will solicit and receive customer feedback and address any concerns to the best of its abilities directly with their customers. In 2019, the online survey and in-person events participants had the opportunity to provide open feedback on the DSP and request contact from an OPUCN employee to further discuss questions or concerns.

In addition to adding opportunities for customers to interact with OPUCN in-person more self-serve options were added online. Customers provided feedback that they wanted to be able to take care of their accounts at their convenience. An online self-service hub was created allowing customers to access online forms, information and account access.

OPUCN took efforts to engage the local contractor and developer community with the goal to keep them up-to-date on safety, incentives and opportunities. OPUCN created a dedicated webpage "Contractor's Corner" for developers and contractors to go to find guidelines, specifications and service applications. Centralizing the information simplified the contractor's process and help streamline the service application process.

In June and November of 2018, OPUCN hosted their first Developer Conference and Contractor Safety Day respectively. In 2019, OPUCN expanded on Contractor Safety and worked with industry partners to host a larger event in November. The attendance more than doubled from 2018. In addition to addressing any inquiries contractors have, OPUCN was able to educate how to safely work around OPUCN's infrastructure.

OPUCN continues to meet with its major customers (e.g. Durham College, Lakeridge Health Centre, Region of Durham, The City of Oshawa) and key developers (e.g. Tribute Homes, Panatonni Development Company; Sorbora, Podium Development), for ongoing updates and service-related consultation on their project plans and future developments as well as account consultation.

OPUCN considers all customer feedback and preferences in determining the pacing of its investments and in optimal selection of projects. Furthermore, OPUCN has been prudent when incurring costs since the Customer Satisfaction survey results indicate that the low price of electricity is an important factor to customers.

Appendix C contains the detailed results from OPUCN's efforts in engaging with the customer in identifying their needs and preferences. Included is a full summary of OPUCN's Engagement and a report on Taking A.I.M. Survey results.

5.4.b System Development over the Forecast Period

Load and Customer Growth

OPUCN expects a moderate to high peak demand and customer connection growth (approximately 1.4% annually) throughout the 2021 to 2025 planning window, which is primarily driven by greenfield development in Kedron II planning area and RioCan located in north Oshawa. This is in line with development plans from the City and Region including where it indicates forecast population and housing unit numbers of 194,273 residents and 79,416 housing units respectively by 2029. GDP growth in the City was recorded at 2.7% in 2018 which is relatively fast in terms of economic growth. It is forecasted that the GDP will stabilize in 2020, following a gain of 1.8% in 2019 and will quickly resume in 2021 at a projected rate of 2.2%.

System capacity has been addressed in the previous capital investment plan through the commissioning of new TS and MS (Enfield TS and MS9). In addition and in order to further accommodate the anticipated load and customer growth, OPUCN has considered these within System Access investments in this planning period including revenue metering, connection and expansion programs as well as utility relocation as a result of municipally driven road widening.

Investments in System Renewal will also ensure that customer service levels with respect to reliability are maintained. ACA and performance analytics help direct capital investment to specific at-risk equipment and extend further the safe reliable useful life of all assets.

Climate Change Adaptation

Prominent changes in climate conditions have driven utilities and municipalities in addressing and adapting to climate change. OPUCN understands the impact of climate change to the distribution system, which can result in varying electrical demands and unusual operating conditions resulting from extreme temperatures, flooding, high winds and ice build-up.

Consequently, it is vital for OPUCN to ensure that the distribution system is able to withstand these abnormal conditions to mitigate any risks of damaging distribution assets and to prevent significant customer outages.

OPUCN is undertaking a number of initiatives as a result of climate change to deal with prevention and mitigation of extreme event impacts and to be resilient to changing weather conditions including, but not limited to:

- Distribution System Hardening – Climate change has contributed to environmental stress on equipment that can also cause outages. In preparing and preventing these type of outages, we have implemented in the engineering standards practice to build and design pole lines to meet or exceed the latest revision of CSA C22.3 No.1. Overhead Systems which ensures that new distribution system expansions, extensions and replacements comply with current standards and are storm-hardened to withstand weather pattern changes.
- System Resiliency – To prevent outages caused by flooding, OPUCN has several programs in place including utilization of sump pumps, equipment specification improvements, preventive maintenance programs and proper storm water management on new substation design.
- Vegetation Management – Tree trimming performed on a 3-year cycle with increased clearances that reduces outages caused by falling tree limbs. Standards have been updated to specify required clearance from padmount transformers during tree planting to allow for future tree canopy.

Grid Modernization

Grid modernization will continue to advance as OPUCN continues to invest in activities such as communication infrastructure, distribution system and MS monitoring, automated switches, OT and IT systems to meet reliability performance expectations and cybersecurity requirements. Investments in distribution automation such as SCADA controlled switches, automated switches, centralized automation, and network monitoring as well as the improvement in the OMS, GIS and related operational and data systems are part of OPUCN's grid modernization efforts. OPUCN will continue these efforts over the period of the DSP.

Forecasted REG Accommodation

The accommodation of REGs are not expected to drive any significant system developments during this planning period. Throughout the implementation of investments in System Access, System Renewal, System Service, and General Plant initiatives, considerations for REGs will be undertaken in the year of the confirmed installation date. As the investment costs are unknown at this time, OPUCN proposes that any future qualifying expenditure would be recorded in the Board approved Deferral Accounts and recovered at a more opportune time, through the provincial cost recovery mechanism set out in Section 79.1 of the OEB Act.

5.4.1 Capital Expenditure Planning Process Overview

This section of the DSP provides a high-level overview of OPUCN's capital investment planning process. The capital investment planning process is also embedded within OPUCN's AM process and focuses on determination of which investments should be included in the DSP under the four investment categories: System Access, System Renewal, System Service and General Plant.

5.4.1.a Description of Analytical Tools and Methods for Risk Management

Currently, OPUCN does not have any formal analytical tools and methods used for risk management. OPUCN is planning to investigate within the forecast period in developing a more structured and formal process to aggregate existing and new planning methods associated with risk management. However, risks are considered throughout the AM process and embedded within the AM objectives as described in Section 5.3.3.b. Please also refer to Figure 15 regarding risk management process.

In general, risk could either be safety, regulatory, reliability, security, environmental or financial and is applied throughout the AM process and capital investment planning by meeting AM objectives. Investments that meets the AM objectives and provide the greatest benefit and highest level of risk mitigation will receive a higher prioritization ranking and preference for inclusion in the proposed capital investment plan.

5.4.1.b Description of Processes, Tools and Methods for Investment Prioritization

Project Identification

In line with OPUCN's Asset Management Process stipulated in Section 5.3, OPUCN has identified projects in the capital expenditure plan that promotes a safe, sustainable and reliable infrastructure to service the needs of customers while complying with regulatory obligations and license conditions. Needs are determined based on inputs and drivers which can be either internal, external or driven by strategic investments. Information collected from these investment drivers will determine the initial investments and are classified into four categories, as defined in OEB's Chapter 5 filing requirements: System Access, System Renewal, System Service and General Plant.

- System Access projects including modifications to the distribution system infrastructure to allow connection of new load or generation customers and to relocate distribution system infrastructure installed in public right-of-way to accommodate municipal road reconstruction projects are identified through engagement and consultations with City, Region and developers . These projects are mandatory in nature and are budgeted and scheduled to meet the timing needs of third party proponents.

- System Renewal projects are identified through OPUCN's AM process. The project needs for a specific period are supported by a combination of asset inspection, individual asset performance, and ACA.

- System Service projects are identified through OPUCN's AM process, Regional Planning, Grid Modernization Plan and operational needs to ensure that the distribution system provides consistent service delivery are dealt with in a timely manner as well as to meet system operational objectives including system reliability, system capacity and system modernization.

- General Plant projects are identified through the BCA, OPUCN's AM process and internally by specific departments (engineering, finance, operations, facilities, IT etc.) based on business needs. These projects can be routine investments such as vehicle replacements, tools and facilities or special projects such as new CIS, office systems, cybersecurity, etc.

<u>Project Selection and Prioritization</u>

Mandatory capital projects are automatically included and prioritized based on externally driven schedules and needs, as there is normally little flexibility to defer these projects as described in Section 5.3.1. In general, mandatory projects are defined as:

- System Access investments that facilitate modifications to the distribution system infrastructure to allow connection of new load or generation customers and to relocate distribution system infrastructure installed in public right-of-way to accommodate municipal road reconstruction projects. System Access investments are mandatory and therefore, receive the highest priority in the overall investment envelope.
  - New/modified customer service connections
  - Road authority driven utility relocation projects
  - Mandated service obligations
  - Renewable energy projects
- System Renewal investments that are reactive in nature in addressing assets that failed, assets identified in ACA that are in critical condition or assets posing any safety concerns:
  - Emergency plant replacement
  - Safety related projects
  - ACA recommended replacement programs
- System Service investments that addresses capacity requirements
- General Plant investments that are reactive in nature or projects that have been identified in the BCA that is essential in supporting business needs or addressing safety concerns.

Prioritization and selection of the remaining capital investments is completed by determining the level of AM objectives achieved, risks associated and value of projects. Most System Renewal, System Service and General Plant projects fall into this category and some projects may involve multiyear program investments to meet AM objective needs. Projects that provide the greatest benefit and highest level of risk mitigation will receive a higher prioritization ranking and preference for inclusion in the proposed capital investment plan. This approach is mostly relevant to System Renewal projects where proactive replacement is mostly considered.

An important step in the investment prioritization process is the ACA where an asset HI framework is formulated. An ACA is used to produce the HI, which is a quantified condition score of a given asset and represents a probability of failure. The HI score is ultimately calculated using asset age, inspection and historical performance data (as applicable). This procedure allowed separation of the assets in “very good”, “good” and “fair” condition that require minimal risk mitigation from those in “poor” and “very poor” condition. For assets determined to be in “poor” or “very poor condition,” consequences of asset failures were assessed and those requiring renewal/rehabilitation were ranked in order of priority, with highest risk of failure being assigned the highest priority.

Since a large part of OPUCN’s infrastructure assets have been determined to be in “poor” or “very poor” condition, prioritization of investments in the System Renewal category, required a comprehensive risk assessment approach, which is described in Section 5.3.3 in detail.

System Service projects are prioritized and assessed based on modernization opportunities relative to the desired benefits and/or impact to the system drivers. A project or program is considered to be the greatest potential benefit if they:

- support need for customer choice, either driven by customers or driven externally,
- enable REGs, EVs and storage,
- improve reliability,
- comply with regulation, or
- reduce costs

General Plant are prioritized based on business needs. Investments in fleet, facilities, tools, IT and special projects are prioritized and paced on as-needed basis. Management staff and specialists in their respective fields make a determination of what projects are required to be included in the capital investment plan and reviewed against the overall requirement and financial risks.

In addition to the asset condition and risk assessment, customer engagement sessions were held to receive feedback and determine customer preferences for service quality level and rate increase, which assisted in shaping the preliminary investment portfolio to addresses customer needs.

Project Pace

Project pace for System Access projects is generally driven by third party schedules and needs. System Service and General Plant projects tend to be lumpy in nature and most are paced to begin and complete within a specific budget year. System Renewal projects tend to be multi-year programs and are paced to balance the AM objective needs of the specific program with regard to available resources and managing the program impacts. OPUCN's multi-year System Renewal programs have been prepared and paced based on the ACA report.

5.4.1.c Description of Processes, Tools and Methods for REG Investment Prioritization

The prioritization process for REG investments is the same process as above where the REG investment is triggered and driven by customer requirements.

When OPUCN is required to do an expansion or enhancement to the distribution system to connect a REG facility, the provisions of the OEB DSC Section 3.2 will apply. OPUCN will perform an economic evaluation to determine the generating facility's share of the present value of the projected capital costs and ongoing maintenance costs of the expansion. However, it was identified that there are no OPUCN capital investments related to REG identified at this time.

5.4.1.d Assessing Non-Distribution System Alternatives to Relieving System Capacity

OPUCN actively participates in the Regional Planning process which identifies and assesses system capacity constraints. The second cycle of the Regional Planning process concluded that the capacity needs identified in the previous planning cycle have already been addressed or will be addressed by the new Enfield TS. No non-distribution system alternatives were considered as a result of this, however, OPUCN continues to encourage customers to conserve energy through CDM initiatives. Load-growth in the service territory was well-addressed through the existing IESO programming, which achieved an estimated 66 GWh of conservation via the Save- On-Energy programs between 2016 and 2019.

5.4.1.e Distribution System Modernization

OPUCN believes in planning for future innovative and technological applications of the electrical distribution system, and in keeping with the intents of the Province's Long-Term Energy Plan (LTEP). OPUCN has undertaken a Grid Modernization Plan to strategically take advantage of technological opportunities to implement cost-effective modernization that enables the distribution system to be more efficient, reliable and to provide more customer choice. Grid modernization includes the use of technology to improve customer access to real-time consumption data, customer integration of REG, operational efficiencies, AM and services to customers. The following are some of the initiatives OPUCN is taking advantage of in its system planning to drive cost-effective modernization:

- OPUCN will implement an enhanced Green Button Data standard which is a Customer Self-Service Online Portal tool that will allow customers the ability to log into a secure portal to view balances, due dates, bills as well as smart meter activity and predicted bill statistics. The software has the ability to provide near real-time alerts based on customer settings including bill/usage thresholds, high usage and other configurable options. This will provide customer access to consumption data, facilitate behind the meter services and applications, and provide customers with the ability to make decisions about their electricity costs.

- OPUCN will be investing in replacing end of life smart meters with improved technology smart meters. This will provide more reliable smart meter data and would provide near real-time data access to customers. In addition, new smart meter technology would aid the utility's situational awareness of customer outages.

- OPUCN will take advantage of proven technologies in distributed automation to increase operational efficiencies. This includes ongoing installation of automated switches, introducing 44kV remote switches, integrating smart fault indicators & lateral reclosers with OMS, investigating in other cost-effective IEDs, and introducing a Centralized Automation Controller that will be built up across the entire distribution system. These efforts will be a coordinated effort to enable Fault Location, Isolation and Service Restoration (FLISR) to reduce impact (number of customers and duration) of an outage and improve overall efficiency of operation. In addition, OPUCN expects the addition of automated and remote switches to help increase the ability of REGs to connect to the system.

- OPUCN will be improving its AM system through real-time condition monitoring of MS batteries and power transformers. This will provide health information of critical assets to reduce the risk of large MS outages. This will reduce risk and improve over efficiency of operating and maintaining these assets.

- OPUCN will be updating and increasing the functionality of its GIS, OMS and ODS to improve outage response, automated customer notification, operational data availability for business intelligence and AM. These new functionalities include the adoption of innovative processes available through strategic data integration. Specifically, the ODS upgrades will help supply necessary data integration for the Green Button initiative which will provide customer data access.

OPUCN will be improving the OT/IT cybersecurity through security measures as indicated in OEB's Cybersecurity Framework. OPUCN expects to not only increase cybersecurity but also improve data bandwidth and reduce communication latencies for OT devices and other smart grid devices.

5.4.1.f / 5.4.1.1 Rate-Funded Activities to Defer Distribution Infrastructure

OPUCN has reviewed the OEB's "CDM Requirement Guidelines for Electricity Distributors", including Section 4.1, which provides guidance regarding "putting conservation first in infrastructure planning". The guidelines state that applications must be related to "areas of the distribution system where growth is anticipated and potential constraints have been identified". Given this eligibility requirement, OPUCN will not be pursuing funding through distribution rates for any of the four types of activities contemplated by the OEB. For additional clarity:

1. Load growth has already been addressed: Throughout 2018 and 2019, OPUCN commissioned two new pieces of distribution infrastructure (Enfield Transfer Station and Municipal Substation 9) to address the anticipated load growth for Oshawa's North-end. CDM programming was not pursued in lieu of these two infrastructure builds because the supply gap was too critical, large and localized to be met through available measures. Load-growth elsewhere in the service territory was well-addressed through the existing IESO programming, which achieved an estimated 66 GWh of conservation via the Save- On-Energy programs between 2016 and 2019.

2. Lack of identified constraints: OPUCN has not identified any constraints within our distribution system.

Throughout the course of the five-year DSP, OPUCN will continue to monitor less predictable load growth trends, such as electric vehicle uptake, and will consider opportunities for applying for distribution rates to defer infrastructure as appropriate

5.4.2 Capital Expenditure Summary

This section provides a general overview of OPUCN's capital expenditures over an 11 year period, including five historical years (2015-2019), bridge year (2020), test year (2021) and forecast years (2022-2025). OPUCN has allocated its capital expenditures to the four investment categories on the basis of the primary driver of the investment. Appendix 2-AB provides OPUCN's actual and forecast capital expenditures and capital contributions over the historical and forecast periods. Appendix 2-AA shows the capital projects table summary. Costs for projects that are considered Work in Progress (WIP) at the end of a fiscal year are not captured in the year spent; they are captured in the year capitalized.

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

First year of Forecast Period: *2021*

CATEGORY	Historical Period (previous plan[1] & actual)																						
	2015			2016			2017			2018			2019			2020			2021	2022	2023	2024	2025
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var	Plan	Plan	Plan	Plan	Plan
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access	8,595	6,236	-27.5%	3,740	3,207	-14.3%	3,150	1,793	-43.1%	3,435	3,438	0.1%	3,455	10,318	198.6%	5,790	1,637	-71.7%	5,911	5,016	4,662	4,767	4,772
System Renewal	5,943	7,233	21.7%	4,932	4,193	-15.0%	4,472	5,475	22.4%	4,761	3,779	-20.6%	4,851	6,524	34.5%	8,129	3,939	-51.6%	7,498	9,311	8,797	8,884	8,818
System Service	1,068	722	-32.4%	1,380	1,192	-13.6%	420	941	124.1%	10,455	8,514	-18.6%	15,763	11,621	-26.3%	2,508	1,146	-54.3%	1,109	799	1,383	886	995
General Plant	1,675	988	-41.0%	1,180	1,448	22.7%	755	874	15.7%	889	1,299	46.1%	510	704	38.1%	2,124	223	-89.5%	1,975	851	794	875	713
TOTAL EXPENDITURE	17,281	15,179	-12.2%	11,232	10,040	-10.6%	8,797	9,083	3.3%	19,540	17,030	-12.8%	24,579	29,168	18.7%	18,551	6,945	-62.6%	16,493	15,977	15,636	15,411	15,299
Capital Contributions	- 4,911	- 3,324	-32.3%	- 1,455	- 843	-42.1%	- 1,075	- 1,207	12.3%	- 1,095	- 4,073	271.9%	- 1,105	- 5,931	436.8%	- 1,958	- 411	-79.0%	- 2,043	- 1,813	- 1,718	- 1,738	- 1,733
Net Capital Expenditures	12,370	11,855	-4.2%	9,777	9,197	-5.9%	7,722	7,876	2.0%	18,445	12,957	-29.8%	23,474	23,236	-1.0%	16,593	6,534	-60.6%	14,449	14,164	13,918	13,673	13,566
System O&M	$ 2,634	$ 2,797	6.2%	$ 2,860	$ 3,017	5.5%	$ 2,999	$ 2,724	-9.2%	$ 3,015	$ 3,154	4.6%	$ 2,878	$ 3,015	4.8%	$ 3,271	$ 1,184	-63.8%	$ 3,168	$ 3,232	$ 3,296	$ 3,362	$ 3,430

Notes to the Table:

1. Historical "previous plan" data is not required unless a plan has previously been filed. However, use the last Board-approved, at least on a Total (Capital) Expenditure basis for the last cost of service rebasing year, and the applicant should include their planned budget in each subsequent historical year up to and including the Bridge Year.
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year): 6

Explanatory Notes on Variances (complete only if applicable)

Notes on shifts in forecast vs. historical budgets by category

In the System Access Investment Category historical expenditure in third party driven projects and customer growth forecasts were considered heavily to develop the forecast expenditure. Along with customer driven work, the increase of metering projects in this investment category is seen. The System Access Investment Category is expected to increase by 34% on net expenditure and decrease by 2% on gross expenditure when compared to the historical actual expenditure.
In the System Renewal Investment Category forecast net expenditure is expected to increase by 51% from historical net actual expenditure to support the renewal of assets that are at or near, or at the end of Typical Useful Life (TUL) as per the Asset Condition Assessment (ACA). The forecast DSP has shifted to expect increased spending in the System Renewal Category.
In the System Service Investment Category the forecast net expenditure is expected to decrease by 76%. After stripping out the unusual investments in large-scale station work in the historical period, System Service investment are expected to increase by 13%. The forecast DSP has shifted to expect increased spending in the System Service category to support system reliability and mitigate customer outage impacts.
In the General Plant Investment Category the forecast net expenditure is expected to decrease by 16%.

Notes on year over year Plan vs. Actual variances for Total Expenditures

Early in the historical period the capital program variances were under 10% and budget shifting was heavily concentrated within investment categories. In 2018 and 2019, budget shifts were mostly due to station construction and feeder work which was planned for 2018 but the completion of the majority of work was deferred to 2019. This resulted in a shift in spending from 2018 to 2019.

Notes on Plan vs. Actual variance trends for individual expenditure categories

The System Access Investment category experienced variability from plan to actual expenditure in 2018 and 2019 of the historical period. This variability is attributable to delays in contribution from third parties for work completed in previous years resulting in a lower than expected expenditure and the completion of large expansion projects resulting a higher than expected expenditure.
The System Service Investment Category experienced variability from plan to actual expenditure in 2017 and 2019. The increase in spending in 2017 was due to the completion of projects deferred in previous years and increased headway on planned programs. The increase in spending in 2019 is directly attributed to the deferral of large station projects from 2018 and the addition of a project to address urgent reliability concerns.

Table 33: Appendix 2-AB

Appendix 2-AA
Capital Projects Table

Projects	2015	2016	2017	2018	2019	2020 Bridge Year	2021 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
System Access							
Expansions	774,110	-318,665	928,874	-47,919	1,891,799	1,662,014	1,662,014
Connections	307,045	567,800	-393,553	-420,820	620,238	231,550	231,550
Revenue Metering	433,622	549,305	247,460	530,591	453,066	223,000	223,000
MIST Metering	79,367	144,012	116,088	101,585	207,537		
Remote Disconnect/Reconnect Metering	78,174	54,328	-35,063				
Third Party Relocations	1,397,286	1,397,544	-186,995	-791,200	1,704,083	1,110,000	1,365,000
AMI System Upgrade						605,000	386,600
Sub-Total	3,069,603	2,394,324	676,810	-627,763	4,876,723	3,831,564	3,868,164
System Renewal							
Reactive/ Emergency Plant Replacement	1,097,162	1,141,696	1,228,047	1,010,143	1,664,882	1,190,000	1,111,800
Overhead Line Renewal	2,872,934	1,394,679	1,746,845	1,134,682	2,978,280	3,142,190	1,981,000
Underground Line Renewal	756,602	1,195,360	696,087	1,121,338	870,483	1,545,000	1,353,500
Station Renewal	144,227	111,102	964,478	470,407			
MS14 Metalclad Switchgear Replacment	1,632,383						
Pole Replacement Program			423,444	213,793	250,775	400,000	400,000
Porcelain Switch and Insulator Replacement Program						550,000	550,000
Vault Transformenr Replacement Program						162,000	162,000
44kV Quick Sleeve Replacement Program						100,000	100,000
Relay replacement Program						40,000	40,000
MS10 T2 Replacement						1,000,000	
Municipal Substation Switchgear Replacement Program							1,800,000
Sub-Total	6,503,308	3,842,837	5,058,901	3,950,363	5,764,419	8,129,190	7,498,300
System Service							
Downtown Automation	712,331	498,801					
Downtown UG Self-Healing Grid				531,433			
OH Automated Self Healing Switches			646,329	261,496	3,593	50,000	200,000
Neutral Reactors		692,153	206,432	11,590			
Distribution System Supply Optimization		24,167	37,343	40,652	68,588		
Smart Fault Indicators	9,774	238	51,143	28,217	24,704		
Non-electric Fence					245,251		
MS9 Substation Construction				7,600,859	-281,342		
Enfield Contribution to HONI					4,136,705		
MS9 and Enfield Feeders					7,455,780	1,140,400	
Operational Technology (GIS,OMS,ODS,SCADA)						257,500	267,500
Smart Grid						335,000	350,000
Municipal Substation Transformer Monitoring and Telemetry						150,000	150,000
Repair, Improvements and Upgrades of OT and Smart Grid Infrastructure						25,000	41,000
Ground Grid Upgrades						100,000	100,000
Voltage Monitoring (Grid Monitoring and Automation)						450,000	
Sub-Total	722,105	1,215,358	941,246	8,474,247	11,653,279	2,507,900	1,108,500
General Plant							
Fleet	460,652	132,338	503,173	368,394	340,672	545,000	530,000
Facilities	108,415	218,640	49,309	110,787	106,367	565,000	100,000
Major Tools & Equipment	54,338	51,358		126,810	62,006	100,000	100,000
Office IT & Equipment Upgrades	104,672	79,976	187,535	282,572	126,791	87,000	89,000
Operational Technology (GIS, MAS)	8,071		81,907	9,018	41,620		
OMS Implementation and Enhancements	251,533	1,000,607	51,933				
ODS Replacement and Enhancement				360,507	59,515		
Back-up Control Room and Associated IT Infrastructure						200,000	
Back-Up Generator Replacement						205,000	
Information Technology General						282,000	419,500
Customer Self-Serve Online Portal (Green Button Dashboard)						140,000	
Customer Information System (CIS) Acquisition							736,000
Sub-Total	987,680	1,482,919	873,857	1,258,089	736,972	2,124,000	1,974,500
Miscellaneous	572,215	261,250	325,518	-97,827	204,922	0	0
Total	**11,854,911**	**9,196,688**	**7,876,332**	**12,957,109**	**23,236,315**	**16,592,654**	**14,449,464**
Less Renewable Generation Facility Assets and	0	0	0	0	0	0	0
Total	**11,854,911**	**9,196,688**	**7,876,332**	**12,957,109**	**23,236,315**	**16,592,654**	**14,449,464**

Notes:

1 Please provide a breakdown of the major components of each capital project undertaken in each year. Please ensure that all projects below the materiality threshold are included in the miscellaneous line. Add more projects as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the capital budget in the miscellaneous category.

Table 34: Appendix 2-AA

A comparison can be made on OPUCN's annual average budget allocation between the historical period (2015-2020) and the forecast period (2021-2025) within the DSP provided in Figure 16. During the historical period, OPUCN has been largely investing in System Service projects to address capacity requirements within OPUCN service territory, which deferred some System Renewal projects. Over the forecast period, System Service expenditures will decrease and is estimated to be about 6% of the total capital expenditure. System Renewal expenditures will increase significantly and is estimated to be 55% of the total capital expenditure to address the aging infrastructure which includes major station assets. System Access accounts for a slight increase to 32% of the total capital expenditure, while General Plant will go unchanged at 7% of the total capital expenditures.

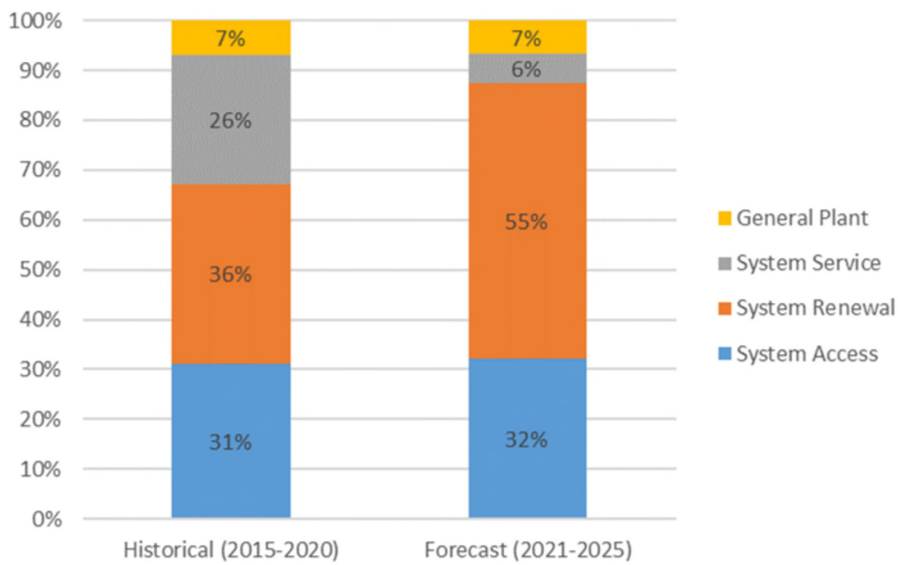


Figure 16: Budget Allocation by Category

Historical Variance Analysis in Capital Expenditures

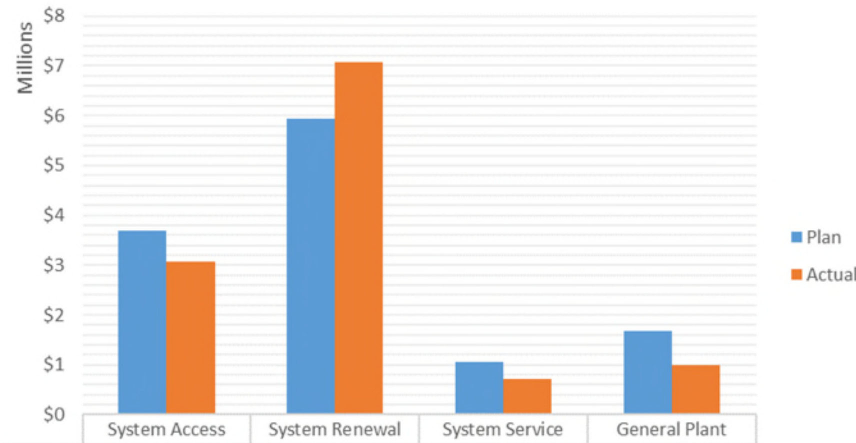
Historical variance from the plan to actual net expenditure is analyzed in this section to support OEB Chapter 2 Appendix 2-AB and Appendix 2-AA. Historical variance will be explained in detail if it exceeds +/-10% or if any major project deferrals or advancements were applied.

2015 Variance Summary

In 2015, the overall percentage variance is -4.16%. The table and figure below followed by category breakdown details the larger variances experienced between the budget and actual costs.

2015 Net CapEx ($ '000's)		
Plan	Actual	% Variance
$12,370	$11,855	-4.2%

Table 35: 2015 Net Variance



	System Access	System Renewal	System Service	General Plant
Plan	$3,684,100	$5,942,500	$1,068,400	$1,675,000
Actual	$3,071,175	$7,073,951	$722,106	$987,680

Figure 17: 2015 Historical Plan and Actual Expenditures by Category

Several projects contributed to the overall variance in 2015 as detailed in the following:

2015 System Access [-16.6%]

- +$936K: System Connection and Expansion work was higher than anticipated in 2015, Expansion projects encompass subdivision developments and these project are often multi staged development. Connection projects encompass service requests and any new connections for customers who lie along OPUCN’s distribution system. Both of these projects are multi-year programs and a final analysis of lifetime budget can be found in 2019, at the end of the program.

- -$1,517K: Relocation projects that experienced changes in scope of timeline were the main driver of this variance. OPUCN had budgeted $2,914K for Third Party Relocation projects in 2015 while the actual spent was only $1,397K. Specific projects scheduled for 2015 did not materialize due to modified scopes and timelines. These projects were either cancelled outright or deferred to later years in the historical period (2016-2019). Refer to Third Party Relocation variance explanation in 2019 for further details on the program’s lifetime variance.

- Remaining variance is attributed to less than +/-10% variances in projects that fall under the materiality threshold in the System Access category.

2015 System Renewal [19.0%]

- +$653K: The largest contributor to System Renewal variance in 2015 were the projects captured in the OH Line Renewal budget. The variance in this sub-category is directly related to the projects that were not in the planned budget. The unplanned expenditure is attributed to remediation work and completion of work planned in previous years. This resulted in unplanned spend of $726K, however, OPUCN realized a 3% cost savings on three other OH Line Renewal Projects budgeted for 2015 which resulted to the overall variance of $653K.

- +$267K: Reactive/Emergency Asset Replacement exceeded the estimated budget. For details on the lifetime expenditure in this program refer to the 2019 variance explanation.

- -$139K: Two UG Line Renewal projects accounting for $188K were added to the plan including a portion of a project on Marwood Drive brought forward from 2019 due to ongoing reliability issues and a project in the downtown core following poor inspection reports. Due to this, two planned UG Line Renewal projects accounting for $290K were deferred to later years. Remaining UG Line Renewal projects budgeted for 2015 realized a cost saving of 4%.

- +$272K: The MS14 Switchgear Replacement exceeded the estimated budget planned for 2015 because of additional requirements to install the new switchgear at the project site such as ensuring that the existing base will be able to withstand and allow the new switchgear to be mounted safely.

- Remaining variance is attributed to less than +/-10% variances in projects that fall under the materiality threshold in the System Renewal category.

2015 System Service [-32.4%]

- -$450K: The start of the Neutral Reactor Project was deferred to 2016 and 2017 to accommodate procurement practices. OPUCN sought to ensure sufficient time was taken through tender to receive the most competitive bids from vendors.

- +$164K: Downtown Automation Project is a multi-phase project with $548K budgeted for 2015. This project saw more spending than anticipated due to the capitalization of work done in previous years which accounts for $712K resulting in a variance of $164K. This project involved modernizing and installing automation to monitor downtown vault switchgears status and remotely operate from the Control Room.

- Remaining variance is attributed to less than +/-10% variances in projects that fall under the materiality threshold in the System Service category.

2015 General Plant [-41.0%]

- -$598K: The primary variance in the General Plant investment category was due to the partial deferment of the OMS Implementation project to 2016 budgeted for $850K. Enabling work was completed in 2014 and 2015, accounting for an expenditure of $252K, but the bulk of the project was deferred to 2016 because a major components of the project experienced scope additions which included the need to procure additional hardware and the need for consultant work.

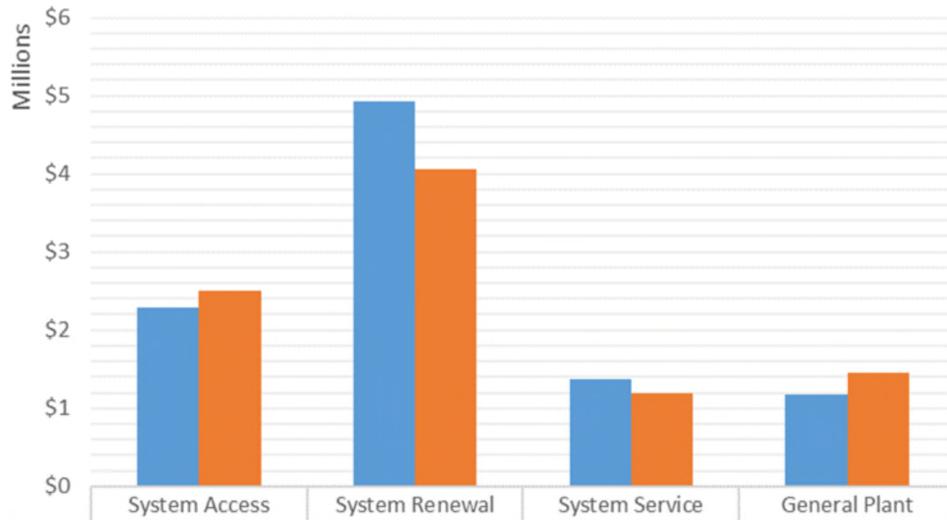
- Remaining variance is attributed to less than +/-10% variances in projects that fall under the materiality threshold in the General Plant category.

2016 Variance Summary

In 2016 the overall variance is -5.9%. The table and figure below followed by category breakdown details the larger variances experienced between the budget and actual costs.

2016 Net Capex ($ '000'S)		
Plan	Actual	% Variance
$9,777	$9,197	-5.9%

Table 36: 2016 Net Variance



	System Access	System Renewal	System Service	General Plant
Plan	$2,285,000	$4,932,000	$1,380,000	$1,180,000
Actual	$2,504,537	$4,051,929	$1,192,387	$1,447,835

Figure 18: 2016 Historical Plan and Actual Expenditures by Category

Several projects contributed to the overall variance in 2016 as detailed in the following:

2016 System Access [9.6%]

- -$434K: Expansions in 2016 was lower than forecasted due to a smaller amount of expansion work reaching completion.
- +$523K: Connections in 2016 were higher than initially anticipated at $568K Net ($1,037K gross less $469K in contributions) and when compared to a budget of $45K net the total variance was $523K. More contributions are expected for projects captured here in later years. This project consists of service requests from customers and new connections that lie along the OPUCN distribution system.
- +$169K: OPUCN experienced an increase in connections during 2016 that increased the number of meters installed to address this demand. This resulted in higher than expected Revenue Metering expenditure.
- Remaining variance is attributed to less than +/-10% variances in projects that fall under the materiality threshold in the System Access investment category.

2016 System Renewal [-17.8%]

- +$312K: Reactive Replacement program exceeded the estimated budget. For details on this programs lifetime expenditure refer to the 2019 variance explanation.
- -$922K: The largest variance in the System Renewal category is attributed to the OH Line Renewal sub-category. Durham Region brought it to OPUCN's attention during routine coordination meetings that a specific project, Rossland Road E from Wilson Rd N to Ritson Rd N, that was planned for renewal in 2016 was within their road widening plans for the future. This project has been deferred until road widening activities began. This resulted in a -$424K variance. Additionally, during the design of another planned OH Line Renewal project, Bloor (Oliver to MS11), it

was determined that some of the poles had been recently replaced due to reactionary failures. This project proceeded but experienced cost savings of $313K. The remaining variance is attributed to cost efficiencies in remaining OH Line Renewal Projects.

- -$200K: The Pole Replacement Program was deferred to 2017.
- +$415K: Three UG Line Renewal projects were added to the 2016 plan accounting for $544K. Two of these projects were deferred projects from the 2015 plan and another project was added to renew lines in the downtown following poor inspection reports. Remediation work was also completed in 2016 for projects energized in 2015 accounting for $107K. An UG Line Renewal project to replace 10F1 and 10F6 at MS10 was also delayed as additional scope was identified that required further investigation, accounting for -$180K. All remaining planned UG Line Renewal Projects realized a cost savings of 7%.
- -$500K: 44kV Breaker Replacement Program is a three year program from 2016-2018. The budget for 2016 was deferred to 2017.
- Remaining variance is attributed to less than +/-10% variances in projects that fall under the materiality threshold in the System Renewal investment category.

2016 System Service [-13.6%]

- -$358K: The Neutral Reactor project was initially planned to begin in 2015 but was deferred to ensure competitive bids were received from vendors. Since this project was a multi-year project, $1,050K was planned for 2016 and $692K was spent. This project was mostly completed in 2016, but the remaining work was deferred and competed in 2017.
- +$499K: The budget attributed to Phase 3 of the Downtown Automation Project, $438K, was deferred in 2015 to 2016. Overall, Phase 3 of the project had a total variance of 8% throughout its lifetime and contributed to $474K of the variance in 2016. The remaining variance, $25K, is attributable to enhancements made to the automation project from Phase 1 and 2.
- -$280K: Underground Self-Healing Grid budget, $280K, was deferred to later years. This project is a multi-year solution based approach. Although work was underway in 2016, this project was not completed until 2018. Please see 2018 for a detailed analysis of lifetime project costs.
- Remaining variance is attributed to less than +/-10% variances in projects that fall under the materiality threshold in the System Service investment category.

2016 General Plant [22.7%]

- +$951K: The primary variance in the General Plant category is due to the addition of the previously deferred OMS Implementation and Enhancement project, accountable for +$951K. The project experienced the addition of unforeseen requirements during implementation including the purchase of Oracle data bases, higher than anticipated software costs, and legal fees to review terms and conditions. This resulted a total project variance of 34%.

- -$400K: The ODS Replacement Project, accountable for -$400K, was also deferred to later years due to the need to procure hardware prior to installing the required software.
- -$283K: Lower than planned Fleet spending in 2016 due to purchase timing. In 2016, a Single bucket Truck and a pickup truck were planned to be replaced. The Single Bucket truck's cab and chassis was purchased but the body of the vehicle was not capitalized until 2017, this explains -$266K of the variance. The remaining variance is attributed to the modification of requirements in the pickup truck replacement. It was determined that a smaller vehicle with decreased functionality could replace the existing vehicle which accounts for -$17K in variance. See 2019 for details on the lifetime costs of the Fleet program.
- Remaining variance is attributed to less than +/-10% variances in projects that fall under the materiality threshold such as General Facilities, GIS, and IT Upgrades among other projects.

<u>2017 Variance Summary</u>

In 2017 the overall variance is 2.01%. The table and figure below followed by category breakdown details the larger variances experienced between the budget and actual costs.

2017 Net Capex ($'000's)		
Plan	Actual	% Variance
$7,722	$7,876	2.0%

Table 37: 2017 Net Variance

Figure 19: 2017 Historical Plan and Actual Expenditures by Category

Several projects contributed to the overall variance in 2017 as detailed in the following:

2017 System Access [-67.4%]

- -$1,337K: Third Party Driven Relocation projects contributed to the largest variance in the System Access category. This variance is due to projects not materializing and contributions being received for projects completed in previous years. In 2017, $1,150K net was budgeted for Third Party Driven Relocation projects but only $879.4K gross materialized and $1,066K of contributions were collected resulting in a net expenditure of -$187K. Refer to Third Party Relocation variance explanation in 2019 for further details on the program's lifetime variance

- +$814K: In 2017, the Expansions expenditure was significantly higher than expected. Work expected in 2016 reached completion in 2017.

- -$439K: In 2017, Connections experienced an influx of late contributions from the previous year. The total capital expenditure for 2017 was -$394K Net ($537K Gross less $931K in contributions) and when compared to the budget of $45K Net, it results in a variance of -$439K. Contributions were received in 2017 from previous years, however, there is still a delay in contributions that will be applied in the remaining period.

- -$150K: This variance is due to the cancellation of the Pre-Paid Metering project. This project was to install disconnect meters which the customer would pre-pay for consumption and be remotely disconnected after reaching the allowance. This was since cancelled due to the OEB order on February 23, 2017.

- -$135K: Remote Disconnect Metering was cancelled due to OEB directive on February 23, 2017. This variance is due to the cancellation of the $100K budget and the subsequent accounting modifications.

- Remaining variance is attributed to less than +/-10% variances in projects that fall under the materiality threshold in the System Service investment category.

2017 System Renewal [20.4%]

- +$464K: The largest variance in the System Renewal category in 2017 is attributed to the 44kV Circuit Breaker Replacement Program. This project was budgeted for 1.5M over 3 years (equally between 2016, 2017, and 2018). The budget deferred from 2016, $500K, along with the budget allocated for 2017, $500K, was spent in 2017. In the first 2 years of the program, $1,000K was planned to be spent and $964K was actually spent.

- +$398K: Reactive Replacement Program exceeded the estimated budget. These budgets are expected to vary year to year but maintain a comparable average expenditure to the plan over the historical period.

- +$223K: The Pole Replacement Program is a four-year project that was planned to begin in 2016. The variance can be attributed to the deferral of 2016 pole replacements to 2017.

- -$175K: UG Line Renewal project in 2017 realized 16% of cost savings.

- Remaining variance is attributed to less than +/-10% variances in projects that fall under the materiality threshold in the System Renewal investment category.

2017 System Service [+124.1%]

- +$212K: The Neutral Reactor project was completed in 2017. Due to the project's delayed start, no expenditure was forecasted for 2017. Over the lifetime, the project realized cost efficiencies of -39%, which can be attributed to the extended planning and procurement process.
- +$296K: The OH Automated Switch Project spans 2 years starting in 2017. Six switches were planned to be installed in each year. There was more throughput than planned in the first year and nine switches were installed. The additional variance can also be attributed to replacing some poles in order to accommodate the new OH automated switches, which is out of scope.
- Remaining variance is attributed to less than +/-10% variances in projects that fall under the materiality threshold in the System Service investment category.

2017 General Plant [15.7%]

- +$98K: Routine Financial Systems Upgrades and Mobile Work Force was added to the capital plan.
- +$22K: Additional spending in GIS Enhancements due to upgrade of the system to the most recent version and modification of the visual interface.
- -$50K: Expenditure under the Major Tools and Equipment category were not captured in 2017 but applied in 2018. This variance is purely due to the accounting treatment and was corrected in 2018.
- +$63K: Increase in Fleet spending to proceed with some deferred and advance replacements from 2016 and 2018, respectively. In 2017 one single bucket truck budgeted for $375K, a pickup truck budgeted for $35K, and a wire and material trailer budgeted for $30K were scheduled for replacement. All of which were replaced as planned and had an overall variance of -$116K which included the variance of -$108K attributed to cost savings on the single bucket truck. Additionally, the body of the single bucket truck budgeted for replacement in 2016 was purchased in 2017 and is attributed to $117K in additional spending. Due to an unforeseen failure a dump truck was replaced ahead of the 2018 replacement year and is attributed to $62K in additional spending.
- Remaining variance is attributed to less than +/-10% variances in projects that fall under the materiality threshold such as General Facilities, GIS, and IT Upgrades among other projects

2018 Variance Summary

In 2018, the overall variance is -29.8%. The table and figure below followed by category breakdown details the larger variances experienced between the budget and actual costs.

2018 Net Capex ($ '000's)		
Plan	Actual	% Variance
$18,445	$12,957	-29.8%

Table 38: 2018 Net Variance

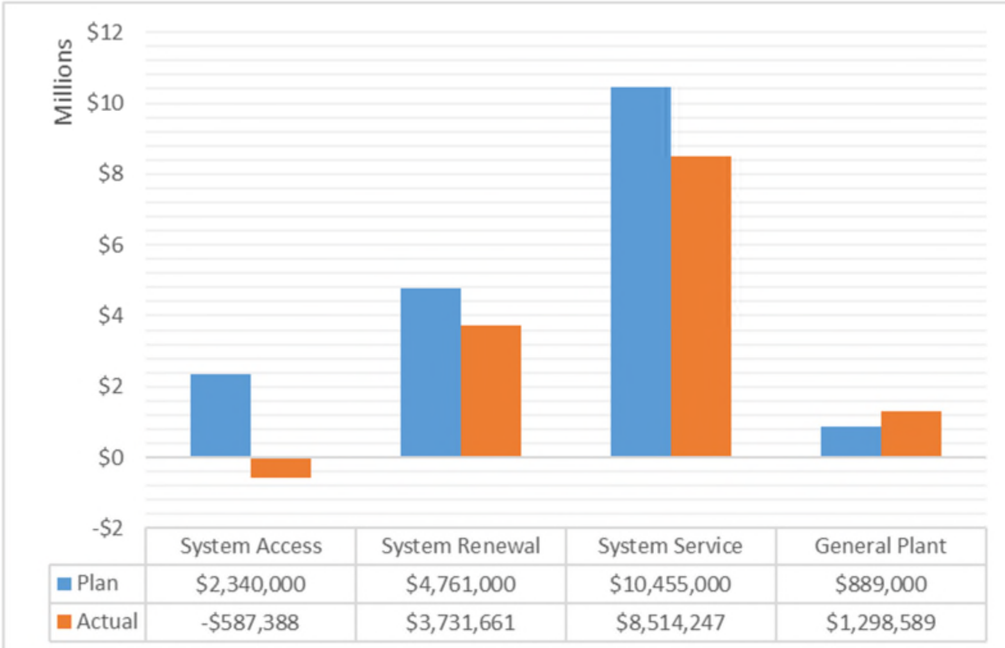


Figure 20: 2018 Historical Plan and Actual Expenditures by Category

Several projects contributed to the overall variance in 2018 as detailed in the following:

2018 System Access [-125.1%]

- -$1,941K: Third Party Relocations were significantly less than anticipated for 2018 due to late contributions. Third Party Relocations were budgeted for $1,150K in 2018, $1,188K materialized as planned and -$1,979K were received in contributions.
- -$578K: $1,883K of late contributions in 2018 resulted in a dramatic underspend on Expansions projects. Although these projects were still underway the magnitude of the late contributions resulted in a negative total expenditure for this project. Overall, the expenditure for Expansion project was -$48K Net ($1,835K less $1,883K in Contributions) and when compared to the planned budget of $530K Net, it resulted in a -$578K variance.
- -$466K: Similar to the Expansions projects, Connections also experienced some late contributions, which accounted for $1,350K. Overall, the expenditure for Connections was -$421K Net ($929K less $1,350K in Contributions) and when compared to the planned budget of $45K Net, it resulted in a -$466K variance.
- -$100K: Remote Disconnect Metering was cancelled due to OEB directive on February 23, 2017. This variance is due to the cancellation of the $100K budget.
- +$141K: Revenue Metering expenditures in 2018 were higher than anticipated due to additional connections throughout the year and the failure of two wholesale meters during a storm.
- Remaining variance is attributed to less than +/-10% variances in projects that fall under the materiality threshold in the System Service investment category.

2018 System Renewal [-21.6%]

- +$180K: Reactive Replacement program exceeded the estimated budget. For details on the lifetime program budget refer to the 2019 explanation.
- -$1,390K: OH Line Renewal projects accounted for the largest variance in 2018. Two projects accounting for -$970K were deferred to 2019 and the remaining planned projects realized cost efficiencies of 16.4%.
- +$200K: In 2018, UG Line Renewal projects experienced increased remediation requirements which included the use of unshrinkable fill material as mandated by the municipality. This resulted in a 21.8% increase in total job costs.
- Remaining variance is attributed to less than +/-10% variances in projects that fall under the materiality threshold in the System Renewal investment category.

2018 System Service [-18.6%]

- -$2,810K: MS9 and Enfield Feeder projects were deferred to 2019 for completion. The prerequisite for feeder construction is the completion of the stations, Enfield and MS9. MS9 was energized in late 2018 and Enfield was completed in 2019.
- +$601K: This variance is attributed to the construction of MS9. The total MS9 construction variance sums to $320K due to over accrual at the end of 2018 accounting for $281K. The +4.6% variance is due to additional municipal requirements for site plan approval.
- -$89K: The OH Automated Switch project is a 2 year program and was mostly completed in 2017. The 3 remaining switches were installed in 2018 resulting in a lower than forecast expenditure. In the projects lifetime, a 30% variance is seen. As explained in 2017, the additional variance in lifetime spending can be attributed to replacing poles in order to accommodate the new OH automated switches, which was out of scope.
- +$521K: This variance is attributed to the completion of the Underground Self-Healing Grid solution that was a multi-year project. When comparing the total costs, $531K, and total budget, $565K, through the lifetime of the project, a 6% cost efficiency was realized.
- -$225K: The Voltage Monitoring project was deferred to apply for additional funding through the Smart Grid Fund in the future. This project aimed to address voltage issues and improve system efficiency through the implementation of smart technology and control.
- Remaining variance is attributed to less than +/-10% variances in projects that fall under the materiality threshold in the System Service investment category.

2018 General Plant [46.1%]

- +$311K: The ODS Replacement and Enhancement project was the largest contributor to General Plant variance in 2018. $50K was budgeted in 2018 for enhancements but was not spent since the project was not yet complete. The $400K budget for implementation from 2016 was deferred to 2018 and $361K was spent. The lifetime of the ODS Implementation project achieved a 10% cost savings.
- +$178K: In 2018 5 light duty vehicles were budgeted for replacement for a total

$190K but none of these vehicles were actually replaced. Due to a catastrophic failure of a critical single bucket truck in 2018 this vehicle had to be prioritized for replacement as soon as possible which resulted in a total spend of $368K.

- +$77K: Expenditures on Major Tools and Equipment in 2018 included both 2017 and 2018 due to accounting treatment. Each year was budgeted for $50K but $127K was spent in total.
- -$159K: MS9 Land was purchased in 2006 but was included in the historical plan to recover this cost through rates.
- +$61K: The General Facilities spending in 2018 was 122% more than the planned expenditure due to the requirement to address aging facilities.
- Remaining variance is attributed to less than +/-10% variances in projects that fall under the materiality threshold in the General Plant investment category.

2019 Variance Summary

In 2019, the overall variance is -1.0%. The table and figure below followed by category breakdown details the larger variances experienced between the budget and actual costs.

2019 Net Capex($ '000's)		
Plan	Actual	% Variance
$23,474	$23,236	-1.0%

Table 39: 2019 Net Variance

Figure 21: 2019 Historical Plan and Actual Expenditures by Category

Several projects contributed to the overall variance in 2019 as detailed in the following:

2019 System Access [+106.1%]

- +$579K: In 2019, Third Party Relocation work was planned for $1,125K and $1,704 was spent. The 51% variance can be attributed to projects from previous years reaching completion in 2019 and the addition of one immaterial project.

Throughout the historical period (2015-2019), $7,834K was budgeted for Third Party Relocations and only 45% actually materialized. Specific variances associated to the three main drivers over the historical period are as follows;

- the 407 ETR had a planned budget of $1,230 and only 48% materialized,
- the City of Oshawa had a planned budget of $2,010 and only 33% materialized, and
- the Region of Durham had a planned budget of $4,439 and only 51% materialized.
- The remaining variance can be attributed to the UOIT MicroGrid, budgeted for $155K, which was cancelled.

- +$1,329K: Expansions experienced higher than usual development in 2019. Projects in this category often span over multiple years. Larger projects from early in the historical period were completed and entirely energized in 2019. Throughout the lifetime of this project the variance reached 271% due to more than expected expansion work throughout the historical period. $1,413K ($4,545K Gross less $3,132K in Contributions) was budgeted over the historical period, and $3,228K ($10,038K less $6,810K in contributions) was actually spent in the historical period. Into the forecast period, historical expenditure in this category was considered for budgeting purposes.
- +$573K: Connections experienced a higher than usual expenditure in 2019 due to additional service requests and connections that lie along OPUCN's service territory that were not foreseen.
- +$146K: Revenue Metering and MIST Metering experienced more than forecasted expenditures in 2019 due to the failure of meter units, the reverification program pre-sampling, and additional connections.
- -$100K: Remote Disconnect Metering was cancelled due to OEB directive on February 23, 2017. This variance is due to the cancellation of the $100K budget.

2019 System Renewal [+25.1%]

- +$835K: Reactive Replacement program exceeded the estimated budget. Motor vehicle accidents from previous years were capitalized in 2019 resulting in a higher than expected expenditure. Throughout the lifetime of this project a total variance of 48% was seen. During the development of the budget for the forecast period actual historical spending was considered as a baseline.
- +$1,061K: OH Line Renewal Projects in 2019 were affected by an addition of two previously deferred projects and excess spending on planned projects. In 2018, two projects with a total budget of $970K were deferred to 2019 and a total of $701K was spent on them. The remaining variance, $360K, is due to excess spending on planned projects.
- -$34K: The variance in UG Line Renewal projects in 2019 can be attributed to the advance completion of the Marwood Rebuild in 2015 and 2016, accounting for

-$290K variance, and the excess spending in planned projects, accounting for +$256K. The excess spending in the planned projects is directly attributed to the increased remediation requirements as required by the municipality.

- -$1,000K: The MS Transformer Replacement project was deferred to 2020 to ensure ample time was taken in the procurement process to realize cost efficiencies. This project is included in the 2020 budget and is forecasted to be completed mid-year.
- +$335K: The Transformer Reserve is an accrual to fixed assets for the incremental movement during the year which fluctuates year over year to capture the balance of transformers on hand that should be depreciating upon purchase.
- Remaining variance is attributed to less than +/-10% variances in projects that fall under the materiality threshold in the System Renewal investment category.

2019 System Service [-26.3%]

- +$137K: This variance is attributed to the contribution to Hydro One for the construction of the new Enfield station. This project was budgeted in 2019 for $4.0M and $4.1 was spent overall. The contribution was based on the CCRA with Hydro One. In the future, more adjustments may be made to this contribution based on load materialization compared to the load forecast under the CCRA.
- -$3,757K: The budget allocated to MS9 and Enfield Feeder Projects was $4,750K and $6,463K, respectively. These projects were planned in 2019 due to the forecasted energization of the corresponding stations. MS9 was energized in late 2018 while Enfield was energized in the second quarter of 2019. The total spend in 2019 on these Feeder projects was $7,456K against an $11,213K budget. Remaining feeder work, $3,757K, is still outstanding due to conflicting Regional road work and was deferred to 2020.
- -$281K: MS9 Construction adjustment to correct the over accrual of work completed in 2018.
- +$246K: Installation of Non-Electric Fence on all outdoor MS was added to the capital plan to address ongoing reliability issues in OPUCN outdoor substations due to animal contact.
- -$265K: The Downtown Self-Healing Grid solution was completed in advance of the forecasted completion date resulting in the budget variance. The project was completed in 2018 and realized a 6% cost efficiency.
- -$225K: The Voltage Monitoring project was deferred to apply for additional funding through the Smart Grid Fund in the future. This project aimed to address voltage issues and improve system efficiency through the implementation of smart technology and control.
- Remaining variance is attributed to less than +/-10% variances in projects that fall under the materiality threshold in the System Service investment category.

2019 General Plant [+38.1%]

- +$171K: Fleet spending increased to proceed with replacements that were deferred from 2018. In 2018, $155K of truck replacements were deferred to 2019 where

$168K materialized. This positive variance is due to increased spending on the replacement of a dump truck due to payload requirements not initially foreseen. In 2019, $170K was budgeted to replace a cargo van, two pickup trucks, and one special service truck. Planned Truck Replacements contributed to a $3K variance. Throughout the lifetime of the Fleet Replacement program, $1,635 was budgeted and $1,805K was spent resulting in a 10% variance.

- -$60K: In 2019, the GIS Enhancement budget was not spent.
- +$56K: The General Facilities spending in 2019 was 113% more than the planned expenditure due to the requirement to address aging facilities.
- +$46K: The IT and Equipment upgrades budget was 58% more than the planned expenditure due to the requirement to renew aging technology.
- Remaining variance is attributed to less than +/-10% variances in projects that fall under the materiality threshold in the General Plant investment category.

2020 Summary

In 2020, projects were included that were deferred in previous years. The following summary reviews these projects, the year they were carried from, any budget changes and the reason they were brought to 2020. From Appendix 2-AB the actual expenditure for the first 6 months of 2020 is shown but no variance explanations are provided.

2020 Net Capex($ '000's)		
Plan	Actual (6mos)	% Variance
$16,593	$6,534	-60.6%

Table 40: 2020 Net Variance

2020 System Access

- Throughout the historical period, Third Party Relocation projects were deferred or added strictly due to the third party driven work. In 2020, revised plans from the municipalities were heavily considered when developing forecast plans and budgets. Investments planned for 2020 of about $1,110K were based directly on planning documentation from the municipalities.

2020 System Renewal

- The MS Transformer Replacement Project was deferred in 2019 to 2020. This project, at a value of $1,000K, experienced no budget change and was brought forward due to the time required to do proper due diligence in the procurement and planning stage. This project is expected to be completed in Q3 2020.
- In 2016, an UG Line Renewal project to replace Lead Cables at a Municipal substation was also delayed as additional scope was identified that required further investigation. The initial budget was $180K, this has since been increased to $250K to be spent in 2020 to accommodate additional scope that has been identified.

2020 System Service

- In 2018 and 2019, the Voltage Monitoring project, accounting for $225K in each year was deferred in order to apply for more funding from the Smart Grid Fund. This project did not experience a change in budget, $450K total, and is expected to be completed in 2020.
- In 2019, the remaining work, $3,757K, on MS9 and Enfield Feeder projects was deferred to 2020 due to conflicting Regional roadwork. The lifetime expenditure of Enfield and MS9 Feeder projects are forecasted to remain within budget.

2020 General Plant

- In 2020, the spending increases are attributable to the addition of Customer Self-Serve Online Portal (Green Button Dashboard) accounting for $140K and an increase in Facilities projects that are critical to supporting business operations requirements while fulfilling leasehold improvement needs in ageing facilities.

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

5.4.3 Justifying Capital Expenditures

The following provides data and analyses that support the capital expenditures proposed in OPUCN's DSP and includes information on how the DSP delivers value to customers, such as controlling costs in relation to proposed investments through optimization, prioritization, and pacing of capital-related expenditures. Additionally, this section will consider the technological changes in the industry that could drive cost-effective and innovative projects into traditional planning needs including load growth, asset condition, and reliability.

5.4.3.1 Overall Plan

Comparative Expenditures by Category over the Historical Period by Category

OPUCN's Capital Expenditure Plan is divided into four investment categories as prescribed by the OEB's Chapter 5 Filing Requirements: System Access, System Renewal, System Service, and General Plant.

Table 41 illustrates the proportion of OPUCN's capital expenditures in 2015-2020 that have been allocated to each investment category. Note that 2020 data is based on budgeted expenditures.

Category	Historical Period ($'000)					
	2015	2016	2017	2018	2019	2020
System Access	6,236	3,207	1,793	3,438	10,318	5,790
System Renewal	7,233	4,193	5,475	3,779	6,524	8,129
System Service	722	1,192	941	8,514	11,621	2,508
General Plant	988	1,448	874	1,299	704	2,124
Gross Total	**15,179**	**10,040**	**9,083**	**17,030**	**29,168**	**18,551**
Contributions	-3,324	-843	-1,207	-4,073	-5,931	-1,958
Net Total	**11,855**	**9,197**	**7,876**	**12,957**	**23,236**	**16,593**
System O&M	2,797	3,017	2,724	3,154	3,015	3,271

Table 41: Expenditures by Category – Historical Period 2015-2020 ($'000)

The following illustrates the actual gross capital expenditures year over year percentage variances:

Category	2015 v 2016	2016 v 2017	2017 v 2018	2018 v 2019	2019 v 2020
System Access	-49%	-44%	92%	200%	-44%
System Renewal	-42%	31%	-31%	73%	25%
System Service	65%	-21%	805%	36%	-78%
General Plant	47%	-40%	49%	-46%	202%
Gross Total	-34%	-10%	87%	71%	-36%
Contributions	-75%	43%	237%	46%	-67%
Net Total	-22%	-14%	65%	79%	-29%
System O&M	8%	-10%	16%	-4%	8%

Table 42: Capital Expenditures by Category – Year over Year Percentage Variances

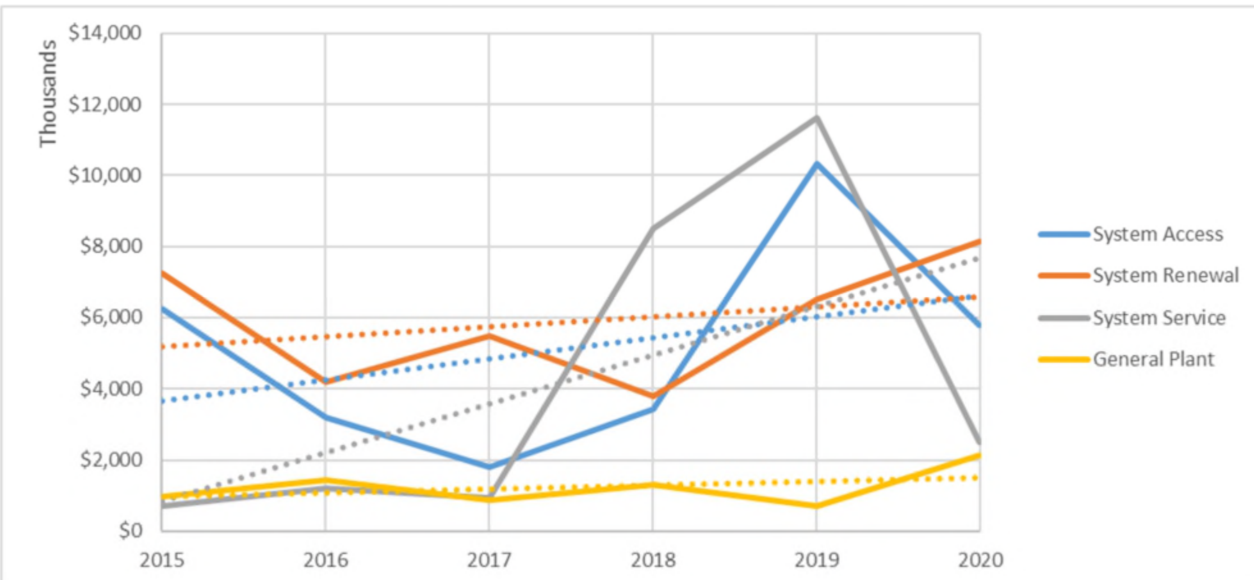


Figure 22: Historical Capital Expenditures Graph (2015-2020)

Figure 22 shows the historical trending of capital expenditures by investment category over the historical period. The trends show that System Access, System Renewal, and System Service investment categories are steadily increasing compared to the very stable trend presented by the General Plant investment category.

Historically, the DSP focused on System Service and System Access investments to accommodate for the load growth and customer base growth in OPUCN's service territory. In 2018 and 2019, majority of the System Service projects concluded resulting in substantial spending at the end of the historical period. Detailed analysis comparing the historical and forecast expenditure by investment category is explained in the following sections.

<u>System Access</u>

The historical trend for System Access investments is highly variable due to municipally driven relocation work and connection or expansion work. OPUCN has limited control on the timing of these investments. On average, the annual forecast spend is 2% less than that of the historical period. System Access investments will continue to focus on customer connections, system expansion projects, third party driven relocations, and mandated service obligations.

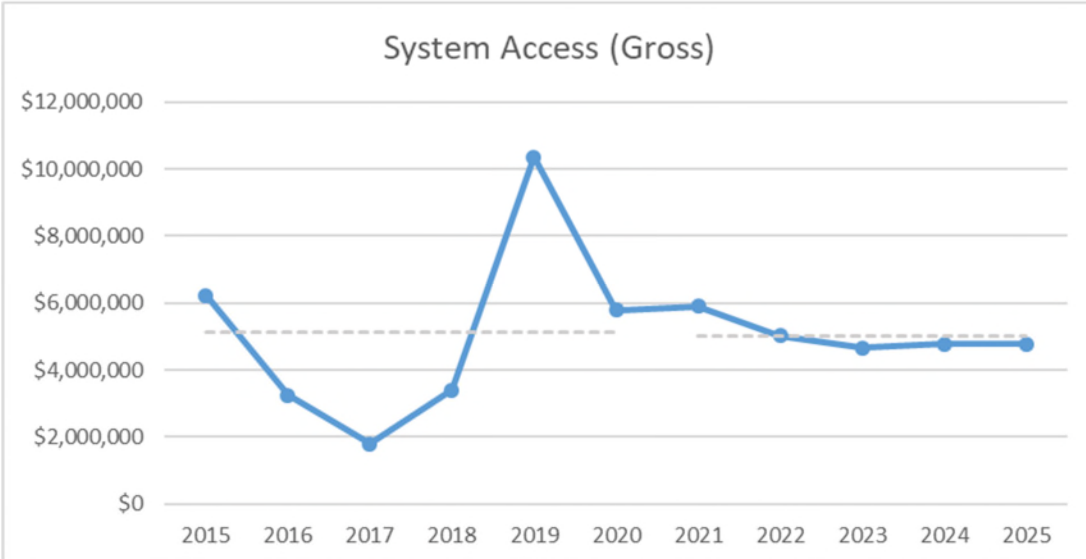


Figure 23: System Access Expenditures

As shown on Figure 23, 2015 presented greater spending when compared to the following years due to third party driven relocation projects primarily caused by the final phase of the 407 extension. With the completion of the 407 construction, expenditures during the subsequent years declined as planned.

Multi-phased subdivision development projects have been completed in OPUCN's service territory throughout the historical period and in 2019, many of these developments finalized construction and were entirely energized which describes the scale of investment seen in this year.

Over the forecast period, expenditures are expected to stay consistent on average, but are anticipated to experience variability year over year based on observations in the historical period.

System Renewal

The historical trend in the System Renewal investment category is a steady increase year over year. As seen in Figure 24, the forecast average is 47% more than the historical average that is primarily due to an increase in substation renewal work. System Renewal investments will continue to focus on investing in the renewal of assets at the end of their TUL or assets that are in "poor" or "very poor" condition. The analysis of historical expenditures is provided in the following:

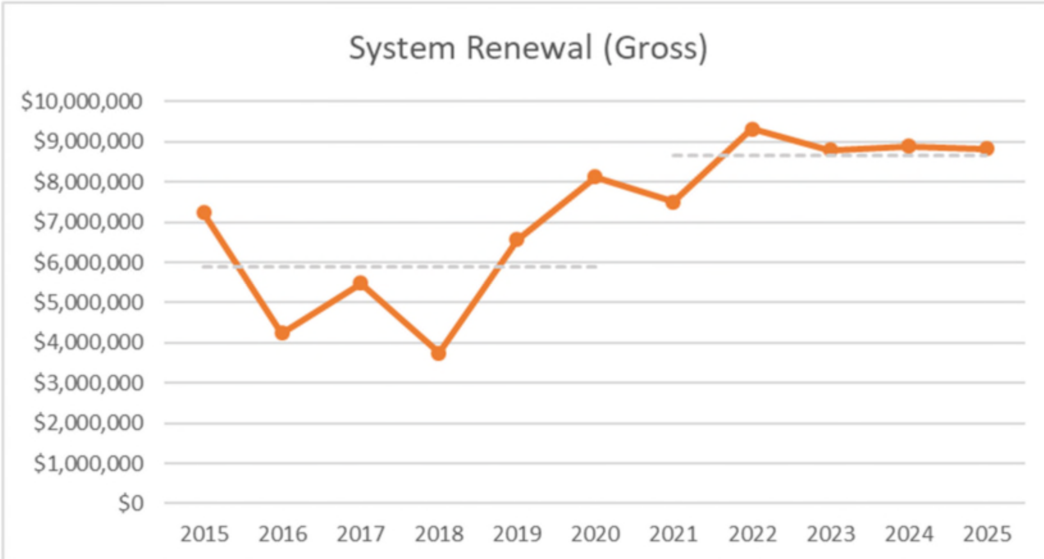


Figure 24: System Renewal Expenditures

2015 spending in the System Renewal category was greater compared to the subsequent years. This is due to the planned completion of “MS14 Switchgear Replacement” and the completion of other various renewal projects planned and carried over from 2014.

Between 2017 and 2018, there was a decline in System Renewal work, which can be directly attributed to the commencement of pole line work for station feeders in the System Service investment category. In order for OPUCN to undertake additional work for the System Service pole line builds, OPUCN reduced expenditures in other areas to pace overall capital expenditures.

In 2019, actual spend in OH Line Renewal projects nearly doubled compared to 2018 to accommodate projects planned for 2019 and the deferred completion of projects in 2018. 2020 demonstrates an increase from average historical spending. This increase is primarily driven by the replacement of a MS transformer and legacy lead cable at MS10 in 2020.

System Service

System Service investment trends are variable based on reliability, load, and system efficiency requirements. As seen in Figure 25, the forecast average is 76% less than the historical average over the DSP period. Forecast expenditures are expected to decrease and return to standard spending for this investment category as a result of commissioning the new MS9 substation and Hydro One owned Enfield TS in 2018 and 2019. These substations will supply additional load to Oshawa’s growing customer base.

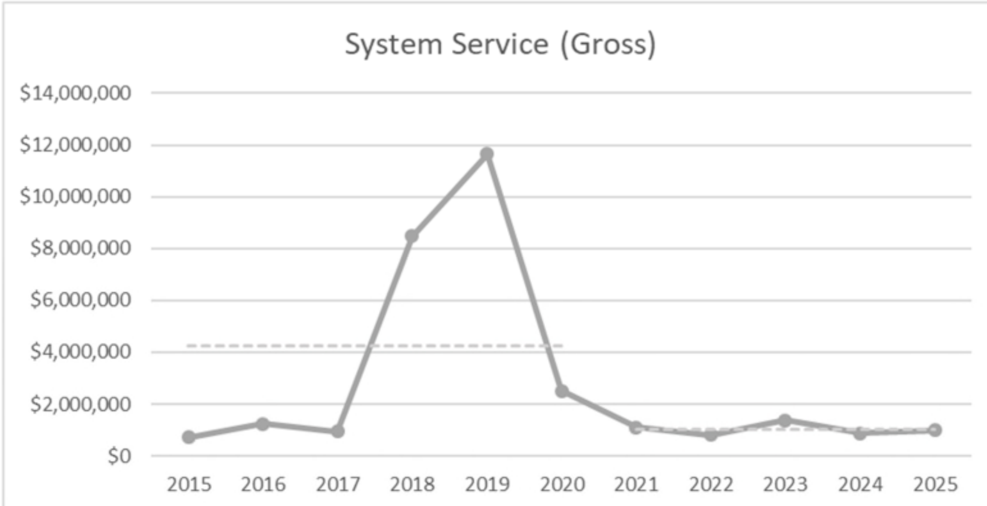


Figure 25: System Service Expenditures

As shown in Figure 25, 2018 and 2019 had significant increases in spending when compared to previous years. This spending is directly attributable to the construction of MS9, Hydro One contribution to build Enfield TS, and the required feeder expansion projects.

For an accurate comparative analysis between historical and forecasted System Service expenditures, expenditures relation to substation construction projects have been removed in the following figure. Contrary to what is shown in Figure 25, Figure 26 shows a 14% increase in the forecast System Service investments from historical investments due to the addition of OT related projects in this category and a proposed 44kV Line Extension at Ritson Rd N in 2023 to establish feeder redundancy. OT related projects, such as GIS and OMS, were reallocated from the General Plant investment category to the System Service investment category, which makes up 25% of the System Service investments on average over the forecast period.

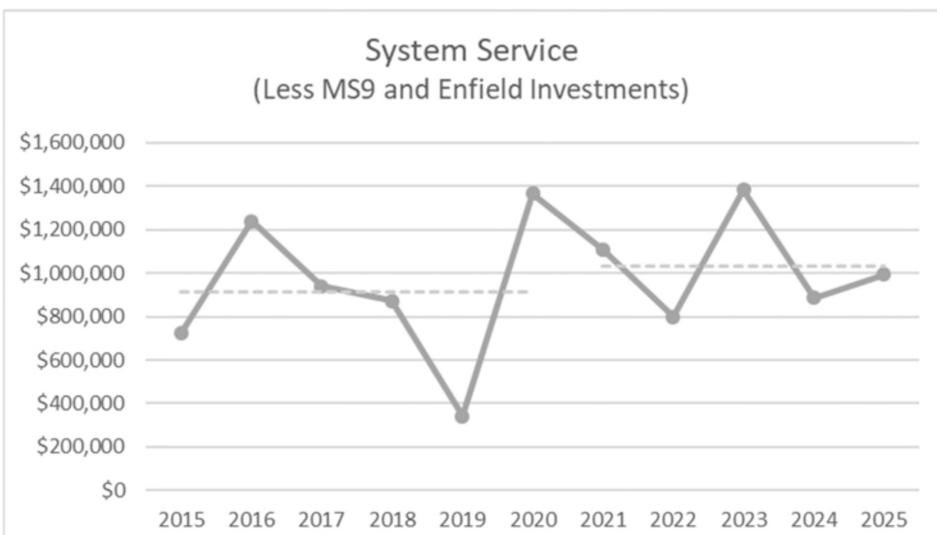


Figure 26: System Service Expenditures, Less MS9 and Enfield Expenditures

General Plant

General Plant investment is variable based on changing annual needs, but remains consistent on average throughout the historical period. General Plant peaked in 2020 to address the developing need to renew OPUCN's IT systems, facilities, and fleet. As seen in Figure 27, the forecast average is 16% less than the historical average over the DSP period. Forecast expenditures are expected to be similar to historical expenditures.

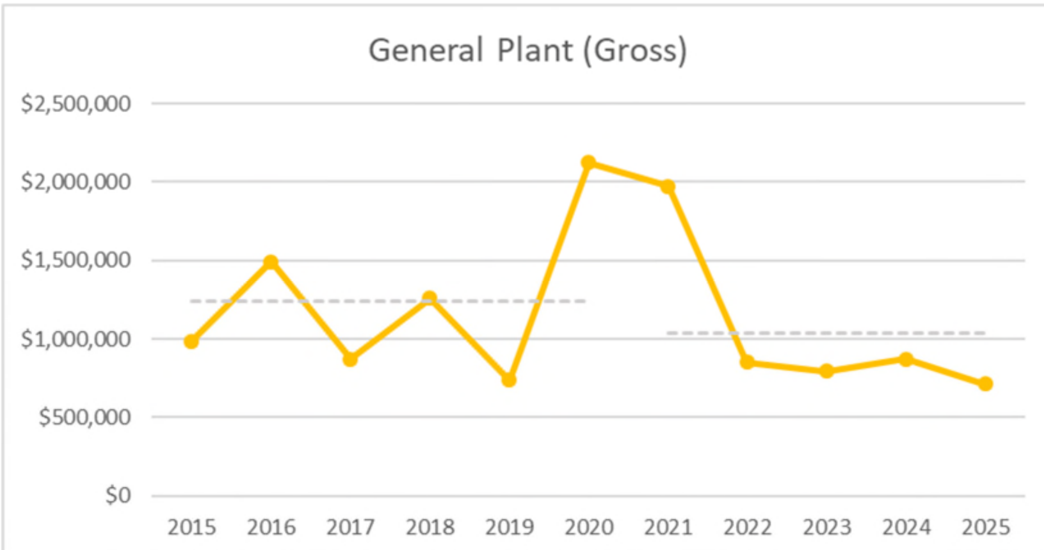


Figure 27: General Plant Historical and Forecast Expenditures

In the General Plant investment category, 2016 and 2018 displayed an increase in spending compared to adjacent years. The OMS implementation and ODS replacement in 2016 and 2018 respectively were the cause for this increased spending.

As mentioned in the System Service narrative, OT, such as GIS and OMS, were reallocated from General Plant investment category to the System Service investment category. On average, OT projects account for approximately $200K spending in the forecast period. If the OT projects were to remain in the General Plant investment category, this category would stand fundamentally unchanged.

In 2020-2021, spending increases are attributable to the Customer Self-Serve Online Portal (Green Button Dashboard) in 2020, CIS Acquisition in 2021 and an increase in Facilities projects that are critical to supporting business operations requirements while fulfilling leasehold improvement needs in ageing facilities.

System O&M

System O&M historical and forecast expenditures are shown below in Figure 28. Overall, the forecast expenditure is expected to follow a similar trend to the actual historical expenditure with inflationary increase. Below is an explanation of variances between plan and actual expenditures through the historical period.

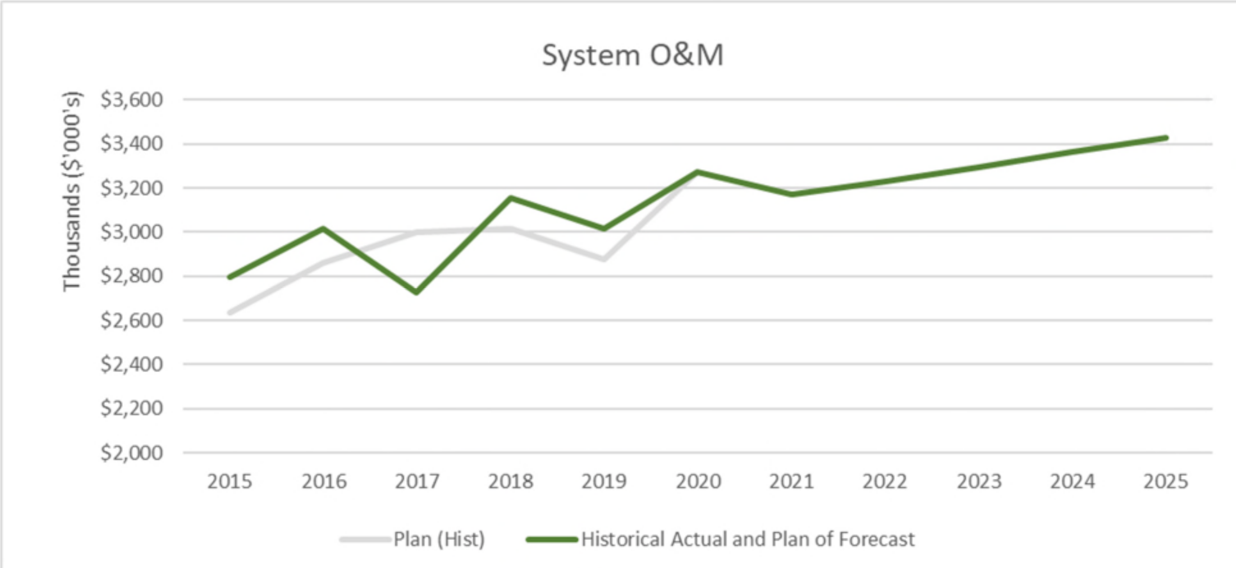


Figure 28: O&M Historical and Forecast Expenditures

Throughout the historical period the actual expenditure varied within +/-10% from the planned expenditure.

In 2015, a variance of $162K from plan to actual was mostly attributed to overtime work, subcontractors, and transformer inspections and painting.

In 2016, a variance of $158K was attributed mainly to additional pole testing not included in the previous rate application.

In 2017, a variance of -$275K was attributed primarily to the actual expenditure on Full Time Employees (FTE). It was forecasted that additional FTE would be hired in 2017 ahead of retirements in subsequent years but this did not materialized.

In 2018, a variance of $139K was attributed mostly to a Ground Grid Study which was not considered in the previous rate application. This Ground Grid Study was imperative to ensure OPUCN's MSs were consistent with current codes and standards relating to grounding (ie. IEEE, OESC, CSA C22.1).

In 2019, a variance of $137K was attributed to a variety of items including expenditure associated to FTE below forecast, additional tools & consumables purchases, and additional communications/telecom requirements among other immaterial variances. Later in the historical period, as seen in 2019, unforeseen operating expenses, which correlated to new technological implementations, were recognized.

Forecast Impact of Investments on System O&M Cost

The impact of the prospective capital investments provided in this DSP on the expected O&M expenditures will vary based on project and program. For instance, incremental plant additions such as distribution system expansion and new "smart grid" devices may require incremental resources for ongoing O&M activities. As for relocation or renewal of existing distribution infrastructure, there would be little or no change to resources for ongoing O&M activities, as inspections will still need to be carried out on a periodic basis as required per the DSC.

Replacement of end of life assets will still require the allocation of resources for ongoing O&M activities. Repair would be the most significant O&M activity impacted by the new asset. Certain assets, such as poles, offer few opportunities for repair related activities and generally require replacement when deemed at end of its TUL or critically damaged. Other assets such as direct buried cable offer opportunities for repair related activities (e.g. splices) up to a point where further repairs are not warranted due to end of TUL conditions. If assets approaching end of life are replaced at a rate that maintains the existing system's condition, then the expectation would be of little or no change to O&M costs under no growth scenarios but would still see upward O&M cost impact under growth scenarios (more cumulative assets to maintain each year). Replacement rates that improve asset class average condition could result in lowering certain maintenance activities costs (e.g. pole testing, reactive repairs, etc.) and could potentially lower O&M cost. Overall, the planned capital investments for these type of investments are expected to have a neutral impact on O&M costs.

OT investments such us upgrades in SCADA, GIS, OMS and ODS are expected to provide a reliable and functional systems. These will provide better understanding and visibility of OPUCN's distribution assets that will lead to more efficient and optimized design, utilization, maintenance and investment activities. These investments will have a neutral impact on O&M costs.

Fleet replacement expenditures and facilities investment will result in reduced O&M cost for new vehicles and facilities equipment, however, this will be offset by increasing O&M of remaining units as they get older. Investment in acquiring a new Customer Information System (CIS) will lower O&M cost significantly in the long run as OPUCN switches from a lease model to an ownership model that will be hosted in-house. There are also additional costs anticipated in IT to maintain the current systems and implement requirements of the Cyber Security Framework.

Overall, the system investments are not expected to have a significant impact on total O&M costs over the forecast period.

Investment Drivers by Category

System Access

System Access investments are modifications to a LDC's distribution system, which, LDC is, obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via the distribution system.

System Access investments discussed are driven by:

- Municipally driven requests for OPUCN plant relocation;
- forecast of service connections, system expansions, and metering requirements based on projected growth in customer connections, developed through OPUCN's consultations with the City, Region, and local developers.

Since System Access investment needs are largely driven by customer, municipally, regionally, provincially, or regulatory-driven, they are typically prioritized based on third party deadlines and resource availability. Historically, this investment has been sporadic due to the fluctuating demands

System Renewal

System Renewal investments involve replacing and/or refurbishing distribution system assets to maintain the ability of the LDC's distribution system to provide customers with electricity services.

Investments described in the System Renewal category are driven by:

- maintenance and operational inspections and tests reports;
- recommendations from the ACA; and
- power outage incident reports and associated analysis of root cause, duration, fault locating, restoration time and customer impact.

System Service

System Service investments are modifications or upgrades to the distribution system that ensure the operational objectives are met while addressing anticipated future customer electricity service requirements. These upgrades are imperative for allowing OPUCN's distribution system to continue meeting operational excellence related to safety, reliability and system efficiency.

System Service investments illustrated in this category are driven by:

- projected increase in system demand and peak load resulting from anticipated accelerated growth in residential subdivisions and commercial developments.
- system capacity studies;
- concerns stemming from OPUCN's control room;
- distribution automation
- OEB's Cybersecurity Framework
- Grid Modernization Plan; and
- the consideration of effective and proven technology to modernize the distribution system.

System Service investment requirements over the forecast period are expected to vary due to initiatives to improve Operational Effectiveness (as outlined in OEB's annual scorecard for OPUCN) as per Section 5.2.3 including the new Grid Modernization Plan, OEB's Cyber Security Framework, and ageing station service equipment.

General Plant

General plant investments are modifications, replacements or additions to an LDC's assets that are not part of its distribution system including land and buildings, tools and equipment, rolling stock and electronic devices and software used to support day to day business and operations activities.

General Plant investments addressed in this category are driven by:

- investment needs for the refurbishment or replacement of the fleet, office building, substations, and any other property;
- refurbishment or replacement of major tools and equipment;
- customer needs; and
- new technologies that are required or advisable to improve OPUCN's efficiency and work environments not in direct relation to the distribution system.

Compared to historical investment in the General Plant category the forecast needs have increased significantly. Specifically, in the first years of the forecast period there exists a substantial deviation from the historical General Plant budget. Aside from the ordinary investments, which include Fleet, Facilities, Tools and Equipment, and basic information technology needs, additional investments have been identified concerning the acquisition of the CIS, a more rigorous IT systems upgrade, office systems, and customer facing data access and billing platforms.

Distribution System Capability Assessment

Based on the available capacity identified in section 5.3.4, there are no constraints identified and there is sufficient capacity in both OPUCN's distribution system and Hydro One's TS to accommodate the potential connection of future REGs. OPUCN does not anticipate any requirement for immediate investments as a result of this for this planning period. This will be further monitored as future proposed REGs are identified.

5.4.3.2 Material Investments

The focus of this section is on projects/programs that meet the materiality threshold set out in Chapter 2 of the *Filing Requirements for Electricity Distribution Rate Applications*. The materiality threshold for OPUCN's DSP is $150,000. Project Narratives have been prepared to address the following requirements:

- General information on the project/ program;
- Evaluation criteria and information requirements for each project/program;
- Category-specific requirements for each project/program

All capital expenditures for the forecast years (2021-2025) are summarized in the table below and the material capital expenditures (>$150K) are justified in the following section, Appendix A. For projects that fall solely within the bridge year, 2020, their narratives are located in Appendix S.

Category	Project #	Project/Program Name	Total Net Forecasted Expenditure (2021-2025) $'000	AM Score Ranking	Prioritization
System Access	SA-01	Third Party Driven Relocation	3,315	4.0	HIGH
	SA-02	Connections	1,158	4.0	HIGH
	SA-03	Expansions	8,310	4.0	HIGH
	SA-04	Revenue Metering - New Connections	1,115	5.6	HIGH
	SA-05	AMI System Update	2,185	7.2	HIGH
System Renewal	SR-01	OH Line Renewal Program	10,579	5.2	HIGH
	SR-02	Porcelain Insulator and Switch Replacement Program	2,750	6.6	HIGH
	SR-03	Pole Replacement Program	2,000	6.4	HIGH
	SR-04	44kV Quick Sleeve Replacement Program	200	6.6	HIGH
	SR-05	Vault Transformer Replacement Program	810	6.6	HIGH
	SR-06	UG Line Renewal Program	7,604	5.2	HIGH
	SR-07	Municipal Substation Transformer Replacements and Oil Containment Installa	4,500	7.8	HIGH
	SR-08	Municipal Substation Switchgear Replacements	9,000	7.8	HIGH
	SR-09	Relay Replacement Program	80	6.8	HIGH
	SR-10	Reactive Replacement Program	5,786	5.0	HIGH
System Service	SS-01	Municipal Substation Transformer Monitoring and Telemetry	750	4.8	HIGH
	SS-02	Expansion of Overhead Automated Switching	1,000	4.2	HIGH
	SS-03	SCADA Operated 44kV OH Switches	500	4.2	HIGH
	SS-04	SCADA Integration and Deployment of Automation Controllers and Network C	550	4.2	HIGH
	SS-05	Municipal Substation Network Cybersecurity Upgrade	450	5.6	HIGH
	SS-06	Municipal Substation Battery and Battery Charger Upgrades	50	5.0	HIGH
	SS-07	Geographic Information System (GIS) Upgrades and Enhancements	468	3.0	MEDIUM
	SS-08	Outage Management System (OMS) Upgrade	175	6.0	HIGH
	SS-09	Upgrades and Enhancements to Operational Data Store (ODS) Systems	500	3.0	MEDIUM
	SS-10	Planned SCADA Upgrade	60	5.4	HIGH
	SS-11	Repair, Improvements and Upgrades of OT and Smart Grid Infrastructure	194	4.4	HIGH
	SS-12	44kV Line Extension - Ritson Rd - Winchester Rd E and Conlin Rd E	375	4.6	HIGH
	SS-13	Ground Grid Upgrades	100	4.6	HIGH
General Plant	GP-01	Facilities	500	4.0	HIGH
	GP-02	Fleet Replacement Program	1,585	4.4	HIGH
	GP-03	Major Tools & Equipment	500	5.2	HIGH
	GP-04	Customer Information System (CIS) Acquisition	736	6.0	HIGH
	GP-05	Office Systems	306	3.2	MEDIUM
	GP-06	IT Systems Upgrade	1,581	5.6	HIGH
		TOTAL	**69,770**		

Table 43: 2021-2025 Material Capital Expenditure

The following tables provide the list of “OH Line Renewal” and “UG Line Renewal” projects during the forecast years (2021-2025).

Year	Project #	OH Line Renewal Project Name	Net Forecasted Expenditure $'000	Project Condition Ranking
2021	SR-01-08	Bader Ave, Finucane St, Fernhill Blvd, Rosmere St, Malan Ave, Cunningham Ave	504	32%
	SR-01-09	Valencia Rd, Oxford St, Cordova Rd, Malaga Rd	639	36%
	SR-01-10	Kitchener Ave, Dean Ave, Normandy St, Dunkirk Ave, Sterling Ave, Dieppe Ave, Lomor	645	36%
	SR-01-11	Miller Ave	73	36%
	SR-01-12	Buena Vista Ave	120	36%
2022	SR-01-13	Roxborough Ave	140	36%
	SR-01-14	Rossland - Ritson to Wilson	600	48%
	SR-01-15	Durham Crt	72	42%
	SR-01-16	Grandview St S, Olive Ave	739	36%
	SR-01-17	Front St, Albany St, First Ave, Second Ave, Third Ave, Fisher St, Lviv Blvd	459	42%
	SR-01-18	Currie Ave, Montgomery St, Jackson Ave	120	42%
	SR-01-19	Athol St E	102	42%
	SR-01-20	Oshawa Blvd N from Bond to Maplewood	490	42%
2023	SR-01-21	Ridgeway Ave, Elizabeth St	176	42%
	SR-01-22	Gorevale Cres., Hillsdale Ave, Oshawa Blvd N, Hillcroft St.	327	42%
	SR-01-23	Ascot Crt, Ascot Ave, Arden Dr, Acadia Dr	318	42%
	SR-01-24	Arthur St, Drew St, Bruce St	207	46%
	SR-01-25	Ridgeway Ave, Fairlawn St, Nipigon St, Humber Ave, Muriel Ave	335	46%
	SR-01-26	Lauder Rd	59	46%
	SR-01-27	Olive Ave, Central Park Blvd S	584	48%
2024	SR-01-28	Dearborn Ave, Kendal Ave, Mary St N, Agnes St, Elgin St E, William St E, Ontario St, D	987	46%
	SR-01-29	Poplar St, Linden St	129	48%
	SR-01-30	Creighton Ave, Harris Crt, Harris Ave, Rosehill Blvd	242	48%
	SR-01-31	Grassmere Ave, Wellington Ave E, Nelson St, Harbour Rd	779	52%
2025	SR-01-32	Beechwood St, Pinewood St, Edgewood Ave, Oakwood Ave	191	48%
	SR-01-33	Farewell St from Harbour to Wentworth E	659	52%
	SR-01-34	Cromwell Ave from Hillside to Grace Lutheran Church	65	52%
	SR-01-35	Milton St from Chesterton Ave to Keates	28	52%
	SR-01-36	Kilmaurs Ave	60	52%
	SR-01-37	Cedar Valley Blvd, Cedar Valley Crt, Patton St, Seneca Ave, Chippewa St,	290	52%
	SR-01-38	Eastwood Ave N	75	52%
	SR-01-39	Bloor St from Dnipro Blvd to Wilson Rd S including Dnipro Blvd	210	56%
	SR-01-40	Rossland Rd W (West of Thornton Rd N)	155	58%
		TOTAL	**10,579**	

Table 44: SR-01 Overhead Line Renewal Program

Year	Project #	UG Line Renewal Project Name	Net Forecasted Expenditure $'000	Project Condition Ranking
2021	SR-06-05	Walnut Ct	45	44%
	SR-06-06	Seville St, 384 Hillside Ave	63	44%
	SR-06-07	512 Canonberry Crt - MAY BE REDEVELOPED - Should also include 511 Cannonberry	221	44%
	SR-06-08	285 Taunton Rd E	53	44%
	SR-06-09	Madawaska Ave, Wecker Dr, Rondeau Ct, Ritson Rd S (Valley Dr to Lakeview Park)	172	52%
2022	SR-06-10	Overbank Dr, Castlegrove Ave, Sagebrush St,Lichen Cres, Adele Cres,	540	52%
	SR-06-11	540 Dorchester Dr	92	52%
	SR-06-12	Keates Ave	69	52%
	SR-06-13	Central Park Blvd N (Brentwood Ave to Hillcroft St)	113	52%
	SR-06-14	510 Rossland Rd E, 455 Mayfair Ave	85	52%
	SR-06-15	Norman Cres, Grandview Dr, Downsview Cres, Grandview St S, Wesley Dr, Edna Ct, C	505	60%
	SR-06-16	777 Terrace Crt	99	52%
2023	SR-06-17	601 & 611 Galahad Dr	227	52%
	SR-06-18	Naples St	67	52%
	SR-06-19	1330 Trowbridge Dr, Ludlow Ct	175	52%
	SR-06-20	Prestwick Dr, Dunrobin Ct, Lochness Cres, Apple Valley Ln	460	60%
	SR-06-21	Townline Rd S, King St E (Tx 4421), Carling Ave, Merivale St	72	52%
	SR-06-22	420 and 450 Bristol Cres	121	60%
2024	SR-06-23	Glenridge Ct	101	60%
	SR-06-24	Limerick St, Tralee Ct, Monaghan Ave	136	60%
	SR-06-25	Huntingwood Dr, Goodman Dr, Amber Ave, Waverly St N (Adelaide Ave W to Dawnhill	590	60%
	SR-06-26	Copperfield Dr,	50	60%
	SR-06-27	William Booth Cres, Exeter St	178	60%
2025	SR-06-28	Roundelay Dr, Roundelay Ct, Mahina St, Aztec Dr, Charisma Cres, Rimosa Ct, Moniqu	770	60%
	SR-06-29	Whistler Dr, Griffith St, Barnes Cres, Logan Ct, St Anne Ct, Cartref Ave, Mount Allan Av	600	60%
2021-2022	SR-06-30	Municipal Substation Cable Replacement Program	1,600	36%
2022-2025	SR-06-31	UG Downtown Cable Replacement Program	400	56%
		TOTAL	**7,604**	

Table 45: SR-06 Underground Line Renewal Program

Appendix A: 2021-2025 Material Investment Justifications

<table>
<tr><th colspan="6">A. General Information (5.4.3.2.A)</th></tr>
<tr><td>Project/Activity</td><td colspan="5">Third Party Driven Relocation</td></tr>
<tr><td>Project Number</td><td colspan="5">SA-01</td></tr>
<tr><td>Investment Category</td><td colspan="5">System Access</td></tr>
<tr><td></td><td>2021</td><td>2022</td><td>2023</td><td>2024</td><td>2025</td></tr>
<tr><td>Capital Cost</td><td>$1,820,000</td><td>$900,000</td><td>$520,000</td><td>$600,000</td><td>$580,000</td></tr>
<tr><td>Capital Contribution</td><td>$455,000</td><td>$225,000</td><td>$130,000</td><td>$150,000</td><td>$145,000</td></tr>
<tr><td>Net Cost</td><td>$1,365,000</td><td>$675,000</td><td>$390,000</td><td>$450,000</td><td>$435,000</td></tr>
<tr><td>O&M Cost</td><td>2021</td><td>2022</td><td>2023</td><td>2024</td><td>2025</td></tr>
<tr><td></td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td></tr>
<tr><td colspan="6">Customer Attachments and Load</td></tr>
<tr><td colspan="6">Customer attachments and load varies annually.</td></tr>
<tr><td>Start Date</td><td colspan="2">2021-2025</td><td>In-Service Date</td><td colspan="2">2021-2025</td></tr>
<tr><td>Expenditure Timing for the Planning Horizon</td><td>2021Q1</td><td>2021Q2</td><td colspan="2">2021Q3</td><td>2021Q4</td></tr>
<tr><td></td><td>$200,000</td><td>$450,000</td><td colspan="2">$450,000</td><td>$265,000</td></tr>
</table>

Project Summary

This program consists of line relocation projects which are required in order to accommodate projects related to road work by the City of Oshawa, the Region of Durham and the Ministry of Transportation. Projects within this program are initiated by third party request to relocate OPUCN's facilities. The City of Oshawa's and Region of Durham's 9 year plans were referenced along with detailed correspondence to estimate spending required and timing of projects although detailed planning is not available at this time.

The size of load and number of customers affected varies by project in this category. The budget will consist of several relocation projects which will not be more detailed in scope until closer to the driver's construction when designs have been established.

Risk Identification & Mitigation

Scheduling Risks – Relocation projects are driven by development plans of municipal government and other third parties. OPUCN has very limited control over the scope and timing of these projects, however, past history has been taken into account when predicting the expenditure for these projects. In order to mitigate risk of scheduling problems, OPUCN works very closely with these third parties to exchange scheduling information. This is to ensure that all road work requiring system relocations are planned for and well-coordinated with other OPUCN projects.

Risks of Scope Change – Since relocation projects are driven by the development plans of municipal government and other third parties, there is a risk of the scope of the project being changed or the project being cancelled all together. Similar to the mitigation strategies discussed above, OPUCN ensures there are continuous communication channels open with the third party drivers to forecast when scope changes or cancellations may occur.

Comparative Information on Expenditures for Equivalent Projects/Activities

Third Party Relocation costs are based on best available information gained through coordination meetings with appropriate authorities and historical annual average expenditure. Relocation costs will be variable, as can be seen in the historical comparative, depending on the scope of work defined year over year by the third party.

The following shows the historical actuals and forecast costs:

	Historical Costs ($ '000)					Forecast Costs ($ '000)					
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Gross	2,537	1,816	879	-	1,884	1,480	1,820	900	520	600	580
Contributions	(1,139)	(418)	(1,066)	(791)	(180)	(370)	(455)	(225)	(130)	(150)	(145)
Net	1,397	1,398	(187)	(791)	1,704	1,110	1,365	675	390	450	435

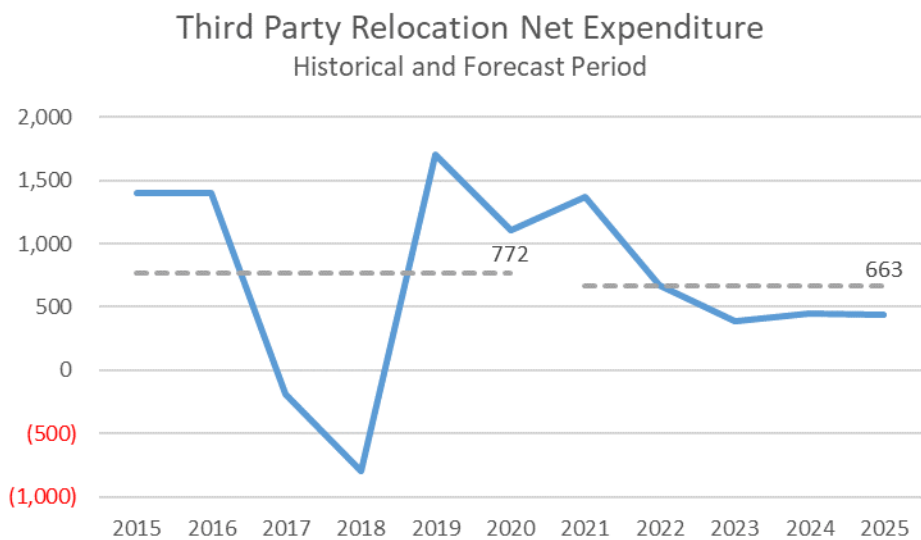


Figure 1: Third Party Relocation Net Expenditure in the Historical and Forecast Period

Shown above is the net expenditure on third party relocation projects over the historical and forecast period. Fluctuations in the historical period are solely due to the discretion of third parties. OPUCN is required to conform to the schedules determined by the third party. Overall the average expenditure is forecasted to decrease by 14%, or 109K, compared to historical expenditures. This can be attributed to the additional work required in the historical period for the 407 Extension project which equates to approximately 117K annually on average. Negative net expenditures in 2017 and 2018 is due to delayed contributions from third parties as presented in the table.

REG Investment Details including Capital and OM&A costs

As this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.

Leave to Construct approval under Section 92 of the OEB Act

This project is below 50 kV and therefore Leave to Construct is not required, as per O.Reg. 161/99.

Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material

General project scope and maps for 2021 Third Party Driven Relocation projects are shown in the following:

SA-01-04: City - Widen Conlin - Simcoe - Ritson

Scope: OH Relocate - 1650m 3 phase (2x13.8kV), 1650m 3 phase (44kV), 52 Poles, 5 Tx

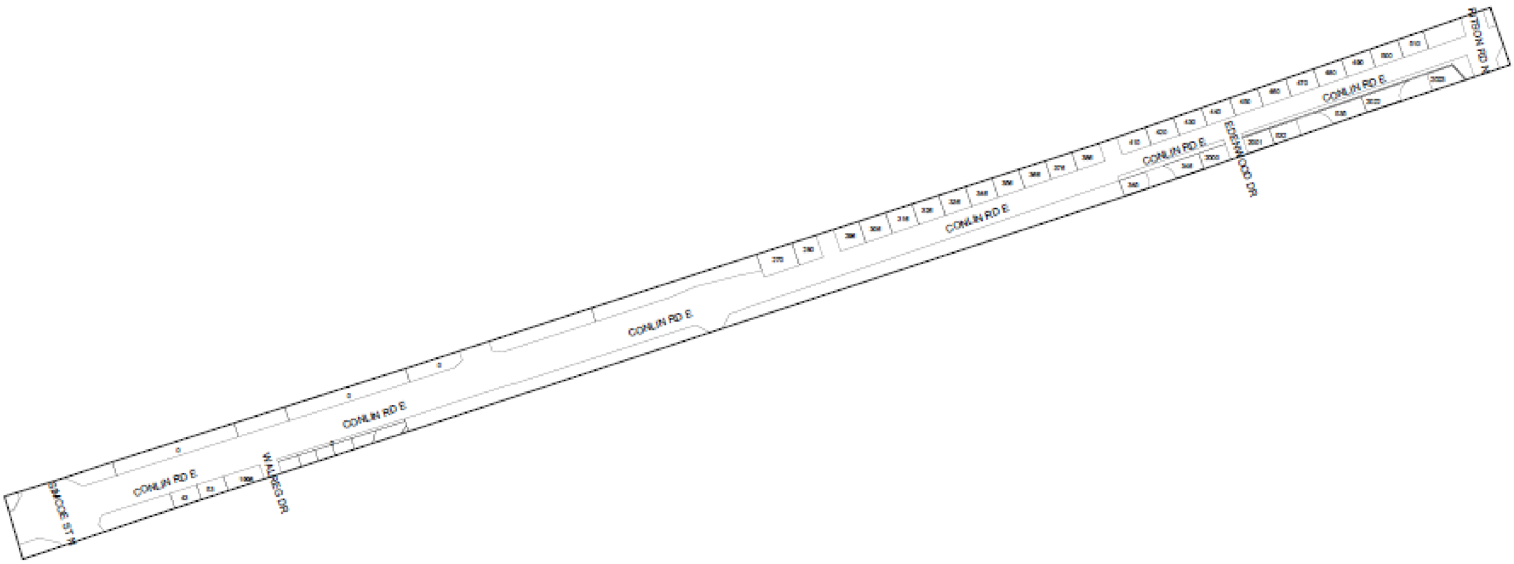


Figure 2: SA-01-04 City Widen Conlin (Simcoe to Wilson) Map

SA-01-05: Glenwood Cres. - South limit to Winona Ave
Scope: OH Relocate - 200m secondary only, 6 Poles

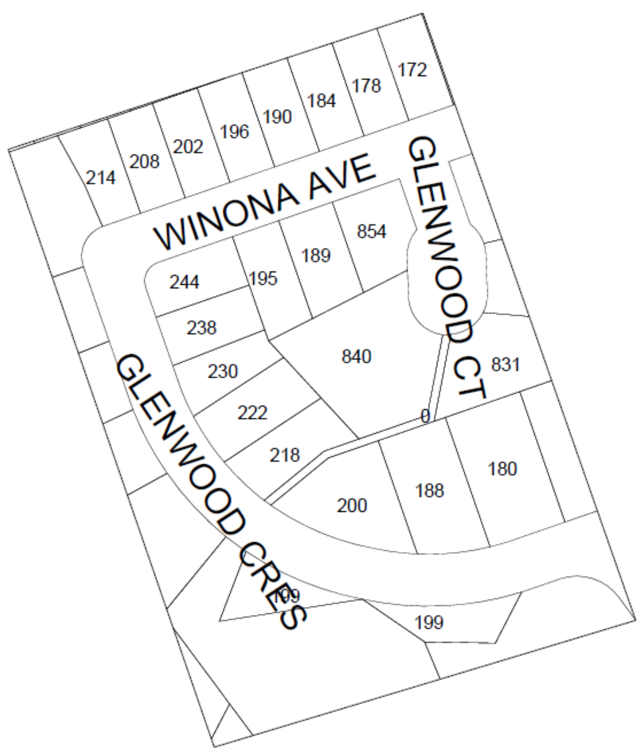


Figure 3: SA-01-05 Gelnwood Cres. South Limit to Winona Ave Map

SA-01-06: MTO - 401 Widening - Simcoe and Albert bridges

Scope: OH Relocate - 150m 3 phase (13.8kV), 6 Poles

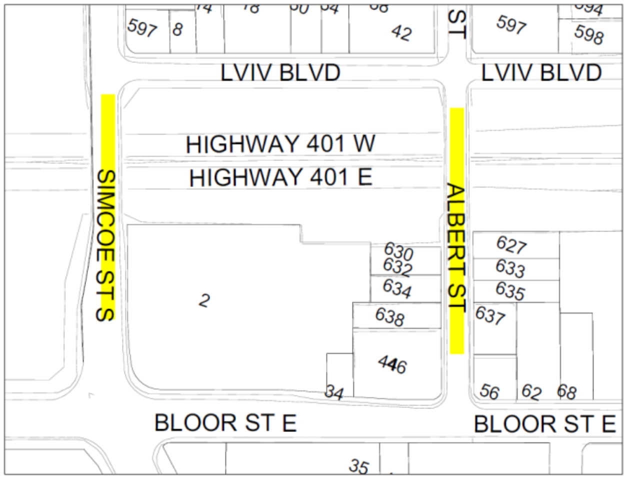


Figure 4: SA-01-06 MTO Widening Map

SA-01-07: Region widening - Gibb St from Stevenson to Simcoe
Scope: OH Relocate - 1740m 3 phase (13.8kV), 1740m 3 phase (2x44kV), 51 Poles, 10 Tx

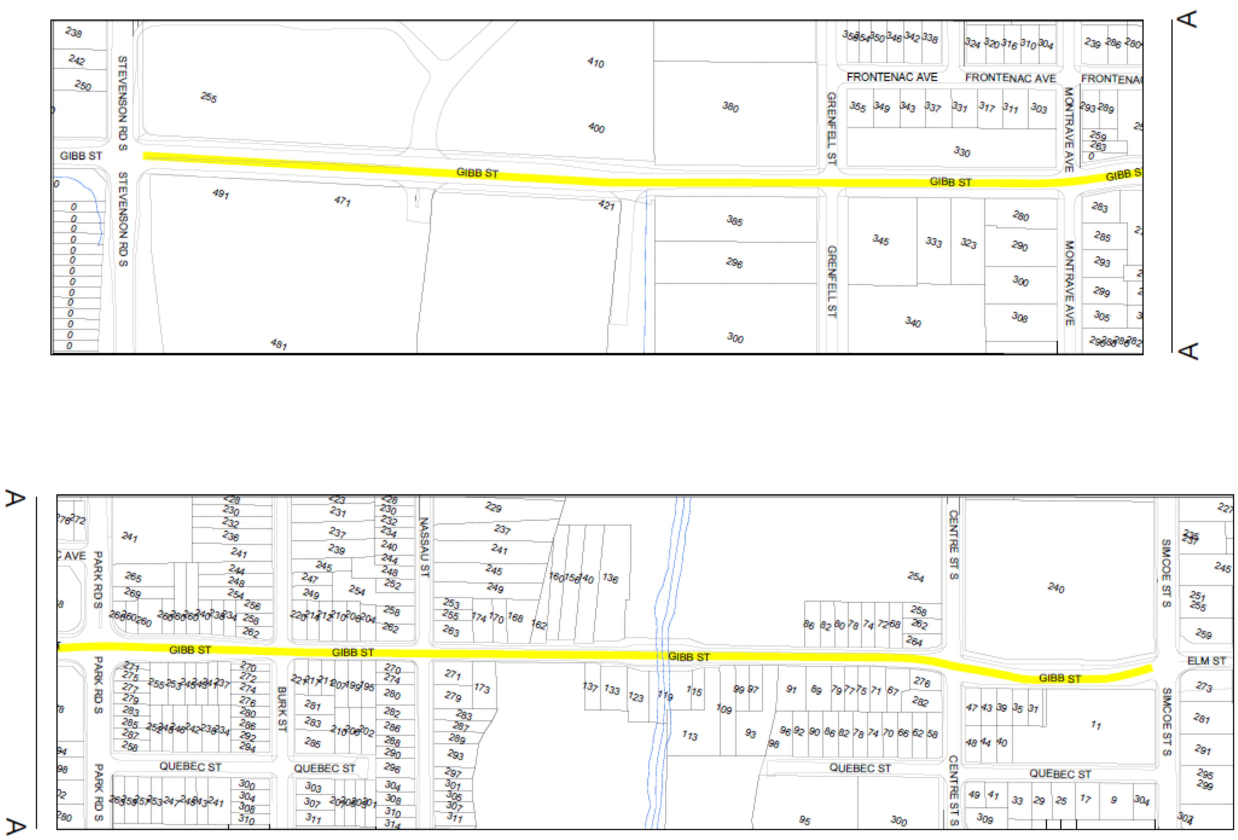


Figure 5: SA-01-07 Region Widening of Gibb Street Map

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)
Efficiency, Customer Value & Reliability – Investment Main Driver
The primary driver for this program is mandatory service obligation to accommodate third party infrastructure development requirements.
Efficiency, Customer Value & Reliability – Investment Secondary Driver
There are no secondary drivers.
Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets
The objective of this program is to meet regulatory obligation to relocate facilities for municipal and regional road work and other third party driven infrastructure upgrades. Generally, OPUCN tried to complete third party relocation projects within one year prior to the construction date indicated by the third party driver. This timeline ensures that coordination for third party pole attachment transfers can also be completed ahead of the prescribed construction schedule. Additionally, OPUCN makes every effort possible to stay within the budget forecasted but scope changes made by the third party driver could adversely affect these performance targets.
Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment
OPUCN's capital plan for system relocation as presented in the DSP is based on consultation with municipal officials to understand future projects requiring relocations of distribution system assets. The locations of municipal road work plans were also compared with OPUCN's planned renewal projects already budgeted for approval. This ensures that a renewal project will not be completed prior to a planned third party relocation project in the short term unless there is a completed design to avoid the relocation of recently rebuilt assets which ultimately increases construction efficiencies. Also, as discussed in the AM process in Section 5.3.1, OPUCN puts mandated work within the System Access Category as the highest priority if compared to investments in different categories.
Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges
Relocation due to third party driven requests do not specifically address reliability, however, OPUCN will build to the latest industry standards and regulations to maintain reliability and install remotely operated switches and communications circuits where applicable. In order to address future challenges OPUCN designs the relocated system to avoid future hazards such as tree growth or land development where possible.
Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment
This program meets some of OPUCN's AM objectives identified in Section 5.3.1, however, this is considered as high priority as it is part of OPUCN's mandated service obligations and therefore must be completed prior to the construction date indicated by the third parties.
Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness
While relocating the facilities OPUCN can take the opportunity to upgrade/modify the system to create flexibility in operations and accommodate future needs on the system. This will reduce the need for additional System Service work required in the future and contribute to higher system operational efficiency and cost effectiveness in the long term.
Analysis of Project & Alternatives – Net Benefits Accruing to Customers

There are no direct benefits to customers except in areas where the infrastructure is old and then there will be an increase in reliability, Customers also benefit indirectly from the work performed by municipalities which supports community development and growth.
Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages
This program is not intended to improve system reliability performance, however, in areas where the infrastructure is old, the use of present standards and new equipment will contribute to an increase in reliability.
Project Alternatives (Design, Scheduling, Funding/Ownership)
While line relocations are generally executed on a like-for-like basis the opportunity is taken to look at feeder routes, future needs and increasing conductor size to plan for future requirements. This exercise will reduce the need for any system renewal and/or system service work required in the future years as well as contribute to a long-term enhanced system operational efficiency, and cost effectiveness. Each project is analyzed on a case-by-case basis to determine if there are any design changes the Third Party could implement to improve cost effectiveness of the relocation thereby reducing costs for both parties. In addition, OPUCN ensures that all relocation projects are completed in accordance with OPUCN's standards which have been developed to minimize overall cost and expenses.
Safety
Facilities will be built to maintain and potentially improve the risk of safety concerns through the renewal of aged infrastructure and design of new infrastructure to the latest distribution standards such as CSA 22.3 for overhead and underground systems..
Cyber-Security, Privacy (where applicable)
Not Applicable
Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)
OPUCN meets quarterly with the City, Region and all other utilities to discuss projects, timelines and co-ordinate efforts. During this process, the designs are sent to all involved parties in each individual project to support in third party designs and obtain feedback from other utilities regarding design changes OPUCN could make to support overall project cost savings or other non-essential requirements. As these projects are driven by third parties they are also co-ordinating the work between various utilities, including OPUCN.
Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)
Future operational requirements are considered in projects where appropriate and accommodation is made in the design for same. For example, provision for remotely operated switches and communications circuits are incorporated where applicable.
Environmental Benefits (where applicable)
The redesign of these areas will also include an assessment of existing transformer loading and where applicable, transformers will be replaced with an appropriately sized transformer to reduce distribution losses.
Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)
Not Applicable

Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)
Not Applicable
Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity
Future operational requirements are considered in projects where appropriate and accommodation is made in the design for same. For example, provision for remotely operated switches and communications circuits are incorporated where applicable.

C. Category-Specific Requirements – System Access (5.4.3.2.C)
Factors Affecting Timing/ Priority
Prioritization of relocation projects is based on development plans of the third parties. Projects can be delayed, cancelled or replaced as a result of changes in the third party's plans. Third Party Relocation projects are mandatory and therefore, receives a high priority in the overall investment envelope as discussed in the AM process in Section 5.3.1.
Factors Related to Customer and other Third Parties
Customer and third party preferences are considered in the design phase of the projects. This is illustrated in the design phase when OPUCN attempts to accommodate the requirements provided by the driver. In most cases we make our best effort to design our infrastructure a way that abides by the customer's requirements but factors such as codes and standards, high costs, and operational concerns could require third party compromise.
Factors Affecting the Final Cost

Factors affecting the final cost of these projects can include:
 	
1. Scope changes in the road work being planned resulting in a potential scope change of OPUCN's relocation.
2. Modifications to the road authority's capital plan resulting in projects being dropped, delayed or added to in a given year.
    a. Major changes in scope of roadway projects could increase the costs of OPUCN's relocation work. This is due to the increased design labour that would be required for major scope changes.
    b. Same way if a project gets delayed/cancelled the design cost already incurred creates a financial burden on the system

Methods Utilized to Minimize Controllable Cost
OPUCN ensures all system relocations are in accordance with OPUCN standards which have been designed to minimize overall costs and impact on the customer, are based on established processes, use standard materials and methods and benefit from efficiencies established through OPUCN's experience in such projects.
Other Planning Objectives
Where appropriate, OPUCN's other planning objectives are considered on a project by project basis. These objectives include: maintain assets in a safe and reliable system, meet existing and future demand requirements and support general plant. This program will maintain or improve system reliability performance, safety performance and operational efficiency and cost-effectiveness, based on the installation of equipment to the latest standards and in excellent condition.

Technically Feasible Project Design and/or Implementation Option Exist
OPUCN typically completes a third party relocation design based on a cost efficient option (where practicable) to avoid any future rework and provides flexibility based on justified future requirements.
Summary of Result Analysis – Least Cost, Cost Efficient Options
Options are considered on a project by project basis to ensure the most practical option is selected but are limited due to service obligations but typically, completes a design based on a cost efficient option. Third party relocation design is completed based on a cost efficient option (where practicable) to avoid any rework and provides flexibility based on justified future requirements. Below is a comparison between least cost and cost efficient option for this project. <u>Least Cost Option</u> Like-for-like replacement are considered in the design which replaces existing distribution assets with same features (i.e. same pole height) without accounting for reliability improvements or consideration for future plans. This option provides the lowest cost solution but does not provide an optimize solution overall as there are risks in rebuilding the same infrastructure in the short term due to future requirements. <u>Cost Efficient Option</u> This option offers more than the basic like-for-like replacement where future requirements are considered in the design including optimizing assets to future requirements in the area as a result of anticipated development which includes but not limited to; sizing conductors to the required capacity, providing switch capabilities for redundancy and reliability, sizing poles to accommodate future circuits anticipated in the short term, etc.
Results of a Final Economic Evaluation (where applicable)
Final economic analysis as described in the DSC is not applicable to this program.
System Impact Cost or Cost Recovery Method
Relocation of distribution system infrastructure to accommodate municipally driven projects has minimal impact to the overall system. Cost recovery is generally based on a cost sharing between OPUCN and the third party driving the project. This is typically based on cost apportionment agreed upon by both LDC and third party or in accordance with Public Service Works on Highway Act. Where major infrastructure changes are required or design changes are made at the specific request of the third party then a cost sharing agreement will be created before the start of the construction.

A. General Information (5.4.3.2.A)					
Project/Activity	Connections				
Project Number	SA-02				
Investment Category	System Access				
	2021	2022	2023	2024	2025
Capital Cost	$1,100,000	$1,100,000	$1,100,000	$1,100,000	$1,100,000
Capital Contribution	$868,450	$868,450	$868,450	$868,450	$868,450
Net Cost	$231,550	$231,550	$231,550	$231,550	$231,550
O&M Cost	2021	2022	2023	2024	2025
	-	-	-	-	-

Customer Attachments and Load

Customer Attachments and Load varies by year and is subject to the amount, capacity, and type of customer request.

Start Date	2021-2025	In-Service Date	2021-2025

Expenditure Timing for the Planning Horizon	2021Q1	2021Q2	2021Q3	2021Q4
	$57,888	$57,888	$57,888	$57,888

Project Summary

The Connections program will encompass projects that facilitate the connection new customers who lie along our distribution system. The cost to install ducts, poles, transformers, and cable to supply electricity to new or upgraded services are captured here. The cost per service can vary widely with the nature of the work and the capacity of each new service. This project is driven by customers, developers and varies from year to year. OPUCN is obligated to complete this work. The forecast costs are mainly driven by historical trends and considerations of growth and development in Oshawa.

Risk Identification & Mitigation

The biggest risk to the completion of this program as planned relates to the cost and timing of the investment. Projects within this program are initiated by customers and the actual spending can vary between years. This is an OEB-mandated activity under the Distribution System Code (DSC). OPUCN has highly trained staff that work with project developers to the best of their ability to manage timelines and to best accommodate the customer. Meetings/correspondence with customers take place frequently and at their request to best manage customer expectations.

Comparative Information on Expenditures for Equivalent Projects/Activities

Historical costs are provided that show comparative expenditure information. Note that actual costs can vary dramatically from year to year.

The following shows the historical actuals and forecast costs:

	Historical Net Costs ($ '000)						Future Net Costs ($ '000)				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Gross	915	1,037	537	929	1,331	1,100	1,100	1,100	1,100	1,100	1,100
Contra	(608)	(470)	(931)	(1,350)	(711)	(868)	(868)	(868)	(868)	(868)	(868)
Net	307	568	(394)	(421)	620	232	232	232	232	232	232

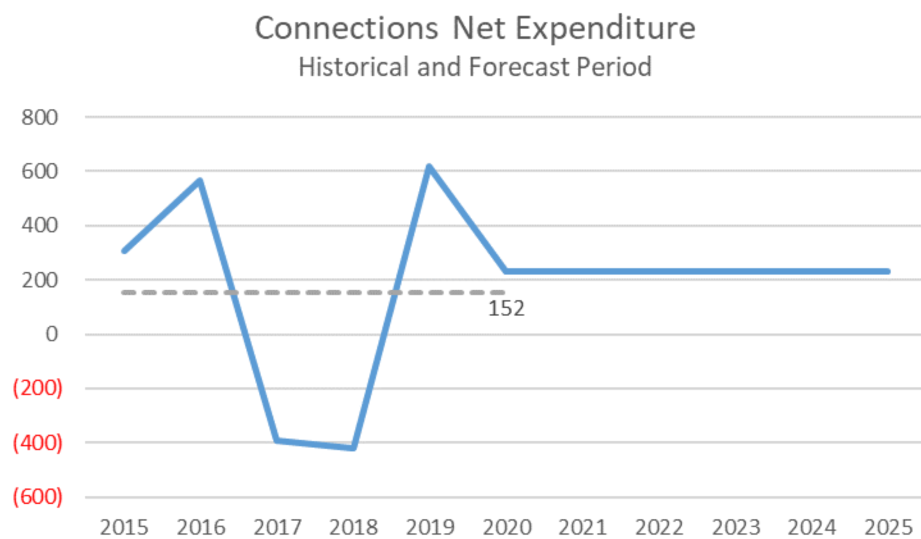


Figure 6: Net Expenditure for Connections in the Historical and Forecast Period

Overall, the net connections budget is increasing by 80K in the forecast period when compared to historical expenditure. This increase was estimated by generating a three year moving average trend supplemented by the customer growth rate of gross expenditures to determine forecast expenditures (grey hashed line). Gross costs were used for trending to ensure that any late contributions, as seen in 2017 and 2018, would not inaccurately skew the forecast. Contributions in this category were estimated based on a ratio of historical gross to historical contributions.

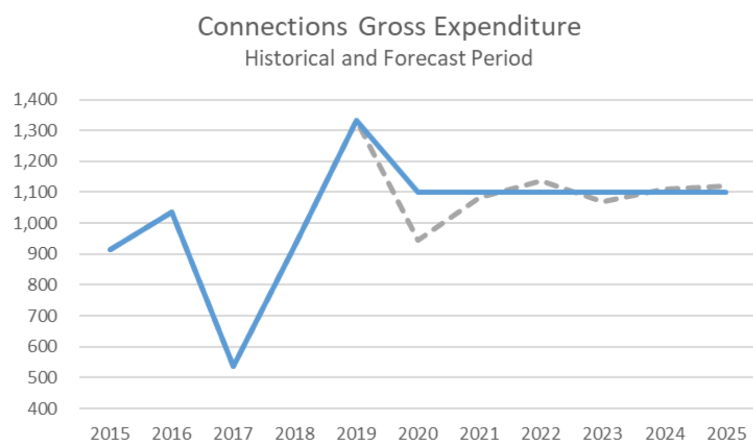


Figure 7: Gross Expenditure for Connections in the Historical and Forecast Period

OPUCN opted for a steady budget into the forecast period because of the variability in connections work. Although OPUCN has strong rational that the expenditure will materialize, there is not significant evidence to justify variable expenditure timelines. The costs captured here and driven directly by customer service requests and commercial/industrial development projects that lie along our existing system. Presently, OPUCN is receiving higher than normal commercial/industrial applications and is projecting this to continue.

REG Investment Details including Capital and OM&A costs

As this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.

Leave to Construct approval under Section 92 of the OEB Act
This project is below 50 kV and therefore Leave to Construct is not required, as per O.Reg. 161/99.
Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material
Not Applicable

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)
Efficiency, Customer Value & Reliability – Investment Main Driver
As a regulatory requirement, OPUCN must remain compliant with the obligations set forth for connecting customers in the DSC. This is a mandatory service obligation to connect customers within 5 calendar days.
Efficiency, Customer Value & Reliability – Investment Secondary Driver
There are no secondary drivers.
Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets
This project is a main contributor to performance metrics tied to the mandatory service obligation outlined in the DSC to connect customers within five calendar days. Success is measured and posted publicly by means of the OEB scorecard which can be found on the OEB's website.
Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment
New services/upgrades are driven by customer/developer requests and are mandated by the OEB to be completed as stated in OPUCN's AM Process in Section 5.3.1.
Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges
New connections are constructed using best utility practices that consider reliability by design i.e designing the system in a way that is safe and reliable through distribution system hardening and ensuring that it meets OPUCN standard design which are typically over and above the CSA minimum requirements.
Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment
This program meets a few of OPUCN's AM objectives, however, is considered a high priority due to the mandatory nature of this investment. New connections are made based on customer/developer request and the process is managed by OPUCN staff through various systems to ensure proper visibility and timelines. Projects within this program are executed with a high priority as they are linked directly with the customers that OPUCN serves and connections must be made within timelines specified in the DSC.
Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness
Whenever possible new service connections use standardized designs to maximize cost effectiveness for the affected customer and to minimize rate impact for OPUCN's customers in general. Standardized design practices also address system operational efficiency.
Analysis of Project & Alternatives – Net Benefits Accruing to Customers

The benefits to Customers through this project includes receiving a connection to the electricity grid and/or the ability to request an upgrade. This project captures the cost to install ducts, poles, transformers, and cable to supply electricity to new or upgraded services.
Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages
New connections are constructed using best utility practices that consider reliability by design through distribution system hardening and ensuring that it meets OPUCN standard design which are typically over and above the CSA minimum requirements.
Project Alternatives (Design, Scheduling, Funding/Ownership)
<u>Project Design Alternatives:</u> OPUCN is responsible for system design and connection. For each customer request there are specific requirements, such as service size, transformer size, service egress type (overhead or underground), and any site specific barriers that must be accommodated. Where possible the designers will investigate the different supply options for a customer and make a recommendation as to the most cost effective solution. <u>Scheduling Alternatives:</u> These projects are customer driven and do not have alternative scheduling options with the exception of minor variation in timing of connecting the service.
Safety
New construction meets the latest distribution standards for safety including CSA standards for OH and UG.
Cyber-Security, Privacy (where applicable)
This program does not have a direct impact on cyber security or privacy. However, during the setup of new customer accounts, OPUCN handles customers' personal information in accordance with established privacy policies and guidelines.
Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)
OPUCN co-ordinates directly with customers, contractors, developers and agencies such as ESA. The process for this program starts with the service request form. From there our technicians respond to the request and begin coordinating with the customer and the ESA until the project's completion.
Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)
Future operational requirements are considered in projects where appropriate and accommodation is made in the design for same. For example, provision for remotely operated switches, fault indicators and communications circuits are incorporated where applicable.
Environmental Benefits (where applicable)
There are no applicable environmental benefits.
Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)

Not Applicable
Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)
Not Applicable
Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity
Future operational requirements are considered in projects where appropriate and accommodation is made in the design for same. For example, provision for remotely operated switches and communications circuits are incorporated where applicable.

C. Category-Specific Requirements – System Access (5.4.3.2.C)
Factors Affecting Timing/ Priority
New connections are made based on customer/developer request. The process is managed by OPUCN staff through various systems to ensure proper visibility and timelines. Projects within this program are executed with a high priority as they are mandatory and driven by the connection requirements set out in the DSC. The timing and priority is also determined through OPUCN's AM process as per Section 5.3.1. In some cases where extensive civil work is required for the customer to gain access to the distribution system, scheduling requirements are adjusted. The availability of an egress to the existing main distribution system within proximity of the proposed connection will have the largest impact on timing. All new customers in this program lie along the distribution system, but these connections often require enabling civil work to construct duct banks, install transformers, and/or install poles.
Factors Related to Customer and other Third Parties
These projects are initiated by customers and are designed to meet the needs of the customers for connection.
Factors Affecting the Final Cost
Costs are generally driven by connection requests of the customer/developer and can vary from project to project. OPUCN employs good utility practice and engineering practices to ensure that costs are controlled and minimized for the customer.
Methods Utilized to Minimize Controllable Cost
The design and connection of services is standardized and therefore costs are controlled through well-established processes, the use of standardized material and the efficiencies established through OPUCN's experience in connecting such projects.
Other Planning Objectives
Other capital projects are reviewed and future projects are taken into account when designing the new connections to see if projects can be done together.
Technically Feasible Project Design and/or Implementation Option Exist
Customers have options with respect to servicing. However, feasible options must be reviewed on a project by project basis which cannot start until each project is initiated.

Summary of Result Analysis – Least Cost, Cost Efficient Options
Customers and/or Developers are involved in the OPUCN design process from the initiation of the project. They are given options based on OPUCN standards and Conditions of Service. OPUCN and the Customer/Developer work closely to ensure all requirements are met using the most cost effective options.
Results of a Final Economic Evaluation (where applicable)
Only applicable if infrastructure has to be extended or enhanced. In this case an economic evaluation will be run on the cost of this extension after five years.
System Impact Cost or Cost Recovery Method
Costs for these projects are fairly predictable based on standardized processes and materials and are recovered through economic evaluations as prescribed in the DSC.

A. General Information (5.4.3.2.A)					
Project/Activity	Expansions				
Project Number	SA-03				
Investment Category	System Access				
	2021	2022	2023	2024	2025
Capital Cost	$2,381,621	$2,381,621	$2,381,621	$2,381,621	$2,381,621
Capital Contribution	$719,607	$719,607	$719,607	$719,607	$719,607
Net Cost	$1,662,014	$1,662,014	$1,662,014	$1,662,014	$1,662,014
O&M Cost	2021	2022	2023	2024	2025
	-	-	-	-	-

Customer Attachments and Load

Customer Attachments – 12,000
Load – Approximately 18MW

Start Date	2021-2025	In-Service Date	2021-2025
Expenditure Timing for the Planning Horizon	2021Q1	2021Q1	2021Q1	2021Q1
	$415,504	$415,504	$415,504	$415,504

Project Summary

The purpose of the expansion program is to facilitate the connection of new residential subdivisions and associated customers to OPUCN's distribution system that do not lie along the existing distribution system. This is driven by Developers and varies from year to year. Forecast costs are estimated using the historical expenditure and the forecasted growth rate. A mean of 791 new residential customers annually are expected to be connected over the forecast period. The expenditure division for the test year was done equally between each quarter which will not be how the expenditure is captured. The expenditure timeline for this project is driven strictly by developers and will vary.

Risk Identification & Mitigation

The biggest risk to the completion of this program as planned relates to the cost and timing of the investment. Projects within this program are initiated by developers and the actual spending can vary between years. This is an OEB-mandated activity under the DSC. OPUCN has highly trained staff that work with project developers to the best of their ability to manage timelines and to best accommodate the customer. Meetings/correspondence with customers take place frequently and at their request to best manage customer expectations.

Comparative Information on Expenditures for Equivalent Projects/Activities

Historical costs are provided that show comparative expenditure information. Actual costs can vary dramatically from year to year.

	Historical Costs ($ '000)					Future Costs ($ '000)					
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Gross	2,190	(505)	48	1,835	6,471	2,382	2,382	2,382	2,382	2,382	2,382
Contra	(1,416)	186	881	(1,883)	(2,563)	720	720	720	720	720	720
Net	774	(319)	929	(48)	1,892	1,662	1,662	1,662	1,662	1,662	1,662

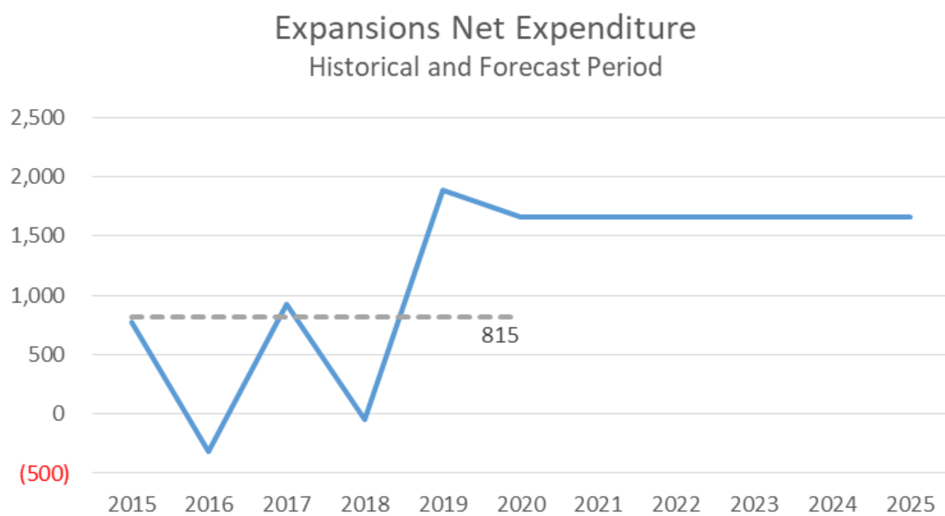


Figure 8: Net Expenditures for Expansions in the Historical and Forecast Period

Overall, the expansions budget is forecast to increase by 847K on average from the historical period. The forecast was determined by using the modelled growth rate, 1.4%, and historical expenditures per lot. On average, OPUCN contributed $2,100 per lot in new residential developments over the historical period and expects to connect approximately 791 lots per year in the forecast period. OPUCN opted for a steady budget into the forecast period because of the variability in expansions work. Although OPUCN has strong rational that the expenditure will materialize due to a modelled growth rate and municipal indication of growth in the city, there is not significant evidence to justify variable expenditure timelines. The costs captured here are driven directly by developer requests and their ultimate timelines.

REG Investment Details including Capital and OM&A costs
As this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.
Leave to Construct approval under Section 92 of the OEB Act
This project is below 50 kV and therefore Leave to Construct is not required, as per O.Reg. 161/99.
Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material
Please refer to the following approximate area for new developments and expansion (circled in red). Note that the shaded areas with different colours determines the status of the Site Plan Application (SPA) with the City. This map is to be used for reference only:

Figure 9: Residential Subdivision Development Activity Map

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)
Efficiency, Customer Value & Reliability – Investment Main Driver
The main driver is developer's requests where they are to make provision for electrical servicing of residential units. Scope and timelines are based on requirements put forth by customers and/or obligations set forth for connecting customers in the DSC.
Efficiency, Customer Value & Reliability – Investment Secondary Driver
There are no secondary drivers.
Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets
This project is a main contributor to performance metrics tied to the mandatory service obligation outlined in the DSC to connect customers within five calendar days. This project also supports OPUCN's core values of customer and community value, operational excellence and financial and environmental sustainability.
Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment
New services are driven by customer/developer requests and are mandated by the OEB to be completed under the DSC as stated in OPUCN's AM Process in Section 5.3.1.
Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges

New subdivisions are constructed using best utility practices that consider reliability by design i.e designing the system in a way that is safe and reliable through distribution system hardening and ensuring that it meets OPUCN standard design which are typically over and above the CSA minimum requirements.
Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment
This program meets a few of OPUCN's AM objectives, however, is considered a high priority due to the mandatory nature of this investment. New connections are made based on customer/developer request and the process is managed by OPUCN staff through various systems to ensure proper visibility and timelines. Projects within this program are executed with a high priority as they are linked directly with the customers that OPUCN serves and connections must be made within timelines specified in the DSC.
Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness
Whenever possible new service connections use standardized designs to maximize cost effectiveness for the affected customer and to minimize rate impact for OPUCN's customers in general. OPUCN also considers System Operation Efficiency by ensuring new infrastructure enables the customer's load to grow without requesting a service upgrade. This is done by ensuring every new service is rated up to 200A.
Analysis of Project & Alternatives – Net Benefits Accruing to Customers
New Customers benefit from a connection to an electrical system that is modern, reliable, efficient, and built to current standards.
Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages
New subdivisions are constructed using best utility practices that consider reliability by design. The electrical infrastructure in expansion projects are designed and constructed to provide a resilient distribution system by utilizing the loop feed method. This reduces the duration of outages by providing an alternate feed when an outage event occurs.
Project Alternatives (Design, Scheduling, Funding/Ownership)
Developments are planned and funded in accordance with OPUCN's Conditions of Service. <u>Project Design Alternatives:</u> OPUCN is responsible for all system design and the ultimate ownership of the electrical distribution plant. The options for design alternatives are limited to the requirements of the City of Oshawa for servicing new subdivisions and OPUCN's standards. <u>Project Scheduling Alternatives</u>: Project schedule is based on the Developers requirements. <u>Project Funding Alternatives:</u> There are two alternatives for project funding that are provided to the developer and outlined in the Conditions of Service. OPUC completes an economic evaluation for every application and it is the developers discretion to determine to proceed with one of the following alternatives: 1. Distributor Constructed OPUCN will make an "Offer to Connect" and will include without limitation: the description of the expansion facilities and connection assets, Basic and variable connection fees, an economic evaluation, a capital contribution evaluation

and the customers choice of obtaining alternative bids, settlement of capital contribution, rebates related to expansions, the OPUCN Offer to Connect document, and a reference to the OPUCN conditions of service. 2. Developer Constructed (Alternative Bids) Where a capital contribution is required and the work does not involve work with the existing OPUCN distribution system, the developer may obtain alternative bids for the expansion project from qualified contractors.
Safety
New construction meets OPUCN's standards, Canadian Standards Association (CSA) standards, Utilities Standards Forum (USF) Standards, and meets the safety requirements of Ontario Regulation 22/04.
Cyber-Security, Privacy (where applicable)
This program does not have direct impact on OPUCN's cyber security or privacy. When a customer submits a request for a new customer account, OPUCN handles this information in accordance with established guidelines and privacy policies.
Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)
New subdivision development is a very standardized process. For new subdivisions, OPUCN has designated standard locations within the municipal right-of-way as do the other utilities. Through this standardization, co-ordination and joint use trenching opportunities are maximized. Differences in project requirements requested by developers are addressed with municipalities and other utilities via meetings, drawing exchange and joint utility, City, Region meetings.
Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)
Subdivisions are supplied with loop feeds to allow for ease of operation with minimal outages. Loops feeds provide an alternate electrical source during an outage event to minimize outage duration. Each new service is sized appropriately to facilitate customer load growth to mitigate the need for future upgrade requests.
Environmental Benefits (where applicable)
Not Applicable.
Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)
Not Applicable
Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)
Not Applicable
Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity
Subdivisions are supplied with loop feeds to allow for ease of operation with minimal outages. Loops feeds provide an alternate electrical source during an outage event to minimize outage duration. Each new service is sized appropriately to facilitate customer load growth to mitigate the need for future upgrade requests.

C. Category-Specific Requirements – System Access (5.4.3.2.C)
Factors Affecting Timing/ Priority
New connections are made based on customer/developer request. The process is managed by OPUCN staff through various systems to ensure proper visibility and timelines. Projects within this program are executed with a high priority as they are linked directly with the customers that OPUCN serves. This program is mandatory and the timing and priority is also determined through OPUCN's AM process as per Section 5.3.1. OPUCN is obligated to complete expansion projects as per the requirements set out in the DSC. Factors that may affect the timing of these projects include the availability of distribution system, developer's schedules, coordination with third parties, and availability of labour resources.
Factors Related to Customer and other Third Parties
These projects are initiated by developers when they request to service new homes. This system is designed to meet the requirements of the City of Oshawa, the customer and other utilities servicing the residential development (eg. location and offset of underground plant).
Factors Affecting the Final Cost
Additional costs are generally driven by the specific requests of the customer/developer and can vary from project to project. OPUCN employs good utility practice and engineering practices to ensure that costs are controlled and minimized for the customer. Factors such as access to existing distribution facilities could affect the final cost. The total cost per service is typically $2,000 on average but could be up to $5,000 per service.
Methods Utilized to Minimize Controllable Cost
The design and connection of services is standardized and therefore costs are controlled through well-established processes, the use of standardized material and the efficiencies established through OPUCN's experience in connecting such projects. These processes can be found in the attached document "Subdivision Developer Information Package".
Other Planning Objectives
Other objectives such as transformer loading and ability to supply adjacent subdivisions are always considered (i.e. when subdivisions are phased, OPUCN completes a master plan to accommodate future growth in loop feed plans and ensure capacity is available). However, investments under this program are driven primarily by customer requests.
Technically Feasible Project Design and/or Implementation Option Exist
Project design and implementation options for this program are not known until the customer request is received. Designs can vary from project to project and must be made in accordance with OPUCN's Conditions of Service. Whenever possible, OPUCN uses standardized designs. Final design and implementation decisions are made by OPUCN's engineering department.
Summary of Result Analysis – Least Cost, Cost Efficient Options
Customers and/or Developers are involved in the OPUCN design process from the initiation of the project. They are given options based on OPUCN standards and Conditions of Service. OPUCN and the Customer/Developer work closely to ensure all requirements are met using the most cost effective options.
Results of a Final Economic Evaluation (where applicable)
A final economic evaluation is performed after all units are energized as per section 3.2 of the DSC and in OPUCN's Conditions of Service.

System Impact Cost or Cost Recovery Method
If development of a new subdivision is staged, for the duration of the time between connection of the first customer in the stage and last customer in the stage, the construction of the main distribution system may not be fully complete. This may result in system segregation and lesser ability to restore power quickly in the case of faults. This is mitigated by the fact that the plant is fairly new and other than manufacturing defects, no outages are expected. Costs for these projects are fairly predictable based on standardized processes and materials and are partially recovered through economic evaluations as prescribed in the DSC.

A. General Information (5.4.3.2.A)					
Project/Activity	Revenue Metering – New Connections				
Project Number	SA-04				
Investment Category	System Access				
	2021	2022	2023	2024	2025
Capital Cost	$223,000	$223,000	$223,000	$223,000	$223,000
Capital Contribution	N/A	N/A	N/A	N/A	N/A
Net Cost	$223,000	$223,000	$223,000	$223,000	$223,000
O&M Cost	2021	2022	2023	2024	2025
	$2,230	$2,230	$2,230	$2,230	$2,230

Customer Attachments and Load

All New Customers

Start Date	2021-2025	In-Service Date	2021-2025

Expenditure Timing for the Planning Horizon	2021Q1	2021Q2	2021Q3	2021Q4
	$55,750	$55,750	$55,750	$55,750

Project Summary

New Meters to be installed on new services including commercial, residential and industrial. O&M for new meter installs is negligible. We are continuing to utilize our existing Automated Metering Infrastructure (AMI) Head End and use next generation meters Elster RexU meters for all single phase new residential and small commercial installations. All 3 phase installation will use Elster A3 meters compatible with our existing AMI. All meters must be compliant to OEB, CSA and Measurement Canada rules.

Risk Identification & Mitigation

We have identified that Rex-U meters will bridge the gap between our current communication platform and next generation platform. Our head end system has already been upgraded to mitigate risk. Mitigation is to test the new meters in service and monitor performance. Risk would be to stay with current Rex2 technology and be subjected to eventual obsolesce in meter data collection technology. New technology requirements to be compliant with Cyber Security Framework specifications. Scheduled upgrades in advance, customer notification and information prior to implementation. Validation and verification of processes, testing with MDMR prior to implementation. Testing with OMS to ensure messaging and manufacturer specifications are correct for outage messages and operational data.

Working with the Vendor to secure meter supply and delivery schedules to avoid any shortfall with meters. Installation of new meters for residential has been done by line crews, meter technicians have installed and will install all new commercial and industrial meters. Work volumes for new meter installs have not increased significantly and are almost equivalent to historical workload volumes. Working with builders and constructor to ensure that volume spikes are mitigated to prevent any delays on installation.

Comparative Information on Expenditures for Equivalent Projects/Activities

Meter costs for new connections, residential, commercial and Meters Inside Settlement Timeline (Interval) are equivalent to historical programs.

Historical Costs ($ '000)						Forecast Costs ($ '000)				
2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
434	549	247	531	453	223	223	223	223	223	223

REG Investment Details including Capital and OM&A costs

This project is not associated with REG investment.

Leave to Construct approval under Section 92 of the OEB Act

This project does not require Leave to Construct approval under section 92 of the OEB Act.

Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material

The following are images of a typical meter.

Figure 10: RexU Meter

Figure 11: Commercial Meter

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)

Efficiency, Customer Value & Reliability – Investment Main Driver

The purpose of this project is to comply with Federal and Provincial regulation. Mainly, The OEB Smart Metering Initiative EB-210-0218 effective June 14, 2010 and the Electricity and Gas Inspection Act.

Efficiency, Customer Value & Reliability – Investment Secondary Driver

There are no secondary drivers.

Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets
Mandatory service obligation required by the OEB to connect customers within 5 business days. Revenue meters are a mandatory requirement.
Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment
This is a mandatory service requirement that a Measurement Canada approved meter is installed on all services that we charge for energy.
Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges
Meters will be able to handle momentary outages better than current generation. Momentary outages cause false predictions. This leads to better information, leads to better response and communication. RexU meters are design to operate on the existing wireless mesh network while providing the option to use an improved wireless communication technology in the future.
Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment
This program meets some of OPUCN's AM objectives and considered as high priority as OPUCN is required by regulations to install meters. Cost of next generation meters is same as current generation meters.
Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness
Operating efficiency would improve through better reporting from meters, these meters would be the first step leading towards a Wifi/WAN technology base system as a push system, instead of pull. This will also provide better reliability of data for Meter Data Management Repository (MDMR) and Outage Management System (OMS).
Analysis of Project & Alternatives – Net Benefits Accruing to Customers
This program will continue to provide accurate electricity measurement and outage alerts.
Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages
Provide reliable meters for all new customers. The RexU meters have an improved technology when compared older meters that enables them to endure a momentary outage (<1min) before sending out an outage alert. Currently, during momentary outages the meters send out outage alerts which saturate the wireless mesh network causing issues. This new technology will prepare us for better operation in the future.
Project Alternatives (Design, Scheduling, Funding/Ownership)
No alternatives are available to replace the Rex2 meter as the manufacturer is not longer producing this meter type. The replacement meter is the RexU meter.
Safety
Meters and associated equipment will adhere to CSA and Measurement Canada Standards.
Cyber-Security, Privacy (where applicable)
Data encryption is to current AMI standard C12.22 and C12.19 to ensure cybersecurity and privacy. The following provides general description of these standards.

ANSI C12.22 (c1222) is the protocol used to transport ANSI C12.19 tables which are metering specific data structures. The ANSI C12.22/IEEE 1703 protocol define the framework for transporting ANSI C12.22/IEEE 1703 Advanced Metering Infrastructure (AMI) Application Layer Messages on an IP network on the Smart Grid.

ANSI C12.19 defines a Table structure for utility application data to be passed between an End Device and any other device. It neither defines device design criteria nor specifies the language or protocol used to transport that data. The Tables defined in this Standard represent a data structure that shall be used to transport the data, not necessarily the data storage format used inside the End Device.

Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)

In discussions with other LDCs, it was identified that Ottawa Hydro, Toronto Hydro, Elexicon, Alectra, also use Elster/Honeywell smart meters (Rex2). The Elster/Honeywell RexU meter is being deployed by Elexicon and Alectra.

Meters will comply with the following requirements:

- IESO MDMR data transfer requirements as per California Metering Exchange Protocol (CMEP)
- Multi-speak communication from Head End system to OMS, ODS systems.
- Zigbee communication standard communication protocol

Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)

The Meters will connect and send outage messages back to the OMS, be utilized in transformer loading and asset management of transformers in the ODS system and can be used for future ADMS systems. RexU meters will provide voltage values.

Environmental Benefits (where applicable)

Not Applicable

Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)

Time of use and voltage information collected by the meter per premise may be used

Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)

Not Applicable

Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity

This investment will provide better insight and analytics for demand management

C. Category-Specific Requirements – System Access (5.4.3.2.C)
Factors Affecting Timing/ Priority

Need to commence in 2021 as new revenue meters for new services are required on an on-demand basis.
Factors Related to Customer preferences and other input from Third Parties
Better resolution of data will be available to customers.
Factors Affecting the Final Cost
Meters are purchased in parallel with the Meter Replacement program to reduce costs based upon meter unit volumes.
Methods Utilized to Minimize Controllable Cost
Meters are purchased in parallel with the Meter Replacement program to reduce per unit cost on volume. Minimizing on the number of meter procured and staging when the meters are delivered reduce the inventory carrying costs.
Other Planning Objectives
Incorporation of next generation collectors with level 3 cyber security connected to fiber for better/ faster backhaul.
Technically Feasible Project Design and/or Implementation Option Exist
We are required to install meters on new connections. The procurement of the meters is minimized a purchased
Summary of Result Analysis – Least Cost, Cost Efficient Options
Continuing to the existing Elster Rex2 meter is a more cost effective method but this does not utilize the communication and recording capabilities of the next generation of meters for the same costs. Installing next generation new smart meters results in avoiding a meter change out in the future to avoid obsolescence of meter technology.
Results of a Final Economic Evaluation (where applicable)
The cost of the meter is the only cost applicable to this project.
System Impact Cost or Cost Recovery Method
Cost recovery is through rates.

A. General Information (5.4.3.2.A)					
Project/Activity	AMI System Update				
Project Number	SA-05				
Investment Category	System Access				
	2021	2022	2023	2024	2025
Capital Cost	$386,600	$411,800	$437,000	$462,200	$487,400
Capital Contribution	N/A	N/A	N/A	N/A	N/A
Net Cost	$386,600	$411,800	$437,000	$462,200	$487,400
O&M Cost	2021	2022	2023	2024	2025
	-	-	-	-	-

All residential customers and small commercial smart meters. OPUCN is using smart meter technology to collect hourly interval data up to 200KW. Below 50KW the meter data is sent to the MDMR for Time of Use (TOU) billing. Between 50KW and 200KW, the smart meters are used for hourly interval data collection. Above 200KW, data collection is completed through cellular communication using an different meter reading technology platform to provide interval data.

Start Date	2021-2025	In-Service Date	2021-2025
Expenditure Timing for the Planning Horizon			

Expenditure Timing for the Planning Horizon	2021Q1	2021Q2	2021Q3	2021Q4
	$77,320	$115,980	$115,980	$77,320

Project Summary

The AMI System Update consists of replacing all failed smart meters that are currently in-service with the next generation of meters. The replacement program includes upgrading the AMI data collector units to wireless routers and connecting these to the fiber network. Currently the maintenance program is fixed to the initial deployment of smart meters. As a result, the majority of meter maintenance is completed to maintain meter seal compliance to Measurement Canada. Each re-seal of meters reduces the subsequent length of sealing. This program will also include Measurement Canada reverification of meters requiring re-seal will be scrapped. Sample test meters will be replaced with next generation meters.

Meter depreciation at the time of purchase of the meters was set to 10 years. The last meters will be removed from service as part of this program at 21 years. Meter failure rate for meters, increases each year for the meters left in service.
Spreading the project out over 10 years will help to reduce unbalanced operational costs that are currently being faced once every 10 years to an even expenditure and work force each year. Once this project is completed or near completion, decisions would be made in the future on the next generation of meters. These again can be deployed on a yearly basis with reduced costs per year.

Risk Identification & Mitigation

Scheduling Risk –. OPUCN is planning to replace failed meters annually during the planning period. Depending on the number of failed meters, this will have an impact on lead time and delivery but will be mitigated by developing a schedule and placing the equipment order well in advance. Work force management and data integration automation will help to reduce meter errors and data errors by reducing manual entry and paperwork. Procurement schedule is done 1 year ahead and monitored monthly for failed meter replacements.

Resource Risks – these are limited to too many meters failing at one time for staff to handle. We are working with service providers to have them available in case the failed meters escalate.

Comparative Information on Expenditures for Equivalent Projects/Activities

New meter costs, are consistent with current meter generation costs and the cost to repair and reseal the meters outweighs the cost to proactively replace failed meters. Measurement Canada seal requirements reduce the available number of years after each subsequent meter reseal. As a result in 8 years the meters can only be extended an additional 6 years. The costs of OM&A increases without the benefit of better functionality.

REG Investment Details including Capital and OM&A costs

This project is not associated with REG investment.

Leave to Construct approval under Section 92 of the OEB Act

This project does not require Leave to Construct approval under section 92 of the OEB Act.

Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material

The following are images of a typical meter.

Figure 12: RexU Meter

Figure 13: Commecial Meter

Conexo Connectivity System – This diagram illustrates the connection between residential meters, commercial meters, industrial meters and “smart grid” devices for data collection purposes on a “smart grid” network.

Figure 14: Connexo Connectivity System Diagram

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)
Efficiency, Customer Value & Reliability – Investment Main Driver
Mandatory service and regulatory obligations. This is to provide the customer with metered power as required by Federal and Provincial regulation. Measurement Canada requires sample testing of meters. The meters will be removed from service, be sent to an accredited meter facility and will not be put back into service after the sample tests are complete. Replacement of collector units with next generation RF mesh network routers helps to reduce lag from radio frequency and cellular transmission times by connecting to the fiber network.
Efficiency, Customer Value & Reliability – Investment Secondary Driver
There are no secondary drivers.
Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets
Reliability – momentary outages (less than 1 minute) causing false outage message notifications from the meter and false dispatching of crews. We have filtered in the OMS and the AMI system but due to volumes of data not all messages can be filtered in all situations, it is better to control the meter outage alarms at the source – the meter which will increase visibility. For AMI data collection to be 5 minute interval for all meter data collected. Voltage value data collection for transformer loading and BI analysis warnings on areas of deployment. Reduction of meter failure rate in areas of deployment with a reduction in operational costs.
Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment

The following historical records and annual tracking of meter failures were used to justify the investment. From OPUCN's perspective, the meters will begin to fail more rapidly after the year 2030. We assessed replacing the meters starting in this DSP, but the rate of failure to the payback of meter replacement would not happen until 2038.

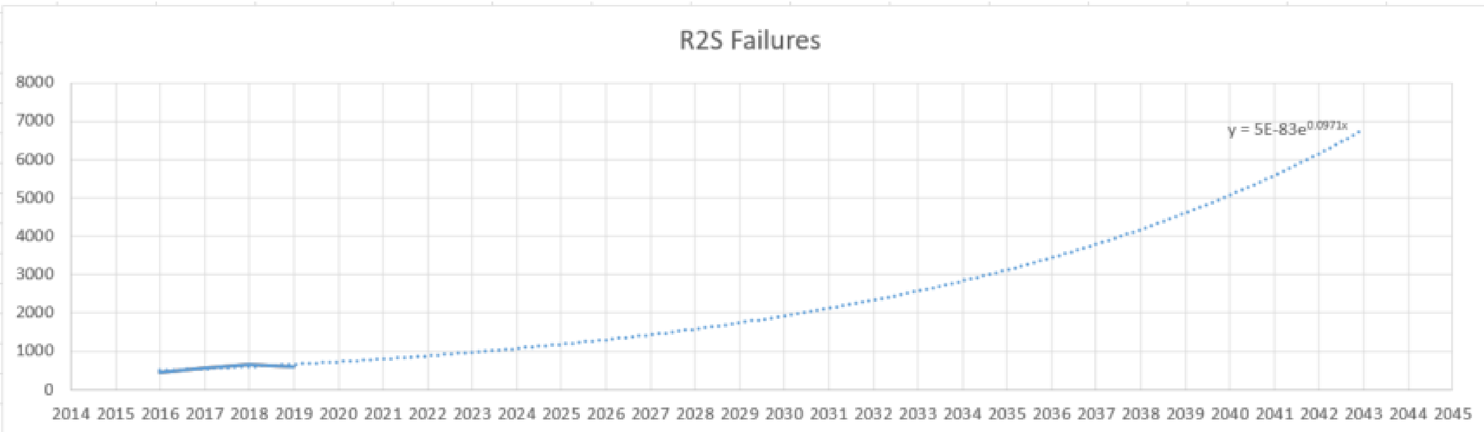


Figure 15: RS2 Failures, Historical and Forecast

Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges
Meters will be able to handle momentary outages better than current generation. Momentary outages cause false predictions. This leads to better information, better response and communication.
Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment
This investment meets majority of the AM objectives and is considered one of the highest priority in the capital investment plan due to mandatory regulatory and service obligations.
Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness
Operating efficiency would improve through better reporting from meters, these meters would be the first step leading towards a Wifi/Wan. Current technology meter data is collected through a 1:1 polling of the meter data. Next generation of meters push data to the head end allowing more data to flow back to the head end. Current outage messages are read by collector/head end sequentially, next generation will allow for faster outage messages to the head end by messages being submitted when communication is established by the meter. Reliability can be reduced by removing the filtering time period of 15 minutes, it is possible to reduce SAIDI for all nested outages. This is a result of momentary outages and the entire feeder of meters trying to submit messages back to the head end at the same time, this message flood causes some meters messages to be delayed reaching the head end by up to 2 hours especially if they are required to hop more meters due to the communication path on the mesh network. Given that we need to respond within minutes this current messaging process is unacceptable. Remaining with the current generation of meters would mean eventual obsolesce as the manufacturer is currently looking at stopping production of 2nd generation smart meters. Using alternative smart meter providers would not result in better data capture or outage message information.
Analysis of Project & Alternatives – Net Benefits Accruing to Customers
Net benefits to customers would be accurate billing with better outage information to the head end system.

Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages
The impact to reliability would not be known until all smart meters are replaced in 2038.
Project Alternatives (Design, Scheduling, Funding/Ownership)

If we were to 'Do Nothing' the current generation of meters would eventually be obsolete as the manufacturer is currently considering the end of production of 2nd generation smart meters. If we would consider using an alternative manufacturer, it would not result in better data capture or outage message information and compatibility may be an issue.

3rd generation smart meters allows OPUCN to use the current head end system and current collector units until OPUCN has the next generation collector units deployed.

Below is the graphical comparison of 2 alternatives for scheduling this project.

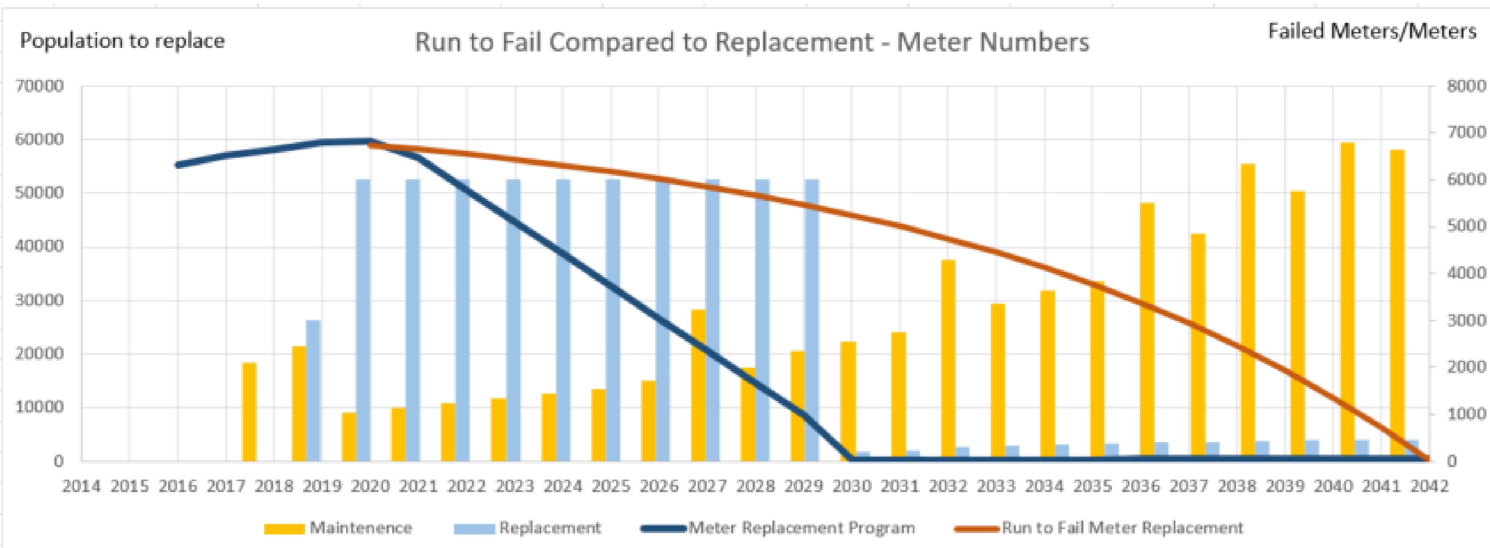


Figure 16: Graphical Representation of Project Alternatives

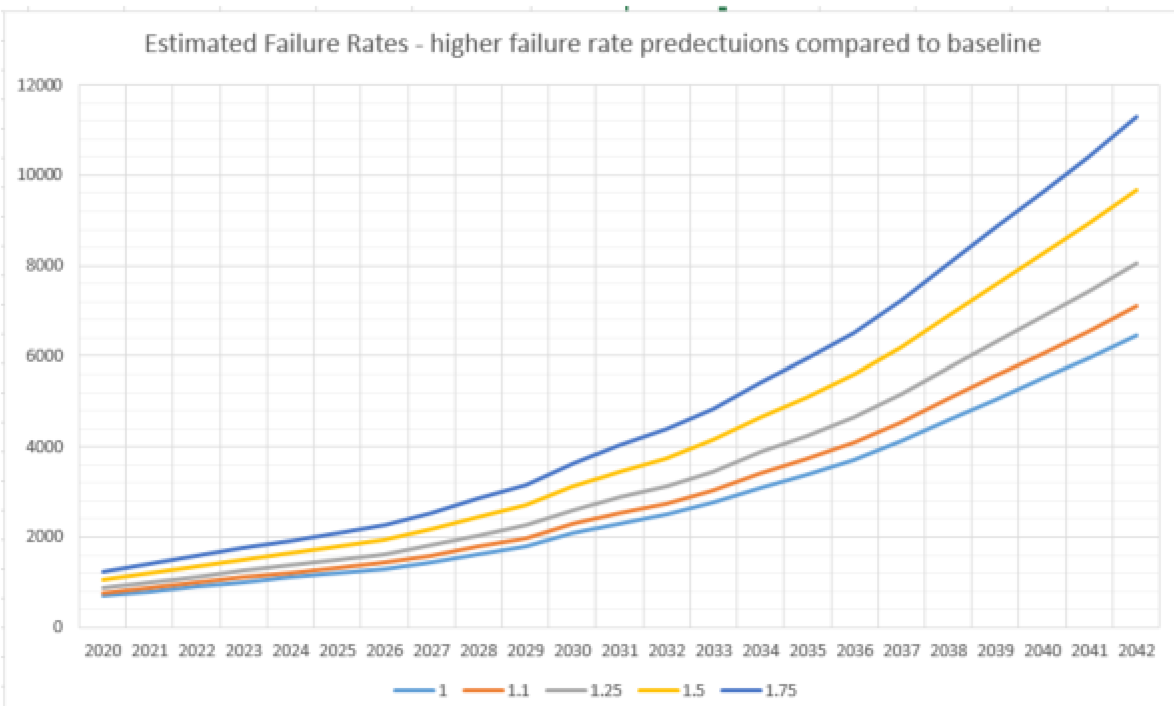
The orange line shows the run to fail option where the meters would be replaced as they fail naturally in our system. The yellow bars indicate the associated maintenance cost increases that would be applicable if the run to fail option was pursued. Since the failure rate is an exponential curve we would expect our operational and maintenance costs to be relative.

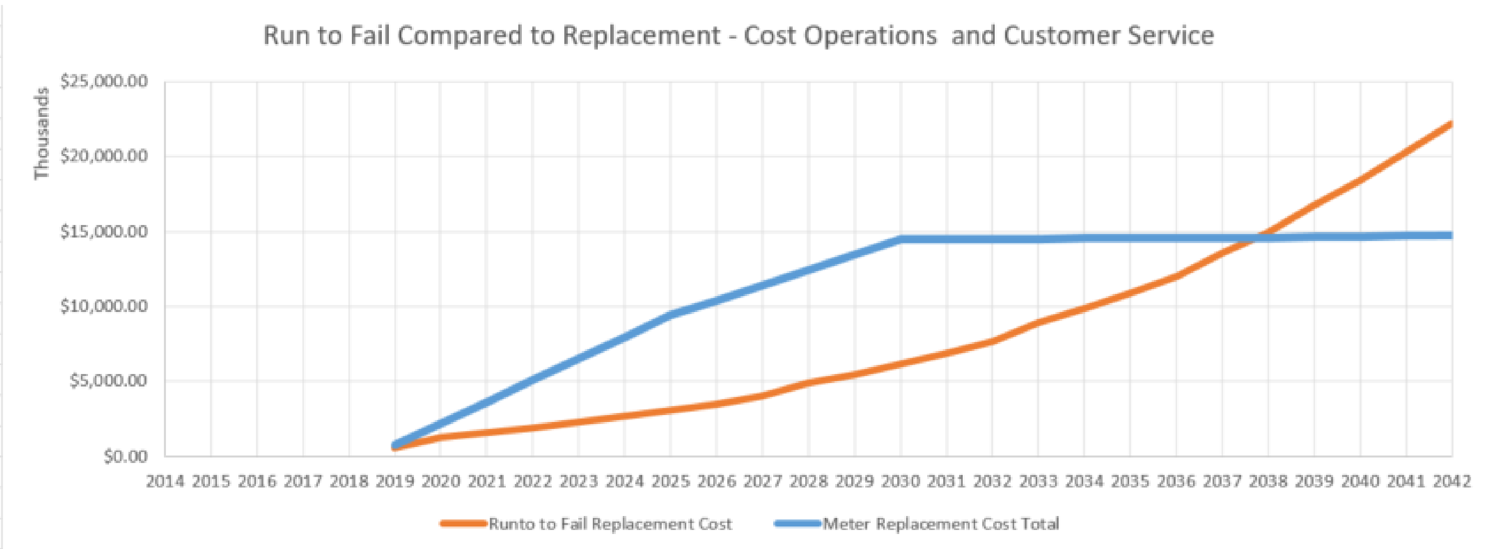
The blue line shows an option where are all meters are replaced prior to 2030 regardless of their typical useful life and condition. This option has a high capital cost to proceed with as shown using the blue bars.

Safety
Meters and associated equipment adhere to CSA and Measurement Canada Standards.
Cyber-Security, Privacy (where applicable)
There is a secure connection between the meter and head end system through a collector unit deployed in the field. The meter data (hourly interval and outage messages) is collected wirelessly to a collector from the meter using encrypted standards.

From the collector to the head end meter, data is communicated through cellular communication on a private network or through a direct and secure fiber connection.
Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)
Other LDC's have done area replacements for first generation smart meters to 2nd generation smart meters. Other LDC's are deploying 3rd generation smart meters for failed meters and new installations.
Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)
The meters send outage messages to the OMS. This is completed by a common language protocol called Multi-speak. The Multi-speak output from the Automated Meter Reading Infrastructure (AMI) is connected to the OMS. The OMS would poll the AMI for inventory and check which meters are on or off. When an outage occurs this is sent from the AMI to the OMS. The OMS would make automated requests to the AMI system to confirm specific locations prior to the OMS finalizing outage locations.
Environmental Benefits (where applicable)
Not Applicable
Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)
Next generation meters will be programmed with 5 minute data to provide more information to data analytic systems for possible conservation of energy and demand management.
Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)
Not Applicable
Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity
The meters send outage messages to the OMS. This is completed by a common language protocol called Multi-speak. The Multi-speak output from the Automated Meter Reading Infrastructure (AMI) is connected to the OMS. The OMS would poll the AMI for inventory and check which meters are on or off. When an outage occurs this is sent from the AMI to the OMS. The OMS would make automated requests to the AMI system to confirm specific locations prior to the OMS finalizing outage locations.

C. Category-Specific Requirements – System Access (5.4.3.2.C)
Factors Affecting Timing/ Priority
OPUCN did an analysis of the replacement of meters and when it would be best to replace the meters. The result is that it is in the best interest of the rate payer that we do not start a meter replacement program in the next 5 years (as part of this DSP). This priority may change IF the meter failure rates that has been estimated is too low, and the meters fail faster than predicted. At this time it is anticipated that the meter failure rate is acceptable until 2030. OPUCN will replace the meters as they fail until 2030. Customer may want data in real time, the current generation of meters and data collection.
Factors Related to Customer and other Third Parties

Customers will be accurately billed on usage following the failed meter replacement. Communication for outage information to customers at a single service and transformer level that would be detected and presented automatically. Collection of data without error and presented to customers in real time. Failure rate of meters for replacement. Measurement Canada sealing requirements and testing required to extend the life of the meter past the initial seal period.
Factors Affecting the Final Cost
The project is driven by mandated service obligations. Purchasing quantities by volume and US$ fluctuation.
Methods Utilized to Minimize Controllable Cost
Monitoring of the market and procuring at the time of low exchange rates.
Other Planning Objectives
The meters and program will only replace meters that have failed in areas not under the initial years of implementation of the AMI hardware replacement. We did an analysis of possible failure rates and required replacement. This program is based upon the middle curve of 1.25 of the baseline cure failure rate. The failure rates are based upon a reactive approach to replacing meters instead of a proactive approach. Each curve below is based upon the "R2S failures chart" (first chart in this project). By estimating a higher failure rate of 1.1 x the base curve, 1.25 x the base curve, 1.5 x the base curve, and 1.75 x the base curve, the rates of failure are plotted on a yearly basis until 2042. These failure rate indicate the Risk associated with the meter failure and the impact possible to the meter population. OPUCN will re-evaluate the meter failure rate each year and check what the escalation point would be.  *Figure 17: Estimated Rates of Failure*
Technically Feasible Project Design and/or Implementation Option Exist

Like for Like replacement fit to existing equipment. Next generation meters are compatible with the current generation collector units. When an area is fully deployed the meters can be moved over to the next generation collector.
Summary of Result Analysis – Least Cost, Cost Efficient Options
An analysis was completed based upon replacing meter in 10 years instead of replacing meters due to failure. As a result, it was determined that in the best interest of the ratepayer we would replace the meters as they fail. Impact to the customer is that consumption would be estimated for the time of the meter failure until replacement. Service supply would not be impacted due to the failure of the meter. The meter communication/display or electronic module calculating or storing energy data would malfunction.  *Figure 18: Replacement Cost by Alternative*
Results of a Final Economic Evaluation (where applicable)
Not Applicable
System Impact Cost or Cost Recovery Method
Cost recovery method would be through rates.

A. General Information (5.4.3.2.A)					
Project/Activity	Overhead Line Renewal				
Project Number	SR-01				
Investment Category	System Renewal				
	2021	2022	2023	2024	2025
Capital Cost	$1,981,000	$2,722,300	$2,006,000	$2,137,190	$1,733,000
Capital Contribution	N/A	N/A	N/A	N/A	N/A
Net Cost	$1,981,000	$2,722,300	$2,006,000	$2,137,190	$1,733,000
O&M Cost	2021	2022	2023	2024	2025
	-	-	-	-	-
Customer Attachments and Load					

# of Residential Customers - 3,050
# of Commercial Customers - 77
Total Approximate Load - 10,314 kW

Start Date	2021-2025	In-Service Date	2021-2025

Expenditure Timing for the Planning Horizon	2021Q1	2021Q2	2021Q3	2021Q4
	$441,000	$630,000	$630,000	$280,000

Project Summary

This project category is comprised of renewing overhead assets in poor condition and past their Typical Useful Life (TUL), including poles, conductors and transformers, which were originally installed between 1960 and 1980. Results of the Section 5 of the Asset Condition Assessment (ACA) and field inspections have determined that complete replacement of these overhead asset is the most feasible action due to their condition.

The project scope includes design, construction and installation of new assets and taller poles framed to conform and comply with the latest standards and regulations including Ontario Regulation 22/04 (O.Reg. 22/04). By completing the overhead line renewal, OPUCN plans to improve the level of safety and reliability associated with newer standards and materials. The determination between which line sections could be refurbished and which need a full replacement is based on ACA results and further investigations and analysis.

Risk Identification & Mitigation

Scheduling Risks – These projects are subject to scheduling risks with respect to external contractors and with other major projects but are prioritized based on condition of assets and failure risks. The majority of the design work and Municipal Consent(s) are completed a year ahead of construction so that construction may begin in Q1 to mitigate this risk. Schedules are also determined the year before and progress meetings are held to ensure construction stays on track.

Comparative Information on Expenditures for Equivalent Projects/Activities

The following shows the historical and forecast annual costs. 2020 is a budget cost.

	Historical Costs ($ ‘000)						Forecast Costs ($ ‘000)				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Capital	2,873	1,395	1,747	1,135	2,978	3,142	1,981	2,722	2,006	2,137	1,733

The number of line sections, their length, the number/type of circuits and equipment differs from year to year which explains the variability in comparable investments in previous years. However, the average spend over the period of 5 years of DSP is still in the same range.
REG Investment Details including Capital and OM&A costs
As this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.
Leave to Construct approval under Section 92 of the OEB Act
This project is below 50 kV and therefore Leave to Construct is not required, as per O.Reg. 161/99.
Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material
The following is the list of OH Line Renewal projects that has been identified based on project conditions:

Year	Project #	OH Line Renewal Project Name	Net Forecasted Expenditure $'000
2021	SR-01-08	Bader Ave, Finucane St, Fernhill Blvd, Rosmere St, Malan Ave, Cunningham Ave	504
	SR-01-09	Valencia Rd, Oxford St, Cordova Rd, Malaga Rd	639
	SR-01-10	Kitchener Ave, Dean Ave, Normandy St, Dunkirk Ave, Sterling Ave, Dieppe Ave, Lo	645
	SR-01-11	Miller Ave	73
	SR-01-12	Buena Vista Ave	120
2022	SR-01-13	Roxborough Ave	140
	SR-01-14	Rossland - Ritson to Wilson	600
	SR-01-15	Durham Crt	72
	SR-01-16	Grandview St S, Olive Ave	739
	SR-01-17	Front St, Albany St, First Ave, Second Ave, Third Ave, Fisher St, Lviv Blvd	459
	SR-01-18	Currie Ave, Montgomery St, Jackson Ave	120
	SR-01-19	Athol St E	102
	SR-01-20	Oshawa Blvd N from Bond to Maplewood	490
2023	SR-01-21	Ridgeway Ave, Elizabeth St	176
	SR-01-22	Gorevale Cres., Hillsdale Ave, Oshawa Blvd N, Hillcroft St.	327
	SR-01-23	Ascot Crt, Ascot Ave, Arden Dr, Acadia Dr	318
	SR-01-24	Arthur St, Drew St, Bruce St	207
	SR-01-25	Ridgeway Ave, Fairlawn St, Nipigon St, Humber Ave, Muriel Ave	335
	SR-01-26	Lauder Rd	59
	SR-01-27	Olive Ave, Central Park Blvd S	584
2024	SR-01-28	Dearborn Ave, Kendal Ave, Mary St N, Agnes St, Elgin St E, William St E, Ontario	987
	SR-01-29	Poplar St, Linden St	129
	SR-01-30	Creighton Ave, Harris Crt, Harris Ave, Rosehill Blvd	242
	SR-01-31	Grassmere Ave, Wellington Ave E, Nelson St, Harbour Rd	779
2025	SR-01-32	Beechwood St, Pinewood St, Edgewood Ave, Oakwood Ave	191
	SR-01-33	Farewell St from Harbour to Wentworth E	659
	SR-01-34	Cromwell Ave from Hillside to Grace Lutheran Church	65
	SR-01-35	Milton St from Chesterton Ave to Keates	28
	SR-01-36	Kilmaurs Ave	60
	SR-01-37	Cedar Valley Blvd, Cedar Valley Crt, Patton St, Seneca Ave, Chippewa St,	290
	SR-01-38	Eastwood Ave N	75
	SR-01-39	Bloor St from Dnipro Blvd to Wilson Rd S including Dnipro Blvd	210
	SR-01-40	Rossland Rd W (West of Thornton Rd N)	155
		TOTAL	**10,579**

Project scope and maps for 2021 OH Line Renewal projects are shown in the following:

SR-01-08: Bader Ave, Finucane St, Fernhill Blvd, Rosmere St, Malan Ave, Cunningham Ave
Scope: OH Rebuild - 1925m 1 phase, 21 Tx, 58 Poles

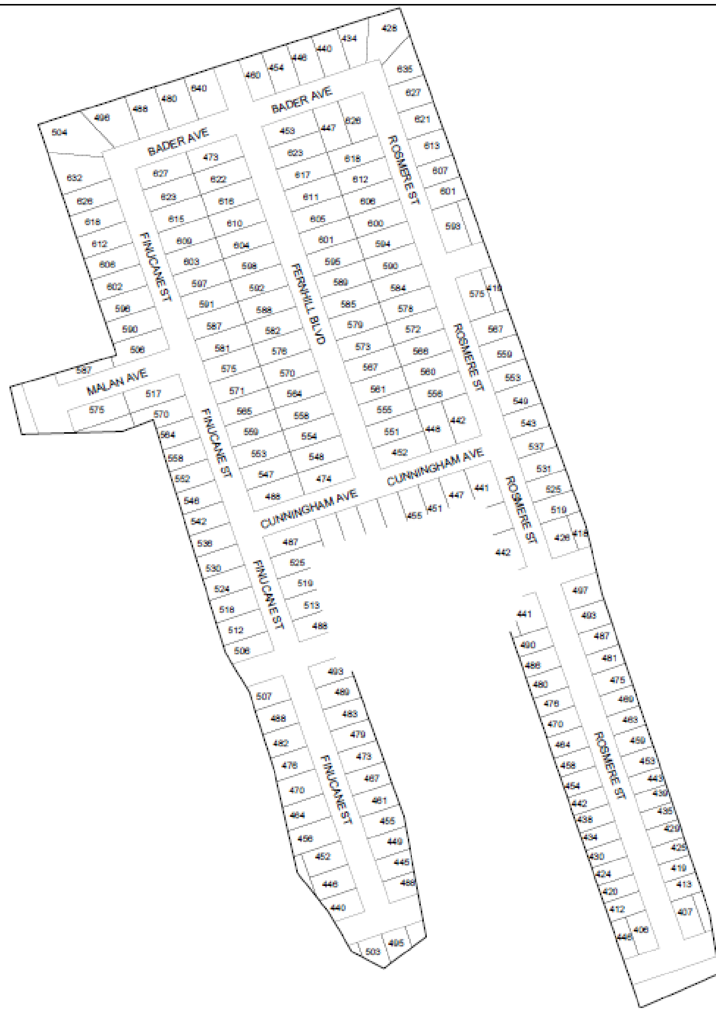


Figure 19: SR-01-08 Bader Ave, Fernhill Blvd, Rosemere St, Malan Ave, and Area Map

SR-01-09: Valencia Rd, Oxford St, Cordova Rd, Malaga Rd
Scope: OH Rebuild - 1284m 3 phase and 344m 1 phase, 15 Tx, 43 Poles

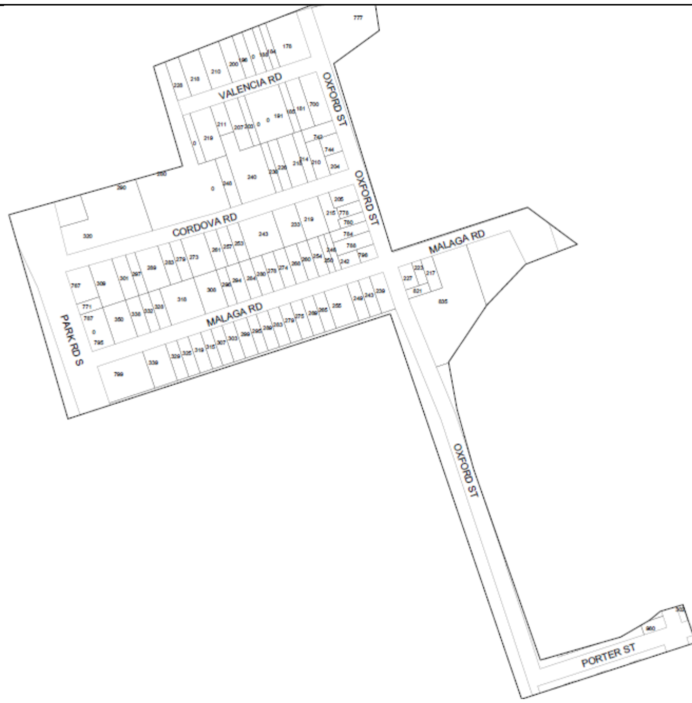


Figure 20: SR-01-09 Valencia Rd, Oxford St, Cordova Rd, Malaga Road and Area Map

SR-01-10: Kitchener Ave, Dean Ave, Normandy St, Dunkirk Ave, Sterling Ave, Dieppe Ave, Lomomd St, Dieppe Ct
Scope: OH Rebuild - 1433m 3 phase and 717m 1 phase, 16 Tx, 56 Poles

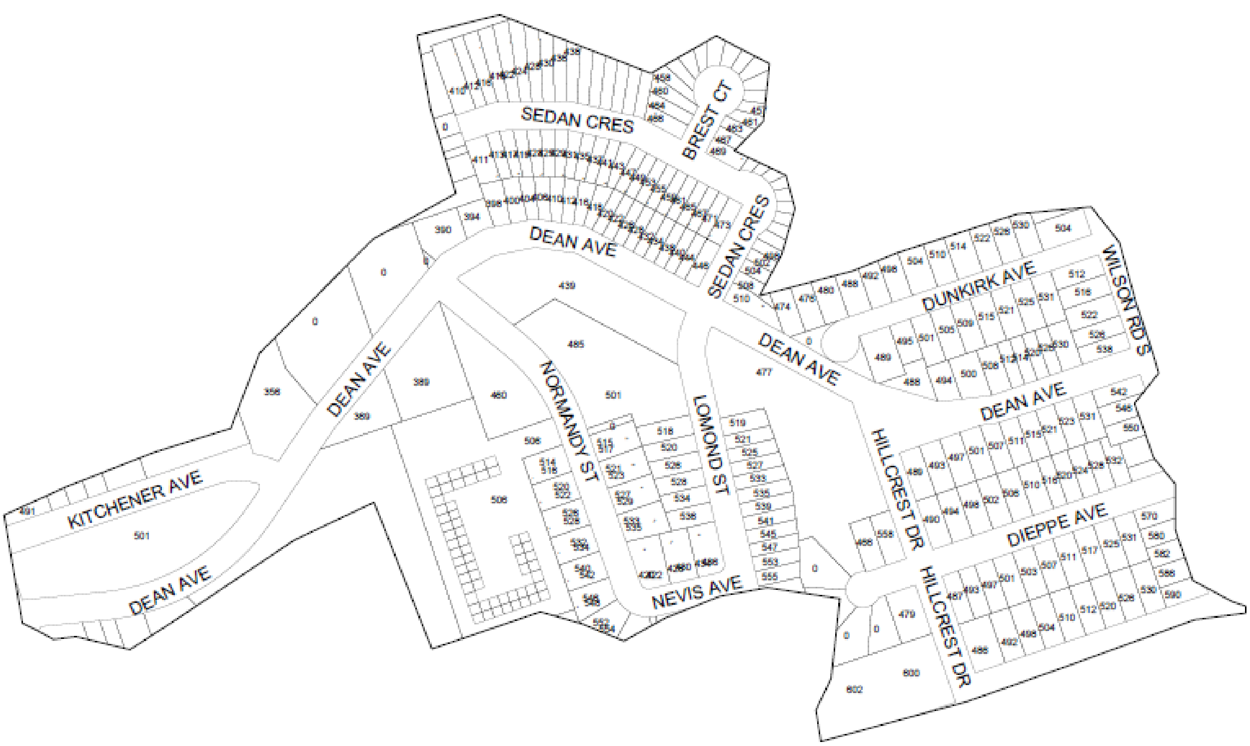


Figure 21: Kitchener, Dean, Normandy, Dunkirk and Area Map

SR-01-11 Miller Ave
Scope: OH Rebuild - 22m 1 phase, 3 Tx, 5 Poles

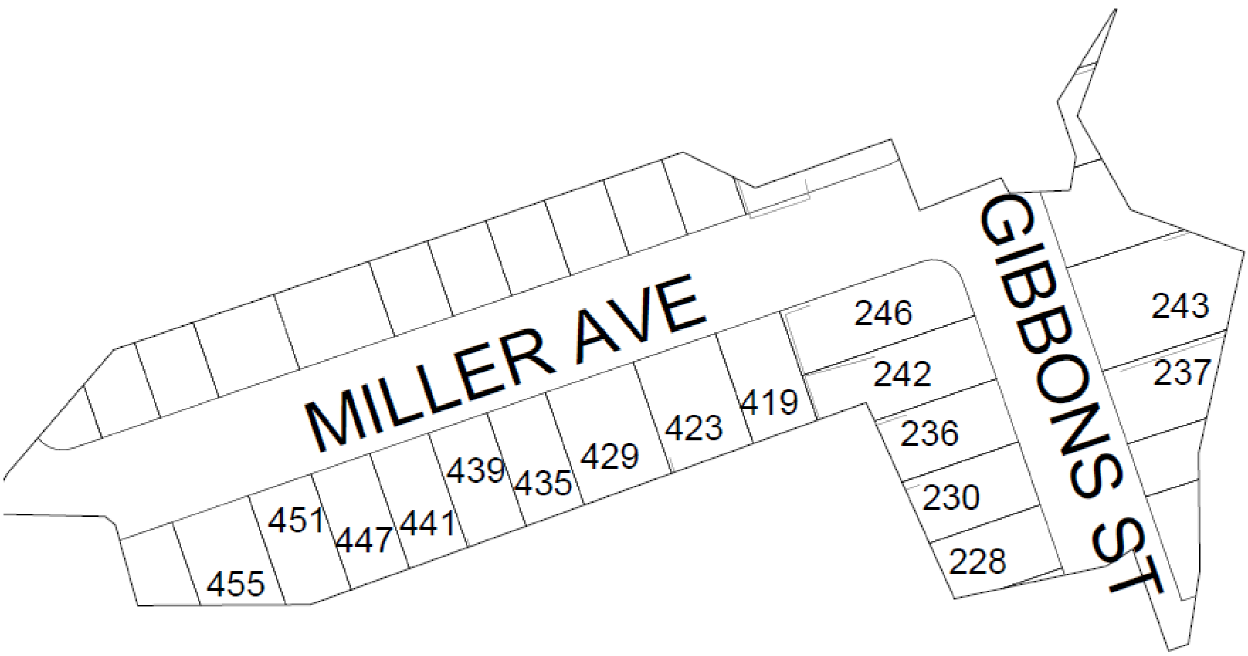


Figure 22: SR-01-11 Miller Ave Area

SR-01-12: Buena Vista Ave
Scope: OH Rebuild - 418m 1 phase, 4 Tx, 11 Poles

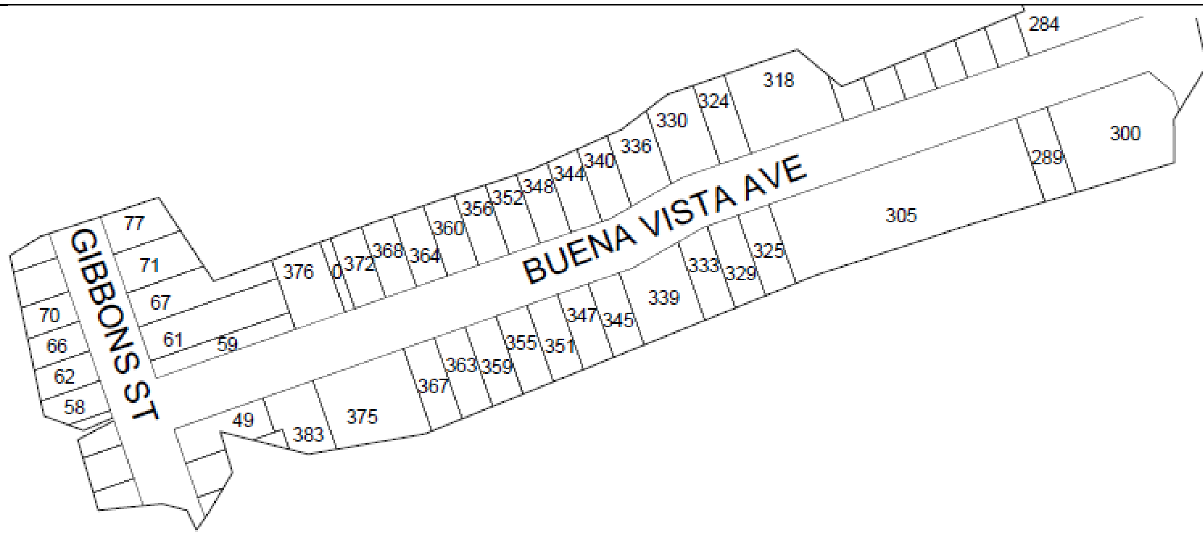


Figure 23: SR-01-12 Buena Vista Ave Map

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)
Efficiency, Customer Value & Reliability – Investment Main Driver
System Renewal is the driver for this project aimed at reducing failure risk – Assets are at the end of their TUL which poses a greater risk of failure. Most of the infrastructure being replaced was installed from 1960 - 1980 and has been identified as being in poor condition by the ACA. Mitigating failure risk will also minimize safety risks and impact to reliability. Reliability – A planned replacement will minimize the risk of overhead asset failure and mitigate the impact on reliability performance including SAIDI and SAIFI. Safety – The overhead asset renewal will make the lines safer as this will be built to the current standards and regulations which are more capable of withstanding adverse weather conditions.
Efficiency, Customer Value & Reliability – Investment Secondary Driver
There are no secondary drivers.
Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets
These projects will reduce probability of equipment failure that may pose a safety risk and could negatively impact one of the performance targets, power supply reliability.
Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment
The sources of the information used to justify the investment are the results of the ACA that incorporate information and data from GIS registry, asset database, field inspections, pole testing data, reliability data and information from incident reports. Third party work/relocations are also taken into account so that work may be co-ordinated as much as possible.
Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges

This program will maintain or improve the reliability of the system by replacing overhead assets in poor condition and future proofing the design by meeting all current standards.
Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment
This program receives a high priority based on the level of AM objectives it meets and mandatory nature in addressing failing assets. The projects within this program were prioritized based on age of infrastructure, ACA, reliability and safety. Third party work/relocations are also taken into account so that work will be co-ordinated as much as possible. Scope of projects was also taken into account to ensure that the construction could be completed in the assigned year.
Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness
Completion of the overhead renewal program will improve system operational efficiency by maintaining system reliability and reducing overhead asset failures. Current overhead design and industry practices will be incorporated in accordance with all existing standards and regulations, thus, providing a safer and more reliable overhead distribution system. This will also help us in reducing cost of maintenance by proactively replacing OH assets which are addressed under our asset management program.
Analysis of Project & Alternatives – Net Benefits Accruing to Customers
Customers within the project area will benefit from this project through the reduction of the risk of outages and will also indirectly benefit from the lower corrective maintenance costs that the improved distribution system will provide.
Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages
Replacement of overhead assets in poor condition will provide a more reliable system and will reduce the risk of asset failures.
Project Alternatives (Design, Scheduling, Funding/Ownership)
All overhead line sections under this project have been identified as being in poor condition and at the end of their TUL and in need of replacement. The following alternatives were considered: 1. Do nothing – this option would result in an increased safety risk and decrease in reliability and higher corrective maintenance costs. It is not considered an acceptable option. 2. Refurbish the lines – these lines are not considered appropriate candidates for refurbishment as the overhead pole line could not be rebuilt to current standards without replacing the poles and changing the overhead configuration. This will also not address the condition of the overhead assets other than poles, i.e. conductors and pole mounted transformers that are also approaching the end of their TUL. 3. Replace like for like – Similar to refurbishing the lines, the overhead pole line could not be rebuilt to current standards without replacing the poles and changing the overhead configuration
Safety
Proper asset management of old and deteriorating equipment in the field mitigates safety concerns for OPUCN staff, contractors, third party attachers and customers. New construction will also meet the latest distribution standards for safety.
Cyber-Security, Privacy (where applicable)
This program has no adverse impact on cyber security and privacy.
Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)

OPUCN meets quarterly with the City, Region and all other utilities to discuss projects, timelines and co-ordinate efforts. In addition to this, designs are sent to each of these parties for each individual project which also aids in co-ordination.
Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)
Future operational requirements will be considered in the design where appropriate by providing provisions to incorporate remotely operated switches that will enable future technological functionality.
Environmental Benefits (where applicable)
The redesign of these areas will also include an assessment of existing transformer loading and where applicable, transformers will be replaced with an appropriately sized transformer to reduce distribution losses.
Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)
Not Applicable
Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)
Not Applicable
Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity
Future operational requirements will be considered in the design where appropriate by providing provisions to incorporate remotely operated switches that will enable future technological functionality.

C. Category-Specific Requirements – System Renewal (5.4.3.2.C)
Asset Performance-Related Operational Targets & Asset Lifecycle Optimization Policies and Practices
Majority of assets planned for replacement in this program are deteriorated to the point they must be replaced. This poses a risk to field staff and customers. Proceeding with these projects will also improve the Operational Effectiveness of the system by contributing to lowering SAIDI and SAIFI numbers.
Information on the Condition of the Assets Relative to their Typical Life-Cycle and Performance Record
Poles, pole mounted transformers and overhead circuits have a TUL of 40 – 60 years. On average, these pole lines are 50 years old which places them in this range. At the same time, most of these assets have a calculated health index in the very poor, poor and lower end of fair categories as per the ACA results.
The Number of Customers in Each Class Potentially Affected by Failure of the Assets
Residential Customers - 3,050 # Commercial Customers - 77
Quantitative Customer Impacts

Customers will experience improvement in reliability of power supply minimizing the frequency and duration of interruptions as a result of overhead renewal. The quantitative customer impacts beyond the completion of the OH Line Renewal project are indeterminate.
Qualitative Customer Impacts
Customers will receive increased reliability and indirectly maintenance costs will be lower.
Value of Customer Impact in Terms of Characteristics of Customers Potentially Affected by Failure that have Bearing on the Criticality and/or Cost of Failure
The majority of these projects are in residential areas and so there is a low impact to these customers in terms of the criticality and cost of an asset failure. A few projects are in areas with large businesses such as the Port of Oshawa. Customer impact on these customers is medium to high.
Timing and Priority of the Project
The timing and priority of the projects takes into account the condition of these assets, reliability and the available resources to design and construct these projects. Delaying these projects will impact renewal work that is required in future years to properly maintain a reliable system. Projects within this program are prioritized based on age of infrastructure, ACA, reliability and safety. Third party work/relocations are also taken into account so that work may be co-ordinated as much as possible. Since System Access projects are a higher priority in the AM process an additional project has the potential to modify the timing of any System Renewal project. Additionally, if OPUCN documents any extreme reliability issues due to ageing in a specific area that needs to be addressed projects can be shuffled from year to year during the forecast period.
Consequences for System O&M Costs
There will be no immediate material impact to O&M costs for distribution lines. Without these projects taking place O&M costs would be expected to rise over time at an increasing rate due to equipment failures.
Impact on Reliability Performance and/or Safety
Proper asset management of old and deteriorating equipment in the field mitigates safety concerns for OPUCN staff and customers. This program helps maintain or improve system reliability.
Analysis of Project Benefits and Timing
The timing and priority of the projects takes into account the condition of these assets, reliability and the available resources to design and construct these projects. Delaying these projects will impact renewal work that is required in future years to properly maintain a reliable system.
Like for Like Renewal Analysis, Alternative Comparison (Like for Like vs. Not Like for Like, Timing, Rate of Replacements, etc.)
The overhead lines will be rebuilt to today's standards. In residential areas, accommodation for additional circuits will not usually be made, however, on major thoroughfare roads the area will be assessed and a determination will be made as to whether future accommodations are warranted in the design.

A. General Information (5.4.3.2.A)					
Project/Activity	Porcelain Switch and Insulator Replacement Program				
Project Number	SR-02				
Investment Category	System Renewal				
	2021	2022	2023	2024	2025
Capital Cost	$550,000	$550,000	$550,000	$550,000	$550,000
Capital Contribution	N/A	N/A	N/A	N/A	N/A
Net Cost	$550,000	$550,000	$550,000	$550,000	$550,000
O&M Cost	2021	2022	2023	2024	2025
	-	-	-	-	-

Customer Attachments and Load

Customer Attachments and Load are not expected to change with the execution of this program, however improvements to system components will positively affect the following:

Customer Attachments and Load: All

Start Date	2021-2025	In-Service Date	2021-2025

Expenditure Timing for the Planning Horizon	2021Q1	2021Q2	2021Q3	2021Q4
	$137,500	$137,500	$137,500	$137,500

Project Summary

Porcelain insulation material is used in overhead assets such as line post insulators, switch/cut-out arrestors and lightning arrestors. This program is comprised of replacing all identified porcelain switch/cut-out arrestors and insulators that are susceptible to contamination build-up and electrical tracking, which can cause cracking, ruptures and failures. The porcelain insulators and switches will be replaced with the current approved equipment that is less susceptible to contamination in high corrosion areas and minimizes the leakage current that can cause tracking. OPUCN will replace approximately 290 porcelain insulators and approximately 285 porcelain switch/cut-out arrestors annually during the period of 2021-2025.

Risk Identification & Mitigation

Porcelain material has been phased out because of safety and system performance issues. Porcelain is susceptible to hairline cracks that can lead to failure caused by electrical tracking and leakage current. This presents a risk of injury to OPUCN employees and the customers who are in close proximity of the porcelain equipment at the time of the failure and presents major outage risks. These risks can be mitigated by replacing the porcelain units.

This project is also subject to scheduling risks. To ensure that no delays occur, it is imperative to have consistent consultation among the design and construction teams to ensure proper resource allocation to complete the work on schedule. OPUCN shall use the internal staff resources as necessary, to mitigate the schedule risks.

Comparative Information on Expenditures for Equivalent Projects/Activities

There are no direct comparator for this investment. This program commenced in 2020 with expected completion by 2025.

Historical Costs ($ ‘000)						Forecast Costs ($ ‘000)				
2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
-	-	-	-	-	550	550	550	550	550	550

REG Investment Details including Capital and OM&A costs

As this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.

Leave to Construct approval under Section 92 of the OEB Act
This project is below 50 kV and therefore Leave to Construct is not required, as per OEB.Reg. 161/99.
Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material
Please refer to the ACA in Appendix B.

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)
Efficiency, Customer Value & Reliability – Investment Main Driver
System Renewal is the driver for this program and it is aimed at improving Asset Performance and Safety as well as reliability. The risk to the utility and the customer is that the asset will fail and result in an outage that negatively affects reliability and customer satisfaction.
Efficiency, Customer Value & Reliability – Investment Secondary Driver
There are no secondary drivers.
Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets
The investment objectives are to reduce the asset failure risk and to ensure reliable service to customers by mitigating the risk of power outage duration and frequency.
Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment
Porcelain Insulator and porcelain switch/cut-out arrestor replacements are driven primarily by the identification of their condition via the ACA and historical failure rate.
Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges
This program will replace porcelain material before they fail and cause extended outages; hence, improving the reliability.
Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment
Priority is high due to safety and system performance issues. It also meets most of AM objectives identified in Section 5.3.1. Porcelain is susceptible to hairline cracks that can lead to failure caused by electrical tracking and leakage current. This program will replace the porcelain insulators and porcelain switch/cut-out arrestors before they fail and cause extended outages; hence, improving safety and reliability. Assets replaced under this program are prioritized based on their condition and risk. The program was also prioritized based on ensuring public/worker safety, maintaining system reliability and managing costs.
Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness
The new insulators and switch/cut-out arrestors are more dependable over the long term compared to porcelain units and will improve system operating efficiency. The current approved equipment is a polymer material containing an anti-beading function that naturally prevents water from forming a continuous path over its surface. This prevents the flow of leakage current between live conductor and grounding point on the pole, which greatly reduces the risk of tracking and flashover over the insulation surface that could lead to power outages. Hence, the proactive replacement of porcelain insulators and porcelain switch/cut-out

arrestors is more cost effective than reactive replacements due to lower replacement unit cost and reduced equipment failure risk.
Analysis of Project & Alternatives – Net Benefits Accruing to Customers
This program will improve reliability and will reduce the potential for property damage from broken insulators.
Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages
This program will positively impact system reliability, as proactive replacement will greatly reduce the risk of outages.
Project Alternatives (Design, Scheduling, Funding/Ownership)
The alternative to replacing porcelain insulators and porcelain switch/cut-out arrestors is to do nothing In this scenario, OPUCN would accept the risk of porcelain units' failure and address it on a reactive basis. This approach was rejected as the old and deteriorating porcelain equipment in the field can result in significant safety concerns, lengthy customer outages that will result to increases in O&M costs. Therefore, planned replacements are the preferred alternative. Polymeric insulating material has less destructive failure modes, better safety and system performance than currently used porcelain material. Also, these insulators have a self-washing feature that minimizes contaminant build up on the insulation surface. In addition, it contains an anti-beading function that naturally prevents water from forming a continuous path over its surface. This prevents the flow of leakage current between live conductor and grounding point on the pole, which greatly reduces the risk of tracking and flashover over the insulation surface that could lead to power outages.
Safety
Porcelain material is susceptible to contamination build-up and electrical tracking, which can cause cracking, ruptures and catastrophic failures. Porcelain material is known to prematurely fail or fracture posing a hazard to the public and the workers. This program will reduce the risk of injury to the field crew and to the public and property from the falling pieces.
Cyber-Security, Privacy (where applicable)
Not Applicable
Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)
OPUCN uses USF standards and meets Ontario Regulations 22/04 requirements. This program will not impact any other regional planning activities. Customers and third party attachers will be notified and coordinated with.
Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)
Not Applicable
Environmental Benefits (where applicable)
Not Applicable
Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)
Not Applicable

Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)
Not Applicable
Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity
Not Applicable

C. Category-Specific Requirements – System Renewal (5.4.3.2.C)
Asset Performance-Related Operational Targets & Asset Lifecycle Optimization Policies and Practices
Implementation of this program in a timely manner will enable OPUCN to meet its performance goals in customer satisfaction and system reliability.
Information on the Condition of the Assets Relative to their Typical Life-Cycle and Performance Record
OPUCN identified approximately 290 porcelain insulators and approximately 285 porcelain switch/cut-out arrestors to be replaced annually during the period of 2021-2025 within its service territory. Porcelain material has been phased out because of safety and system performance issues.
The Number of Customers in Each Class Potentially Affected by Failure of the Assets
Specific yearly values are not currently known; however the number of customers can vary significantly from year to year.
Quantitative Customer Impacts
Specific yearly values are not currently known; however the length of outages can vary significantly from year to year.
Qualitative Customer Impacts
Failure of this equipment will negatively impact the electricity supply to many residential, commercial and industrial customers.
Value of Customer Impact in Terms of Characteristics of Customers Potentially Affected by Failure that have Bearing on the Criticality and/or Cost of Failure
The characteristics of customers potentially affected by porcelain insulator and switch/cut-out arrestors failures varies widely from a high number of residential customers with a low per customer cost of failure, to single large industrial customers with a very high cost of failure. The most critical units (those affecting the largest number of customers and those having the highest impact of failure) will be prioritized over others.
Timing and Priority of the Project
This program has a high priority due to the impact of the equipment failure. OPUCN will replace approximately 290 porcelain insulators and approximately 285 porcelain switch/cut-out arrestors annually during the period of 2021-2025..
Consequences for System O&M Costs

Replacement of porcelain insulators and switch/cut-out arrestors in a proactive way will reduce the cost of unplanned failures and the associated corrective maintenance costs. This program will help reduce system O&M costs over time through reductions in corrective maintenance spending.
Impact on Reliability Performance and/or Safety
Replacement of these assets will have a positive impact on the reliability performance and safety in the following ways: 1. Improved reliability by reducing potential failures and greatly decreasing restoration times. 2. Significant improvement in safety by removing old and deteriorating equipment from the system.
Analysis of Project Benefits and Timing
This program has a high priority because it offers high benefit of reducing unplanned outages and therefore improving the service reliability.
Like for Like Renewal Analysis, Alternative Comparison (Like for Like vs. Not Like for Like, Timing, Rate of Replacements, etc.)
From an installation and configuration perspective, this will be a like for like replacement which will enhance both design and component characteristics in the most cost efficient manner to ensure overall system reliability performance is improved. All new construction will meet the latest distribution standards.

A. General Information (5.4.3.2.A)					
Project/Activity	Pole Replacement Program				
Project Number	SR-03				
Investment Category	System Renewal				
	2021	2022	2023	2024	2025
Capital Cost	$400,000	$400,000	$400,000	$400,000	$400,000
Capital Contribution	N/A	N/A	N/A	N/A	N/A
Net Cost	$400,000	$400,000	$400,000	$400,000	$400,000
O&M Cost	2021	2022	2023	2024	2025
	-	-	-	-	-

Customer Attachments and Load

Customer Attachments and Load are not expected to change with the execution of this project. Depending on the individual pole's location, impacted load can range from that of a single feeder (5-10 MW) to that of a single customer (<50 kW).

Start Date	2021-2025	In-Service Date	2021-2025
Expenditure Timing for the Planning Horizon	2021Q1	2021Q2	2021Q3	2021Q4
	$100,000	$100,000	$100,000	$100,000

Project Summary

Using ACA data, OPUCN owns approximately 10,453 poles where approximately 198 of the poles are rated poor and very poor in the ACA and it is recommended that approximately 330 poles are replaced annually to address the end of TUL. During the forecast period 35-40 poles will be replaced annually under the Pole Replacement Program and the remainder will be addressed under the OH Line Renewal.

Risk Identification & Mitigation

Risks are minimal for these projects as they represent standard industry practices. Hydro vacuuming pole holes during the winter months is a risk to this project; this can be mitigated by scheduling this type of work during months when temperatures are near to and above freezing temperatures. Many replacements take place near customer premises or businesses; therefore, OPUCN will ensure that the necessary signage and safety precautions are utilized. All customers that will be inconvenienced will be notified.

Comparative Information on Expenditures for Equivalent Projects/Activities

OPUCN's poles are inspected on a three (3) year cycle. The following provides the historical and forecasted costs. 2020 is a budget cost.

	Historical Costs ($ '000)						Forecast Costs ($ '000)				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Capital	-	-	423	214	251	400	400	400	400	400	400

The increase in pole replacement cost was due to the result of the ACA to address poles that are nearing its end of life which are scattered throughout the service territory and could not be addressed under a typical overhead line renewal program.

REG Investment Details including Capital and OM&A costs

As this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.

Leave to Construct approval under Section 92 of the OEB Act

This project is below 50 kV and therefore Leave to Construct is not required, as per OEB.Reg. 161/99.
Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material
Please refer to the ACA in Appendix B.

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)
Efficiency, Customer Value & Reliability – Investment Main Driver
This program falls under System Renewal Investment Driver and is aimed at improving Reliability and Safety. The risk to the utility and the customers is that when a pole fails, it results in an outage that negatively affects reliability and customer satisfaction and depending on the pole location, presents a safety hazard.
Efficiency, Customer Value & Reliability – Investment Secondary Driver
There are no secondary drivers.
Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets
The investment objectives are to mitigate the risk of lengthy unplanned customer interruptions.
Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment
OPUCN's ACA, pole testing data and recent failures are the sources of the information used to justify this project.
Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges
Replacing an aged pole before it fails is the ideal case. With reference to reliability and budget, replacing aged poles before failure provides a significant net benefit to OPUCN's customer safety, reliability and cost effectiveness.
Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment
Failed poles cause serious safety concerns to public and the workers; they also cause serious lengthy power outages which affects service reliability. Considering these impacts to customer value and reliability, this program is assigned a high priority and is considered mandatory. It also addresses most of OPUCN's AM objectives identified in Section 5.3.1, thus, making it a high priority.
Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness
Planned replacement of poles rather than replacement at the time of failure can usually be organized as a part of regular work. In addition, OPUCN will coordinate pole replacement with other work in the area by the City, Region or MTO, if applicable.
Analysis of Project & Alternatives – Net Benefits Accruing to Customers
Customers will benefit from fewer outages while planned replacement of poles will results in shorter outages than when they are replaced following a failure.
Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages

This investment will result in improved reliability by reducing both frequency and duration of outages: fewer failures are expected to occur and planned replacements take less time than replacements following a failure
Project Alternatives (Design, Scheduling, Funding/Ownership)
The project alternatives are run-to-failure or defer. Not replacing end of life poles and pole failures is not an option due to public safety impacts, system reliability and further increasing O&M costs.
Safety
Planned replacement reduces the risk of failure leading to a collapse of the pole and a 'wire down' situation. The work is required in order to maintain safety to workers and the customers.
Cyber-Security, Privacy (where applicable)
Not Applicable
Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)
OPUCN utilizes Utility Standards Forum (USF) standards and meets the Ontario Regulations 22/04 requirements. Coordination with other utilities and municipalities will be required with this project in order to reduce damage to underground utilities, joint use attachments, and to be efficient. Coordination with customers will be a priority when scheduling outages and access to customer property.
Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)
Like for like replacement of poles will not enhance future technological functionality.
Environmental Benefits (where applicable)
A failed hydro pole poses the potential of oil spills from pole mount transformers. Oil spills can be extremely damaging to wildlife and vegetation. This project will aid in eliminating this danger by removing the poles with high probability of failure.
Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)
Not Applicable
Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)
Not Applicable
Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity
The pole replacement program does not include advanced technology, interoperability, and cybersecurity.

C. Category-Specific Requirements – System Renewal (5.4.3.2.C)
Asset Performance-Related Operational Targets & Asset Lifecycle Optimization Policies and Practices
This project generally has the highest priority in relation to system renewal project, after emergency forced renewal. The replacement of the aged assets is expected to improve OPUCN's reliability performance, specifically the number of outages.
Information on the Condition of the Assets Relative to their Typical Life-Cycle and Performance Record
OPUCN owns approximately 10,450 poles. 198 of which rated in poor or very poor condition indicating they need to be replaced immediately or within the next three years. Additionally, OPUCN has a significant number of poles beyond the typical useful life. The conclusion of the ACA suggested OPUCN replace approximately 330 poles annually. 200 poles in total will be covered under the pole replacement program and the remaining will be replaced under Overhead Line Renewal projects.
The Number of Customers in Each Class Potentially Affected by Failure of the Assets
Specific yearly values are not currently known; however the number of customers can vary significantly from year to year.
Quantitative Customer Impacts
Specific yearly values are not currently known; however the length of outages can vary significantly from year to year.
Qualitative Customer Impacts
Failure of this equipment will negatively impact the electricity supply to many residential, commercial and industrial customers.
Value of Customer Impact in Terms of Characteristics of Customers Potentially Affected by Failure that have Bearing on the Criticality and/or Cost of Failure
The pole replacement program will improve reliability by reducing unplanned outages and hence reducing outage costs. Also, this project avoids future system O&M costs since replacements can be scheduled during regular hours rather relying on the trouble calls, which can take longer and can require overtime hours. Failure of a pole is unplanned and will usually create an outage due to line down and/or a forced outage. Outages are disruptive to all customer classes. Through this pole replacement program, the customers will receive value through reduced unplanned outages and enhanced reliability.
Timing and Priority of the Project
35-40 poles will be replaced annually over the next five years (2021 to 2025). Although all are considered to be of high or very high priority, priorities among specific poles being replaced may shift.
Consequences for System O&M Costs
Run to fail for this asset will increase O&M costs. At the time of the failure, mitigating the effect of the pole failure on the customers will be an O&M expense. This may occur outside of normal business hours and require unplanned overtime hours.
Impact on Reliability Performance and/or Safety
The pole replacement program will improve reliability and safety by reducing unplanned outages and hence, reducing the probability of failure and consequences to public safety.
Analysis of Project Benefits and Timing

This project has been given a high priority because it offers a high benefit for risk mitigation and improving the service quality with enhanced reliability and improved safety.
Like for Like Renewal Analysis, Alternative Comparison (Like for Like vs. Not Like for Like, Timing, Rate of Replacements, etc.)
Poles are typically replaced on a like for like basis and where necessary bring the installation up to current standards. All new construction meets the latest distribution standards.

<table>
<tr><th colspan="6">A. General Information (5.4.3.2.A)</th></tr>
<tr><td>Project/Activity</td><td colspan="5">44kV Quick Sleeve Replacement Program</td></tr>
<tr><td>Project Number</td><td colspan="5">SR-04</td></tr>
<tr><td>Investment Category</td><td colspan="5">System Renewal</td></tr>
<tr><td></td><td>2021</td><td>2022</td><td>2023</td><td>2024</td><td>2025</td></tr>
<tr><td>Capital Cost</td><td>$100,000</td><td>$100,000</td><td>-</td><td>-</td><td>-</td></tr>
<tr><td>Capital Contribution</td><td>N/A</td><td>N/A</td><td>N/A</td><td>N/A</td><td>N/A</td></tr>
<tr><td>Net Cost</td><td>$100,000</td><td>$100,000</td><td>-</td><td>-</td><td>-</td></tr>
<tr><td>O&M Cost</td><td>2021</td><td>2022</td><td>2023</td><td>2024</td><td>2025</td></tr>
<tr><td></td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td></tr>
<tr><td colspan="6">Customer Attachments and Load</td></tr>
<tr><td colspan="6">Customer Attachments and Load are not expected to change with the execution of this program, however improvements to system components will positively affect the following:

Customer Attachments and Load: All</td></tr>
</table>

<table>
<tr><td>Start Date</td><td>2021-2025</td><td>In-Service Date</td><td>2021-2025</td></tr>
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<tr><td>Expenditure Timing for the Planning Horizon</td><td>2021Q1</td><td>2021Q2</td><td>2021Q3</td><td>2021Q4</td></tr>
<tr><td></td><td>$25,000</td><td>$25,000</td><td>$25,000</td><td>$25,000</td></tr>
</table>

Project Summary

Historically, OPUCN utilizes quick sleeves to quickly splice 44kV overhead primary conductor and to minimize planned and unplanned outage duration, however, OPUCN has experienced failures of quick sleeves causing major interruptions to our customers. It was determined that the most common failure mechanism appears to be the long term increase in the electrical resistance and due to the long-time scales of this process, most sleeves fail. Quick sleeves also do not have similar TUL of an overhead conductor and permanent sleeves.

Based on this determination of a failure mechanism and the failure impact of quick sleeves in our distribution network, it is proposed to replace approximately all 100 quick sleeves with permanent sleeves on the 44kV primary overhead conductor lines during the period of 2020-2022. 2021-2022 program is a continuation of the 2020 44kV Quick Sleeve Replacement Program.

Risk Identification & Mitigation

Scheduling Risk - Timely consultation among the design and construction teams ensures proper resource allocation to complete the work on schedule. OPUCN shall use the internal staff resources as necessary, to mitigate the schedule risks.

Comparative Information on Expenditures for Equivalent Projects/Activities

There are no direct comparator for this investment. This program commenced in 2020 with expected completion by 2022.

Historical Costs ($ ‘000)						Forecast Costs ($ ‘000)				
2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
-	-	-	-	-	100	100	100	-	-	-

REG Investment Details including Capital and OM&A costs

As this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.

Leave to Construct approval under Section 92 of the OEB Act

This project is below 50 kV and therefore Leave to Construct is not required, as per OEB.Reg. 161/99.
Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material
Please refer to the ACA in Appendix B.

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)
Efficiency, Customer Value & Reliability – Investment Main Driver
System Renewal is the driver for this program and it is aimed at improving Asset Performance, Safety and Reliability. The risk to the utility and the customer is that the asset will fail and result in an outage that negatively affects reliability and customer satisfaction and presents safety risks to public and workers.
Efficiency, Customer Value & Reliability – Investment Secondary Driver
There are no secondary drivers.
Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets
The investment objectives are to reduce the asset failure risk and to ensure reliable service to customers by mitigating the risk of power outage duration and frequency.
Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment
44kV quick sleeve replacements on the primary overhead lines are driven primarily by the identification of assets via the ACA provided in Appendix B.
Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges
This program will replace quick sleeves on 44kV primary overhead conductor lines before they fail and cause extended outages; hence, improving the reliability, and safety.
Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment
Priority is high due to safety and system performance issues. This project also meets majority of AM objectives identified in Section 5.3.1. Location of assets that will be replaced under this program are identified based on line patrols. The program was scored on ensuring public/worker safety, maintaining system reliability and managing costs.
Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness
There is no economical alternatives to this program.
Analysis of Project & Alternatives – Net Benefits Accruing to Customers
As a result of this investment, customers will benefit from improved system reliability and reduced safety risk.
Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages

This program has the potential to positively impact system reliability, as proactive replacement will greatly reduce the risk of outages and their duration to customers.
Project Alternatives (Design, Scheduling, Funding/Ownership)
The alternative to this program is to "do nothing." This alternative was rejected because it will result in significant safety concerns, lengthy customer outages and resulting increases to O&M. Therefore, planned replacements was selected as the preferred alternative.
Safety
Factors such as corrosion, improper installation, and manufacturing defects can cause in-service failure of the old and deteriorating equipment leading to safety risks to workers and the public.
Cyber-Security, Privacy (where applicable)
Not Applicable
Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)
OPUCN uses USF standards and meets Ontario Regulations 22/04 requirements. This program will not impact any other regional planning activities. Customers and third party attachers related to the replacement will be notified and coordinated with.
Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)
Not Applicable
Environmental Benefits (where applicable)
Not Applicable
Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)
Not Applicable
Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)
Not Applicable
Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity
Not Applicable

C. Category-Specific Requirements – System Renewal (5.4.3.2.C)
Asset Performance-Related Operational Targets & Asset Lifecycle Optimization Policies and Practices

Implementation of this program in a timely manner will enable OPUCN to meet its performance goals in customer satisfaction and system reliability.
Information on the Condition of the Assets Relative to their Typical Life-Cycle and Performance Record
Specific 44kV quick sleeves that will be replaced are prioritized based on risks within this program. The project was assessed qualitatively on improving the system performance and ensuring public/worker safety and maintaining system reliability. There is a significant impact if this asset fail while supplying critical load as the quick sleeves were installed in the 44kV circuits which supplies OPUCN municipal substations. There is also an impact on public exposure as the lines could fall down if the quick sleeves fail.
The Number of Customers in Each Class Potentially Affected by Failure of the Assets
Specific yearly values are not currently known; however the number of customers can vary significantly from year to year.
Quantitative Customer Impacts
The main impact of this program on the customers is mitigating the risk of SAIDI and SAIFI worsening due to the anticipated failures of the equipment and reduced public safety risk. The quantitative customer impacts beyond the completion of the project are indeterminate.
Qualitative Customer Impacts
The timely replacement of the deteriorating assets and assets prone to failure will improve system reliability and overall customer experience.
Value of Customer Impact in Terms of Characteristics of Customers Potentially Affected by Failure that have Bearing on the Criticality and/or Cost of Failure
The characteristics of customers potentially affected by quick sleeve failures varies widely from a high number of residential customers with a low per customer cost of failure, to single large industrial customers with a very high cost of failure. The most critical units (those affecting the largest number of customers and those having the highest cost of failure) will be prioritized over others.
Timing and Priority of the Project
This program has been given a high priority as the failure may cause a safety concern or a system outage. OPUCN will replace approximately 100 quick sleeves on 44kV primary overhead conductor lines during the period of 2020-2022. 2021-2022 program is a continuation of the 2020 44kV Quick Sleeve Replacement Program.
Consequences for System O&M Costs
Replacement of the quick sleeves on 44kV primary overhead conductor lines in a proactive way will reduce the cost of unplanned failures. This program will help reduce system O&M costs over time through reductions in corrective maintenance spending.
Impact on Reliability Performance and/or Safety
Replacement of these assets will have a positive impact on the reliability performance and safety in the following ways: 1. Improved reliability by reducing potential failures and greatly decreasing restoration times.

2. Significant improvement in safety by removing old and deteriorating equipment from the system.
Analysis of Project Benefits and Timing
This program offers high benefit of reduced unplanned outages.
Like for Like Renewal Analysis, Alternative Comparison (Like for Like vs. Not Like for Like, Timing, Rate of Replacements, etc.)
This program will be completed in a like for like manner in terms of installation and configuration. All new construction will meet the latest distribution standards and regulations.

A. General Information (5.4.3.2.A)					
Project/Activity	Vault Transformer Replacement Program				
Project Number	SR-05				
Investment Category	System Renewal				
	2021	2022	2023	2024	2025
Capital Cost	$162,000	$162,000	$162,000	$162,000	$162,000
Capital Contribution	N/A	N/A	N/A	N/A	N/A
Net Cost	$162,000	$162,000	$162,000	$162,000	$162,000
O&M Cost	2021	2022	2023	2024	2025
	-	-	-	-	-

Customer Attachments and Load

Customer Attachments and Load are not expected to change with the execution of this program, however improvements to system components will positively affect the following:

Customer Attachments: approximately 350-1000 customers
Load: 5-10 MW

Start Date	2021-2025	In-Service Date	2021-2025
Expenditure Timing for the Planning Horizon	2021Q1	2021Q2	2021Q3	2021Q4
	$40,500	$40,500	$40,500	$40,500

Project Summary

OPUCN owns and maintains 394 vault transformers and based on the ACA, several vault transformers could be in "good" or in "fair" condition but have surpassed its TUL and are due for replacement. These vault transformers are high risk as most of these are situated in customer owned vaults or OPUCN downtown vaults. The plan is to replace 12 vault transformers per year as per the recommendations of the ACA. The program will cover procurement, installation and connection of a new vault transformer and removal and disposal of the existing transformer.

Risk Identification & Mitigation

Proactive vault transformer replacement programs are driven by asset health, service age and risks to reliability, safety and customer service. OPUCN performs inspections and maintenance work to prolong asset life and to identify assets that are at risk for failure. Timely consultation among the design and construction teams ensures proper resource allocation to complete the work on schedule. OPUCN shall use the internal staff resources as necessary, to mitigate the schedule risks.

This project is also subject to scheduling risks. To ensure no delays occur, it is imperative to have consistent consultation among the design and construction teams to ensure proper resource allocation to complete the work on schedule. OPUCN shall use the internal staff resources as necessary, to mitigate the schedule risks.

Comparative Information on Expenditures for Equivalent Projects/Activities

Vault transformer replacement project/activities do not have a direct comparator. This program was introduced in 2020.

Historical Costs ($ '000)						Forecast Costs ($ '000)				
2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
-	-	-	-	-	162	162	162	162	162	162

REG Investment Details including Capital and OM&A costs

As this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.
Leave to Construct approval under Section 92 of the OEB Act
This project is below 50 kV and therefore Leave to Construct is not required, as per OEB.Reg. 161/99.
Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material
Please refer to the ACA in Appendix B.

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)
Efficiency, Customer Value & Reliability – Investment Main Driver
This program falls under System Renewal Investment driver and is aimed at improving reliability, operational efficiency, customer service and safety. Transformers are regularly inspected and flagged for replacement based on their condition. Transformers that are in very poor condition, or which have failed, will be replaced on an as-needed basis in order to minimize unplanned outages and environmental and safety concerns such as leaking oil and fires. This program will reduce the risk of prolonged power interruptions and reduce the frequency of the power interruptions due to equipment failure. Allowing old and deteriorating equipment to remain in-service can result in significant safety concerns to OPUCN staff and customers.
Efficiency, Customer Value & Reliability – Investment Secondary Driver
There are no secondary drivers.
Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets
The investment objective is to ensure a reliable service to customers by mitigating the risk of power outage duration and frequency.
Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment
The source of the information used to justify this program investment is ACA which was prepared taking into account all the information pertaining to the age, condition of the assets and risks.
Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges
Typically, transformer replacement is planned to avoid disruption to customers and minimize outage time. This program will replace vault transformers that are at the end or beyond their useful service life before they fail and cause extended outages; hence mitigating safety risks and maintaining service reliability.
Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment
This program receives a high priority based on the level of AM objectives it meets and mandatory nature in addressing failing vault transformers. This program directly affects OPUCN's ability to supply electricity to its customers. Project planning will be coordinated with other projects/programs of the same priority level.
Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness

The proactive replacement of end of life vault transformers to be executed in this program will decrease the probability of unplanned failures. The installation of new assets that meet current standards will allow for the operation of equipment in a more efficient manner.
Analysis of Project & Alternatives – Net Benefits Accruing to Customers
The net benefit to customers is to reduce the potential risk associated with untimely failure and to ensure that any safety hazards are reduced and reliability is maintained.
Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages
This program decreases the frequency and duration of outages by seeking to replace the transformers which are in very poor condition in a planned manner. This program will improve the reliability by reducing the risk of prolonged or highly frequent outages by reducing the risk of in-service equipment failures.
Project Alternatives (Design, Scheduling, Funding/Ownership)
Alternatives to this project is limited. Transformer maintenance is performed, however, all failures cannot be prevented by maintenance. Therefore, planned replacements are the preferred alternative for failures with high risk impact.
Safety
These investments are directly linked to public and worker safety, as they aim to replace vault transformers with high risk of failure.
Cyber-Security, Privacy (where applicable)
Not Applicable
Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)
Transformer replacement at this level do not impact inter-utility coordination or regional planning activities. Coordination with customers and electricians is a part of every project. Authorization from the Electrical Safety Authority may be required prior to reconnect service if activities are being coordinated with a change to the customer's service and is handled through an established process.
Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)
Transformers are sized to the latest standards for operational needs. Transformers will be installed according to the latest standards and technologies that meet future operational requirements.
Environmental Benefits (where applicable)
Proactive replacement of transformer mitigates the possible environmental risk of oil leaks due to deteriorating in-service transformers and oil spills due to failed transformers. Also, "right sizing" the transformers reduces the losses
Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)
Not Applicable

Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)
Not Applicable
Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity
Transformers are sized to the latest standards for operational needs. Transformers will be installed according to the latest standards and technologies that meet future operational requirements.

C. Category-Specific Requirements – System Renewal (5.4.3.2.C)
Asset Performance-Related Operational Targets & Asset Lifecycle Optimization Policies and Practices
This program fulfills operational effectiveness and customer service quality objectives through a continuous improvement in delivering on system reliability targets of SAIFI and SAIDI results and removing the risk of lengthy unplanned outages from failed assets. This program also supports safety targets by elimination of assets that pose a potential risk to public and worker safety.
Information on the Condition of the Assets Relative to their Typical Life-Cycle and Performance Record
Based on the ACA, 132 vault transformers have surpassed its TUL and are due for replacement. The plan is to replace 12 vault transformers per year which are typically located inside customer owned vault for the period of 2021-2025. At the time of the replacement, these transformers will be more than 35 years old. Please refer to the ACA for the information on the age and the condition of the assets.
The Number of Customers in Each Class Potentially Affected by Failure of the Assets
Transformer failures can affect 1 to several customers depending on the number of customers supplied via the transformer. Typically, smaller distribution transformers will have 12 or fewer customers supplied, while larger units used for commercial and industrial customers will have fewer than 5 customers supplied. Some transformer units supply individually metered apartment buildings and therefore can have 100's of customers attached. The number of customers affected by a failure is therefore variable on a case-by-case basis.
Quantitative Customer Impacts
At this time, OPUCN does not have sufficient data to quantitatively predict the customer impacts related to this program. Actual interruptions will depend on the number of failed transformers, number of customers attached to failed transformers and the configuration and the location of the transformer.
Qualitative Customer Impacts
The completion of this program will ensure that OPUCN's reliability is not negatively impacted by excessive transformer failures. These improvements will enhance overall customer satisfaction.
Value of Customer Impact in Terms of Characteristics of Customers Potentially Affected by Failure that have Bearing on the Criticality and/or Cost of Failure
The characteristics of customers potentially affected by transformer failures varies widely from a high number of residential customers with a low per customer cost of failure, to single large industrial customers with a very high cost of failure. The most

critical units (those affecting the largest number of customers and those having the highest cost of failure) will be prioritized over others.
Timing and Priority of the Project
12 vault transformers will be replaced annually. Although all are considered to be of high or very high priority, priorities among specific units may shift.
Consequences for System O&M Costs
This program will help reduce system O&M costs over time through reductions in corrective maintenance spending.
Impact on Reliability Performance and/or Safety
This program will minimize the extent of danger to employee or public safety during a failure event.
Analysis of Project Benefits and Timing
This program has been given a high priority because it offers a high benefit for risk mitigation and improving the service quality with enhanced reliability.
Like for Like Renewal Analysis, Alternative Comparison (Like for Like vs. Not Like for Like, Timing, Rate of Replacements, etc.)
Like for like construction will be utilized where practical, if such transformers meet the current safety standards a similar unit will be installed in the same location and fashion. The rate of replacement is determined by the ACA results, customer requests for new service and service upgrades, failure and loading changes.

A. General Information (5.4.3.2.A)					
Project/Activity	Underground Line Renewal				
Project Number	SR-06				
Investment Category	System Renewal				
	2021	2022	2023	2024	2025
Capital Cost	$1,353,500	$2,403,000	$1,222,000	$1,155,000	$1,470,000
Capital Contribution	N/A	N/A	N/A	N/A	N/A
Net Cost	$1,353,500	$2,403,000	$1,222,000	$1,155,000	$1,470,000
O&M Cost	2021	2022	2023	2024	2025
	-	-	-	-	-

Customer Attachments and Load

Residential Customers – 3,208
Commercial Customers – 13
Total Load – 7,992 kW

Start Date	2021-2025	In-Service Date	2021-2025
Expenditure Timing for the Planning Horizon	2021Q1	2021Q2	2021Q3	2021Q4
	$50,000	$525,000	$625,000	$203,500

Project Summary

This project category is comprised of renewing underground primary lines in poor condition and past their TUL that were originally installed between 1970 and 1980. Results of the ACA, and primary cable fault analysis have determined that complete replacement of these underground assets is required due to their condition.

The project scope includes design, construction and installation of new, primary voltage underground cable complete with associated duct system designed to conform with the latest standards and regulations including Ontario Regulation 22/04 (O.Reg. 22/04). By completing the underground line renewal, OPUCN plans to improve the level of reliability associated with newer standards and materials.

Risk Identification & Mitigation

Scheduling Risks – These projects are subject to scheduling risks with respect to external contractors and with other major projects but will be mitigated through good planning and project execution. The majority of the design work and Municipal Consent(s) will be completed a year ahead of construction so that construction may begin at the beginning of Q2 of each year as soon as the frost leaves the ground to mitigate this risk. Schedules are also determined the year before and progress meetings will be held to ensure construction schedule stays on track.

Comparative Information on Expenditures for Equivalent Projects/Activities

The following show the historical and forecasted annual costs. 2020 is a budget cost:

	Historical Costs ($ ‘000)						Forecast Costs ($ ‘000)				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Capital	757	1,143	696	1,121	870	1,545	1,353	2,403	1,222	1,155	1,470

The number of line sections and their length differs from year to year which explains the variability in comparable investments in previous years. An added underground line renewal in the downtown area and MS cable replacement program have also been included in the proposed projects. The other factor related to the increase in the overall average spend is change in requirements from the City of Oshawa related to site restoration work.

REG Investment Details including Capital and OM&A costs

As this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.

Leave to Construct approval under Section 92 of the OEB Act

This project is below 50 kV and therefore Leave to Construct is not required, as per OEB.Reg. 161/99.

Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material

The following is the list of UG Line Renewal projects that has been identified based on project conditions:

Year	Project #	UG Line Renewal Project Name	Net Forecasted Expenditure $'000
2021	SR-06-05	Walnut Ct	45
	SR-06-06	Seville St, 384 Hillside Ave	63
	SR-06-07	512 Canonberry Crt - MAY BE REDEVELOPED - Should also include 511 Cannor	221
	SR-06-08	285 Taunton Rd E	53
	SR-06-09	Madawaska Ave, Wecker Dr, Rondeau Ct, Ritson Rd S (Valley Dr to Lakeview Par	172
2022	SR-06-10	Overbank Dr, Castlegrove Ave, Sagebrush St,Lichen Cres, Adele Cres,	540
	SR-06-11	540 Dorchester Dr	92
	SR-06-12	Keates Ave	69
	SR-06-13	Central Park Blvd N (Brentwood Ave to Hillcroft St)	113
	SR-06-14	510 Rossland Rd E, 455 Mayfair Ave	85
	SR-06-15	Norman Cres, Grandview Dr, Downsview Cres, Grandview St S, Wesley Dr, Edna	505
	SR-06-16	777 Terrace Crt	99
2023	SR-06-17	601 & 611 Galahad Dr	227
	SR-06-18	Naples St	67
	SR-06-19	1330 Trowbridge Dr, Ludlow Ct	175
	SR-06-20	Prestwick Dr, Dunrobin Ct, Lochness Cres, Apple Valley Ln	460
	SR-06-21	Townline Rd S, King St E (Tx 4421), Carling Ave, Merivale St	72
	SR-06-22	420 and 450 Bristol Cres	121
2024	SR-06-23	Glenridge Ct	101
	SR-06-24	Limerick St, Tralee Ct, Monaghan Ave	136
	SR-06-25	Huntingwood Dr, Goodman Dr, Amber Ave, Waverly St N (Adelaide Ave W to Daw	590
	SR-06-26	Copperfield Dr,	50
	SR-06-27	William Booth Cres, Exeter St	178
2025	SR-06-28	Roundelay Dr, Roundelay Ct, Mahina St, Aztec Dr, Charisma Cres, Rimosa Ct, M	770
	SR-06-29	Whistler Dr, Griffith St, Barnes Cres, Logan Ct, St Anne Ct, Cartref Ave, Mount Alla	600
2021-2022	SR-06-30	Municipal Substation Cable Replacement Program	1,600
2022-2025	SR-06-31	UG Downtown Cable Replacement Program	400
		TOTAL	**7,604**

Project scope and maps for 2021 UG Line Renewal projects are shown in the following:

SR-06-05: Walnut Ct
Scope: UG Cable Replacement - 170m single phase, 2 Tx

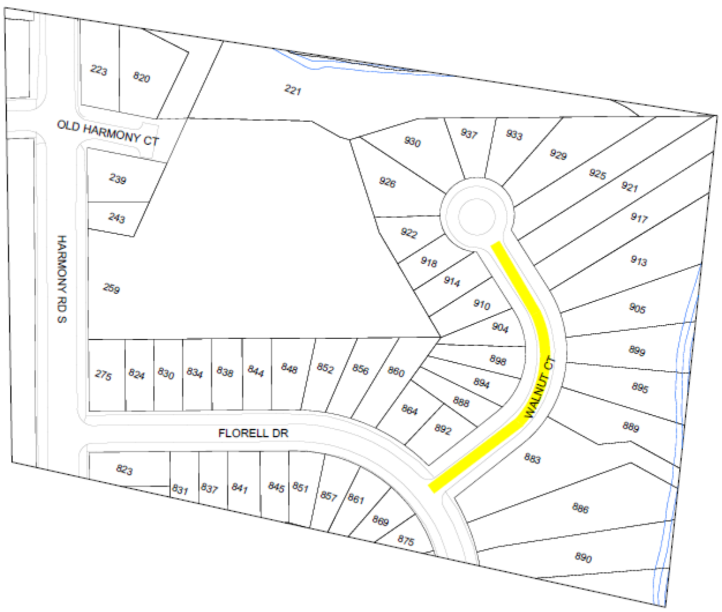


Figure 24: SR-06-05 Walnut Crescent Area Map

SR-06-06: Seville St, 384 Hillside Ave
Scope: UG Cable Replacement - 85m single phase, 36m three phase, 1 Tx

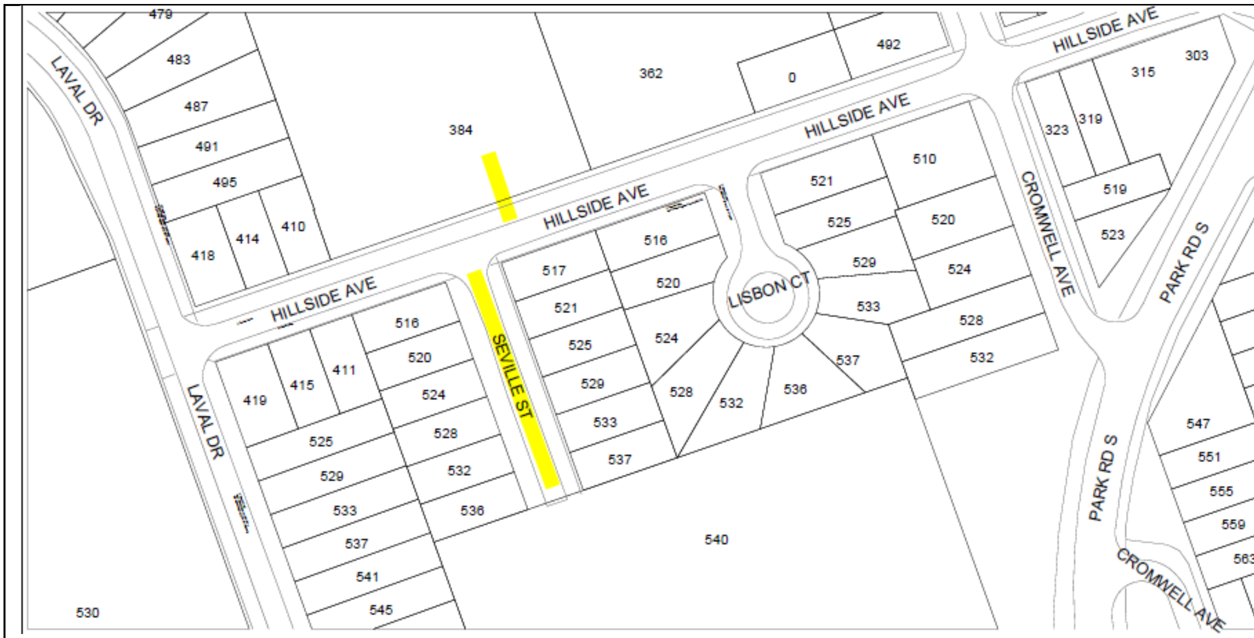


Figure 25: SR-06-06: Seville St, 384 Hillside Ave Area Map

SR-06-07: 512 Canonberry Crt
Scope: UG Cable Replacement - 250m three phase, 3-3PH Vault Tx - 4 vaults

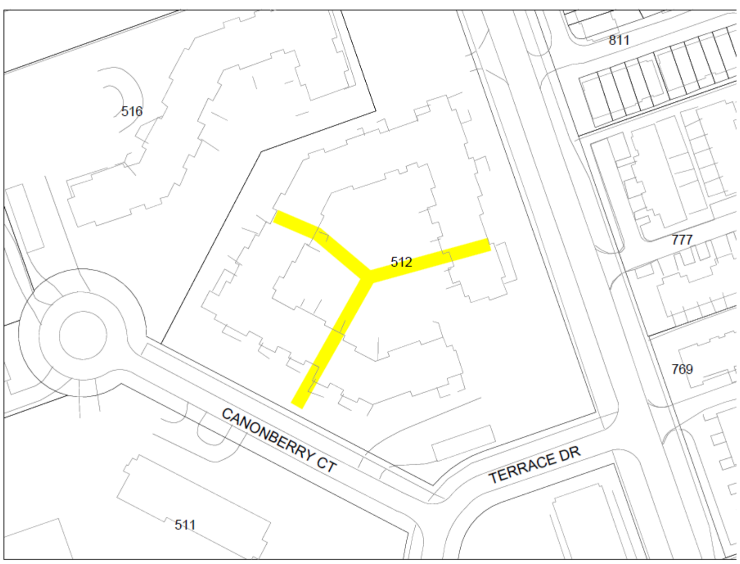


Figure 26: SR-06-07: 512 Canonberry Crt Area Map

SR-06-08: 285 Taunton Rd E
Scope: UG Cable Replacement - 250m three phase, 3-3PH Vault Tx - 4 vaults

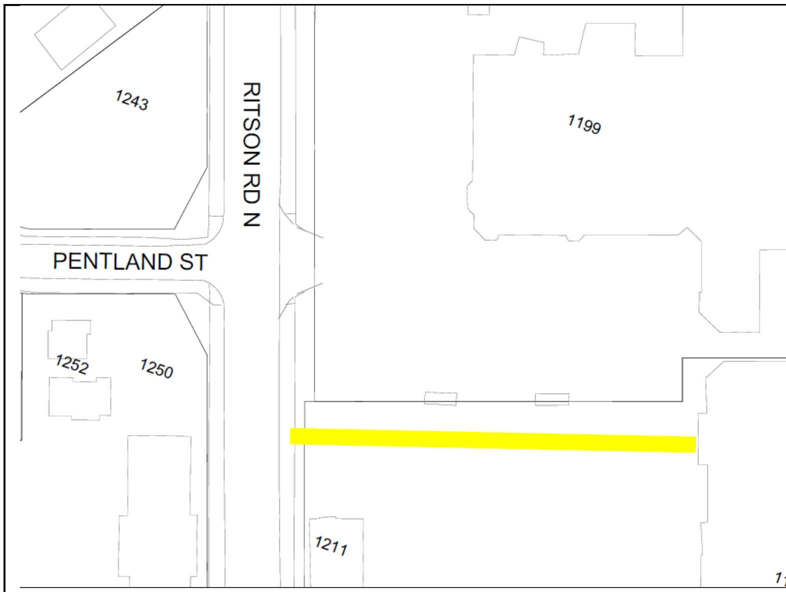


Figure 27: SR-06-08: 285 Taunton Rd E Area Map

SR-06-09: Madawaska Ave, Wecker Dr, Rondeau Ct, Ritson Rd S (Valley Dr to Lakeview Park)
Scope: UG Cable Replacement - 910m single phase, 8 Tx

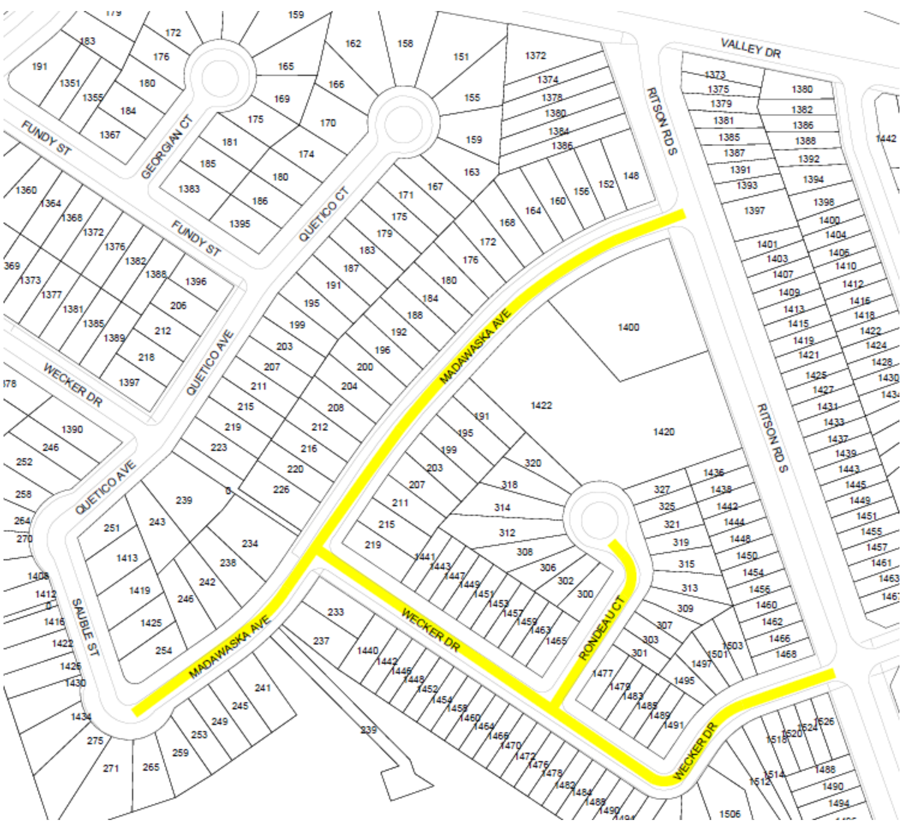


Figure 28: SR-06-09: Madawaska Ave, Wecker Dr, Rondeau Ct, Ritson Rd S (Valley Dr to Lakeview Park) Area Map

SR-06-30 (2021 Project): MS10 Incoming 44kV Line and Outgoing 13.8kV 10F6 Feeder Line
Scope: 28m - 3 phase 44kV, 73m - 3 phase 13.8kV 6 Poles

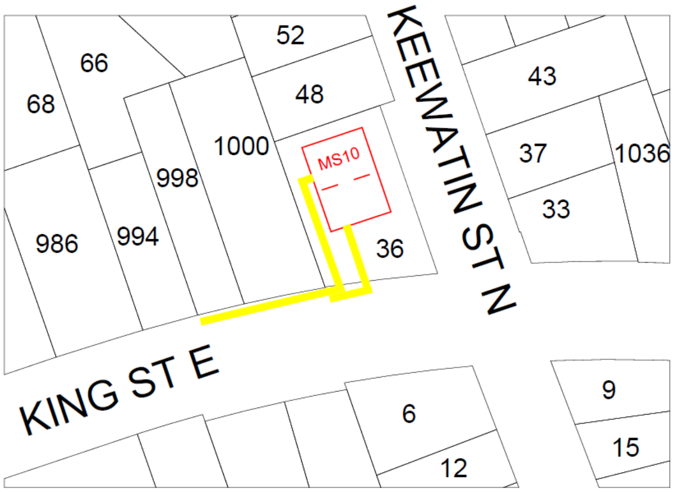


Figure 29: SR-06-30 (2021 Project): MS10 Incoming 44kV Line and Outgoing 13.8kV 10F6 Feeder Line Area Map

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)
Efficiency, Customer Value & Reliability – Investment Main Driver
This project falls under System Renewal Investment driver and will mitigate failure risk since cables identified for replacement are at the end of their life. The infrastructure being replaced was installed in the 1970's and 1980's and has been identified as being in poor condition in the ACA. The primary cable could be direct buried or in ducts and many of the cables identified have failed and have been spliced. – A planned replacement will minimize the risk of underground asset failure and mitigate the impact on reliability performance including SAIDI and SAIFI.
Efficiency, Customer Value & Reliability – Investment Secondary Driver
There are no secondary drivers.
Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets
These projects will mitigate the risk of equipment failure that may pose a safety risk and negatively impact power supply reliability.
Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment
The sources of the information used to justify the investment are the results of the ACA, GIS registry, asset database, field inspections, primary cable fault analysis, reliability data and information from incident reports. Third party work/relocations are also taken into account so that work may be co-ordinated with them as much as possible.
Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges

This program will maintain or improve the reliability of the system by replacing underground assets in poor condition and installing fault indicators on padmount transformers and remotely operated padmount switchgears, where applicable, within the project areas.
Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment
This program receives a high priority based on the level of AM objectives it meets and mandatory nature in addressing failing assets. The projects under the UG renewal program were prioritized based on age of infrastructure, asset assessment, reliability and safety. Third party work/relocations are also taken into account so that work may be co-ordinated as much as possible. Scope of projects was also taken into account to ensure that the construction could be completed in the assigned year.
Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness
Completion of the underground renewal program will improve system operation efficiency by maintaining system reliability and reducing the number of underground asset failures. New underground design and industry practice will be introduced based on more robust standards and current regulations providing a safer and more reliable underground distribution system.
Analysis of Project & Alternatives – Net Benefits Accruing to Customers
Customers within the project area will benefit from this project through the reduction of the risk of an outage that the new system will provide. Customers will also indirectly benefit from the lower maintenance costs that a new system will provide.
Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages
Replacement of underground assets in poor condition will provide a more reliable system and will reduce the risk of asset failures, particularly prolong outages associated with unplanned replacement of direct buried cables.
Project Alternatives (Design, Scheduling, Funding/Ownership)
All cable sections under this project have been identified as being in poor condition, at the end of their TUL, and in need of replacement. The following alternatives were considered: 1. Do nothing – this option would result in a decrease in reliability and is not considered an acceptable option. 2. Rejuvenate the cables – these cables are not considered appropriate candidates for refurbishment as these cables are past the end of their TUL where rejuvenation is not effective. Rejuvenation of underground cables involves the use of injection technology to repair insulation ageing issues theoretically minimizing faults and extending the life of the cable. The cables to be replaced under this project are not opportune candidates for this technology due to their age and poor condition.
Safety
Proper asset management of old and deteriorating equipment in the field mitigates safety concerns for OPUCN staff and customers. New construction will also meet the latest distribution standards for safety.
Cyber-Security, Privacy (where applicable)
This program has no adverse impact on cyber security and privacy.

Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)
OPUCN meets quarterly with the City, Region and all other utilities to discuss projects, timelines and co-ordinate efforts. In addition to this, designs are sent to each of these parties for each individual project to aid in co-ordination.
Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)
Where cables are being replaced in the downtown underground system, specialized cable design will be used to enable more cables in each duct freeing up ducts for future development and operational needs.
Environmental Benefits (where applicable)
The padmount transformers are assessed during the design phase and any leaking or questionable transformers are replaced.
Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)
Not Applicable
Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)
Not Applicable
Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity
Where cables are being replaced in the downtown underground system, specialized cable design will be used to enable more cables in each duct freeing up ducts for future development and operational needs.

C. Category-Specific Requirements – System Renewal (5.4.3.2.C)
Asset Performance-Related Operational Targets & Asset Lifecycle Optimization Policies and Practices
Assets planned for replacement in this program are deteriorated to the point they must be replaced. Proceeding with these projects will improve the operational effectiveness of the system by contributing to better SAIDI and SAIFI performance.
Information on the Condition of the Assets Relative to their Typical Life-Cycle and Performance Record
Direct buried primary cable has a TUL of 30 years. On average, these cables are 40 years old which puts them past their TUL. Underground cables that will be replaced have a calculated health index in the very poor, poor and fair categories as per the ACA results.
The Number of Customers in Each Class Potentially Affected by Failure of the Assets
Residential Customers – 3,208 # Commercial Customers – 13
Quantitative Customer Impacts

Customers will experience improvement in the reliability of power supply minimizing the frequency and duration of interruptions as a result of underground renewal. The quantitative customer impacts beyond the completion of the UG Line Renewal project are indeterminate.
Qualitative Customer Impacts
Customers will receive increased reliability and indirectly maintenance costs will be lower.
Value of Customer Impact in Terms of Characteristics of Customers Potentially Affected by Failure that have Bearing on the Criticality and/or Cost of Failure
The majority of these projects are in residential areas and so there is a low impact to these customers in terms of the criticality and cost of an asset failure. Two projects are in areas with businesses or main feeders. Customer impact on these customers is medium to high.
Timing and Priority of the Project
The timing and priority of the projects takes into account the condition of these assets, reliability and the available resources to design and construct these projects. Since System Access projects are a higher priority in the AM process an additional project has the potential to modify the timing of any System Renewal project. Additionally, if OPUCN documents any extreme reliability issues due to ageing in a specific area that needs to be addressed projects can be shuffled from year to year during the forecast period.
Consequences for System O&M Costs
Without these projects taking place, O&M costs would be expected to rise over time at an increasing rate due to equipment failures.
Impact on Reliability Performance and/or Safety
Proper asset management of old and deteriorating equipment in the field mitigates safety concerns for OPUCN staff and customers. This program helps maintain or improve system reliability.
Analysis of Project Benefits and Timing
The timing and priority of the projects takes into account the condition of these assets, reliability and the available resources to design and construct these projects. Delaying these projects will impact renewal work that is required in future years to properly maintain a reliable system.
Like for Like Renewal Analysis, Alternative Comparison (Like for Like vs. Not Like for Like, Timing, Rate of Replacements, etc.)
The underground cables will be replaced to today's standards. In residential areas, accommodation for additional circuits will not usually be made, however, on major thoroughfare roads the area will be assessed and a determination made as to whether future accommodations are warranted in the design.

A. General Information (5.4.3.2.A)					
Project/Activity	Municipal Substation Transformer Replacement Program and Oil Containment				
Project Number	SR-07				
Investment Category	System Renewal				
	2021	2022	2023	2024	2025
Capital Cost	-	-	$1,500,000	$1,500,000	$1,500,000
Capital Contribution	N/A	N/A	N/A	N/A	N/A
Net Cost	-	-	$1,500,000	$1,500,000	$1,500,000
O&M Cost	2021	2022	2023	2024	2025
	-	-	-	-	-

Customer Attachments and Load

Customer Attachments and Load are not expected to change with the execution of this program, however improvements to system components will positively affect the following:

Customer Attachments: approximately 11,000 customers
Load: 30-40 MW

Start Date	2023-2025	In-Service Date	2023-2025

Expenditure Timing for the Planning Horizon	2021Q1	2021Q2	2021Q3	2021Q4
	-	-	-	-

Project Summary

OPUCN owns and maintains 9 Municipal Substations (MS) and based on the ACA, several of the station transformers are in poor condition and have reach the end of their TUL. This program will replace three transformers over a period of 3 years within 2023-2025 as per ACA recommendation. The program will cover procurement, installation and connection of a new MS Transformer, installation of oil containment and removal and disposal of the transformers being replaced.

Risk Identification & Mitigation

Scheduling Risk – The equipment has a very long lead time for delivery. This will be mitigated by developing the project plan and placing the equipment order well in advance. Customers will also be notified well in advance of any power interruptions, if any.

Comparative Information on Expenditures for Equivalent Projects/Activities

OPUCN last replaced a transformer prior to the historical period in 2014. The cost to replace a substation transformer with oil containment was based on recent quotations, and considerations of inflation and commodity costs.

REG Investment Details including Capital and OM&A costs

As this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.

Leave to Construct approval under Section 92 of the OEB Act

This project is below 50 kV and therefore Leave to Construct is not required, as per OEB.Reg. 161/99.

Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material

Please refer to the ACA in Appendix B.

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)
Efficiency, Customer Value & Reliability – Investment Main Driver
System Renewal is the driver for this program and it is aimed at reducing the risk of prolonged power interruptions due to equipment failure and improving operational efficiency and safety. Allowing station transformers found to be at the end of their TUL stay in service presents significant safety and reliability concerns. With many stations reaching their end of life, the proposed replacement of MS transformers will ensure that these risks are mitigated in the timely manner.
Efficiency, Customer Value & Reliability – Investment Secondary Driver
There are no secondary drivers.
Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets
The investment objectives are to mitigate the risk of power outage duration and frequency.
Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment
The source of the information used to justify this project investment is the ACA which was prepared taking into account all the information pertaining to the condition of the assets.
Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges
Typically, MS transformer replacement is planned to avoid disruption to customers and minimize outage time. This program will replace the MS transformers that are in poor condition and at the end of their service life before they fail and cause extended outages. This will maintain and likely improve reliability going forward.
Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment
This program has high priority and meets most of the OPUCN's AM objectives identified in Section 5.3.1. Catastrophic failure of a MS transformer poses significant environmental and safety risks and affects reliability which are the reasons for prioritizing this project. A failure could result in a complete loss of supply from the MS requiring load transfer to another MS. This transfer could be very challenging that could take several hours and may result in overloading other facilities.
Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness
A planned replacement is the preferred alternative for these assets because it allows OPUCN to proactively mitigate the failure risk posed by end-of-life and poor condition of MS transformers within its system and thereby, reduce the risk of outages to customers. The replacement will also provide better system operation efficiency and will minimize preventative maintenance work required.
Analysis of Project & Alternatives – Net Benefits Accruing to Customers
Customers will benefit from outage risks mitigation. Net benefits accruing to the customers have been qualitatively described above but have not been quantitatively calculated because accurate information on the customer interruption costs in not readily available.
Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages
The MS transformer replacement program will maintain and likely improve reliability and equipment performance by reducing the risk of prolonged outage and by reducing the risk of in-service equipment failures.

Project Alternatives (Design, Scheduling, Funding/Ownership)
Alternatives to this project is limited. The alternatives are: 1. Do-Nothing - in this scenario OPUCN would accept the risk of a potential transformer failure and address it on a reactive basis. This approach was rejected as the MS transformer is a major asset and failure at this scale will significantly impact customer in terms of reliability and safety. 2. Spare Transformer - Having a spare transformer will only provide a temporary solution (deferred capital) and will not eliminate the risk of transformer failure. Also, OPUCN currently does not have any spare transformer and will still require to procure if we proceed with this approach. 3. Transformer Maintenance - preventive maintenance on the MS transformers is performed along with periodic inspections including station checks, visual and infrared inspection and tests including DGA (Dissolved Gas Analysis), however end of life failures cannot be prevented by preventive inspection and maintenance programs. 4. Major Refurbishment - This decreases the failure probability of the asset but it does not completely eliminate the risk, if a transformer fails as this is a temporary solution. Therefore, a planned replacement is the preferred alternative for these assets because it allows OPUCN to proactively mitigate the failure risk posed by end-of-life and poor condition MS transformers within its system and thereby reduce the risk of outages to customers.
Safety
These investments are directly linked to public and worker safety, as they aim to eliminate MS transformers with high risk of catastrophic failure.
Cyber-Security, Privacy (where applicable)
Not Applicable
Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)
MS Transformers conforming to ESA, CSA and IEEE standards will be utilized.
Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)
Upgrades to the MS transformer will include transformer monitoring system that collects, aggregates and analyzes critical data to ensure that transformers are continuously being assessed and analyzed.
Environmental Benefits (where applicable)
Because transformer contains oil, transformer failures may cause rupture of the transformer tank, resulting in oil being spilled onto the ground. By replacing the transformers that has reached its end of life with new units and installing an oil containment, the risk of oil contamination can be mitigated and the effects to the environment will be minimized.
Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)
Not Applicable

Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)
Not Applicable
Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity
Upgrades to the MS transformer will include transformer monitoring system that collects, aggregates and analyzes critical data to ensure that transformers are continuously being assessed and analyzed.

C. Category-Specific Requirements – System Renewal (5.4.3.2.C)
Asset Performance-Related Operational Targets & Asset Lifecycle Optimization Policies and Practices
Assets planned for replacement in this program are deteriorated to the point that they must be replaced. Proceeding with these projects will improve the operational effectiveness of the system and maintain SAIDI and SAIFI performance.
Information on the Condition of the Assets Relative to their Typical Life-Cycle and Performance Record
OPUCN operates 18 in-service MS transformers. At the time of the replacement, the existing MS transformers marked for replacement will be approximately 45 years old. Please refer to the ACA for additional information.
The Number of Customers in Each Class Potentially Affected by Failure of the Assets
Number of Residential Customers: 9646 Number of Commercial Customers: 1112 Number of Industrial Customers: 100 Others (Generation Connection): 31
Quantitative Customer Impacts
The main impact of this program on the customers is to mitigate the risk of SAIDI and SAIFI worsening due to the anticipated failures of the equipment determined to be in poor or very poor condition. The quantitative customer impacts beyond the completion of the project are indeterminate.
Qualitative Customer Impacts
Failure of this equipment will negatively impact the electricity supply to many residential, commercial and industrial customers.
Value of Customer Impact in Terms of Characteristics of Customers Potentially Affected by Failure that have Bearing on the Criticality and/or Cost of Failure
The customers will receive value through reduced unplanned outages and enhanced reliability.
Timing and Priority of the Project
This program has a high priority. 3 MS transformers will be replaced over the period of 2023-2025. Although all are considered to be of high or very high priority, priorities among this may shift.

Consequences for System O&M Costs
MS transformer replacement program will help reduce system O&M costs over time through reductions in corrective maintenance spending.
Impact on Reliability Performance and/or Safety
MS transformers participate in a rigorous monitoring and maintenance program to ensure reliable and safe operation. The new MS transformers will have an oil containment and transformer monitoring system that will increase system reliability and safety.
Analysis of Project Benefits and Timing
This program offers a high benefit for risk mitigation and improving the service quality with enhanced reliability.
Like for Like Renewal Analysis, Alternative Comparison (Like for Like vs. Not Like for Like, Timing, Rate of Replacements, etc.)
The MS transformers will be built to today's standards. This program is a like-for-like replacement with added cost to cover the installation of oil containment and transformer monitoring device to improve data collection and analysis.

A. General Information (5.4.3.2.A)					
Project/Activity	Municipal Substation Switchgear Replacement Program				
Project Number	SR-08				
Investment Category	System Renewal				
	2021	2022	2023	2024	2025
Capital Cost	$1,800,000	$1,800,000	$1,800,000	$1,800,000	$1,800,000
Capital Contribution	N/A	N/A	N/A	N/A	N/A
Net Cost	$1,800,000	$1,800,000	$1,800,000	$1,800,000	$1,800,000
O&M Cost	2021	2022	2023	2024	2025
	-	-	-	-	-
Customer Attachments and Load					

Customer Attachments and Load are not expected to change with the execution of this program, however improvements to system components will positively affect the following:

Customer Attachments: approximately 40,000 customers
Load: 120 MW

Start Date	2021-2025	In-Service Date	2021-2025
Expenditure Timing for the Planning Horizon	2021Q1	2021Q2	2021Q3	2021Q4
	-	$900,000	$900,000	-
Project Summary				

Existing switchgears including relays and e-house at MSs – MS2, MS5, MS7, MS11 and MS13 have been identified in the ACA as having a poor condition and exceeding their TUL. These switchgears require replacement within the next six years (2021-2025) as they are a reliability risk serving more than half of OPUCN's customer base. The existing line-up will be replaced with a new switchgear that meets current industry standards.

The age of the switchgears as of 2020 are as follows:

Substation	Age
MS2	36
MS5	46
MS7	52
MS11	52
MS13	52

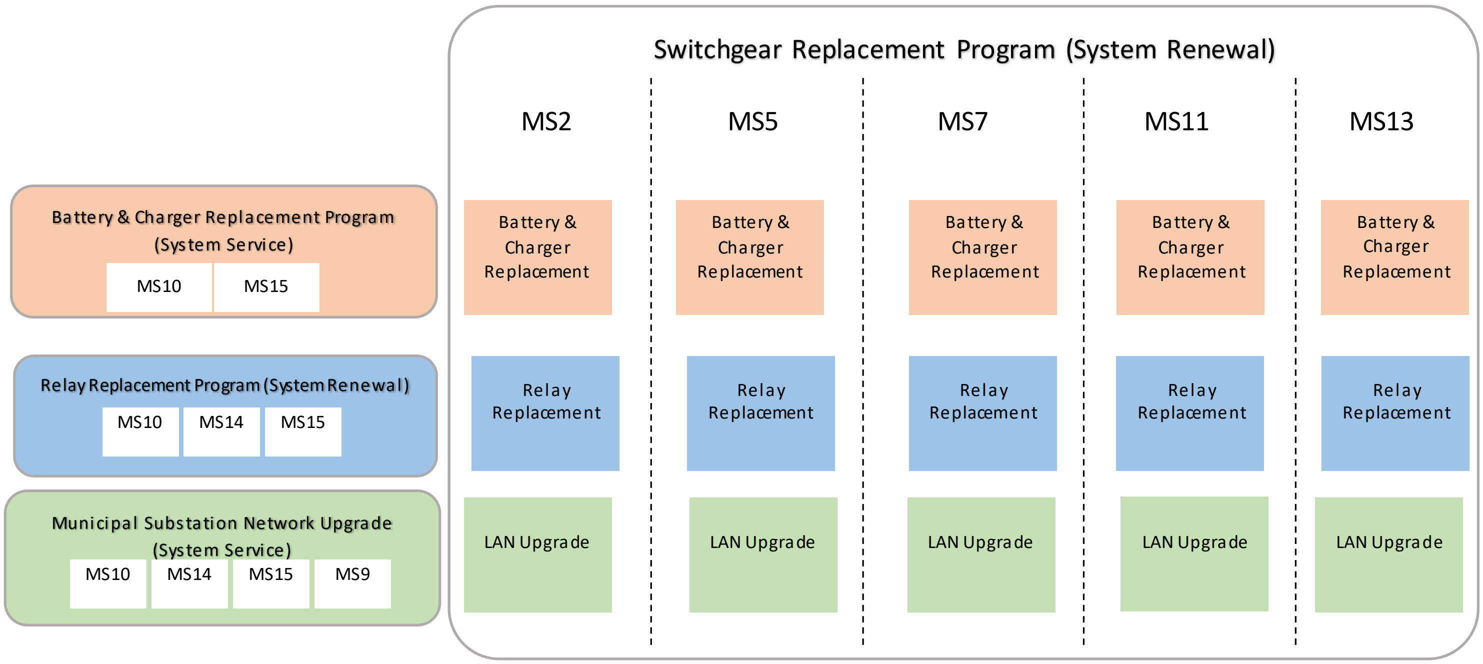


Figure 30-Coordination of Interdependent Substation Projects

The Switchgear Replacement Program will be incorporating new MS battery charger & battery condition monitoring (see Station Battery and Battery Charger Replacement under System Service), relay replacements and new LAN network (See Substation Cybersecurity LAN Upgrade under System Service) for the above-mentioned switchgears. The individual Battery & Charger Replacement Program (System Service), Relay Replacement Program (System Renewal) and Municipal Substation LAN Upgrade Program (System Service) will address other MSs that the Switchgear Replacement Program will not be addressing.

Risk Identification & Mitigation

Scheduling Risk – The main risk is manufacture lead/delivery time. The risk will be mitigated by developing the project plan and placing the equipment order well in advance.

Resource Risk – Timely consultation among the design and construction teams ensures proper resource allocation to complete the work on schedule. OPUCN employs contract resources as necessary, to mitigate the scheduling risks.

Comparative Information on Expenditures for Equivalent Projects/Activities

A 15 kV switchgear including e-house and relays was replaced in 2014 at a total project cost of $1.63 million, as seen in Appendix AA. The proposed total estimated cost of the switchgear and relay replacement has increased to $1.8 million per switchgear due to inflation and changes to equipment cost.

REG Investment Details including Capital and OM&A costs

The protection relays are modern based relays that are capable of dealing with reverse power flow to accommodate REG applications but there does not exist a direct REG investment on this project.

Leave to Construct approval under Section 92 of the OEB Act

This project is below 50 kV and therefore Leave to Construct is not required, as per OEB.Reg. 161/99.

Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material

Please refer to the ACA in Appendix B.

The following are images of a recent 2020 outage incident due to short circuit in one of OPUCN's MS switchgear being proposed to replace.

Figure 31: Images of a recent outage at a OPUCN owned switchgear

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)
Efficiency, Customer Value & Reliability – Investment Main Driver
This program falls under System Renewal Investment driver and aimed at addressing existing reliability concerns. When a MS switchgear fails, outages can be extensive and may last for extended periods of time. This program will reduce the risk of prolonged power interruptions and reduce the frequency of power interruptions due to the equipment failure. This program will

also address Operational Efficiency and Safety. Allowing old and deteriorating equipment in the field can result in significant safety and reliability concerns to OPUCN staff and customers. This project aligns with the guidelines of the Grid Modernization Plan. The installation of advanced communication (substation LAN) and new relays will facilitate a better communication traffic (e.g. lower latencies, more bandwidth) for a smarter grid. The installation of battery condition monitoring system will utilize new technology to provide real-time condition of the station back-up power.
Efficiency, Customer Value & Reliability – Investment Secondary Driver
There are no secondary drivers.
Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets
The investment objectives are to mitigate the risk of lengthy customer interruptions.
Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment
The source of the information used to justify this project investment is the ACA which was prepared taking into account all the information pertaining to the condition of the assets.
Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges
This program will replace switchgears in poor condition and at the end of their service life to prevent potential failures that can cause extended outages and safety risks.
Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment
Priority is very high due to the poor condition of this equipment and its potential impact to a large number of customers in the event of a failure. This program also addresses most of OPUCN's AM objectives identified in Section 5.3.1 receiving the highest priority in all capital investment projects and programs identified in the DSP. A failure could result in a complete loss of supply from the MS requiring load transfer to another MS. Each transfer could be very challenging which may take several hours and may result in overloading conditions to other facilities.
Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness
A planned replacement is the preferred alternative for these assets because it allows OPUCN to proactively mitigate the failure risk posed by end-of-life and poor condition of MS switchgears within the distribution system and thereby, reduce the risk of outages to customers. The replacement will also provide better system operation efficiency and will minimize preventative maintenance work required.
Analysis of Project & Alternatives – Net Benefits Accruing to Customers
Customers will benefit from a more reliable electrical infrastructure. Net benefits accruing to the customers have been qualitatively described above but have not been quantitatively calculated because accurate information on the customer interruption costs is not readily available.
Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages

The switchgear replacement program will maintain or improve reliability by reducing the risk of prolonged outages which will also mitigate outage costs.
Project Alternatives (Design, Scheduling, Funding/Ownership)
The alternative to replacing the switchgear is to do nothing. This alternative is not feasible because allowing old and deteriorating equipment in the field stay in service can result in significant safety concerns, lengthy customer outages and increased in O&M costs.
Safety
These investments are directly linked to the public and worker safety, as they aim to eliminate the switchgear with high risks of catastrophic failure. Additionally, modern protection and controls, capable of responding automatically to mitigate unsafe conditions will provide better public safety.
Cyber-Security, Privacy (where applicable)
Switchgear units will be controlled remotely through a restricted and dedicated substation private fiber loop and SCADA. Switchgears will include new substation LAN design which segregates the substation LAN from other substation LANs as a security control for cybersecurity. Please refer to “Municipal Substation Network Upgrade” project for more details.
Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)
Switchgears and relays will conform to ESA, CSA, IEEE and other applicable standards. The cybersecurity components is based on OEB Cybersecurity Framework which was developed following the National Institute of Standards and Technology (NIST) Standards.
Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)
The protection relays will be modern relays that will be capable of integrating and interacting with future smart grid devices. This project also include new technology with battery condition monitoring (see Station Battery and Battery Charger Replacement under System Service), IEC61850 interoperable relays and new substation LAN design (refer to “Municipal Substation Network Upgrade” project).
Environmental Benefits (where applicable)
There are no significant environmental benefits as a result of these investments.
Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)
Not Applicable
Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)
Not Applicable
Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity

The protection relays will be modern relays that will be capable of integrating and interacting with future smart grid devices. This project also include new technology with battery condition monitoring (see Station Battery and Battery Charger Replacement under System Service), IEC61850 interoperable relays and new substation LAN design (refer to "Municipal Substation Network Upgrade" project).

C. Category-Specific Requirements – System Renewal (5.4.3.2.C)
Asset Performance-Related Operational Targets & Asset Lifecycle Optimization Policies and Practices
Assets planned for replacement in this program are deteriorated to the point that they must be replaced. Proceeding with these projects will improve the operational effectiveness of the system and maintain SAIDI and SAIFI performance.
Information on the Condition of the Assets Relative to their Typical Life-Cycle and Performance Record
At the time of the replacement, the existing switchgears will be more than 45 years old on average. Please refer to the ACA for additional information on the existing condition.
The Number of Customers in Each Class Potentially Affected by Failure of the Assets
Number of Residential Customers: 41007 Number of Commercial Customers: 3039 Number of Industrial Customers: 450 Others (Generation Connection): 275
Quantitative Customer Impacts
The main impact of this project on the customers is mitigating the risk of SAIDI and SAIFI worsening due to the anticipated failures of the equipment determined to be in poor or very poor condition. The quantitative customer impacts beyond the completion of the project are indeterminate.
Qualitative Customer Impacts
Failure of this equipment will negatively impact the electricity supply to many residential, commercial and industrial customers.
Value of Customer Impact in Terms of Characteristics of Customers Potentially Affected by Failure that have Bearing on the Criticality and/or Cost of Failure
The customers will receive value through reduced unplanned outages and enhanced reliability.
Timing and Priority of the Project
5 switchgears will be replaced over the forecast period. Although all are considered to be of high or very high priority, priorities among these may shift.
Consequences for System O&M Costs
The switchgear replacement program will help reduce system O&M costs through reductions in reactive maintenance spending.
Impact on Reliability Performance and/or Safety

The proposed switchgear replacement equipment is more reliable and safer due to arc resistant construction. The modern protection relays and new switchgear will offer major benefits for public and worker safety by reacting to the faults on the system.
Analysis of Project Benefits and Timing
This project offers a high benefit for risk mitigation and maintaining service quality with enhanced reliability.
Like for Like Renewal Analysis, Alternative Comparison (Like for Like vs. Not Like for Like, Timing, Rate of Replacements, etc.)
The switchgear and relay replacement program will be designed to improve operating and maintenance efficiencies. All of the equipment and designs will be specified to meet the current version of applicable standards and to fully meet the current and the future needs of the customers.

A. General Information (5.4.3.2.A)					
Project/Activity	Reactive Replacement Program				
Project Number	SR-10				
Investment Category	System Renewal				
	2021	2022	2023	2024	2025
Capital Cost	$1,111,800	$1,134,036	$1,156,717	$1,179,851	$1,203,448
Capital Contribution	N/A	N/A	N/A	N/A	N/A
Net Cost	$1,111,800	$1,134,036	$1,156,717	$1,179,851	$1,203,448
O&M Cost	2021	2022	2023	2024	2025
	-	-	-	-	-

Customer Attachments and Load

Customer Attachments and Load vary from year to year dependent on outage areas.

Start Date	2021-2025	In-Service Date	2021-2025
Expenditure Timing for the Planning Horizon	2021Q1	2021Q2	2021Q3	2021Q4
	$222,360	$333,540	$333,540	$222,360

Project Summary

Reactive renewal projects represent unplanned projects that consist of assets that are failed, are about to fail, or present a safety hazard to the public. These projects typically arise from trouble calls, storm damage, dig-in damage, accidents, fires as well as information provided from third parties (ESA, customers, communication companies, etc.)

Risk Identification & Mitigation

The primary risk to completion of this program is ensuring adequate capital availability to mitigate a variety of different restoration/repair scenarios. Asset management practices within OPUCN will provide better information to direct the preventative maintenance activities for this type of work over the long term. The risks and mitigation measures for this project are difficult to predict based on the nature of the project.

Comparative Information on Expenditures for Equivalent Projects/Activities

The proposed budget is based on an average historical expenditures. 2020 is a budget cost. As this budget is dependent on externally driven aspects such as weather and traffic accidents, the expenditures are considered on an annual basis and become difficult to predict.

	Historical Costs ($ '000)						Forecast Costs ($ '000)				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Capital	1,097	1,142	1,228	1,025	1,010	1,665	1,112	1,134	1,157	1,180	1,203

REG Investment Details including Capital and OM&A costs

As this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.

Leave to Construct approval under Section 92 of the OEB Act

This project is below 50 kV and therefore Leave to Construct is not required, as per OEB.Reg. 161/99.

Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material

Replacements will be constructed using the latest standards and industry standards and practices. The following is a list of reactive renewal work:

- Overhead Transformers - Unplanned Replacement
- Underground Transformers - Unplanned Replacement
- Distribution (OH/UG) Component Changeouts
- Substation - Unplanned Replacement
- Overhead Unplanned Replacement
- U/G Secondary Cable Unplanned Replacement
- U/G Primary Cable/ Duct Structure Unplanned Replacement
- Removal of OH poles & Restoration of sidewalk
- Delta Wye conversion

Please also refer to Section 5.5 of the ACA in Appendix B regarding recommended annual replacement for distribution transformers.

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)
Efficiency, Customer Value & Reliability – Investment Main Driver
This program falls under System Renewal Investment driver and addresses safety to the public and workers when assets fail and need to be repaired/refurbished and also is needed to maintain system reliability and provide customer service.
Efficiency, Customer Value & Reliability – Investment Secondary Driver
There are no secondary drivers.
Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets
The investment objectives are to continue a safe operation of electrical system and maintain OPUCN's reliability by limiting the duration of outages
Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment
Historical expenditures have been analyzed in conjunction with age and condition of existing infrastructure. Emergency service restoration is an OEB-mandated activity.
Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges
Failed assets, if not replaced/repaired immediately, pose system reliability hazards. Replacement of failed assets is needed to maintain system reliability.
Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment
This project meets some of OPUCN’s AM objectives identified in Section 5.3.1, however, this project/program receives a high priority as it deals with addressing system outages and safety concerns. Tasks are typically considered emergency in nature and, thus, are of a high priority.

Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness
Investment to be able to quickly replace assets in an emergency nature is expected to provide increased system reliability. . OPUCN does attempt to make it as cost effective as possible by performing minimal repairs during after hours and tries when possible to complete full replacement during regular hours at regular rates. Additionally, distribution transformers are generally set at a run to failure scheme, which is predicted to be the most cost effective method but results in unplanned failure. Proposed budget is based on an average historical expenditures, however, the proposed expenditure for reactive replacement of distribution transformers is still in line with the proposed replacement in the ACA.
Analysis of Project & Alternatives – Net Benefits Accruing to Customers
Customers benefit from this project is having outage times reduced and safety concerns managed in a timely fashion.
Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages
This project does not have a direct impact on frequency and duration of outages, however, the reactive work will reduce probability of future outages at the same location.
Project Alternatives (Design, Scheduling, Funding/Ownership)
There are no other practical and cost effective alternatives to this project. This project is a reactive based project that receives a very high priority when tasks arise.
Safety
Public and worker safety is a primary purpose in this project. Attending the site, making it safe and replacing the failed infrastructure reduces hazards for both the public and workers. Final installation are completed as per CSA, USF and/or OPUCN specific standards which adhere to a high level of safety standards.
Cyber-Security, Privacy (where applicable)
Not Applicable
Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)
Emergency replacement of assets will be constructed to USF and/or OPUCN specific standards which are in line with industry standards allowing third parties reasonable access.
Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)
Emergency replacements are typically constructed like-for-like, but when practical, they are constructed to USF and/or OPUCN standards.
Environmental Benefits (where applicable)
There are no significant environmental benefits as a result of these investments.
Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)
Not Applicable

Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)
Not Applicable
Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity
Not Applicable

C. Category-Specific Requirements – System Renewal (5.4.3.2.C)
Asset Performance-Related Operational Targets & Asset Lifecycle Optimization Policies and Practices
This project is non-discretionary and has been allocated a very high priority due to safety and system reliability concerns once a failure has arisen.
Information on the Condition of the Assets Relative to their Typical Life-Cycle and Performance Record
Information is not proactively available regarding assets that will be replaced due to the nature of the project. Typically, assets that fail on their own are older with some exceptions as assets that fail due to external impacts may be any age.
The Number of Customers in Each Class Potentially Affected by Failure of the Assets
The number of customers affected by each failure is dependent on the location of the failure and the assets affected. If a single 50kVA distribution transformer fails, the customers affected should be limited to approximately 15. If the asset failed is a distribution pole supporting the sub transmission line (44 kV), the customers affected could be up to 50% of the City. Number of customers immediately affected is not within OPUCN's control. OPUCN attempts to limit the quantity of customers that experience extended outages by switching, repairing and/or replacing assets or through implementation of intelligent devices.
Quantitative Customer Impacts
It is not possible to determine quantitative customer impacts for this project ahead of time.
Qualitative Customer Impacts
Customers located in the area of the failure up to the complete distribution and/or sub transmission circuit will be affected by potential power outages caused by failed assets. OPUCN will strive to minimize duration of all outages by responding in a timely manner and have replacement units available to perform repairs safely and effectively.
Value of Customer Impact in Terms of Characteristics of Customers Potentially Affected by Failure that have Bearing on the Criticality and/or Cost of Failure
Impacts to customers vary on a case to case basis. Some examples are extended outages on residential homes that uses electrical heat, commercial properties with extended outages during regular business hours and critical customers who rely on electricity for emergency services. Due to the unknowns and the possibility for loss of electricity being detrimental, OPUCN responds to each case with the goal of minimizing the duration of outages for all customers.
Timing and Priority of the Project

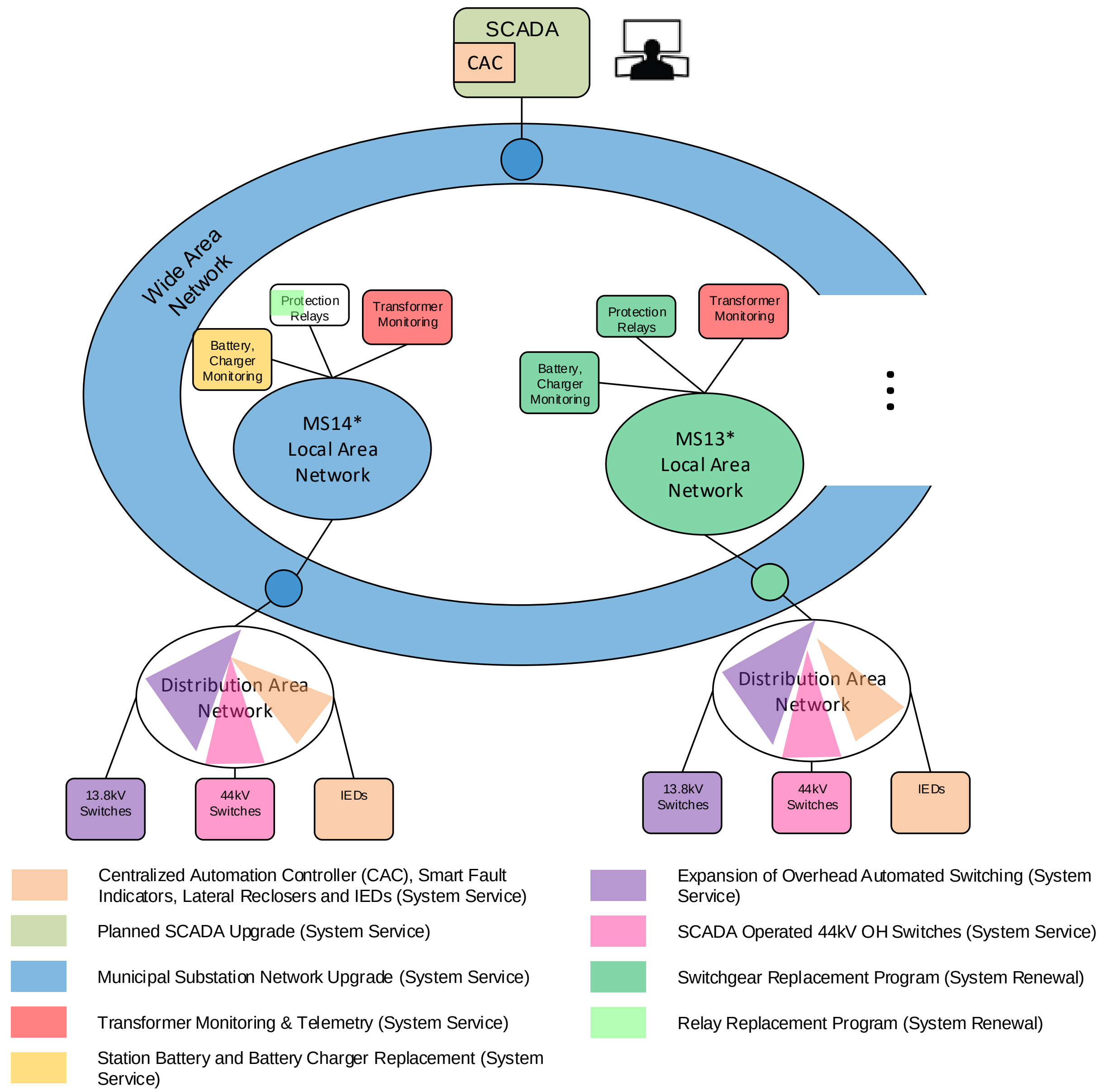
This project is critical as the failure is related to system outage and could be a safety concern.
Consequences for System O&M Costs
This project has a neutral effect on O&M costs.
Impact on Reliability Performance and/or Safety
Reliability performance statistics are immediately impacted by this project as it is a project initiated by failures. Safety is also impacted by this project as failures may create safety concerns until our staff arrive to fix the problem.
Analysis of Project Benefits and Timing
Project timing is generally considered emergency as the majority of the tasks are based upon system outages or safety concerns. Transformers is one of the assets where OPUCN has chosen to generally apply a "run to failure" approach. This maximizes the life of the transformer, obtains additional value from the transformer while paying only a slight premium for reactive replacement.
Like for Like Renewal Analysis, Alternative Comparison (Like for Like vs. Not Like for Like, Timing, Rate of Replacements, etc.)
Like for like replacements are typical for majority of tasks that arise from outages or safety concerns due to typical timing of tasks. To have the asset designed on the spot after the failure has occurred is not a practical alternative. Proactively designing all potential failure assets is another alternative that is not practical.

A. General Information (5.4.3.2.A)					
Project/Activity	Municipal Substation Transformer Monitoring and Telemetry				
Project Number	SS-01				
Investment Category	System Service				
	2021	2022	2023	2024	2025
Capital Cost	$150,000	$150,000	$150,000	$150,000	$150,000
Capital Contribution	N/A	N/A	N/A	N/A	N/A
Net Cost	$150,000	$150,000	$150,000	$150,000	$150,000
O&M Cost	2021	2022	2023	2024	2025
	-	-	-	-	-
Customer Attachments and Load					
Customer Attachments: Approximately 45,000 customers Load: Approximately 160MW					
Start Date	2021-2025	In-Service Date	2021-2025		
Expenditure Timing for the Planning Horizon	2021Q1	2021Q2	2021Q3	2021Q4	
	$75,000	$0	$75,000	$0	
Project Summary					

Figure 32- Photo of a Municipal Substation Transformer

The ACA provided in Appendix B has identified the need for more data points to assess the condition of the MS transformer which can be achieved by continuously monitoring these assets. This will ensure an effective and reliable operation of the electric power system. Oshawa PUC Networks Inc. (OPUCN) is planning to retrofit 10 transformers and install monitoring system to increase performance, reduce failure risks and optimize maintenance costs.

The transformer monitoring system will monitor dissolved gasses of the MS transformers on a real-time basis and will trend the amount of rising dissolved gasses (e.g. CO, C_2H_2, C_2H_4) and moisture to determine the health of the transformer. This will help reduce the risk of transformers failing by trending the health of the transformer and alerting field staff to proactively maintain transformers. There will be an overall improvement in operation efficiency as there is reduced maintenance cost of manually sampling transformer oil and sending samples to laboratories for analysis.



* - See description of Switchgear Replacement Program for specific Municipal Substations covered under each narrative

Figure 33- Scope Comparison of SCADA Related Projects

Please see above Figure 33- Scope Comparison of SCADA Related Projects which illustrates how the scope of this project is related with other SCADA related projects.

Risk Identification & Mitigation

Scheduling Risk - The installation of the transformer monitoring system on the transformers is dependent on MS operation and work planned during off-peak load periods. To mitigate this risk, a project timeline will be created in advance along with resource alignments.

Comparative Information on Expenditures for Equivalent Projects/Activities

There are no comparative information for this investment. OPUCN has not completed any projects of this type in the past. The program commenced in 2020 with expected completion by 2025.

Historical Costs ($ '000)						Forecast Costs ($ '000)				
2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
-	-	-	-	-	150	150	150	150	150	150

REG Investment Details including Capital and OM&A costs

As this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.

Leave to Construct approval under Section 92 of the OEB Act

This project is below 50 kV and therefore Leave to Construct is not required, as per OEB.Reg. 161/99.

Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material

Refer to Section 4.9 of the ACA in Appendix B regarding recommendation for data points.

The following figure provides an example of an installed transformer monitoring device.

Figure 34- Example of Transformer Monitoring Device Installed

Figure 35 - Example 2 of Transformer Monitoring Device Installed

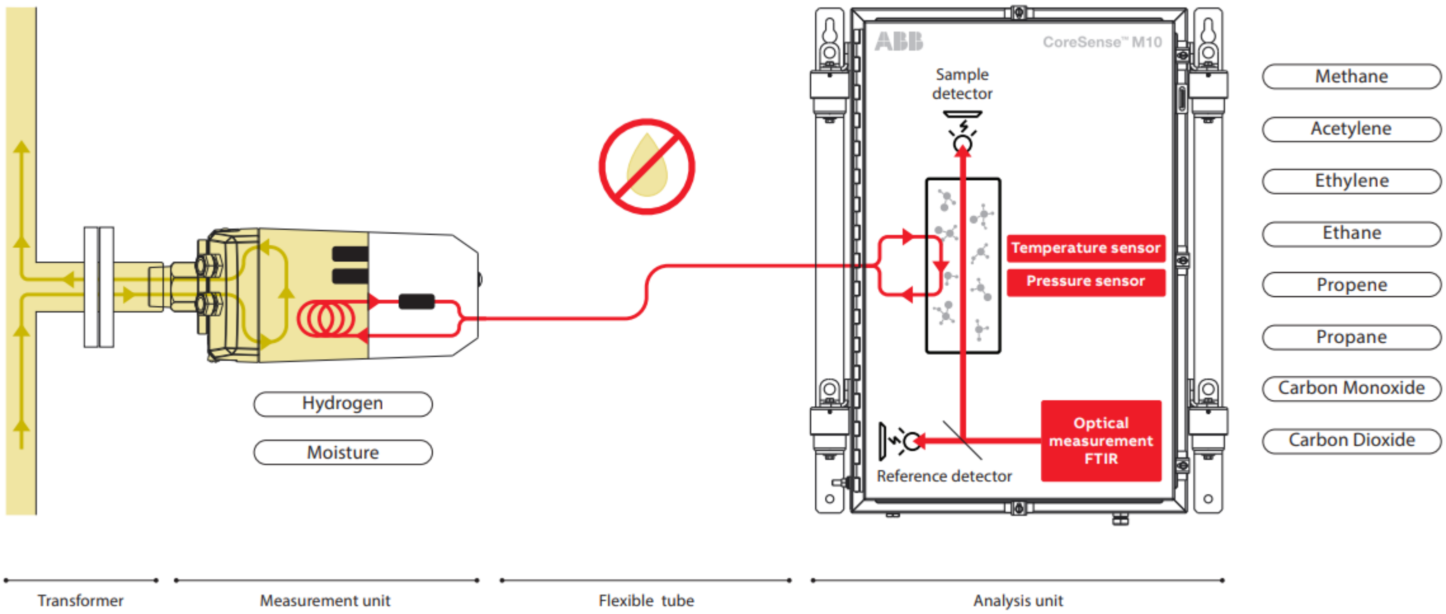


Figure 36- An Example of a Transformer Monitoring Device with Multi-gas Analyzer

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)
Efficiency, Customer Value & Reliability – Investment Main Driver
The main driver for this project is Operational Efficiency and Reliability. The transformer monitoring system will reduce the risk of prolonged power interruptions due to a transformer failure. The transformer monitor will provide accurate real-time assessment of the condition of the transformer during operation which will drive efficient and proactive operation and maintenance of transformers.

Figure 37 - Oil Sampling from Transformers

Operating and maintaining the transformer will be more efficient as dissolved gas analysis will not require sending staff to take samples and send to the lab for analysis. Staff will have health trending of the transformer and will be able to respond more efficiently to maintaining the transformers to reduce risk of a transformer failure and improving the overall life-cycle cost of operating the transformer.

This project aligns with the guidelines of the Grid Modernization Plan. The installation of transformer monitoring will facilitate a use of technology and communication to manage asset risks for a smarter-grid.

Efficiency, Customer Value & Reliability – Investment Secondary Driver

There are no secondary drivers.

Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets

The investment objectives are to mitigate the risk of equipment failure and monitor the real-time condition of MS transformers thereby improving the Operational Effectiveness as outlined in OEB's annual scorecard for OPUCN. Also, the efficient use of technology to provide real-time assessment of the condition of the transformers will improve the overall cost to operate and maintain the asset.

Another investment objective is to mitigate the risk of service reliability falling below the performance targets as outlined in OEB's annual scorecard for OPUCN. Specific operational efficiency targets include SAIDI and SAIFI.

Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment

The source of the information used to justify the investment is the ACA which identified the need of collecting more asset condition data and information. As a part of the ACA Process (see section 2.2.2 2.Data Analysis), the report recommends "adopting advanced technology to record inspection/testing data". Transformer monitoring will provide this additional information for ACA data analysis.

Almost all of OPUCN's customers (99%) are fed through MS transformer. The catastrophic failure of each transformer affects roughly 3700 customers approximately 140 minutes contributing (0.062 SAIFI and 0.145 SAIDI). Testing Analysis (Dissolved Gas Analysis) is the highest weighted condition criteria affecting MS transformer's overall asset health (see section 3.2.1.1 in

ACA). By providing real-time information of the presence of dissolved gas, OPUCN will make the most of advanced technology to manage and reduce the risk of failure for these major assets. Approximately 88% of customers surveyed (see OPUCN's 2019 Distribution System Plan Customer Engagement Report, Figure 2 – Customer Priority Table) want OPUCN to invest in smart grid technologies, making grid technology one of the top five priorities to customers. Information used to support this investment include the Grid Modernization Plan. Transformer Monitoring System will build a stronger Asset Management System (Grid Modernization Plan, Section 7) that helps optimize the overall life-cycle cost of the asset.
Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges
Investments in the MS will ensure that system reliability is improved. This program will provide real-time information that can be used for a more comprehensive real-time ACA. The data collected in the field through the transformer monitoring system will also form a component for an Advanced Distribution Management System (ADMS) implementation. This real-time transformer health data will support control operator real-time decisions to reduce risks of catastrophic transformer failures. Long term trending of the dissolved gasses would help overall understanding of how the operations of the transformer affects the longevity of the transformer. For instance, real-time transformer condition monitoring will help staff to correlate how tap changer operations will affect the amount of dissolved gasses in the transformer and help determine more effective tap changer operations that will not only optimize the voltage at the customer but also increase the lifespan of transformers.
Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment
This project meets OPUCN's AM objectives identified in Section 5.3.1 and has a higher priority. OPUCN plans to mitigate risk of MS transformer failure which is the main supply point for majority of our customers. Failure of a MS transformer poses significant environmental and safety risks and affects reliability which are the reasons for prioritizing this project. A failure could result in a complete loss of supply from the station requiring load transfer to another station. Such a transfer could be very challenging and could take several hours and may also result in overloading other facilities.
Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness
An alternative to this project would be to "do-nothing". This approach would not be effective as it would not take advantage of advanced technology to improve operational efficiency and manage major asset risks in real-time. Staff would continue to sample transformer oil and send to a lab on a regular basis. For a transformer showing increasing presence of dissolved gasses, staff would have to increase the sampling rate of transformer oil and make decisions on the operation of the transformer after results are provided from the laboratory. The do-nothing approach is not an efficient use of field staff resources. Also, the do-nothing proactive approach in responding to the rising risk of a transformer failure.
Analysis of Project & Alternatives – Net Benefits Accruing to Customers
Customers will benefit by having a more reliable (reduced SAIFI and SAIDI from transformer catastrophic failures) system as a result of better managed risk of transformer failures. Customers will also benefit from operational efficiencies (reduced manual sampling of transformer oil) which will result in overall lower cost.
Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages
This project will improve the reliability performance by reducing the risk of prolonged outages due to a major equipment failure.
Project Alternatives (Design, Scheduling, Funding/Ownership)

Alternatives to this project are limited. Transformer maintenance is performed, however, maintenance data is not being collected in real-time. For regular supervision with laboratory gas analysis, manual samples are typically taken every 6 months or every year with a delay to receive laboratory results. In some situations where the transformer is showing signs of concern, samples are completed quarterly. With the transformer monitoring system, gas analysis will be performed much more frequently with no additional O&M cost. Frequency of test would provide a reliable early detection system. This program will also avoid the need for excessive site visits and manual samplings.
Safety
These investments are directly linked to worker safety, as they aim to mitigate transformers with high risk of catastrophic failure. The transformer monitor will provide data on the rise of dissolved gasses developed in the insulation of the transformer. By monitoring and trending the presence of these chemicals, OPUCN will be able to proactively and efficiently prevent a catastrophic failure due to deteriorated poor transformer insulation.
Cyber-Security, Privacy (where applicable)
The transformer monitoring system will be connected to OPUCN's fibre network connecting most of the OPUCN owned facilities. The fibre network is protected by OPUCN's corporate IT managed services which utilizes cybersecurity standards and regulations. OPUCN ensures that all of its communication systems are configured in a secure manner and in compliance with OPUCN's security and privacy policies.
Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)
Transformer monitoring system will be procured using specification that includes but not limited to secure communication using DNP3 protocols which will ensure interoperability with other OT devices including the SCADA system. Also, appropriate standards where applicable from ESA, CSA and IEEE standards will be utilized.
Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)
The transformer monitoring system shall be installed in accordance with the latest standards and technologies to meet future operational requirements. The monitoring system will be one of the systems connected to a future ADMS platform.
Environmental Benefits (where applicable)
Because transformer contains oil, transformer failures may cause rupture of the transformer tank, resulting in oil being spilled onto the ground. Transformer monitoring is the most effective tool to mitigate these environmental risks caused by a transformer failure and oil spill.
Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)
Not Applicable
Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)
Not Applicable
Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity

The transformer monitoring system shall be installed in accordance with the latest standards and technologies to meet future operational requirements. The monitoring system will be one of the systems connected to a future ADMS platform.

C. Category-Specific Requirements – System Service (5.4.3.2.C)
Assessment of Customer Benefits Based on Project Objectives and Cost Impact
According to OPUCN's 2019 Distribution System Plan Customer Engagement Report, this project will cost a portion of a monthly average cost of 15.3 cents (overall total cost of system service projects), which the majority (60%) of customers surveyed supported (See Figure 14 – System Service Investment Chart). In addition, 88% of customers surveyed (see OPUCN's 2019 Distribution System Plan Customer Engagement Report, Figure 2 – Customer Priority Table) want OPUCN to invest in smart grid technologies, making grid technology one of the top five priorities to customers. Customers will benefit by having a more reliable (reduced SAIFI and SAIDI from transformer catastrophic failures) system as a result of better managed risk of transformer failures. Almost all of OPUCN's customers (99%) are fed through MS transformer. The catastrophic failure of each transformer affects roughly 3700 customers approximately 140 minutes contributing (0.062 SAIFI and 0.145 SAIDI). Testing Analysis (Dissolved Gas Analysis) is the highest weighted condition criteria affecting MS transformer's overall asset health (see section 3.2.1.1 of the ACA). By providing real-time information of the presence of dissolved gas, OPUCN will make the most of advanced technology to manage and reduce the risk of failure for these major assets. Due to the impact on reliability to customers of a MS transformer failure, OPUCN's Grid Modernization Plan has identified this project as an advantageous smart-grid project using advanced gas sampling technology. Please see Grid Modernization Plan Section 9 Project Cost and Impact Scores and this specific project in Section 10 Project Descriptions and Benefits. Customers will also benefit from operational efficiencies (reduced manual sampling of transformer oil) which will result in overall lower cost. The transformer monitoring system is a tool to increase operating and maintenance efficiencies by continuously monitoring the MS transformer including dissolved gases. Please see "Project Alternatives (Design, Scheduling, Funding/Ownership)" above for details) for likely O&M savings.
Information on Regional Electricity Infrastructure Requirements Identified in the Regional Planning Process
Not Applicable
Description of how Advanced Technology has been Incorporated (where applicable)
The transformer monitoring system shall be installed in accordance with the latest industry standards and technologies to meet future operational requirements. The monitoring system will also be integrated to a future ADMS platform.
Identification of any Reliability, Efficiency, Safety and Coordination Benefits or Affects
Investments in the MSs will ensure that system reliability is improved. The transformer monitoring system will maintain the reliability performance, reduce failure risks and optimize maintenance costs. This program will also offer major benefits for public and worker safety by continuously monitoring MS transformers.
Identification and Explanation of the Factors Affecting Implementation Timing/ Priority
Transformer monitoring system will be installed at 10 MS transformers, which will be completed over the period of 2021-2025. Although all are considered to be of high priority, priorities among these may shift. Approvals and equipment delivery lead times

can be factors that could cause delays in the project schedule. OPUCN proposes to initiate procurement of transformer monitors well in advance and work in coordination with supplier to avoid risk of delay.
Analysis of Project Benefits and Costs Comparing to a) Doing Nothing and b) Technically Feasible Alternatives
Currently, for regular supervision with laboratory gas analysis, manual samples are typically taken every 6 months or every year and "doing nothing," will not allow OPUCN to collect data in real-time to comprehensively assess the condition of the MS transformer. This program will also avoid the need for excessive site visits and manual samplings. Installing an online transformer monitoring system, would reduce the risk of a transformer outage (as real-time data is available) and would remove delays waiting for results. Also, there will be operational efficiencies and O&M savings (see "Project Alternatives (Design, Scheduling, Funding/Ownership)" above for details).

A. General Information (5.4.3.2.A)					
Project/Activity	Expansion of Overhead Automated Switching				
Project Number	SS-02				
Investment Category	System Service				
	2021	2022	2023	2024	2025
Capital Cost	$200,000	$200,000	$200,000	$200,000	$200,000
Capital Contribution	N/A	N/A	N/A	N/A	N/A
Net Cost	$200,000	$200,000	$200,000	$200,000	$200,000
O&M Cost	2021	2022	2023	2024	2025
	-	-	-	-	-
Customer Attachments and Load					
Number of Customers: Approximately 13,000 Load Impacted: Approximately 55 MW					

Start Date	2021-2025	In-Service Date	2021-2025
Expenditure Timing for the Planning Horizon	2021Q1	2021Q2	2021Q3	2021Q4
	-	-	-	$200,000

Project Summary

This project is a part of OPUCN's efforts towards improving service reliability and modernizing the existing grid into a smart grid system. During the period of 2021-2025, OPUCN will continue to replace existing 13.8kV manual switches with remotely operated & automated switches. These new smart switches will allow remote operation through Control Room operator and will work in automation - under outage conditions locate faults, automatically isolate faulted sections of powerlines and restore power to remaining sections. Approximately 15 smart switches will be installed at strategic locations of the system.

This project will work in tandem with Deployment of Automation Controller & Network Connected Devices project to increase the number of devices that work together in automation thereby further increasing operational efficiencies & improving reliability.

This project will include extending the communication network to these smart switches. Network planning will include this project, Deployment of Automation Controllers and Network Connected Devices project, and SCADA Operated 44kV OH Switches project.

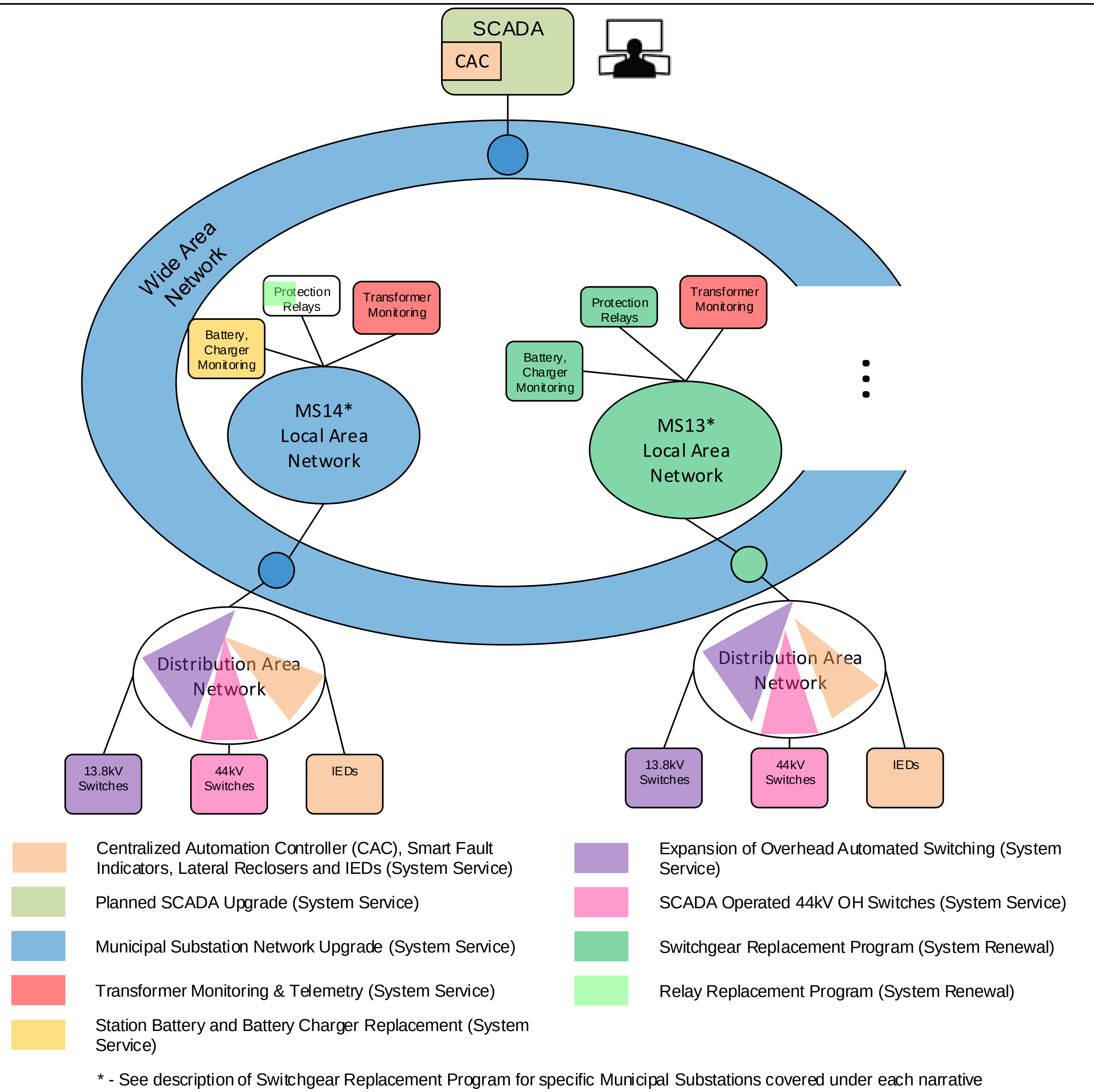


Figure 38- Scope Comparison of SCADA Related Projects

Please see above Figure 38- Scope Comparison of SCADA Related Projects which illustrates how the scope of this project is related with other SCADA related projects.

Risk Identification & Mitigation

Scheduling Risk – Timely delivery of equipment is important to complete the project in time. OPUCN proposes to initiate procurement of switches well in advance and work in coordination with supplier to avoid risk of delay.

Resource Risk – Resource to complete the required design and installation is important for successful completion of the project. OPUCN has resources and experience available in-house and also through approved, experienced contractors, to complete the design and installation.

Budget Risk – During initial assessments, some additional work may be required to accommodate the installation of the new automated switches and to comply with current installation standards including replacement of old hydro poles and expansion of wireless/fibre communication network. This may pose a risk of incurring additional cost and scheduling risk due to additional scope. To mitigate this risk, OPUCN will plan its communication network expansion together with the SCADA Operated 44kV OH Switches and Deployment of Automation Controllers and Network Connected Devices project. OPUCN will use the pole replacement program to address any poor condition poles.

Please refer to the diagram above which illustrates how the scope of this project is related with other SCADA related projects.

Comparative Information on Expenditures for Equivalent Projects/Activities

OPUCN has installed the last smart switch in 2018 costing approximately $55,000 per unit including installation, communication (wireless) and additional materials and equipment.

Replacing existing manual 13.8kV switches with remote & automated switches allow for faster redirection of 13.8kV power flow through remote operation of switches from a Control Operator. Operators will be given real-time information about fault conditions and loading. Remote overhead switches allow faster restoration to customers.

Past installations involved independent groups of switches which performed relatively simple switching operations. To deploy the use of automated switches throughout the system in 2021-2025 would require interdependent groups of switches from several feeders and MSs that need to coordinate over a larger MS/distribution network. Additional costs are expected to install communication modules to accomplish this.

Historical Costs ($ ‘000)						Forecast Costs ($ ‘000)				
2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
-	-	646	261	-	50	200	200	200	200	200

REG Investment Details including Capital and OM&A costs

The smart switch will provide voltage and power flow information remotely to the control room and will automatically isolate faults. Therefore, the project will help OPUCN to monitor power quality and use power flow information in planning, accommodating and integrating Distributed Energy Resources (DERs).

OPUCN has a number DERs/REGs connected at the 13.8kV distribution system. These 13.8kV automated switches will allow DERs to connect to the system more easily through remote switching of the 13.8kV power lines as there will be easier transitioning of 13.8kV feeders onto other sources when planned or unplanned interruptions occur. The benefits to each DER/REG will be assessed on a case by case basis.

This project supports future REG connections but does not contain any capital investments or OM&A costs that are directly attributable to REGs.

Leave to Construct approval under Section 92 of the OEB Act

This project is below 50 kV and therefore Leave to Construct is not required, as per OEB.Reg. 161/99.
Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material

Figure 39-13.8kV Automation Switches

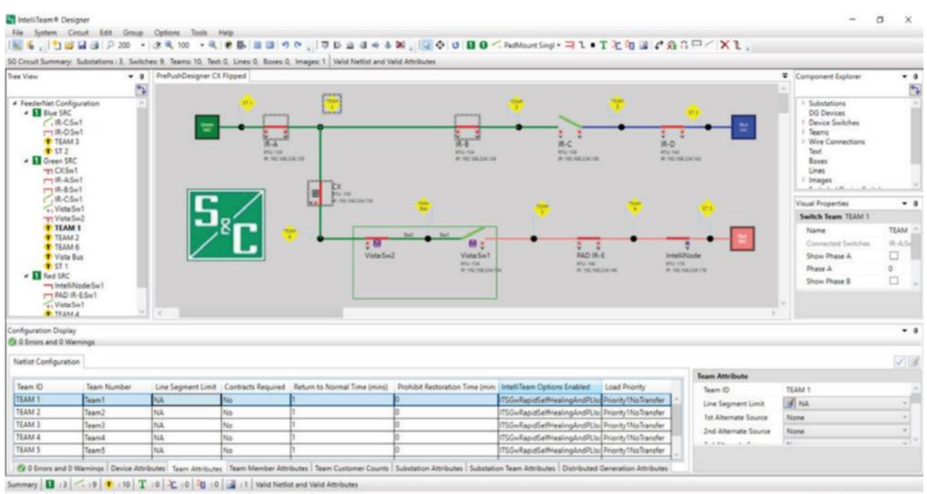


Figure 40-Software interface used to configure switches to work in teams

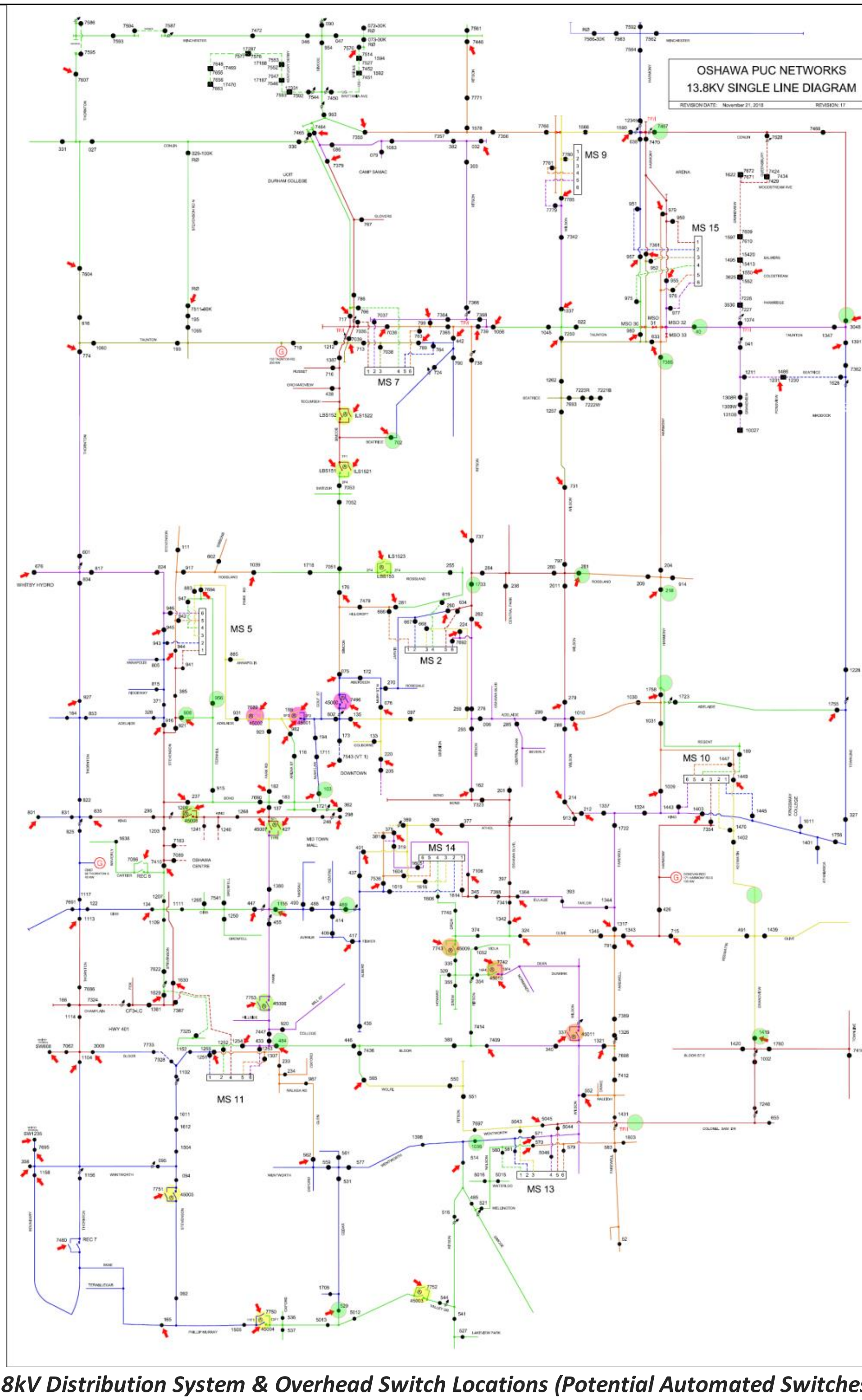


Figure 41- OPUCN 13.8kV Distribution System & Overhead Switch Locations (Potential Automated Switches Highlighted in Green)

Figure 42 - An Automated Switch Mounted On A Pole That Was Struck By A Vehicle

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)
Efficiency, Customer Value & Reliability – Investment Main Driver
Service Reliability & Operational Efficiency is the main driver for this project. The automated switches provide faster & more accurate fault locations which reduces durations and length of feeder patrols. Also automated outage isolation & restoration through the Centralized Automation Controller and IEDs will reduce the number of customers affected during each outage. This project will help OPUCN reduce the outage duration through automated and remote switching to sectionalize fault. System Operators will receive fault detection alerts indicating when fault conditions have occurred downstream of overhead switches which further reduces outage durations. The automated switches will provide ability to perform automatic and remote switching without dispatching line crew, improving operational efficiency and reduce operating cost. Automated switches will also provide real-time power flow information to system operators who will be able to efficiently reconfigure the electrical distribution system. This project aligns with the guidelines of the Grid Modernization Plan. The installation of automated switches will create a smarter-grid.
Efficiency, Customer Value & Reliability – Investment Secondary Driver
Not Applicable.
Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets
The investment objective is to improve service reliability and operational effectiveness by mitigating the number of customers affected during an outage. New switches will replace existing manual switches and will improve operational effectiveness as switches can be operated remotely without the need of sending field staff. New switches will also be able perform fault locating, isolation and system restoration (FLISR) reducing outage duration and customers interrupted.

The investment objective is to improve Operational Effectiveness as outlined in OEB's annual scorecard for OPUCN. Some specific scorecards measures affected are namely "Average Number of Hours that Power to a Customer is Interrupted", "Average Number of Times that Power to a Customer is Interrupted", "Total Cost per Customer" and "Total Cost per Km of Line".

Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment

Service Reliability & Operational Efficiency will be improved by the installation of automated switches. The automated switches provide faster & more accurate fault locations which reduces durations and length of feeder patrols. Also automated outage isolation & restoration through the Centralized Automation Controller and IEDs will reduce the number of customers affected during each outage.

This project will help OPUCN reduce the outage duration through automated and remote switching to sectionalize fault. System Operators will receive fault detection alerts indicating when fault conditions have occurred downstream of overhead switches which further reduces outage durations. The automated switches will provide ability to perform automatic and remote switching without dispatching line crew, improving operational efficiency and reduce operating cost. Automated switches will also provide real-time power flow information to system operators who will be able to efficiently reconfigure the electrical distribution system.

According to feedback from OPUCN's customers, approximately 92% of customers want OPUCN to "look for ways to use technology to safeguard the electricity network or get more out of the equipment" (see OPUCN's 2019 Distribution System Plan Customer Engagement Report, Figure 2 – Customer Priority Table) and approximately 88% of customers surveyed want OPUCN to invest in smart grid technologies including system automation, making grid technology one of the top five priorities to customers. This project aims to focus on these priorities.

This project is aligned with the guidelines in OPUCN's Grid Modernization Plan which identifies key projects that will help OPUCN use technology to make the distribution system a smarter grid and improve the way the system operates.

OPUCN's Grid Modernization Plan has identified that this smart grid project will provide advantageous benefits to the Outage Management System and enable Fault Locating, Isolation, and System Restoration (FLISR). Please see this specific project in Grid Modernization Plan Section 10 Project Descriptions and Benefits. The Grid Modernization Plan has identified a high score on this project (see Section 9 Project Cost and Impact Scores).

Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges

The project will improve service reliability & operational efficiency by allowing remote switching from the control room rather than sending field staff to operate switches. Service reliability will be further improved through automated switching to restore power in the situation of a sustained power outage.

Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment

The project has been determined as a high priority to be included in the DSP due to the need for improving system reliability and operating efficiencies as well as meetings aspects of the AM objectives identified in Section 5.3.1.

Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness

The project will address the need for improving system reliability and operating efficiencies. Information used to support this investment include the Grid Modernization Plan. Automated Switches will create a better OMS that is able to respond quickly to outages and also support FLISR. Since the project is tied to improvements in the OMS (see this specific project in Section 10 Project Descriptions and Benefits), DA and FLISR, the project has been given a high score.

Doing nothing or replacing existing switches with new manual switches would not take advantage of operational efficiencies available through use of new technologies to fault locate, isolate and perform system restoration.

Analysis of Project & Alternatives – Net Benefits Accruing to Customers
The net benefits accruing to Customers will be service reliability and operational efficiencies as mentioned in "Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness" above.
Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages
The installation of smart switches will be able to provide fast restoration of 13.8kV customers. The installation of automated switches will reduce SAIFI and SAIDI values as the switches will be able to perform fault locations to send field staff closer to the outage location thereby reducing outage durations. Also the switches will be able to automatically isolate and perform system restoration of remaining power lines further limiting the amount of customers affected by an outage. By doing nothing there will be no incurring benefit of using new technologies to reduce outage duration and number of customers affected by an outage. Operational efficiency will not be improved as switches will require sending out field staff to perform manual operation.
Project Alternatives (Design, Scheduling, Funding/Ownership)
There are no other practical and cost-effective design or funding alternatives, or co-ownership options available.
Safety
New design of switch, remote switching functionality and the real- time status information through SCADA will improve safety for the line crew. The installation of automatic and remote switches eliminates exposing staff to arc-flashes that may occur due to operating defective overhead switches. The installation will be built in compliance with O.Reg. 22/04 and new utility installation standards to ensure safety for the general public.
Cyber-Security, Privacy (where applicable)
The communication required for these devices will use OPUCN's dedicated fiber and radio communication which would restrict access for cyber-security purposes. This will ensure (PR.DS-2 OEB Cybersecurity Framework) Data-in-transit is protected as a Security Control. This ensures that only authorized staff have access to critical information that operates power delivering equipment. Equipment installed will comply with NIST cyber security standards and OEB's cyber security framework.
Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)
The controller for the remote switches will be specified to offer secure communication using DNP3 protocols, to meet the interoperability standards. This will ensure devices will be able to communicate with Control Room SCADA system and other IEDs.
Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)
The controller for the remote switches will provide additional functionality in communication with the existing automatic restoration software and with multiple other SCADA operated switches to achieve advance level of coordinated Fault Detection, Isolation and Restoration capability.
Environmental Benefits (where applicable)

Installation of automated switches will enable remote operation of switches by either control room staff or pre-programmed routine, without requiring to dispatch crew(s) /truck roll in case of outages. The avoided truck rolls therefore will help reduce GHG emissions.
Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)
Not Applicable
Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)
Not Applicable
Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity
The controller for the remote switches will provide additional functionality in communication with the existing automatic restoration software and with multiple other SCADA operated switches to achieve advance level of coordinated Fault Detection, Isolation and Restoration capability.

C. Category-Specific Requirements – System Service (5.4.3.2.C)
Assessment of Customer Benefits Based on Project Objectives and Cost Impact
According to OPUCN's 2019 Distribution System Plan Customer Engagement Report, this project will cost a portion of a monthly average cost of 15.3 cents (overall total cost of system service projects), which the majority (60%) of customers surveyed supported (see Figure 14 – System Service Investment Chart). In addition, 88% of customers surveyed (see OPUCN's 2019 Distribution System Plan Customer Engagement Report, Figure 2 – Customer Priority Table) want OPUCN to invest in smart grid technologies, making grid technology one of the top five priorities to customers. Service Reliability & Operational Efficiency will be improved by the installation of automated switches which will produce better service reliability and improved costs to customers. The automated switches provide faster & more accurate fault locations which reduces durations and length of feeder patrols. Also automated switches in tandem with centralized automated outage isolation & restoration (see Centralized Automation Controller, Smart Fault Indicators, Lateral Reclosers and IEDs Project Narrative) will produce larger coverage areas to further reduce the number of customers affected during each outage. System Operators will receive fault detection alerts indicating when fault conditions have occurred downstream of overhead switches which further reduces outage durations. The automated switches will provide ability to perform automatic and remote switching without dispatching line crew, improving operational efficiency and reduce operating cost. Automated switches will also provide real-time power flow information to system operators who will be able to efficiently reconfigure the electrical distribution system. This will further enable connection of Distributed Energy Resources (DERs) on the system as operators will be able to reconfigure the system to allow DERs resources onto they system.
Information on Regional Electricity Infrastructure Requirements Identified in the Regional Planning Process
Not Applicable
Description of how Advanced Technology has been Incorporated (where applicable)
The controller for the smart switches will provide additional functionality in communication with the existing automatic restoration software and with multiple other smart switches to achieve advance level of coordinated Fault Detection, Isolation and Restoration functionality.

Identification of any Reliability, Efficiency, Safety and Coordination Benefits or Affects
The investment in automated switch will improve system reliability and visibility. It will also reduce the operational cost as it will reduce the need to dispatch and engage line crew to perform manual switching operations. There will be an added level of safety due to remote operation as field staff will not be required to operate switches manually.
Identification and Explanation of the Factors Affecting Implementation Timing/ Priority
The project has been given a high priority (see Grid Modernization Plan Section 9 – Project Cost and Impact Scores and this specific project in Section 10 Project Descriptions and Benefits) because it offers a high benefit for improving operational efficiency, reliability and visibility through improvements of the Outage Management System. OPUCN will provide appropriate weightage on the vintage of the existing switch in selecting location to leverage the opportunity for asset renewal. OPUCN will be taking advantage of the timing to replace existing 13.8kV switches that are past their service to renew the system with smart switches that will improve service reliability and operation efficiency.
Analysis of Project Benefits and Costs Comparing to a) Doing Nothing and b) Technically Feasible Alternatives
By doing nothing, OPUCN will continue operating the existing switches manually and continue without improving operational efficiencies and grid visibility. This is not a proactive approach for grid modernization.

A. General Information (5.4.3.2.A)					
Project/Activity	SCADA Operated 44kV OH Switches				
Project Number	SS-03				
Investment Category	System Service				
	2021	2022	2023	2024	2025
Capital Cost	$100,000	$100,000	$100,000	$100,000	$100,000
Capital Contribution	N/A	N/A	N/A	N/A	N/A
Net Cost	$100,000	$100,000	$100,000	$100,000	$100,000
O&M Cost	2021	2022	2023	2024	2025
	-	-	-	-	-

Customer Attachments and Load
Number of Customers approximately 15,828 Load Impacted: Approximately 61 MW

Start Date	2021-2025	In-Service Date	2021-20225
Expenditure Timing for the Planning Horizon	2021Q1	2021Q2	2021Q3	2021Q4
	-	-	$100,000	-

Project Summary
This project is a part of OPUCN's efforts towards improving service reliability and modernizing the existing grid into a smart grid system. During the period 2021-2025, OPUCN will purchase approximately 5 SCADA operated 44kV switches that will be installed at key locations on our 44kV distribution system to enhance the utility's ability to perform switching operations during normal and emergency conditions. This project will include extending the communication network to existing and new smart switches. Network planning will include this project, Deployment of Automation Controllers and Network Connected Devices project, and Expansion of Overhead Automated Switching project. Please see Figure 33- Scope Comparison of SCADA Related Projects which illustrates how the scope of this project is related with other SCADA related projects.
Risk Identification & Mitigation
Scheduling Risk - Timely delivery of equipment is important to complete the project in time. OPUCN proposes to initiate procurement of switches well in advance and work in coordination with supplier to avoid risk of delay. Resource Risk - Resource to complete the required design and installation is important for successful completion of the project. OPUCN has resources and experience available in-house and also through approved, experienced contractors, to complete the design and installation. Budget Risk - Additional work may be required to be performed including replacement pf pole(s) to comply with the current installation standards while installing the new 44kV switches and connection of wireless/fibre communication network to the new switches. This may pose a risk of incurring additional cost and time. To mitigate this risk, OPUCN will plan its communication network expansion together with the Expansion of Overhead Automated Switching project and Deployment of Automation Controllers and Network Connected Devices project. OPUCN will use the pole replacement program to address any poor condition poles.
Comparative Information on Expenditures for Equivalent Projects/Activities
OPUCN has installed one 44 kV overhead switch in 2019 at a total of $80,000 as part of an existing project. This cost excludes extending communication to the remote switch and pole replacement.

Replacing existing manual 44kV switches with remote switches allows for faster redirection of 44kV power flow through remote operation of switches through a Control Operator. Operators will be given real-time information about fault conditions and loading. Remote overhead switches allow faster restoration to customers.

Historical Costs ($ '000)						Forecast Costs ($ '000)				
2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
-	-	-	-	-	125	100	100	100	100	100

This program was introduced in 2020 and will continue during the planning year. 2020 is a budget cost.

REG Investment Details including Capital and OM&A costs

The SCADA operated 44 kV overhead switch will provide voltage and power flow information remotely to the control room. Therefore, the project will help OPUCN to monitor power quality and use power flow information in planning, accommodating and integrating of DERs/REGs.

OPUCN's largest DERs/REGs are connected at the 44kV distribution system. These DERs/REGs will be able to connect more easily onto the distribution system through remote 44kV switching as there will be easier transitioning of 44kV feeders onto other sources when planned or unplanned interruptions occur. The benefits to each DER/REG will be assessed on a case by case basis.

This project supports future REG connections but does not contain any capital investments or OM&A costs that are directly attributable to REGs.

Leave to Construct approval under Section 92 of the OEB Act

This project is below 50 kV and therefore Leave to Construct is not required, as per OEB.Reg. 161/99.

Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material

Figure 43- Remote 44kV Switch

Figure 44-Motorized Controller of 44kV Switch

descriptive-bulletin
-761-30.pdf

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)
Efficiency, Customer Value & Reliability – Investment Main Driver
Service Reliability & Operational Efficiency is the main driver for this project. The switches provide rapid and efficient operation as staff are not required to be sent to perform manual switching. Outage durations will be reduced through remote switching. The SCADA operated switch will also allow monitoring of the switch which will also help reduce the risk of power interruptions due to in-service equipment failures. This project aligns with the guidelines of the Grid Modernization Plan. The installation of automated switches will create a smarter-grid.
Efficiency, Customer Value & Reliability – Investment Secondary Driver
There are no secondary drivers.
Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets
The investment objectives are to mitigate the risk of service reliability falling below the performance targets as outlined in OEB's annual scorecard for OPUCN. New switches will replace existing manual switches and will improve operational effectiveness as switches can be operated remotely without the need of sending field staff. The investment objective is to improve Operational Effectiveness as outlined in OEB's annual scorecard for OPUCN. Some specific scorecards measures affected are namely "Average Number of Hours that Power to a Customer is Interrupted", "Total Cost per Customer" and "Total Cost per Km of Line".

Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment

The source of information for support of this project include the ACA which identifies the need for replacing primary switches expected to reach or already past their TUL within the planning period. Although not explicitly stated in the ACA report, the study determined that the majority of 44kV switches will be past their minimum useful life.

Service Reliability & Operational Efficiency will be improved by the installation of remote 44kV switches – higher service reliability and improved costs to customers. This project will help OPUCN reduce the outage duration through remote switching of the 44kV distribution. All of OPUCN's customers are fed through the 44kV distribution including customers fed from the 13.8kV distribution (which are fed through step down MS transformers). As a result, the use of 44kV remote switches have a large impact to customers.

System Operators will receive fault detection alerts indicating when fault conditions have occurred downstream of overhead switches which further reduces outage durations. The remote switches will provide ability to perform remote switching without dispatching line crew, improving operational efficiency and reduce operating cost. Remote switches will also provide real-time power flow information to system operators who will be able to efficiently reconfigure the electrical distribution system.

According to feedback from OPUCN's customers, approximately 92% of customers want OPUCN to "look for ways to use technology to safeguard the electricity network or get more out of the equipment" (see OPUCN's 2019 Distribution System Plan Customer Engagement Report, Figure 2 – Customer Priority Table) and approximately 88% of customers surveyed want OPUCN to invest in smart grid technologies including system automation, making grid technology one of the top five priorities to customers.

Using SCADA operated switches during replacement of the old primary switches will provide an opportunity at low incremental cost, to modernize the grid into a 'smart grid' as identified in OPUCN's Grid Modernization Plan. This project uses Distribution Automation (DA) to improve the OMS and enables Fault Locating (see this specific project description in Grid Modernization Plan, Section 10-Project Descriptions and Benefits). As a result, the Grid Modernization Plan has determined a high score on this project (see Section 9- Project Cost and Impact Scores).

Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges

The project will improve service reliability and operational efficiency by remotely operating the switch to restore power instead of dispatching a field staff to operate a switch. In addition, this project will take advantage of replacing poor condition switches (according to the ACA) with new switches. This will also make the grid ready for an Advanced Distribution Management System (ADMS) implementation in the future.

Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment

The project has been determined as a high priority due to the condition of existing switches. It will also address the need for improving system reliability and operating efficiencies which are some of OPUCN's AM objectives identified in Section 5.3.1.

Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness

The project will address the need for improving system reliability and operating efficiencies. Information used to support this investment include the Grid Modernization Plan. Automated Switches will create a better OMS that is able to respond quickly to outages and also support fault locating (FL). Since the project is tied to improvements in the OMS (see section 9 – Project Cost and Impact Scores in OPUCN's Grid Modernization Plan) and DA and FL, the project has been given a high score.

Doing nothing or replacing existing switches with new manual switches would not take advantage of operational efficiencies available through use of new technologies to fault locate, isolate and perform system restoration.

A retrofitted existing switch is not likely to yield the same benefits of a new remote switch since a large portion of existing switches are past their service life. These switches may not be able to handle many operations and will likely incur more Operational & Maintenance costs. This option would incur higher overall maintenance cost of the switch and risks (e.g. motor mechanism incompatibility) which would outweigh the benefits. In addition, a retrofitted assembly would not have the voltage and current sensing capabilities of a newly installed integrated switch that help determine fault locations.
Analysis of Project & Alternatives – Net Benefits Accruing to Customers
The net benefits accruing to Customers will be a better service reliability and operational efficiencies as mentioned in "Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness" above.
Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages
The installation of 44kV SCADA switches will be able to provide fast restoration to customers and mitigate the number of customers affected during a power outage. The installation of remote 44kV switches will reduce SAIDI values as the time to perform switching operations would be greatly reduced compared to sending field staff to perform manual operations. The alternative of doing nothing will not take advantage of new technologies to remotely operate switches and reduce customer outage duration. Operational efficiency will remain the same as switches will require sending out field staff to perform manual operation. Doing nothing will incur a risk of not being able to operate on switches which have passed their service life. The alternative of a retrofitted switch is not likely to yield the same reliability performance since a large portion of existing switches are past their service life. These switches may not be able to handle many operations and in the event of a failed switching operation would prolong the outage. Also a retrofitted assembly would not have the voltage and current sensing capabilities of a newly installed integrated switch that help determine fault locations.
Project Alternatives (Design, Scheduling, Funding/Ownership)
There are no other practical and cost-effective design or funding alternatives, or co-ownership options available.
Safety
New design of switch, remote switching functionality and the real-time status information through SCADA will improve safety for the line crew. The installation of automatic and remote switches eliminates exposing staff to arc-flashes that may occur due to operating defective overhead switches. The installation will be built in compliance with O.Reg. 22/04 and new standards to ensure safety for the general public.
Cyber-Security, Privacy (where applicable)
The communication with SCADA operated switches will be implemented using OPUCN's dedicated fiber or a secure wireless network for SCADA communication loop which will ensure (PR.DS-2 OEB Cybersecurity Framework) Data-in-transit is protected as a Security Control. This ensures that only authorized staff have access to critical information that operates power delivering equipment. Access to the control system will be managed according to LDC's IT/OT standards in compliance to NIST cyber security standards and OEB's cyber security framework.
Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)
The controller for the SCADA operated switches will be procured using specification that includes, but not limited to, secure communication using DNP3 protocols, compliance to applicable industry standards including IEEE and NIST, to meet the

interoperability requirements. This will ensure devices will be able to communicate with Control Room SCADA system and other IEDs.
Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)
The controller for the SCADA operated switches will provide additional functionality and will be provisioned to form a communication backbone to a network of multiple SCADA operated switches.
Environmental Benefits (where applicable)
Installation of SCADA operated switches will enable remote operation of switches by control room staff, without requiring dispatching of crew(s)/ truck during normal and in case of outages. The avoided truck rolls therefore will help reduce GHG emission.
Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)
Not Applicable
Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)
Not Applicable
Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity
The controller for the SCADA operated switches will provide additional functionality and will be provisioned to form a communication backbone to a network of multiple SCADA operated switches.

C. Category-Specific Requirements – System Service (5.4.3.2.C)
Assessment of Customer Benefits Based on Project Objectives and Cost Impact
According to OPUCN's 2019 Distribution System Plan Customer Engagement Report, this project will cost a portion of a monthly average cost of 15.3 cents (overall total cost of system service projects), which the majority (60%) of customers surveyed supported (see Figure 14 – System Service Investment Chart). In addition, 92% of customers surveyed want OPUCN to "look for ways to use technology to safeguard the electricity network or get more out of the equipment" and 88% of customers surveyed (see OPUCN's 2019 Distribution System Plan Customer Engagement Report, Figure 2 – Customer Priority Table) want OPUCN to invest in smart grid technologies, making grid technology one of the top five priorities to customers. Customer will benefit due to reduced outage duration and faster restoration that will be achieved with the new SCADA operated switches. Customer satisfaction for the service quality will be improved. Also, customers will benefit from improved costs due to remote switching capabilities of the new switches. This project takes advantage of replacing existing 44kV switches which are past their TUL and new technology to provide operation efficiencies. The new remote switches will reduce overall costs to operate the switch. This project will help OPUCN reduce the outage duration through remote switching of the 44kV distribution. All of OPUCN's customers are fed through the 44kV distribution including customers fed from the 13.8kV distribution (which are fed through step down 44kV to 13.8kV MS transformers). As a result, the use of 44kV remote switches will have a large positive impact to customers.

System Operators will receive fault detection alerts indicating when fault conditions have occurred downstream of overhead switches which further reduces outage durations. The remote switches will provide ability to perform remote switching without dispatching line crew, improving operational efficiency and reduce operating cost.

Remote switches will also enable DERs. The remote switches provide real-time power flow information to system operators who will be able to efficiently reconfigure the electrical distribution system. OPUCN's largest DERs are connected to the 44kV system. These switches will further enable customer DER connection as operators will be able to reconfigure the system to allow DERs onto they system.

Information on Regional Electricity Infrastructure Requirements Identified in the Regional Planning Process

Not Applicable

Description of how Advanced Technology has been Incorporated (where applicable)

The controller for the SCADA operated switches will provide additional functionality and will form a communication backbone to a network of multiple SCADA operated switches.

Identification of any Reliability, Efficiency, Safety and Coordination Benefits or Affects

This program will improve system reliability and will provided added visibility to the grid. It will also reduce the operational cost as it will reduce the need to dispatch and engage line crew to perform manual switching operations.

There will be an added level of safety due to remote operation as field staff will not be required to operate switches manually.

Identification and Explanation of the Factors Affecting Implementation Timing/ Priority

The project has been given a high priority because it offers a high benefit for improving operational efficiency, reliability and visibility. OPUCN will provide appropriate weightage on the vintage of the existing switch in selecting location to leverage the opportunity for asset renewal. OPUCN will be taking advantage of the timing to replace existing 44kV switches that are past their service to renew the system with smart switches that will improve service reliability and operational efficiency.

Analysis of Project Benefits and Costs Comparing to a) Doing Nothing and b) Technically Feasible Alternatives

By doing nothing, OPUCN will continue operating the existing switches manually and continue without improving operational efficiencies and grid visibility. This option also incurs an added risk of operating switches that are past their service life. This is not a proactive approach for grid modernization.

The other alternative is to retrofit the existing load break switches with motorized operator and necessary SCADA communication gateway box. However, this alternative is not preferred due to challenges and overall reliability associated with field assembly of components vs. that of factory assembled equipment. A retrofitted assembly would not have the voltage and current sensing capabilities of a newly installed integrated switch. As a result of this, the switch would not be able to help aid in fault locating and sending field staff closer to the location of the faulted power line.

A. General Information (5.4.3.2.A)					
Project/Activity	SCADA Integration and Deployment of Automation Controllers and Network Connected Devices				
Project Number	SS-04				
Investment Category	System Service				
	2021	2022	2023	2024	2025
Capital Cost	$250,000	$100,000	$100,000	$100,000	-
Capital Contribution	N/A	N/A	N/A	N/A	N/A
Net Cost	$250,000	$100,000	$100,000	$100,000	$-
O&M Cost	2021	2022	2023	2024	2025
	-	-	-	-	-
Customer Attachments and Load					
The total number of customers impacted and the connected load will be determined when the specific project is determined.					

Start Date	2021-2024	In-Service Date	2021-2024

Expenditure Timing for the Planning Horizon	2021Q1	2021Q2	2021Q3	2021Q4
	-	-	$100,000	$150,000

Project Summary

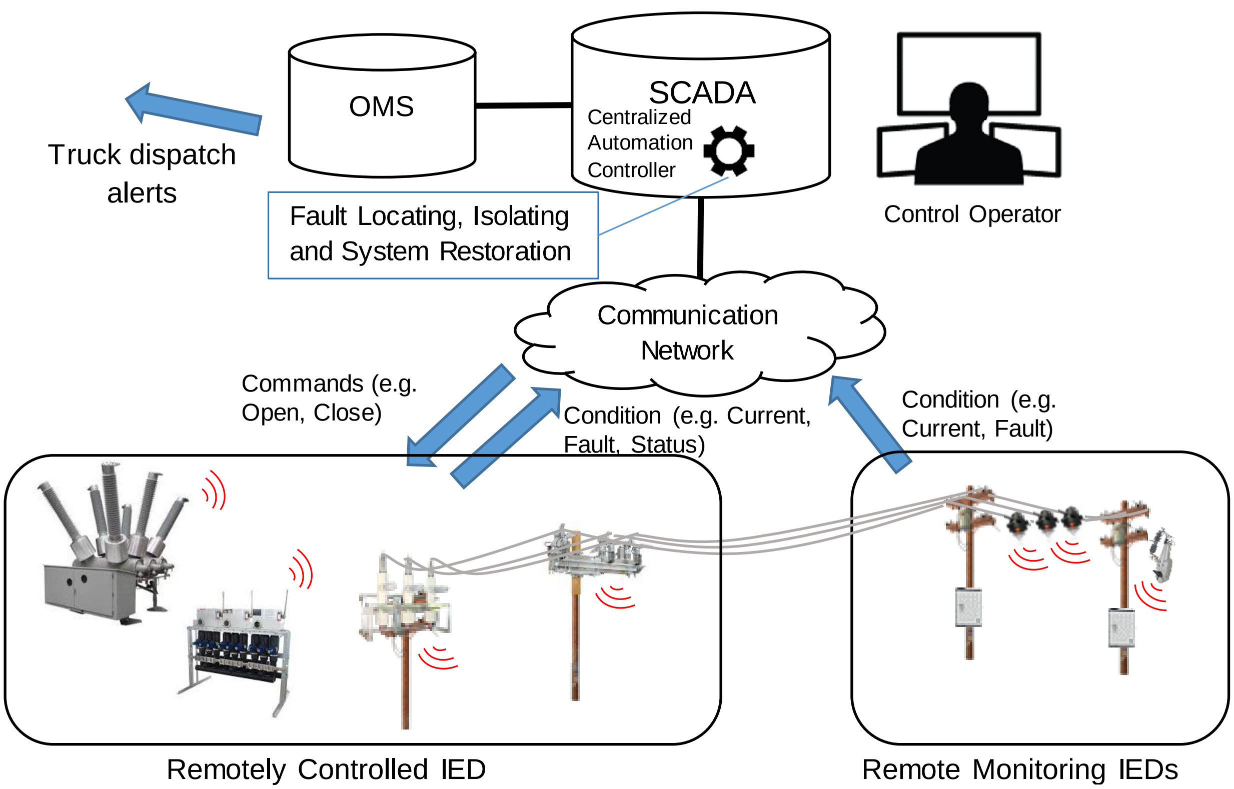


Figure 45- Centralized Controller Functioning with Intelligent Electronic Devices (IEDs)

During the period of 2021-2024, OPUCN will purchase and install a Centralized Automation Controller (CAC) that enables SCADA integration and automation across non-vendor specific smart devices. Automation enables automatic fault locating, automatic fault isolation of faulted powerlines and restoration of power to remaining sections thereby increasing operational efficiencies and reliability.

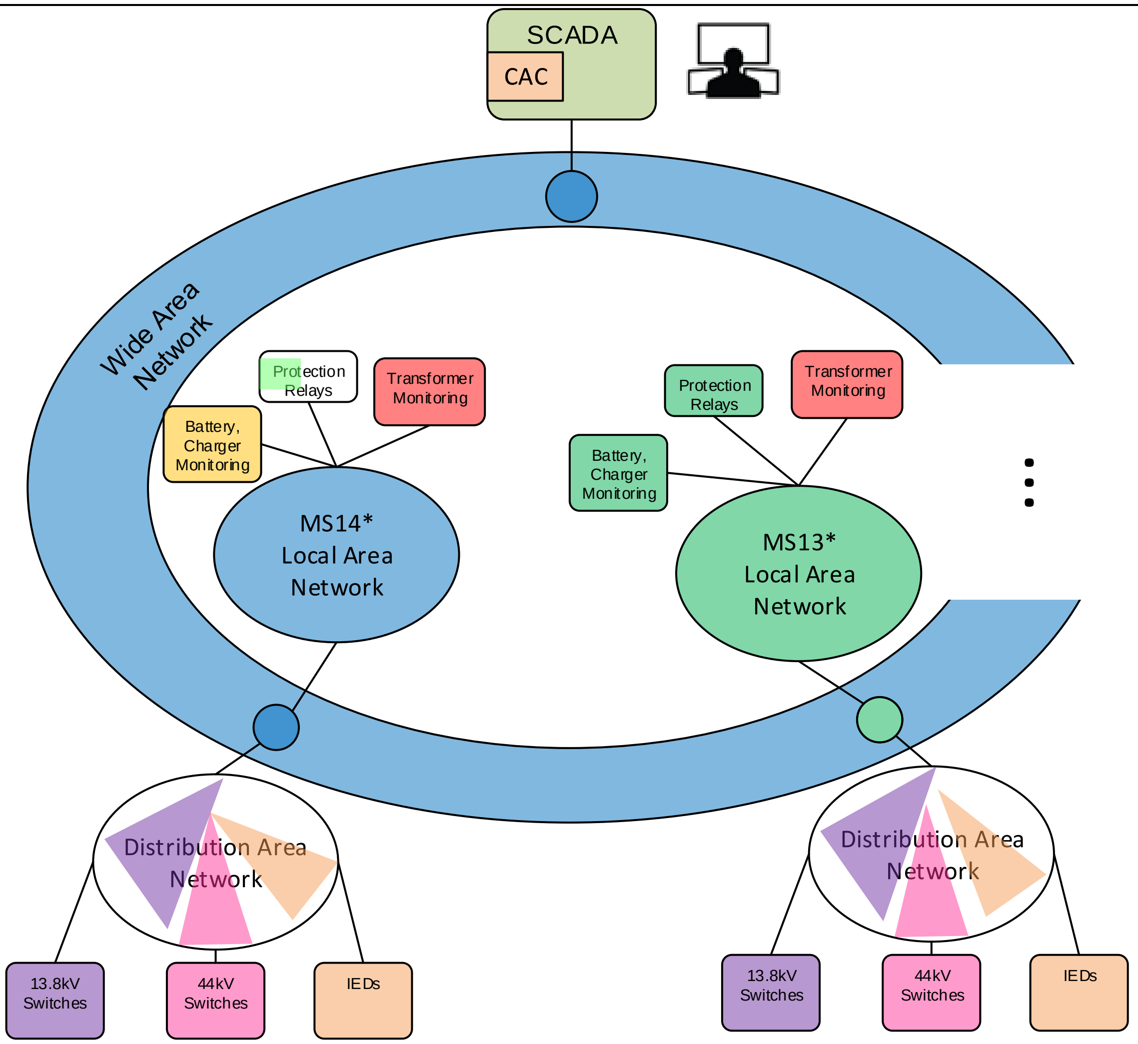
It is critical that this Centralized Automation Controller be installed as it will be a major enabler of automation:

- This Controller will enable automation that is vendor agnostic. OPUCN's existing implementations of automation are tied to specific vendors and does not allow easy interoperability with other vendors of smart devices.
- This controller will enable automation across different types of IEDs to perform faster restoration. OPUCN's existing automation only includes switches which do not include other devices such as MS breakers and other reclosers. Greater operational efficiencies and reliability improvements can be realized when these devices are included as an integrated group of automation devices.
- This controller will be installed at the Control Room and has the potential to be used throughout the system. Existing automation implementations limit automation to a few 13.8kV feeders. With the Centralized Controller, it can be expanded to all feeders.

This project will work in tandem with Expansion of Overhead Automatic Switching project to allow more smart grid devices to work together in automation.

This project will also include extending use of other IEDs or smart grid devices such as smart fault indicators and lateral recloser. The project will also include investigating into using other intelligent electronic devices (IEDs) or smart network devices such as intelligent line sensors and power quality (PQ) monitors. Quantities and type of devices may vary depending on the feeder topology and configuration.

This project will include extending the communication network to new and existing IEDs. Network planning will include this project, Expansion of Overhead Automated Switching project, and SCADA Operated 44kV OH Switches project. Please see below which illustrates how the scope of this project is related with other SCADA related projects.



Centralized Automation Controller (CAC), Smart Fault Indicators, Lateral Reclosers and IEDs (System Service)

Planned SCADA Upgrade (System Service)

Municipal Substation Network Upgrade (System Service)

Transformer Monitoring & Telemetry (System Service)

Station Battery and Battery Charger Replacement (System Service)

Expansion of Overhead Automated Switching (System Service)

SCADA Operated 44kV OH Switches (System Service)

Switchgear Replacement Program (System Renewal)

Relay Replacement Program (System Renewal)

* - See description of Switchgear Replacement Program for specific Municipal Substations covered under each narrative

Figure 46- Scope Comparison of SCADA Related Projects

The project has a risk of delay in completion due to delivery of equipment. OPUCN proposes to initiate procurement activities accordingly in consultation with the respective supplier to avoid delay.

Another risk is integration of the devices with the existing SCADA and OMS system. OPUCN proposes to include the integration requirements in the specifications for each device and will perform scrutiny for compliance with the industry standards and specific technical requirements of OPUCN.

Comparative Information on Expenditures for Equivalent Projects/Activities

There is no comparative information to the Centralize Automation Controller from past installations as this will be the first that OPUCN will install a system Automation controller.

This program commenced in 2020 with expected completion by 2024.

Historical Costs ($ ‘000)						Forecast Costs ($ ‘000)				
2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
-	-	-	-	-	50	250	100	100	100	-

During 2016-2018, each year, OPUCN completed implementation of smart fault circuit indicators at 2 locations at an approximate cost of $12,500 per location using cellular communication. The new estimate is based on lateral reclosers (installation in progress), smart fault circuit indicators and communication using fiber connection – which may vary depending on location of installation and feeder configuration.

REG Investment Details including Capital and OM&A costs

As this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.

Leave to Construct approval under Section 92 of the OEB Act

This project is below 50 kV and therefore Leave to Construct is not required, as per OEB.Reg. 161/99.

Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material

Figure 47-Centralized SCADA Automation Controller

Figure 48 - Smart Fault Indicators and Data Concentrator

Figure 49- Lateral recloser

Figure 50- IED Data concentrator

Figure 51- Power Quality Monitors/Power Line Monitor

Figure 52- Radio communication

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)
Efficiency, Customer Value & Reliability – Investment Main Driver
Service Reliability & Operational Efficiency is the main driver for this project. The Centralized Controller and IEDs provide faster & more accurate fault locations which reduces outages times and field staff patrolling. Also automated outage isolation & restoration through the Centralized Automation Controller and IEDs will reduce the number of customers affected during each outage.

This project aligns with the guidelines of the Grid Modernization Plan (see this specific project in Section 10 Project Descriptions and Benefits). The installation of the Centralized Controller will be a major component of the grid that uses technology to create a smarter-grid.

Efficiency, Customer Value & Reliability – Investment Secondary Driver

There are no secondary drivers.

Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets

The investment objectives are to mitigate the risk of service reliability falling below the performance targets.

In addition, the investment objective is to improve Operational Effectiveness as outlined in OEB's annual scorecard for OPUCN. Some specific scorecards measures affected are namely "Average Number of Hours that Power to a Customer is Interrupted", "Average Number of Times that Power to a Customer is Interrupted", "Total Cost per Customer" and "Total Cost per Km of Line".

Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment

Service Reliability & Operational Efficiency will be improved by the implementation of the Centralized Controller and IEDs. The installation of the Centralized Controller and IEDs provide faster & more accurate fault locations which reduces outages times and field staff patrolling. Also automated outage isolation & restoration through the Centralized Automation Controller and IEDs will reduce the number of customers affected during each outage. In addition, since the Centralized Controller will be implemented at control centre and is IED vendor agnostic, this project provides long term benefits for integrating smart grid devices to provide automated power restoration – long term Service Reliability & Operational Efficiency.

Approximately 88% of customers surveyed (see OPUCN's 2019 Distribution System Plan Customer Engagement Report, Figure 2 – Customer Priority Table) want OPUCN to invest in smart grid technologies including system automation, making grid technology one of the top five priorities to customers.

This project is aligned with the guidelines in OPUCN's Grid Modernization Plan which identifies key projects that will help OPUCN use technology to make the distribution system a smarter grid and improve the way the system operates.

OPUCN's Grid Modernization Plan has identified that this project will provide advantageous benefits to the Outage Management System and enable Fault Locating, Isolation, and System Restoration (FLISR). Please see this specific project in Grid Modernization Plan Section 10 Project Descriptions and Benefits. As a result, the Grid Modernization Plan has given a high score on this project (see Section 9 Project Cost and Impact Scores).

Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges

This project will help OPUCN reduce the outage duration through real time information related to outage data transmitted by the faulted circuit indicators and lateral reclosers to the existing SCADA and OMS in order to automatically dispatch the crew and to implement advance application of fault detection, isolation and restoration in integration. The lateral recloser will also provide enhanced protection for the lateral circuits, which will reduce momentary interruptions on entire feeder in case of faults downstream.

This project will be coordinated with the SCADA upgrade, to ensure that the Centralized Automation Controller and IEDs functions are migrated to the new SCADA platform. OPUCN is strategic partnerships on both projects to ensure success.

Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment

The project will address the need for improving system reliability and operating efficiencies. Information used to support this investment include information taken from the Grid Modernization Plan. A Centralized Automation Controller and IEDs will

create a better OMS that is able to respond quickly to outages and also support FLISR. Since the project is tied to improvements in the OMS (see the specific project in Section 10 Project Descriptions and Benefits of the Grid Modernization Plan) and meets AM objectives identified in Section 5.3.1, the project has been given a high priority.
Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness
<u>Continuing to Only Install Smart Fault Indicators</u> This option will only provide small incremental benefits to the system in operational efficiency and reliability improvements. This solution will not include integration with other automation systems. <u>Do Nothing</u> This option is not economical as the system would continue to run as status quo without use of additional smart technology to modernize the grid and improve operational efficiency and reliability. <u>Install Centralized Automation Controller & IEDs (Including Smart Fault Indicators)</u> Major benefits to the distribution system are possible when data from various smart devices (e.g. breakers, switches, reclosers and smart fault indicators) are centralized to perform better decisions. The proposed project to install a Centralize Automation Controller is a wholistic program to tie in various smart devices & IEDs to better perform fault locating, isolation and restoration.
Analysis of Project & Alternatives – Net Benefits Accruing to Customers
The net benefits accruing to Customers will be a better service reliability and operational efficiency.
Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages
SAIDI and SAIFI will be improved significantly due to enhanced outage management from the Centralized Automation Controller compared with doing nothing or installing only Smart Fault Indicators. The Centralized Automation Controller will gather critical fault data (e.g. breakers, switches, reclosers and smart fault indicators) to determine the location of faults in the system, automatically switch to isolate the fault and restoring remaining power lines. The Controller will provide alerts to send field staff directly to the fault location reducing SAIDI.
Project Alternatives (Design, Scheduling, Funding/Ownership)
There are no other practical and cost-effective design or funding alternatives, or co-ownership options available.
Safety
The installation will be built in compliance with O.Reg. 22/04 and new utility standards to ensure safety for the general public. The current sensor built in these IEDs will provide additional information to the operation control room that will be utilized in creating safer working environment for the line crew.
Cyber-Security, Privacy (where applicable)
Communication between IEDs and Centralized Automation Controller will be implemented using secured channel using free-wave radio or dedicated fiber which will ensure (PR.DS-2 OEB Cybersecurity Framework) Data-in-transit is protected as a Security Control. Access to IEDs will be managed according to standards that comply with NIST cyber security standards and OEB's cyber security framework security controls.
Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)

The IEDs will be procured using specification that includes but not limited to secure communication using DNP3 protocols which will ensure interoperability with other Operational Technology devices. IEDs will be in compliance to applicable industry standards including IEEE and NIST to meet the interoperability requirements.
Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)
OPUCN will ensure that the selected IED meets or exceeds the interoperability requirements for future implementation of an Advanced Distribution Management System (ADMS) and Fault Location, Isolation Scheme and Restoration type functionality which will ensure IEDs will be able to communicate with one another and with the centralized controller for faster fault location, isolation and system restoration.
Environmental Benefits (where applicable)
Implementing this project will provide location information in case of the sustained outage which will help in reducing time to patrol lines and outage duration- translating into reduced truck rolls (and reduction of GHG emissions).
Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)
Not Applicable
Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)
Not Applicable
Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity
OPUCN will ensure that the selected IED meets or exceeds the interoperability requirements for future implementation of an Advanced Distribution Management System (ADMS) and Fault Location, Isolation Scheme and Restoration type functionality which will ensure IEDs will be able to communicate with one another and with the centralized controller for faster fault location, isolation and system restoration.

C. Category-Specific Requirements – System Service (5.4.3.2.C)
Assessment of Customer Benefits Based on Project Objectives and Cost Impact
According to OPUCN's 2019 Distribution System Plan Customer Engagement Report, this project will cost a portion of a monthly average cost of 15.3 cents (overall total cost of System Service projects), which the majority (60%) of customers surveyed supported (see Figure 14 – System Service Investment Chart). In addition, 88% of customers surveyed (see OPUCN's 2019 Distribution System Plan Customer Engagement Report, Figure 2 – Customer Priority Table) want OPUCN to invest in smart grid technologies, making grid technology one of the top five priorities to customers. Service Reliability & Operational Efficiency will be improved by the implementation of the Centralized Controller and IEDs – which will result in improved service reliability and improved costs for customers. The installation of the Centralized Controller and IEDs provide faster & more accurate fault locations which reduces outages times and field staff patrolling. Also automated outage isolation & restoration through the Centralized Automation Controller and IEDs will reduce the number of customers affected during each outage. Implementing this project will reduce patrol lines and outage duration translating into reduced truck rolls which improves Operational Efficiency and overall cost customers.

Since the Centralized Controller will be implemented at the control centre where automated control can be applied to any field device communicating remotely to the control centre and this solution is IED vendor agnostic, this project provides long term future benefits for integrating smart grid devices to provide automated Fault Locating, Isolation, and System Restoration (FLISR) – long term benefits of Service Reliability & cost improvement to customers.
Information on Regional Electricity Infrastructure Requirements Identified in the Regional Planning Process
Not Applicable
Description of how Advanced Technology has been Incorporated (where applicable)
The IEDs and communication technologies will be used to integrate into existing SCADA, OMS and automatic restoration software, which will provide platform for future implementation of ADMS. This will ensure IEDs will be able to communicate with the centralized controller for faster fault location, isolation and system restoration .
Identification of any Reliability, Efficiency, Safety and Coordination Benefits or Affects
The investment in IEDs and the Centralized Automation Controller will improve system reliability and efficiency. The Centralized Automation Controller will gather critical fault data (e.g. breakers, switches, reclosers and smart fault indicators) from various IEDs to determine the location of faults in the system, automatically switch to isolate the fault and restoring remaining power lines. The Controller will provide alerts to send field staff directly to the fault location reducing SAIDI.
Identification and Explanation of the Factors Affecting Implementation Timing/ Priority
The project offers a high benefit for improving service reliability, operational efficiency and visibility. This project will take advantage of past and ongoing implementations of smart grid devices to centralize information and control to perform better fault locating, fault isolation and system restoration. If implementation is delayed, existing devices will continue to work independently and benefits to service reliability, operational efficiency and visibility in an integrated smart grid control will not be secured.
Analysis of Project Benefits and Costs Comparing to a) Doing Nothing and b) Technically Feasible Alternatives
<u>Continuing to Only Install Smart Fault Indicators</u> This option will expand existing use of smart fault indicators but would only provide incremental benefits to fault locating which would reduce duration of an outage. This option would not increase operational efficiency and reliability improvements with isolation and system restoration. This solution will not take advantage of existing smart devices (e.g. switches and breakers) that can further drive improvements in number of customers affected by an outage. <u>Do Nothing</u> By doing nothing, OPUCN will continue operating the existing system the same way as today, without obtaining the benefits of advance monitoring and communication technologies to improve fault location, isolation and system restoration. This is not a proactive approach for grid modernization.

A. General Information (5.4.3.2.A)					
Project/Activity	Municipal Substation Network Upgrade				
Project Number	SS-05				
Investment Category	System Service				
	2021	2022	2023	2024	2025
Capital Cost	-	-	$ 150,000	$ 150,000	$ 150,000
Capital Contribution	N/A	N/A	N/A	N/A	N/A
Net Cost	-	-	$ 150,000	$ 150,000	$ 150,000
O&M Cost	2021	2022	2023	2024	2025
	-	-	-	-	-
Customer Attachments and Load					
Approximately 23,000 customers, 90MW.					

Start Date	2023-2025	In-Service Date	2023-2025

Expenditure Timing for the Planning Horizon	2021Q1	2021Q2	2021Q3	2021Q4
	-	-	-	-

Project Summary

This project will address two primary objectives, OPUCN's efforts towards improving service reliability and modernizing the existing grid into a "smarter grid" system and supporting Ontario Energy Board (OEB) Cybersecurity Framework compliance.

During the period of 2023-2025, OPUCN will be modernizing its MS digital networks between MSs and control room. Each MS digital network will be segregated from other MS networks as a security control. Various Cybersecurity tools and access systems will be investigated and implemented accordingly as security control measures.

OPUCN's MS digital network communication will be migrated to Layer 3 communication to increase cybersecurity, improve data bandwidth, and reduce communication latencies for OT and smart grid device communications. Various Cybersecurity tools will be investigated and implemented accordingly. Some examples include Next Generation Firewalls, Intrusion Detection/Prevention Systems, Security Information and Event Management, and Secure Access Management Systems, Deny-by-default Access Systems.

This program will support the implementation of a number of OEB Cybersecurity Framework Security Controls on OT systems such as the following:
- PR.AC-1: Identities and credentials are managed for authorized devices and users
- PR.AC-3: Remote access is managed
- PR.AC-4: Access permissions are managed, incorporating the principles of least privilege and separation of duties
- PR.AC-5: Network integrity is protected, incorporating network segregation where appropriate
- PR.DS-2: Data-in-transit is protected
- PR.PT-1: Audit/log records are determined, documented, implemented, and reviewed in accordance with policy
- PR.PT-4: Communications and control networks are protected
- DE.CM-1: The network is monitored to detect potential cybersecurity events
- DE.CM-3: Personnel activity is monitored to detect potential cybersecurity events
- DE.CM-7: Monitoring for unauthorized personnel, connections, devices, and software is performed

Each MS network will be reconfigured for segmentation (PR.AC-5). Looking at optimizing traffic between IEDs and SCADA. Wide Area Network (WAN) technologies will be implemented on existing fiber communication network. Cybersecurity software and access management tools will be investigated to track, manage and handle day-to-day system cybersecurity threats. To reduce costs and improve efficiencies, OPUCN will take advantage of tools that can be used on both IT and OT systems for Cyber-security where appropriate.

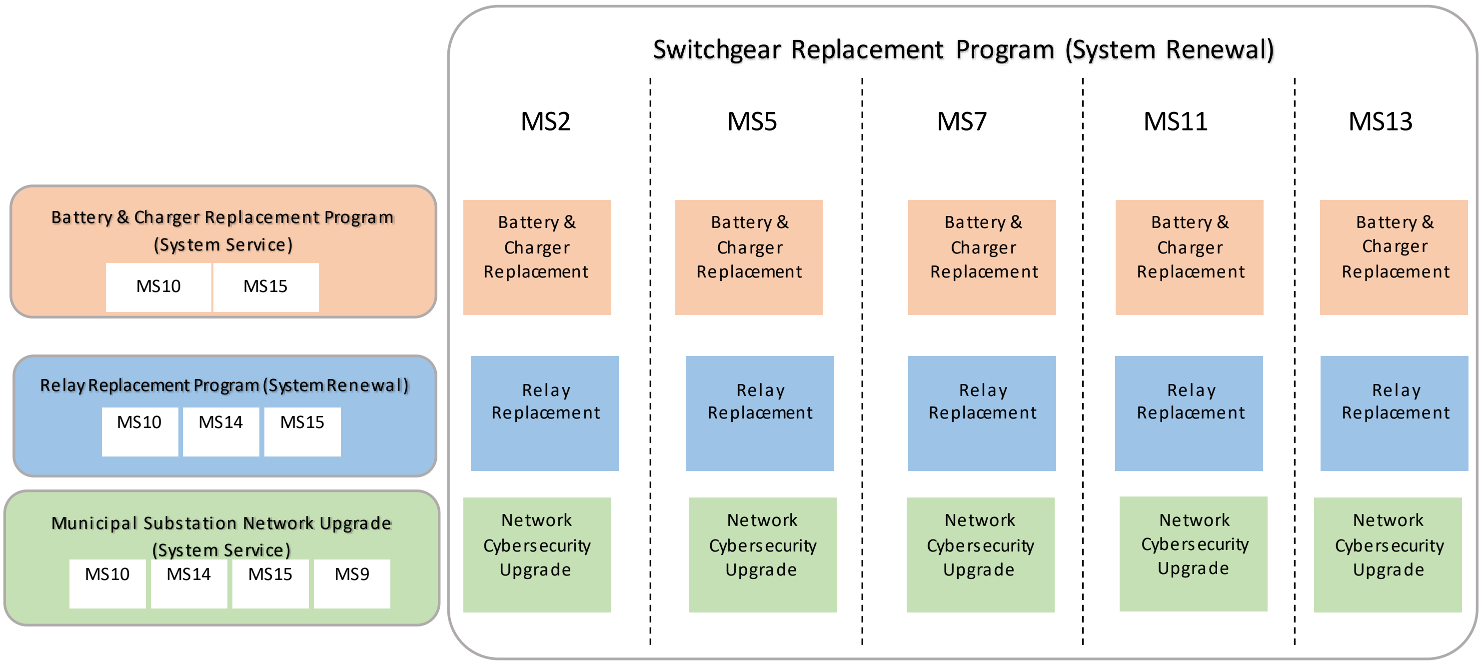


Figure 53 - Coordination of Interdependent Municipal Substation Projects

The Switchgear Replacement Program (System Renewal) will be incorporating new MS digital network. The MS Network Upgrade will focus on remaining MS, namely MS14, MS10, MS15 and MS9 (see Figure 53 - Coordination of Interdependent Municipal Substation Projects). MS10 will be completed in 2020 and the remaining will be completed during the planning period.

Please see image above which illustrates how the scope of this project is related with other SCADA related projects.

Risk Identification & Mitigation
Scheduling Risk – Timely delivery of equipment is important to complete the project in time. OPUCN proposes to initiate procurement of switches and other communication devices well in advance and work in coordination with supplier to avoid risk of delay. Resource Risk – Resource to complete the required design and installation is important for successful completion of the project. OPUCN has resources and experience available in-house and also through approved, experienced contractors, to complete the design and installation. Network System Risk – There may be a risk to the network availability as a result of upgrading the system and incorporating cybersecurity elements. This risk will be mitigated through using test environments before deployment, sectionalizing the network into stages of upgrades to reduce impacts and creating parallel communication paths during network transitions.
Comparative Information on Expenditures for Equivalent Projects/Activities
There is no comparative information on expenditures for equivalent projects or activities. Expenditures consisted of both hardware and software components needed to achieve compliance and establish highly secure and redundant communication networks. This is the first undertaking of the Operational Technology digital network of this size in OPUCN. Expenditures will

highly depend on the technology provided by vendors. OPUCN aims to maximize the benefits of new technology, while using proven technology and meeting budgetary constraints.

Historical Costs ($ ‘000)						Forecast Costs ($ ‘000)				
2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
-	-	-	-	-	100	-	-	150	150	150

This program commenced in 2020 with expected completion by 2025.

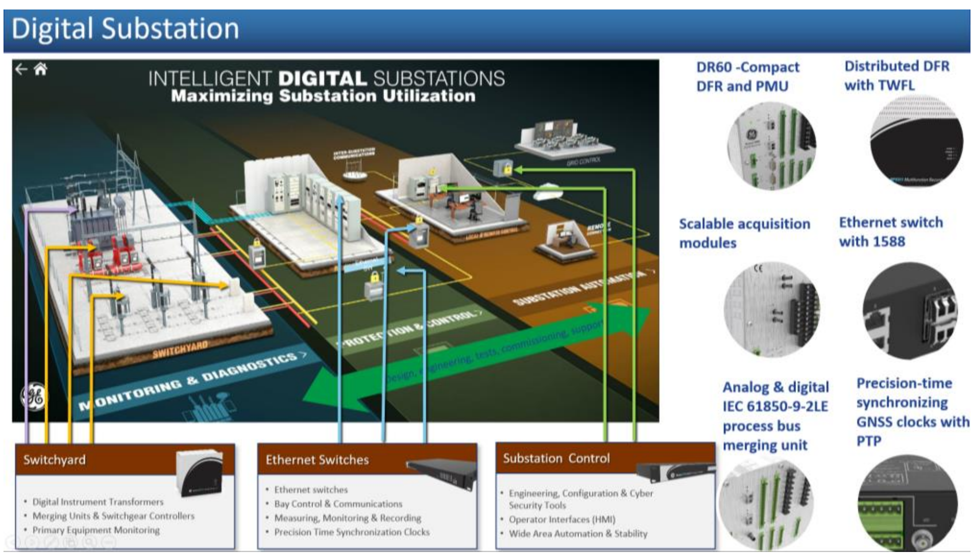
REG Investment Details including Capital and OM&A costs

As this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.

Leave to Construct approval under Section 92 of the OEB Act

This project is below 50 kV and therefore Leave to Construct is not required, as per OEB.Reg. 161/99.

Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material



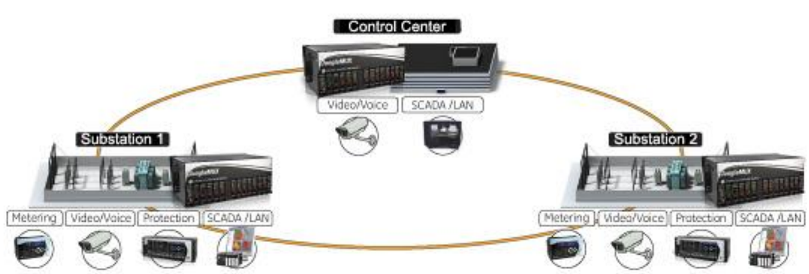


Figure 54- Example of WAN Time Division Multiplexing Equipment and Ring Topology

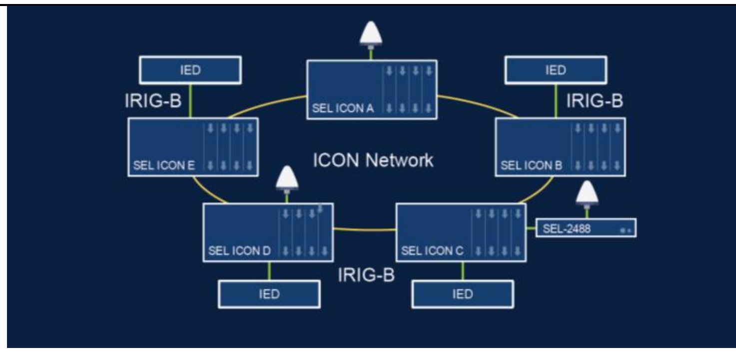


Figure 55-Ring WAN Topology Example of Time Division Multiplexer

Figure 56-Example of Time Division Multiplexing Equipment

Figure 57 - Example Industrial L3 Router Equipment

Figure 58- Example of Industrial L3 Router Equipment

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)
Efficiency, Customer Value & Reliability – Investment Main Driver
This project aligns with the guidelines of the Grid Modernization Plan. The installation of advanced communication will facilitate a better communication traffic (e.g. lower latencies, more bandwidth) for a smarter-grid. The major driver for this program is to support Regulatory Compliance to the OEB Cybersecurity Framework, to ensure that critical infrastructure data for the delivery of electricity is safe & secure. Installing cybersecurity tools will allow tracking and handling of cybersecurity attacks. Installing Layer 3 communication switches and firewalls will segregate networks (reducing the visibility of the entire system for attackers) and prevent unauthorized users from communicating to critical systems and infrastructure.
Efficiency, Customer Value & Reliability – Investment Secondary Driver

There are no secondary drivers.

Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets

The investment objectives are to improve network traffic and mitigate system communication vulnerabilities and to ensure there are systems in place to manage cybersecurity attacks.

Some objectives include investigating the following security controls from the OEB Cybersecurity Framework:

- PR.AC-1: Identities and credentials are managed for authorized devices and users
- PR.AC-3: Remote access is managed
- PR.AC-4: Access permissions are managed, incorporating the principles of least privilege and separation of duties
- PR.AC-5: Network integrity is protected, incorporating network segregation where appropriate
- PR.DS-2: Data-in-transit is protected
- PR.PT-1: Audit/log records are determined, documented, implemented, and reviewed in accordance with policy
- PR.PT-4: Communications and control networks are protected
- DE.CM-1: The network is monitored to detect potential cybersecurity events
- DE.CM-3: Personnel activity is monitored to detect potential cybersecurity events
- DE.CM-7: Monitoring for unauthorized personnel, connections, devices, and software is performed

Segmenting networks and migrating to Layer 3 subnetworks will accomplish PR.AC-5. Next Generation Firewalls, Intrusion Detection/Prevention Systems, Security Information and Event Management, and Secure Access Management Systems, Deny-by-default Access Systems would accomplish most of the remaining security controls mentioned above.

Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment

This program will provide a secure and reliable communication network for the communication of smart grid & OT devices and is part of the OPUCN's Grid Modernization Plan. The installation of advanced communication will facilitate a better communication traffic (e.g. lower latencies, more bandwidth) for a smarter-grid. This project is supported in OPUCN's Grid Modernization Plan (Section 9 – Project Cost and Impact Scores) which identifies that it is mandatory to invest in the OT network cybersecurity.

This program will be used to ensure Regulatory Compliance to the OEB Cybersecurity Framework, to ensure that critical infrastructure data for the delivery of electricity is safe & secure. This program will enable OPUCN to ensure its OT system conforms to the OEB Cybersecurity Framework through use of security controls. Installing cybersecurity tools will allow tracking and handling of cybersecurity attacks. Installing Layer 3 communication switches and firewalls will segregate networks (reducing the visibility of the entire system for attackers) and prevent unauthorized users from communicating to critical systems and infrastructure. As a result, OPUCN's Grid Modernization Plan has determined this project to be non-discretionary (see specific project description in Grid Modernization Plan Section 10 – Project Descriptions and Benefits).

According to feedback from OPUCN's customers, approximately 92% of customers want OPUCN to "look for ways to use technology to safeguard the electricity network or get more out of the equipment" (see OPUCN's 2019 Distribution System Plan Customer Engagement Report, Figure 2 – Customer Priority Table) and approximately 88% of customers surveyed want OPUCN to invest in smart grid technologies including system automation, making grid technology one of the top five priorities to customers.

Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges

The project will improve service reliability by providing reliable and secure communication with the integration of additional smart devices in the electrical system.

As more useful data is provided for control, the system will be able to improve its Fault Location, Isolation Scheme and Restoration capability – which will help to make the grid ready for the ADMS implementation in future.

Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment
The project has been determined as a high priority due to the need to mitigate communication vulnerabilities and install tools to manage cybersecurity attacks. While meeting most of the AM objectives identified in Section 5.3.1, the Grid Modernization Plan has highlighted this as a mandatory project since it is driven largely by an OEB Cybersecurity Framework.
Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness
There are no economical alternatives to this project. There are no technically feasible alternatives. All security controls need to begin with segmentation of the network to reduce the impact of each cybersecurity attack.
Analysis of Project & Alternatives – Net Benefits Accruing to Customers
The net benefits of this project to customers is a secured and reliable distribution system.
Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages
Not Relevant because of the relation to communications and cyber security requirements outline by the OEB. SAIDI and SAIFI are not directly affected by networking equipment.
Project Alternatives (Design, Scheduling, Funding/Ownership)
There are no other practical and cost-effective design or funding alternatives, or co-ownership options available.
Safety
This program will improve safety by securing critical infrastructure in the distribution system. Securing the infrastructure and hardening the system from cyber security attacks prevents attackers from gaining control of equipment that deliver electricity.
Cyber-Security, Privacy (where applicable)
This program helps ensure that OPUCN will be compliant to OEB Cybersecurity Framework. This project will help OPUCN's OT Infrastructure to include the following security controls from the OEB Cybersecurity Framework: - PR.AC-1: Identities and credentials are managed for authorized devices and users - PR.AC-3: Remote access is managed - PR.AC-4: Access permissions are managed, incorporating the principles of least privilege and separation of duties - PR.AC-5: Network integrity is protected, incorporating network segregation where appropriate - PR.DS-2: Data-in-transit is protected - PR.PT-1: Audit/log records are determined, documented, implemented, and reviewed in accordance with policy - PR.PT-4: Communications and control networks are protected - DE.CM-1: The network is monitored to detect potential cybersecurity events - DE.CM-3: Personnel activity is monitored to detect potential cybersecurity events - DE.CM-7: Monitoring for unauthorized personnel, connections, devices, and software is performed
Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)
This project is based on OEB Cybersecurity Framework which was developed following the National Institute of Standards and Technology (NIST) Standards.

Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)
This project will utilize new technology communication to service Operational Technology and smart grid devices. Cybersecurity tools will be used to help protect from cyber-attacks in the growing Smart Grid data infrastructure of the future.
Environmental Benefits (where applicable)
Not Applicable
Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)
Not Applicable
Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)
Not Applicable
Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity
This project will utilize new technology communication to service OT and smart grid devices. Cybersecurity tools will be used to help protect from cyber-attacks in the growing Smart Grid data infrastructure of the future.

C. Category-Specific Requirements – System Service (5.4.3.2.C)
Assessment of Customer Benefits Based on Project Objectives and Cost Impact
An improved digital network technology will enable better managed communications for smart grid technologies. A better managed communication system will ensure that smart grid devices, which rely heavily on the communication network, perform their functions reliably (e.g. faster communication for devices to make power restoration operations). Indirectly, customers would benefit from this project in Service Reliability and Operational Efficiency due to secure and reliable communication that supports the function of smart grid and OT devices. This program will be used to ensure Regulatory Compliance to the OEB Cybersecurity Framework, to ensure that critical infrastructure data for the delivery of electricity is safe & secure. This program will enable OPUCN to ensure its OT system conforms to the OEB Cybersecurity Framework through use of security controls. Customers will benefit from an electricity distribution system that is safe and secure from cybersecurity attacks.
Information on Regional Electricity Infrastructure Requirements Identified in the Regional Planning Process
Not Applicable
Description of how Advanced Technology has been Incorporated (where applicable)
New technology in communications will better utilize existing fiber network to increase bandwidth and reduce communication latencies. Software tools will better protect and detect cybersecurity threats on the OT infrastructure which deals with passing critical data between the control room and equipment that provide power to the grid.
Identification of any Reliability, Efficiency, Safety and Coordination Benefits or Affects

Improved digital network technology will enable smart grid technologies to better drive reliability, safety and efficiencies through reliable communication with the control room and other smart grid devices. Better managed data traffic in the OT infrastructure ensures faster and reliable communication between devices for making power restoration operations.
Identification and Explanation of the Factors Affecting Implementation Timing/ Priority
It is critical that OPUCN begin putting in security controls to prevent cybersecurity attacks in its system. Since the existing OT infrastructure is critical to the daily operations, OPUCN will not be able to complete all of the modifications within the 2023-2025 period. Implementation of digital network in segments will be phased out while keeping parallel networks as a failover system to reduce impact on system availability.
Analysis of Project Benefits and Costs Comparing to a) Doing Nothing and b) Technically Feasible Alternatives
By doing nothing, OPUCN will not be mitigating communication vulnerabilities and continue to operate without having visibility on cybersecurity threats. This is not a proactive approach for grid modernization. There are no technically feasible alternatives. All security controls need to begin with segmentation of the network to reduce the impact of each cybersecurity attack.

A. General Information (5.4.3.2.A)					
Project/Activity	Geographic Information System (GIS) Upgrades and Enhancements				
Project Number	SS-07				
Investment Category	System Service				
	2021	2022	2023	2024	2025
Capital Cost	$142,500	$110,000	$5,000	$55,000	$155,000
Capital Contribution	N/A	N/A	N/A	N/A	N/A
Net Cost	$142,500	$110,000	$5,000	$55,000	$155,000
O&M Cost	2021	2022	2023	2024	2025
	-	-	-	-	-
Customer Attachments and Load					
Not Applicable					

Start Date	2021-2025	In-Service Date	2021-2025

Expenditure Timing for the Planning Horizon	2021Q1	2021Q1	2021Q1	2021Q1
	$37,500	$60,000	$30,000	$15,000

Project Summary

The GIS system is used as our primary asset registry, keeping track of the location and important attributes for all assets in the field. The data stored in the GIS is utilised by all aspects of the company and is a critical part of the OT infrastructure. Most importantly, the data stored in the GIS is used by the operations group to perform switching and load transfers during outages. It is imperative that the data is 100% accurate to ensure field staff are directed to the correct equipment when performing these tasks. The data is also used as our basis for OneCall to ensure the safety of workers excavating within Oshawa city limits.

The GIS data also forms the base maps for the Outage Management System (OMS) which is used to respond to and restore outages as quickly as possible to limit and reduce customer interruptions. The OMS also uses the GIS data to generate outage maps on the customer facing website.

As the data in the GIS is relied upon so heavily within the company, it is a priority to maintain its integrity and ensure all parties have access to the data as they need it. This is the main driver for the GIS enhancements and maintenance listed below.

- Regularly scheduled updates to accommodate windows security updates and maintain cyber security. Must be done every 2 years ($50,000 per upgrade). The GIS version quickly becomes outdated and becomes incompatible with windows security updates. Upgrading the software every 2 years ensures the software remains operational and does not introduce vulnerabilities into the corporate network as windows security updates do not need to be postponed.
- Import of city land base ($7,500), new raster images ($7,500) and streetlight data ($45,000), and connectivity to update legacy data. Current raster images are 5 years old ($60,000).
- Establishment of mobile access to GIS data to provide field staff with the most up to date information of the network ($100,000).
- Establish connectivity between GIS and Computerized Maintenance Management System (CMMS) to ensure most accurate and up to date asset conditions and registry is available for maintenance ($30,000).
- Procurement and installation of GIS servers to maintain cybersecurity requirements ($10,000).
- Regular data model enhancements to the GIS system to accommodate emerging technology in the distribution network such as EVs, smart devices, distributed generation ($25,000)
- Integration of the design software used by the design technicians to improve their operational efficiency and reduce the risk for transcription errors ($150,000). This sub-project includes the integration of the GIS, AutoCAD (design software), SpidaCALC (engineering analysis software), and Quadra (work estimating software).

Risk Identification & Mitigation

1. Resource Risk – Staff dedicated to GIS upgrade may be required on other projects

   a. Stagger IT upgrade projects to limit project overlap of internal resources
2. Budgetary estimates based on initial Rough Order of Magnitude (ROM) from vendor are significantly below the firm pricing obtained after procurement process is complete
   a. Review detailed scope of work with vendor prior to signing PO to ensure all requirements are met. Spread project over multiple years to reduce costs.
3. System Interruption – System becomes unusable during upgrade or enhancement projects
   a. Engage the GIS vendor for system upgrades and maintenance to ensure all work is done properly with little risk of interruption
   b. Utilize test and development databases mitigate risk of service interruption.

Comparative Information on Expenditures for Equivalent Projects/Activities

Year	Actual	Budget
2016	$38,089	$60,000
2017	$43,817	$60,000
2018	$13,762	$60,000
2019	$37,028	$60,000
2020		$57,500
2021		$142,500
2022		$110,000
2023		$5,000
2024		$55,000
2025		$155,000

The table above shows the historical and forecast capital expenditure on the GIS over the period of 2016 – 2025. The capital expenditure during this time frame was to maintain the system without any enhancements to its functionality. The majority of the work done on the GIS historically have been done on an as-needed basis which made predicting the actual expenditures difficult when the original budgets were implemented. Some enhancements that were identified in this way, such as the mobile mapping enhancement or the design suite integration enhancement, were quoted above the original budget and had been delayed until a new budget could be created. Additionally, the cadence of system updates to the latest version was driven on an as-needed basis, often in response to a system interruption due to obsolescence or incompatibility with windows security updates. The most recent system upgrade was performed in 2017. As a result, OPUCN experienced 2 system interruptions that required the rollback of windows security updates which introduces vulnerabilities in the corporate network. To avoid this in the future, the system will be updated to the latest version every 2 years.

The additional capital expenditure above system updates is to expand the functionality of the system to meet evolving business needs or improve operational efficiency. The table below illustrates the proposed timeline and expenditure for each initiative under this project based on the scope of work provided by vendor and past experiences. 2020 is a budget cost and will be part of historical capital expenditures.

	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**Project Total**
CMMS Integration		$30,000					**$30,000**
Data Model Enhancements		$5,000	$5,000	$5,000	$5,000	$5,000	**$25,000**
Server Replacement			$10,000				**$10,000**
System Update	$50,000		$50,000		$50,000		**$150,000**
Mobile Mapping		$100,000					**$100,000**
Design Suite Integration						$150,000	**$150,000**

Streetlight Import Data			$45,000				**$45,000**
City Land Base and Raster Import - Pt 1	$7,500						**$7,500**
City Land Base and Raster Import - Pt 2		$7,500					**$7,500**
Year Total	**$57,500**	**$142,500**	**$110,000**	**$5,000**	**$55,000**	**$155,000**	**$525,000**

REG Investment Details including Capital and OM&A costs

As this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.

Leave to Construct approval under Section 92 of the OEB Act

This project is below 50 kV and therefore Leave to Construct is not required, as per OEB.Reg. 161/99. The information collected will be distribution system data.

Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material

Please refer to the following schematic on how the GIS is integrated to OPUCN's existing systems. This diagram illustrates the connectivity between the GIS and other systems heavily relied upon by the utility. These systems include the OMS which is a critical system for identifying and responding to outages. As the GIS provides the connectivity, location, and attribute data for all features in the OMS it is imperative that the GIS is as accurate as possible which is addressed by the legacy data imports, mobile mapping, and data model modification enhancements.

The connectivity and attribute data is also utilised by the data historian system to calculate transformer loading. This system will be used to identify transformers that are potentially overloaded and may experience a premature failure due to their loading. With this information, the utility can pre-emptively replace those transformers to reduce or eliminate any customer interruptions.

The GIS data is also utilised by the network analysis server to perform system loading and fault calculations on the network. Similar to the OMS and data historian above, this requires that the GIS be as accurate as possible to ensure accurate and reliable calculations.

The intent of the enhancements to the GIS in the next 5 years is to provide additional connectivity to other business systems such as the recently implemented Computerised Maintenance Management System (CMMS), design software, financial system, and engineering analysis software.

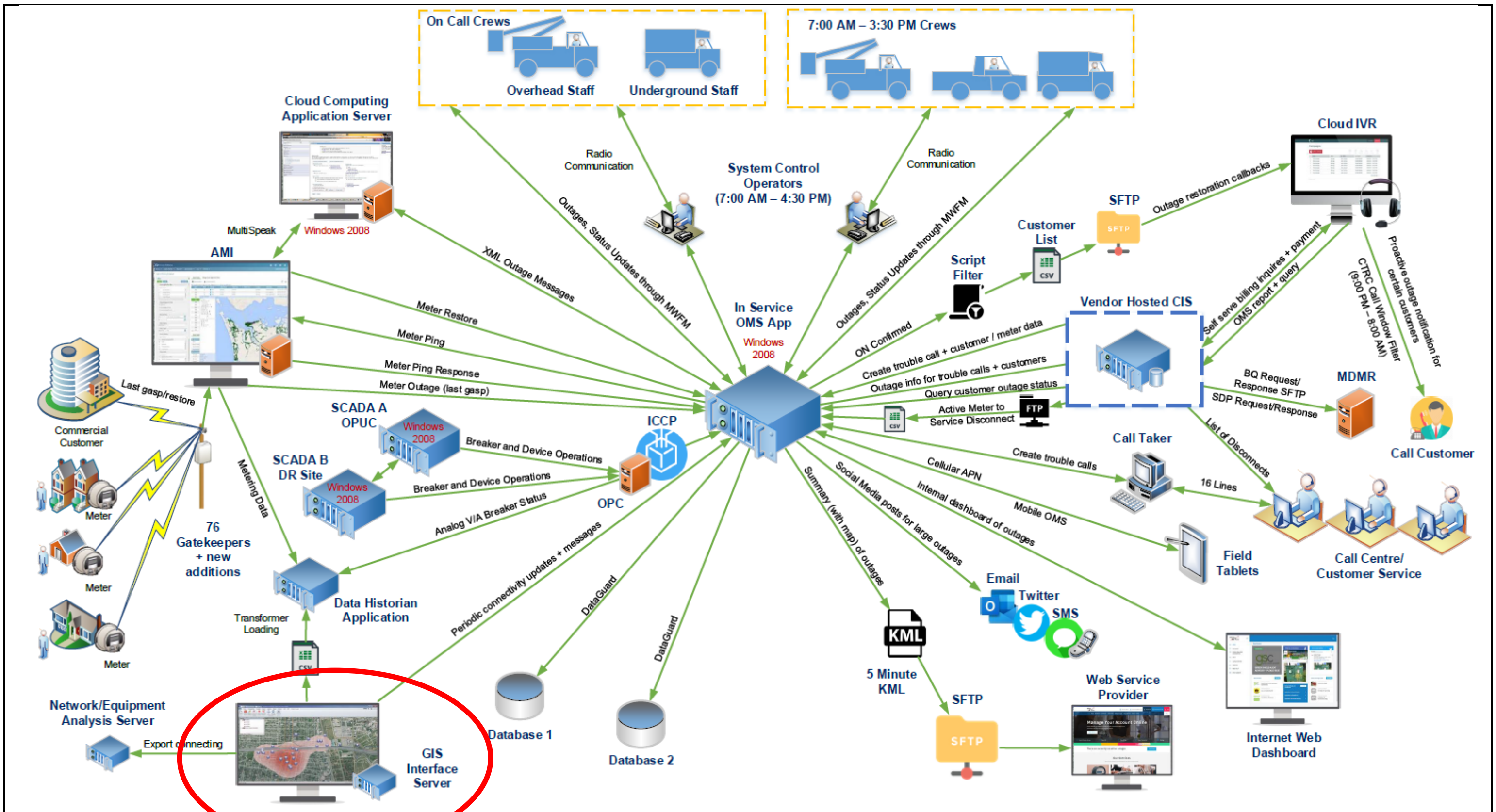


Figure 59: GIS Integration with OMS system

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)
Efficiency, Customer Value & Reliability – Investment Main Driver
Having accurate and accessible system maps allows staff and complimentary systems, such as the OMS, to quickly and safely respond to system interruptions, perform more accurate asset analytics, and perform system maintenance to ensure data validity, through field data collection, third party data imports, and data model enhancements, while meeting all cyber security requirements. The integration of the design systems will further improve the accuracy and timeliness of the data. All of the above is proposed to improve the overall operational efficiency of the systems and users who utilise the GIS and its related systems.
Efficiency, Customer Value & Reliability – Investment Secondary Driver
There are no secondary drivers.
Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets
The primary objective is to maintain validity of the GIS system both for internal use and for external customer facing applications to address operational efficiency and effectiveness.

Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment

The justification for this investment was driven through multiple sources. These were primarily from:

- Grid Modernization Plan provides a roadmap for future needs.
- Daily use of the current GIS system and its limitations. As the GIS is used throughout the company on a daily basis, limitations to its usability are common. Some of the limitations identified are:
  - Field staff need to enter the office to view and print maps when responding to afterhours outages or rely on potentially outdated paper maps. This results in reduced efficiency and potential safety issues.
  - Missing connectivity and streetlight data diminishes the ability to more accurately model transformer and system loading resulting in the need to rely more heavily on assumptions and generalisations
  - Stale land base and raster data requires the use of additional software to locate infrastructure, resulting in inefficiency.
  - As new asset types are added to the field (i.e. EV chargers, distributed generation) the current data model of the GIS does not allow these assets to be accurately modeled resulting in the need for inefficient work-arounds.
- Comparison to other LDCs and their business operations through field visits and discussions with neighbouring utilities on how their staff interact with their GIS.

Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges

An up-to-date GIS system will allow the data model to most accurately reflect the current state of the network. This will allow crew members to respond to system interruptions more quickly which will improve system reliability. By performing regular data model enhancements to the GIS, OPUCN will be able to accurately model the true state of the distribution network and respond to any new technologies introduced into it.

Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment

Having up-to-date software and accurate data models supports all aspects of the utility and is relied upon by various departments throughout the utility. Failure to maintain the system will result in loss of confidence in its usefulness and cybersecurity risks due to software obsolescence. This project has a medium priority when looking at the level of AM objectives met identified in Section 5.3.1.

Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness

The following subprojects to the GIS maintenance and upgrade project will have the following effects on system operation efficiency and cost-effectiveness.

- Regularly Scheduled System Upgrades – OPUCN has experienced 2 service interruptions to the GIS system due to windows security updates being incompatible with older versions of the GIS system. These interruptions resulted in wasted man hours troubleshooting the issues and loss of access to the data resulting in the need for less efficient work arounds. By scheduling upgrades on a more frequent basis we will mitigate the risk for service interruptions due to similar reasons. Delaying windows security updates is not an option as it would introduce security vulnerabilities into the corporate network.
- Import of updated city landbase, raster images, streetlight data, and associated connectivity – The land base for the GIS is currently 2 years old and in need of an update to allow users to quickly locate addresses, view property lines and building outlines, and view newly constructed streets. Not updating the land base will mean the GIS land base will continue to fall out of sync with new builds in the city, resulting in users having to rely on third party applications to locate areas, reducing the operational efficiency. The raster images are currently 5 years old and do not reflect the recent developments in the city. Not updating the raster image has the same effect as the land base. Importing the streetlight data allows for more accurate billing of streetlight connections and more accurate analysis of transformer and feeder loading.

- Establishment of Mobile Mapping – Field crews currently need to rely on potentially out-dated paper maps or return to the office to print out new maps when performing switching and responding to service interruptions. Providing mobile access to the GIS will eliminate this need, increasing the overall operational efficiency. Allowing field crews will to input data directly into the GIS will also eliminate the need for transcription from paper to GIS which improves operational efficiency and reduces the risk for transcription errors.
- Integration of CMMS and GIS – Building an automatic integration between the GIS and CMMS will keep both systems in sync with each other. Without this integration, information collected through the CMMS will need to be manually input into GIS and vice-versa. This will result in reduced operational efficiency and introduce a greater risk that some data will be missed which could, in turn, introduce safety or reliability issues if an asset is not properly identified in both systems.
- Regular Data Model Updates – The assets introduced into the distribution network is constantly evolving. Having a data model that accurately reflects the real world assets allows for accurate analysis of the system. Not including these assets in the GIS could introduce safety risks in the field especially if distributed generation assets are not modeled in the system.
- Integration of Design Software – The current workflow for design technicians is to export the target area for design from the GIS system to get the existing infrastructure in that area. They then overlay that data over data gathered from other sources as required (surveys, customer owned assets, etc.). A design is then completed on those areas in AutoCAD. This design is exported to SpidaCALC for engineering analysis where the design parameters are manually copied from AutoCAD to SpidaCALC. This is an iterative approach until the entire design is validated by the software. The design parameters are then manually transcribed into the work estimate software to establish a full estimate for the job. After complete construction of the job, the as-built conditions of the assets in the field are manually entered into the GIS. By integrating the various software systems involved in the process, the manual transcription between the systems will be drastically reduced or eliminated. This will improve the overall efficiency of the design technicians as they no longer need to copy data from one system to another. It is estimated that a return on investment will be seen in 4 years from full system implementation. It will also reduce the risk of transcription errors.

Analysis of Project & Alternatives – Net Benefits Accruing to Customers

Upgrades to the GIS system maintain its integrity and the accuracy of the data model allowing staff to minimize outages and complete work as efficiently as possible. Improving the operational efficiency of the GIS, its integrated systems, and the users that interact with them, results in better response time to system interruptions and shorter design time for customer requested upgrades.

Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages

Having up-to-date maps in the field allows crews to quickly assess and respond to service interruptions. Field access to accurate maps allows the crews to respond on scene without the need to return to the office to get updated information or rely on potentially out-dated paper maps. This would reduce the overall service interruption experienced by the customer.

Updated and accurate data models also allow for better asset analytics to assist with pre-emptive maintenance to prevent in field failure assets. This will reduce the overall frequency and duration of service interruptions experienced by customers.

Project Alternatives (Design, Scheduling, Funding/Ownership)

1. Do Nothing
    a. This would result in the GIS system and its data becoming obsolete and is not a viable option.
2. Switch Vendors
    a. Switching to a new vendor has the potential of lowering operational costs but will result in an increased capital expenditure both for the purchase and configuration of the new system as well as its integration to existing systems such as the OMS.
3. Partial Implementation

a. Regular system upgrades are a requirement as they ensure the system remains operational and does not impede windows security updates and therefore must be done. b. The stale city land base and streetlight data are quickly becoming unreliable and need to be updated to maintain the accuracy and usefulness of the system. c. Access to the GIS in the field is becoming increasingly important and the distribution network becomes increasingly complex. Not providing field crews with access to mapping will result in the crews continued reliance on possibly outdated paper maps or the requirement for the crew to return to the office to view the network which is not operationally efficient and could introduce safety risks. d. The capital cost involved in integrating the design software will be offset by the operational efficiencies introduced by it, which will be realised in 2026, after full implementation. The return on investment for the integration is expected to be 4 years.
Safety
The GIS upgrade will allow for real-time access to the most current data in the field. This will improve the safety of the field crews working with the system by ensuring that they have the most current information on how the distribution network is configured.
Cyber-Security, Privacy (where applicable)
Overall project will comply with the recent OEB cyber-security framework.
Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)
The system will maintain its current co-ordination and interoperability with existing systems.
Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)
Utilise data model changes and system upgrades for future operational requirements.
Environmental Benefits (where applicable)
Not Applicable
Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)
Not Applicable
Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)
Not Applicable
Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity
Utilise data model changes and system upgrades for future operational requirements.

C. Category-Specific Requirements – System Service (5.4.3.2.C)
Assessment of Customer Benefits Based on Project Objectives and Cost Impact

Up-to-date and accurate GIS information allows staff to work most efficiently at restoring outages, system renewal and maintenance resulting in better reliability and safety of the system. By having in-field access to accurate system models, crews are able to identify and troubleshoot system interruptions faster and thus restore them faster.
Information on Regional Electricity Infrastructure Requirements Identified in the Regional Planning Process
Not Applicable
Description of how Advanced Technology has been Incorporated (where applicable)
The system will be integrated with other operational systems such as the data historian, OMS, Customer Information System and Advanced Metering Infrastructure System. By supplying these additional systems with accurate and timely data, they will be better able to predict potential asset failures and better predict outage locations. Having this information will allow for better business decisions in identifying areas for replacement to improve system reliability.
Identification of any Reliability, Efficiency, Safety and Coordination Benefits or Affects
The following subprojects to the GIS maintenance and upgrade project will have the following effects on system operation efficiency and cost-effectiveness. • Regularly Scheduled System Upgrades – OPUCN has experienced 2 service interruptions to the GIS system due to windows security updates being incompatible with older versions of the GIS system. These interruptions resulted in wasted man hours troubleshooting the issues and loss of access to the data resulting in the need for less efficient workarounds. By scheduling upgrades on a more frequent basis we will mitigate the risk for service interruptions due to similar reasons. Delaying windows security updates is not an option as it would introduce security vulnerabilities into the corporate network. • Import of updated city landbase, raster images, streetlight data, and associated connectivity – The land base for the GIS is currently 2 years old and in need of an update to allow users to quickly locate addresses, view property lines and building outlines, and view newly constructed streets. Not updating the land base will mean the GIS land base will continue to fall out of sync with new builds in the city, resulting in users having to rely on third party applications to locate areas, reducing the operational efficiency. The raster images are currently 5 years old and do not reflect the recent developments in the city. Not updating the raster image has the same effect as the land base. Importing the streetlight data allows for more accurate billing of streetlight connections and more accurate analysis of transformer and feeder loading. • Establishment of Mobile Mapping – Field crews currently need to rely on potentially out-dated paper maps or return to the office to print out new maps when performing switching and responding to service interruptions. Providing mobile access to the GIS will eliminate this need, increasing the overall operational efficiency. Allowing field crews will to input data directly into the GIS will also eliminate the need for transcription from paper to GIS which improves operational efficiency and reduces the risk for transcription errors. • Integration of CMMS and GIS – Building an automatic integration between the GIS and CMMS will keep both systems in sync with each other. Without this integration, information collected through the CMMS will need to be manually input into GIS and vice-versa. This will result in reduced operational efficiency and introduce a greater risk that some data will be missed which could, in turn, introduce safety or reliability issues if an asset is not properly identified in both systems. • Regular Data Model Updates – The assets introduced into the distribution network is constantly evolving. Having a data model that accurately reflects the real world assets allows for accurate analysis of the system. Not including these assets in the GIS could introduce safety risks in the field especially if distributed generation assets are not modeled in the system. • Integration of Design Software – The current workflow for design technicians is to export the target area for design from the GIS system to get the existing infrastructure in that area. They then overlay that data over data gathered from other sources as required (surveys, customer owned assets, etc.). A design is then completed on those areas in AutoCAD.

This design is exported to SpidaCALC for engineering analysis where the design parameters are manually copied from AutoCAD to SpidaCALC. This is an iterative approach until the entire design is validated by the software. The design parameters are then manually transcribed into the work estimate software to establish a full estimate for the job. After complete construction of the job, the as-built conditions of the assets in the field are manually entered into the GIS. By integrating the various software systems involved in the process, the manual transcription between the systems will be drastically reduced or eliminated. This will improve the overall efficiency of the design technicians as they no longer need to copy data from one system to another. It is estimated that a return on investment will be seen in 4 years from full system implementation. It will also reduce the risk of transcription errors.

Identification and Explanation of the Factors Affecting Implementation Timing/ Priority

The cadence of system upgrades must be maintained every two years to allow for regular windows security updates and avoid obsolescence of the GIS system.

Regular data model upgrades are required to account for the ever increasing variety of equipment deployed in the distribution network to maintain data validity of the GIS model.

Analysis of Project Benefits and Costs Comparing to a) Doing Nothing and b) Technically Feasible Alternatives

1. Do-Nothing
    a. This would result in the GIS system and its data becoming obsolete and is not an option.
2. Switch Vendors
    a. Switching to a new vendor has the potential of lowering operational costs but will result in an increased capital expenditure both for the purchase and configuration of the new system as well as its integration to existing systems such as the Outage Management System (OMS).
3. Partial Implementation
    a. Regular system upgrades are a requirement as they ensure the system remains operational and does not impede windows security updates and therefore must be done.
    b. The stale city land base and streetlight data are quickly becoming unreliable and need to be updated to maintain the accuracy and usefulness of the system.
    c. Access to the GIS in the field is becoming increasingly important and the distribution network becomes increasingly complex. Not providing field crews with access to mapping will result in the crews continued reliance on possibly outdated paper maps or the requirement for the crew to return to the office to view the network which is not operationally efficient and could introduce safety risks.
    d. The capital cost involved in integrating the design software will be offset by the operational efficiencies introduced by it, which will be realised in 2026, after full implementation. The return on investment for the integration is expected to be 4 years.

A. General Information (5.4.3.2.A)					
Project/Activity	Outage Management System (OMS) Upgrade				
Project Number	SS-08				
Investment Category	System Service				
	2021	2022	2023	2024	2025
Capital Cost	$25,000	-	$100,000	-	$50,000
Capital Contribution	N/A	N/A	N/A	N/A	N/A
Net Cost	$25,000	-	$100,000	-	$50,000
O&M Cost	2021	2022	2023	2024	2025
	$5,000	$5,000	$5,000	$5,000	$5,000
Customer Attachments and Load					
Not Applicable					

Start Date	2021-2025	In-Service Date	2021-2025

Expenditure Timing for the Planning Horizon	2021Q1	2021Q2	2021Q3	2021Q4
2021	$25,000	0	0	0
Project Summary				

The Outage Management System (OMS) upgrade project will provide better stability, prediction, customer integration, and customer information. Upgrade will ensure system is compliant on current Windows OS platform. Upgrade enhancements include advanced restoration time algorithms, better trouble analysis processes, improved switching simulators, and user security enhancements. Software maintenance O&M costs are change in delta for new software procured for the OMS system. In 2023, there will a major software release and upgrade to maintain compliance with Windows OS platform, costs are for services from the OMS vendor to provide data schema database changes along with software installation and configuration. The cost in 2025 will provide outage information on new remote platforms to provide outage restoration information faster for our customers. The following diagrams provide a high-level schematic on how the OMS is integrated to the current systems. The first diagram below show initial deployment and process flow connectivity in 2015 to systems for interoperability. The 2nd diagram below shows further development of the OMS output for dispatching to crews, Automated Voice dialer to customers and social media (web outage map, twitter/facebook) when we have an outage. OPUCN included a customer service desk application which would allow customers to call into customer service to update the outage map and/or provide real time outage information on a customer by customer basis.

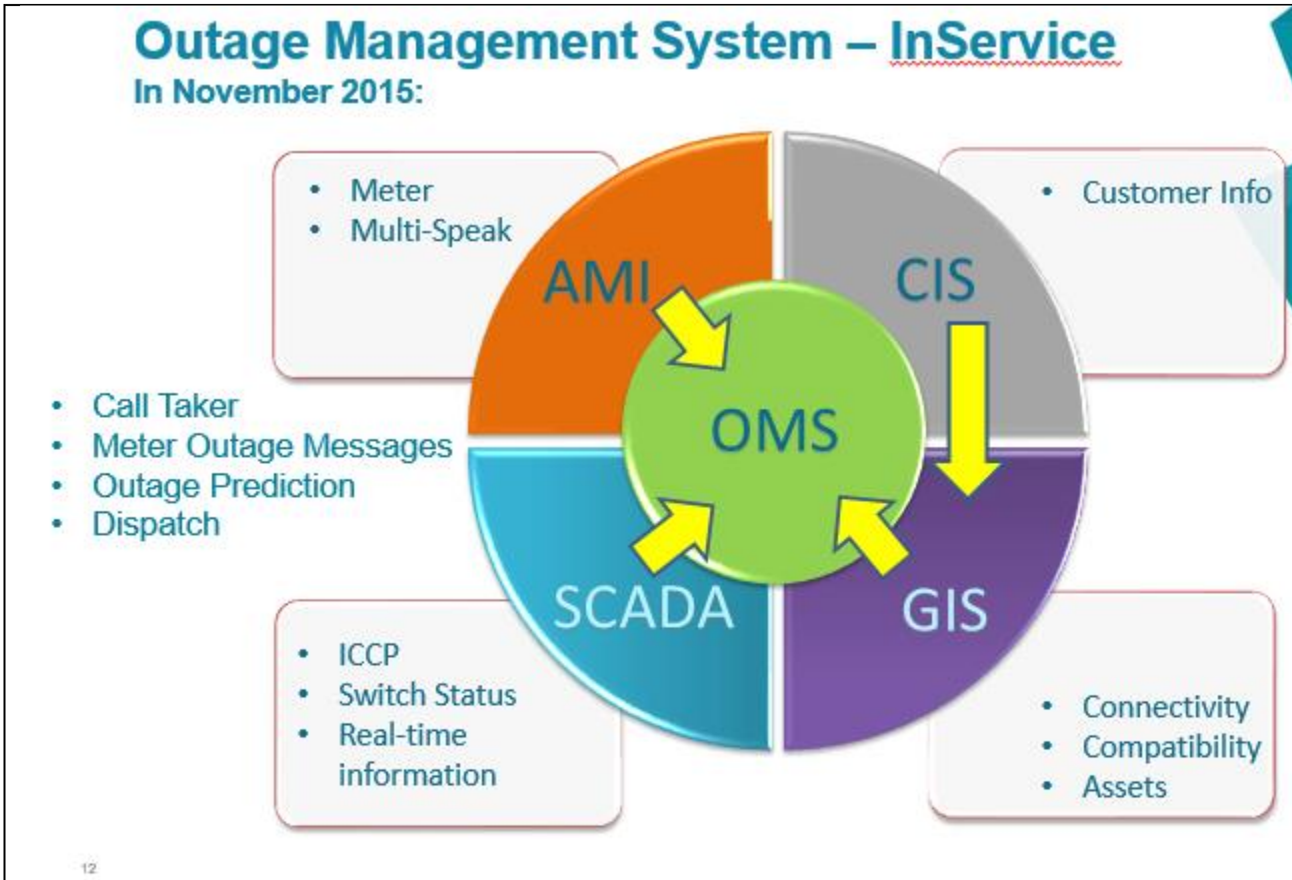


Figure 60: OMS November 2015

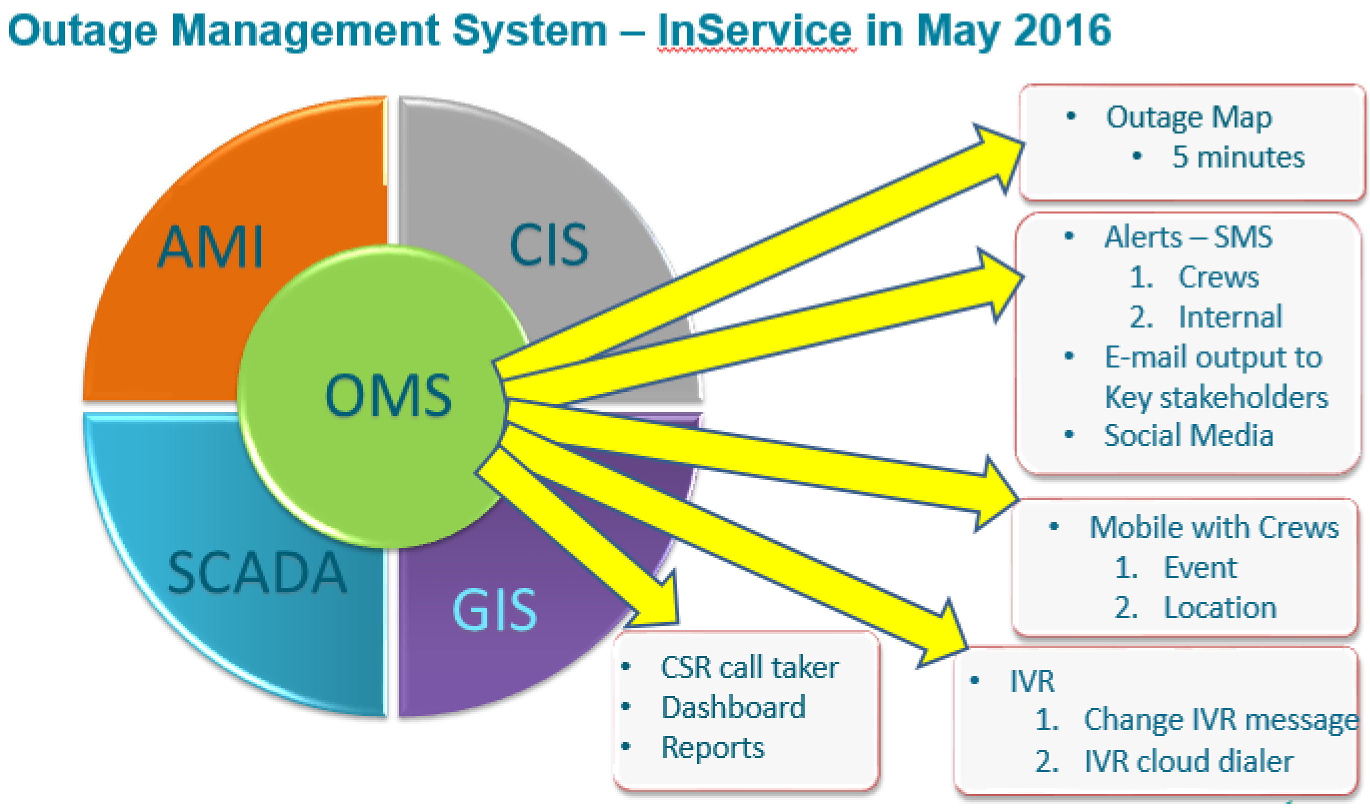


Figure 61: OMS May 2016

Risk Identification & Mitigation
The biggest risk with the OMS upgrade is the connectivity model supply. Mitigation would be to run the upgraded system in development mode until all integration processes are tested and completed. System testing of all outputs and response to simulated meter outages proved that the OMS system worked as designed by predicting the outage location correctly and dispatching outage information to the IVR, e-mail, text messaging, social media and the outage maps with outage shape files depicting outage location. The testing team evaluated and all scenarios that were known at the time of implementation, giving the OMS System the approval to proceed to production. At each upgrade, the OMS testing team must run through the script tests to validate that the system worked the same as the original system design, and that the system will predict outages with the changes to the prediction model/process. Predicting the outage faster and providing customer information faster is always the goal. There is a perceived scheduling risk during the planned upgrade in 2023 and cutover from the old version OMS to the newer version. Project planning and User Acceptance Testing must be completed prior to cutover. Running the system in parallel to production prior to cutover will be planned and project delay and cost over-runs are controlled by planning, statement of work and co-ordination within OPUCN Information Technology (IT) and Operational Technology (OT) groups.
Comparative Information on Expenditures for Equivalent Projects/Activities
The OMS system upgrade costs are based on historical invoices and budgetary quotes. There are no direct comparative information as the scope are different during the planning period. The investment costs would involve hardware computer systems, databases, and software. Yearly maintenance costs are based upon 20% of the value vendor maintenance costs along with yearly specific OPUCN customization to fit existing processes.

Historical Costs ($ '000)						Forecast Costs ($ '000)				
2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
-	-	-	-	-	100	25	-	100	-	50

REG Investment Details including Capital and OM&A costs

As this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.

Leave to Construct approval under Section 92 of the OEB Act

This project is below 50 kV and therefore Leave to Construct is not required, as per O.Reg. 161/99.

Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material

The OMS system went into production in part production in 2015, with full production in 2016. Due to Windows Server 2008 no longer being supported we are required to upgrade our OMS. This contract is to get the Hexagon to upgrade our system from 9.2 to 9.3. In 2023 Windows Server 2012 will no longer be supported, the OMS system will need to upgrade again in 2023. Vendor support for the software (as it is an infrastructure and safety product) is a software system lagging technology.

The following diagrams are additional high-level schematics showing integration of OMS to existing systems and the process flow for line crews to utilize the mobile application, OPUCN does not have a 24/7 staffed control room, dispatching from the OMS is automated to the line crews from predicted outages. Not having a 24/7 staff control room reduces OM&A costs but continues to provide high quality service:

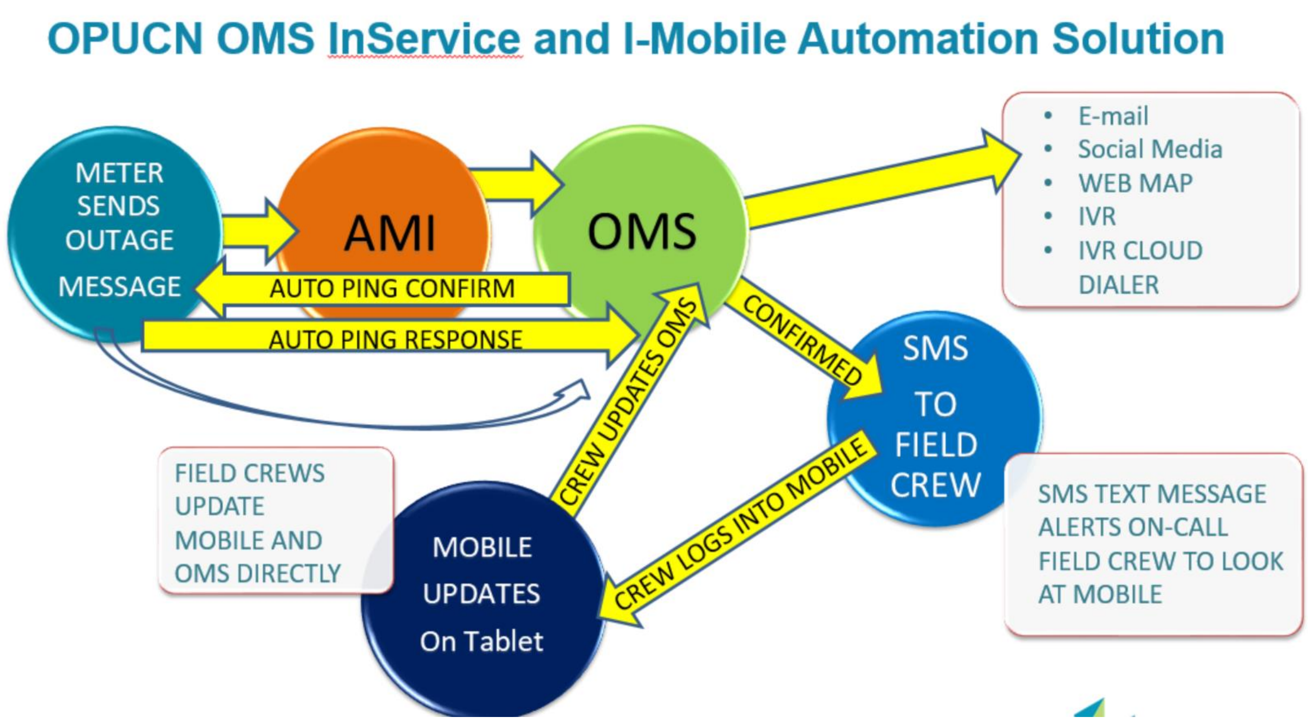


Figure 62: OMS Automation Solution

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)
Efficiency, Customer Value & Reliability – Investment Main Driver
Operational Efficiency through better prediction that will lead to reduced restoration time and therefore improved Reliability and better integration to BI Analytical systems that will help with predictive equipment failure which also improves reliability and customer service as well as customer access to data providing better information to customers and customer integration using mobile devices. This will also provide easier customer input to update the OMS.
Efficiency, Customer Value & Reliability – Investment Secondary Driver
There are no secondary drivers.
Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets
The investment objective is to be able to develop ability to accurately predict outage causes/devices 20% of the time better than existing systems or processes. The purpose of 2023 upgrades is to maintain the system on Windows server supported systems.
Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment
During momentary outages and breaker events, the cause of the outage is difficult to locate due to the limitations of the information supplied to the OMS (meter/SCADA/fault indicators), integration of oscillography to the predictive analytics of the OMS would enhance prediction to reduce feeder patrol time and improve reliability.
Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges
System automation integration will improve reliability and predictability to provide faster response and restoration.
Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment
The continued upgrading of the OMS will improve reliability and improve customer service. The system upgrade and maintenance is a high priority as it is the automated interface for customers during outages and addresses most of OPUCN's AM objectives identified in Section 5.3.1.
Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness
This investment will have the ability to accurately predict outage causes/devices better than the existing systems or processes when combined with the AMI system upgrades.
Analysis of Project & Alternatives – Net Benefits Accruing to Customers
Project scope includes enhancement and upgrades to the current system. Alternatives to this project would be to use different vendors. Previous analysis of vendors resulted in mixed results of AMI system integration specifically in regards to momentary outages and false outages due to AMI response to momentary power loss (<1 minute). Better information to customers in web presentment and data/phone call push during confirmed outages.
Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages
Accurate prediction of outage causing devices can provide a reduction in duration during breaker events when combined with the AMI system updates.

Project Alternatives (Design, Scheduling, Funding/Ownership)
Alternatives to replacement of the OMS were considered, but due to the size of investment in 2015 and the currently functionality available there are no alternatives at this time.
Safety
Better prediction of the outage device will improve safety as the time that the equipment in the field is under fault will be reduced.
Cyber-Security, Privacy (where applicable)
System integration will adhere to the current OEB Cyber Security Framework.
Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)
The system will have Multi-speak, Common Message Bus, ICCP, XML, Soap as part of the integration processes. **Multi-speak:** MultiSpeak is ideally suited to supporting a strategic, SOA-based integration architecture or it can be realized in a tactical point-to-point approach with simple transport layer security. A bus architecture makes it easier for a single application uniformly to support services for a number of other software packages in place at a utility. Structuring the web services in this manner also helps to support a service oriented architecture (SOA). Figure 1 illustrates the MultiSpeak service bus architecture. As shown in the Figure, MultiSpeak supports a number of functions (represented by the single boxes, for example, CD: Connect/Disconnect). Software vendors offer products that will contain one or more functions combined into applications. This functional decomposition permits applications to flexibly support only those functions that are important for that vendor's desired integration and also supports the reusability of interface functionality. The Notification (NOT) endpoint enables any application to subscribe to any number of publish-type messages provided by a wide variety of publishers. **Common Message Bus:** An enterprise contains several existing systems that must be able to share data and operate in a unified manner in response to a set of common business requests.

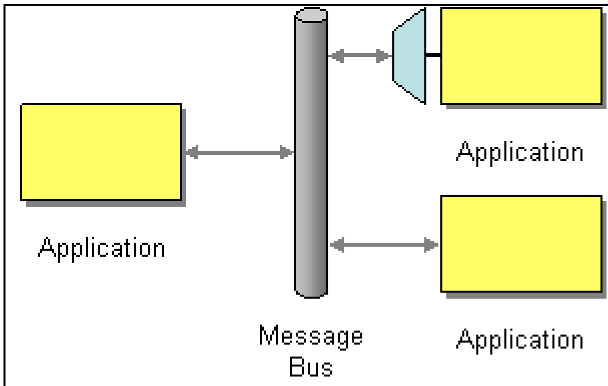


Figure 63: Common Message Bus

Structure the connecting middleware between these applications as a *Message Bus* that enables them to work together using messaging.

A *Message Bus* is a combination of a common data model, a common command set, and a messaging infrastructure to allow different systems to communicate through a shared set of interfaces. This is analogous to a communications bus in a computer system, which serves as the focal point for communication between the CPU, main memory, and peripherals.

ICCP:

The Inter-Control Center Communications Protocol (ICCP or IEC 60870-6/TASE.2)is being specified by utility organizations throughout the world to provide data exchange over wide area networks (WANs) between utility control centers, utilities, power pools, regional control centers, and Non-Utility Generators. ICCP is also an international standard: International Electrotechnical Commission (IEC) Telecontrol Application Service Element 2 (TASE.2).

XML and SOAP:

The design goals of XML emphasize simplicity, generality, and usability across the Internet.[6] It is a textual data format with strong support via Unicode for different human languages. Although the design of XML focuses on documents, the language is widely used for the representation of arbitrary data structures[7] such as those used in web services.

Several schema systems exist to aid in the definition of XML-based languages, while programmers have developed many application programming interfaces (APIs) to aid the processing of XML data.

OMS interface between systems showing the Multi-speak interface connections between the Meter data collection server system and the Outage Management System for power restoration and power service checking, also indicates outputs to the automated voice dialer and social media, with a source input from the GIS for Mapping:

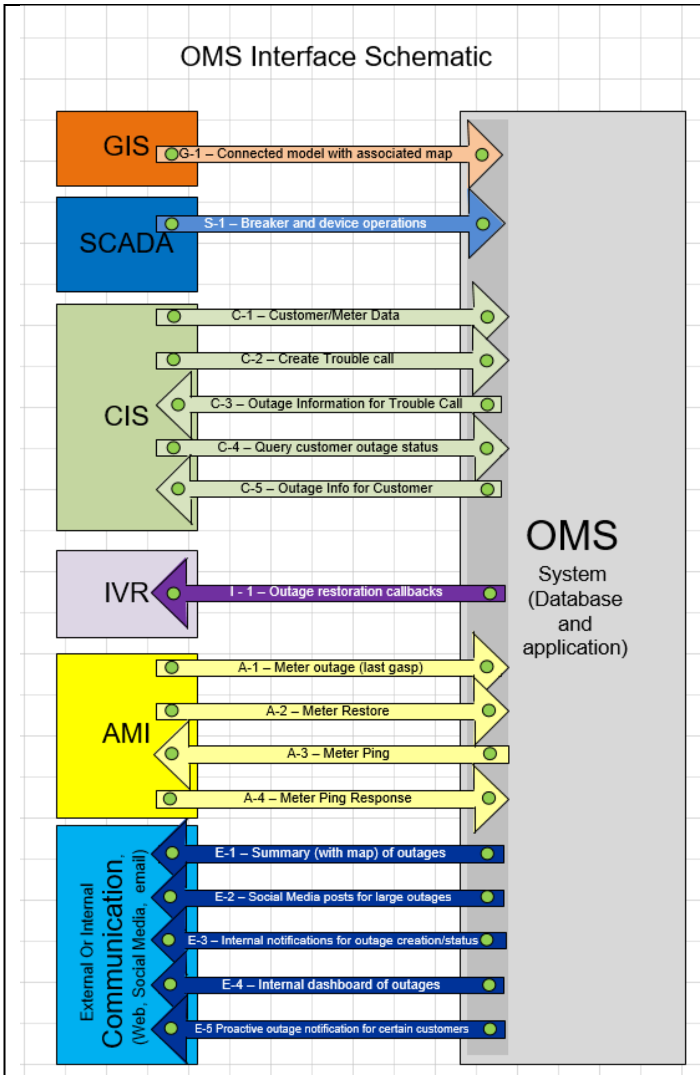


Figure 64: OMS Interface Schematic

Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)
The OMS upgrade will be developed with the next gen communication and meter technologies. Connectivity to the "cloud" mobile apps, customer facing integration will be part of the design of the OMS upgrade.
Environmental Benefits (where applicable)
Not Applicable
Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)
Not Applicable
Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)

Not Applicable
Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity
The OMS upgrade will be developed with the next gen communication and meter technologies. Connectivity to the "cloud" mobile apps, customer facing integration will be part of the design of the OMS upgrade.

C. Category-Specific Requirements – System Service (5.4.3.2.C)

Assessment of Customer Benefits Based on Project Objectives and Cost Impact

Reliability will be improved by improving predictive outage locations. Customer benefit would be outage time would be less due to better prediction. Ideally under the current system there are filter delay time of 20 minutes before an accurate prediction can be made due to momentary outages. If there are no momentary breaker operations, 20 minutes of filter time from AMI can be removed. Therefore, improving response time.

The head end outage management system automatically determines the connected event location and automatically sends out information to line crews, and customers through SMS and IVR dialer. The OMS also automatically updates an outage map with geographical information. The OMS sends information to Social media for customers to see.

OMS provided outage information on part power calls prior to the customer realizing that they had an outage. The OMS dispatched to crews that the customer had an outage and line crews determined that there were part power problems at the customer location. This was a result of bi-metallic corrosion as shown below:

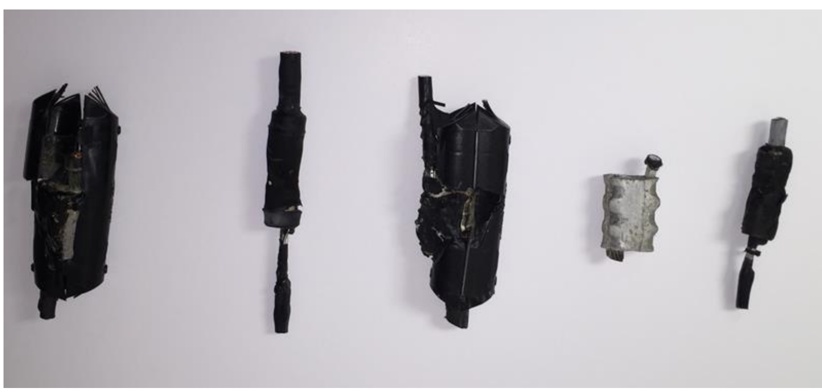


Figure 65: Photo of bi-metallic corrosion

Information on Regional Electricity Infrastructure Requirements Identified in the Regional Planning Process

Not Applicable

Description of how Advanced Technology has been Incorporated (where applicable)

Using AMI, Supervisor Control and Data Acquisition (SCADA), Smart Grid (smart fault indicators, smart switches, and Municipal Stations), and Geographic information System (GIS) integrated to a single platform to predict outage location. Use SMS to dispatch to crews and social media to provide information to customers. OPUCN automatically dispatches outages to line crews (no operators). The system automatically dispatches information to the outage map, phone dialer, and social media.

Identification of any Reliability, Efficiency, Safety and Coordination Benefits or Affects
Reliability improvement due to reduced response times. Efficiency in dispatching to crews where the location of the outage is.
Identification and Explanation of the Factors Affecting Implementation Timing/ Priority
This is about co-ordination of system upgrades and resource constraints as SCADA, Operational Data Store (ODS), CIS, AMI, e-mail, IVR, network switches, upgrades all take place over the next 5 years. Scheduling of other system upgrades will be done so that there is no upgrade conflict. The OMS would need to be upgraded in 2023 as the current system server software support would necessitate a system upgrade Microsoft server version to the next version of software due to support and cyber security. If a system is not capable of being upgraded prior to the OMS scheduled upgrade, this may delay the OMS upgrade 2-3 months. Typically the OMS upgrade would take place in a 2-3 month time span (including testing, measurement and validation). Priority of the OMS upgrade is high, based upon the direct interfacing to customers, through the outage map, social media, and automated outage dialer.
Analysis of Project Benefits and Costs Comparing to a) Doing Nothing and b) Technically Feasible Alternatives
Doing nothing would impact risk due to cybersecurity and would mean a lost opportunity to improve reliability. The system must be upgraded on platforms that are current and supported by Microsoft. The vendor provides the commercial off-the-shelf (COTS) OMS system with a tested and proven software that is N-2 Microsoft Server systems behind the current Microsoft server version. Changing to a different vendor, which would be a software and implementation cost equivalent to the original cost of the OMS procured and implemented in 2015/2016. There is no current alternative vendor that can implement an OMS to provide better outage prediction that our current system. The outage management system is a high ranking item for projects. Doing nothing would leave the system at status quo. Vendor proposed upgrades in 2023 would allow better and easier connectivity to crews for dispatching and restoration. Ranking of the OMS system for support and upgrade is high, due to the automated customer interfaces (outage map, IVR dialer, social media, automated outage capture).

A. General Information (5.4.3.2.A)					
Project/Activity	Upgrades and Enhancements to ODS Systems				
Project Number	SS-09				
Investment Category	System Service				
	2021	2022	2023	2024	2025
Capital Cost	$100,000	$100,000	$100,000	$100,000	$100,000
Capital Contribution	N/A	N/A	N/A	N/A	N/A
Net Cost	$100,000	$100,000	$100,000	$100,000	$100,000
O&M Cost	2021	2022	2023	2024	2025
	-	-	-	-	-

Customer Attachments and Load

Not Applicable

Start Date	2021-2025	In-Service Date	2021-2025

Expenditure Timing for the Planning Horizon	2021Q1	2021Q1	2021Q1	2021Q1
	$25,000	$25,000	$25,000	$25,000

Project Summary

Implementation and continued development of Operational Data Store (ODS) with Business Intelligence (BI) analysis to assist corporate and management in making informed business decisions based on objective data gathered through a variety of data sources. These sources will be comprised of Supervisory Control and Data Acquisition (SCADA), Automated Metering Infrastructure (AMI), Geographic Information Systems (GIS), Customer Information System (CIS) and field information. The purpose of the ODS is to provide information to internal staff regarding assets. It will send automated alerts to staff to review data on an asset and take action through automated process control. The ODS can be setup to send more details information to customers, regarding their meter, transformer, and system information. It can also provide the customer with alerts regarding meter and transformer information.

Risk Identification & Mitigation

1. Insufficient Internal Resources – Staff dedicated to ODS system may be required on other projects
   a. Stagger system upgrade projects to limit project overlap of internal resources
2. Budgetary estimates based on initial ROM from vendor are significantly below the firm pricing obtained after procurement process is complete
   a. Review detailed scope of work with vendor prior to signing PO to ensure all requirements are met. Spread project over multiple years to reduce costs.

Comparative Information on Expenditures for Equivalent Projects/Activities

There are no comparative information for equivalent projects as the implementation of the commercial off-the-shelf (COTS) solution is customize. The integration is with existing systems. Future spending is to assist with asset management automated alerts to help internal staff look at assets proactively and not reactively.

This program commenced in 2020 with expected completion by 2025.

Historical Costs ($ ‘000)						Forecast Costs ($ ‘000)				
2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
-	-	-	-	-	100	100	100	100	100	100

REG Investment Details including Capital and OM&A costs
As this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.
Leave to Construct approval under Section 92 of the OEB Act
This project is below 50 kV and therefore Leave to Construct is not required, as per OEB.Reg. 161/99.
Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material

Please refer to the following diagrams regarding ODS system integration. The Operational Data store is the hub of data from all operational systems. The relationship of having outage data paired with energy data from multiple data collection systems is very helpful to assess the impact of what an outage causes on energy consumption. SCADA system data when compared to summated meter energy values helps to ensure that the energy we are receiving from the grid is being delivered to our customers with all known losses.

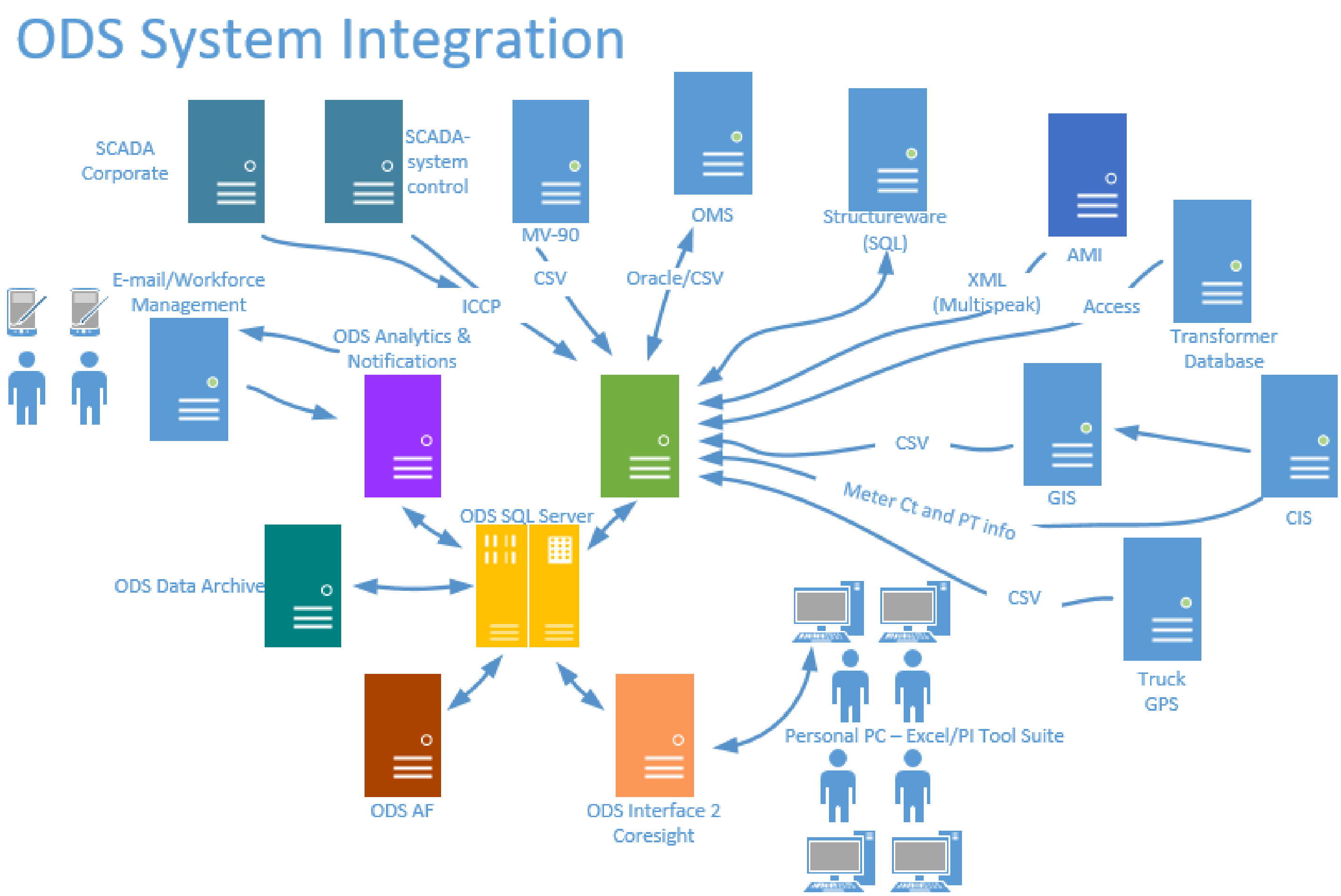
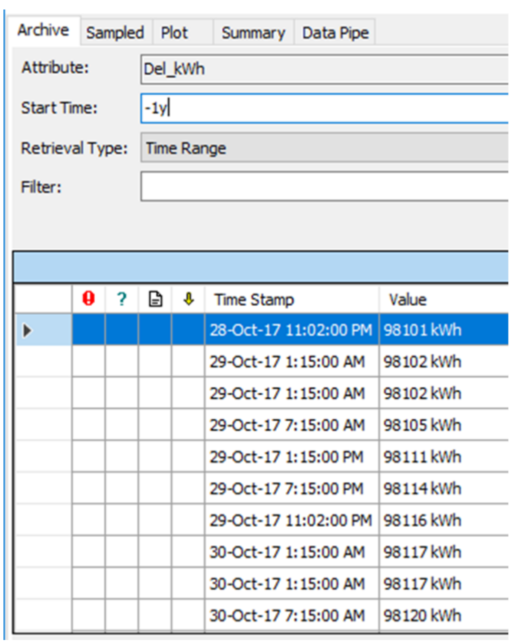


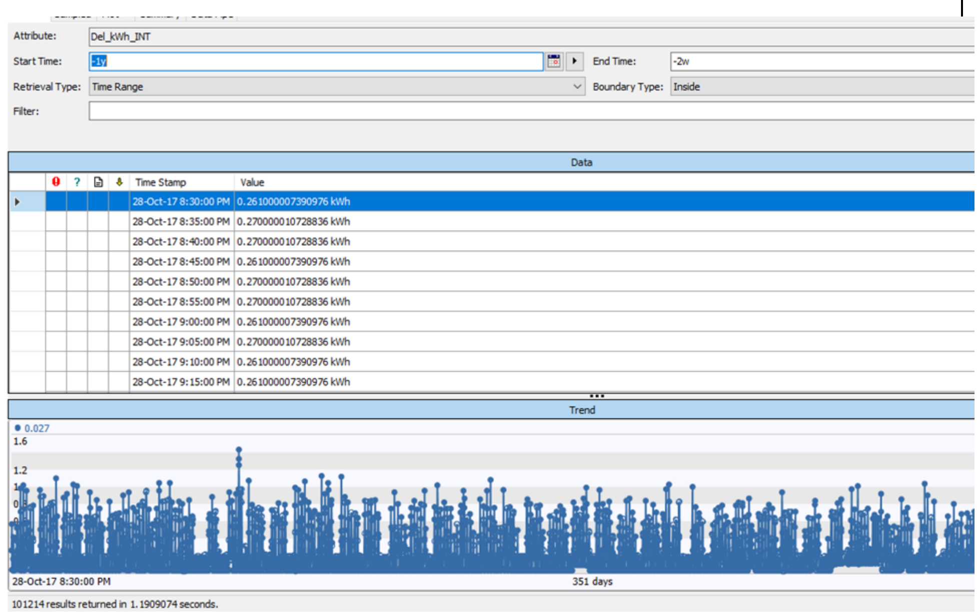
Figure 66: ODS System Integration

Proposed display screen in the following is for customer viewing, this display screen is currently in development for in-house staff, display would show all information relevant for each customers service including Measurement Canada reverification, multipliers, consumption, outage information (last outage, history of outages, outage confirmation) and voltage information (voltage history):

Figure 67: Proposed Display Screen

The following figures provides a future concept Interface proposed for internal staff with simplification for customer:





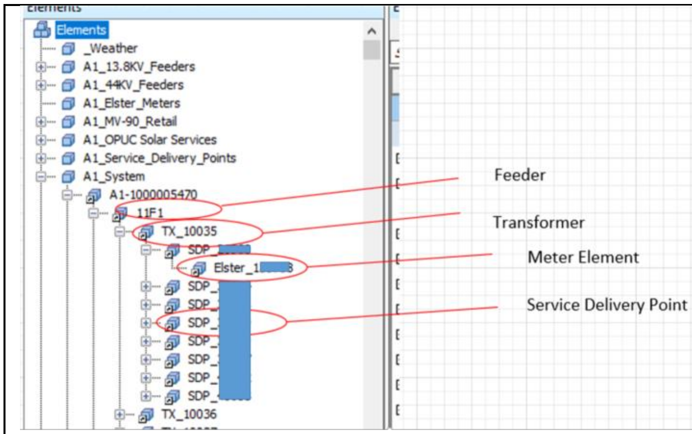


Figure 68: Display Concept

The display below shows details of transformer with graphic for asset management and history:

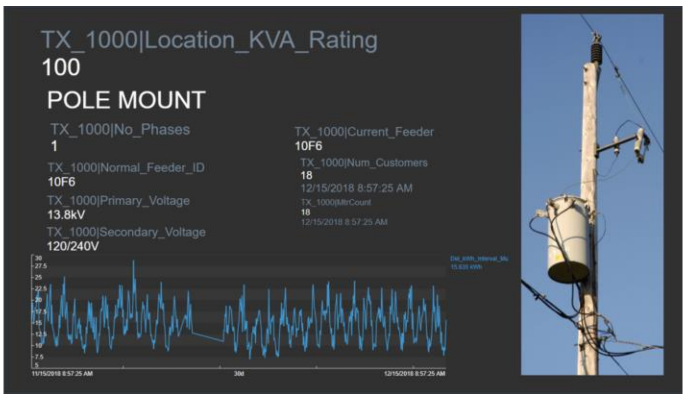


Figure 69: Transformer Display Detail

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)

Efficiency, Customer Value & Reliability – Investment Main Driver

The main driver for this investment are:

- Increased Operational Efficiency through intelligent analysis of objective data through activities such as forecasting asset failure and predicting and correcting billing issues.
- Better Customer Visibility to utility operations through web presentment
- Better analysis of power flow, ACA, risk to power flow assessment
- Cost analysis of power flow to asset condition and risk.
- Forecasting power flow cost to system based upon historical and predicted weather, short and long term.
- Analysis of equipment outages and impacts to power flow/cost

Efficiency, Customer Value & Reliability – Investment Secondary Driver

There are no secondary drivers
Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets
• This will provide an additional platform for a risk-based ACA and will be able to integrate to a future ADMS which will help in maintaining system reliability and improving operational efficiency.
Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment
• The source of information used to justify the investment is the Grid Modernization Plan (refer to Appendix K) • Data is currently stored in multiple databases, due to the volume of data, metadata processing is difficult and takes a lot of resources, combining key elements of operational data assists in the processing of large volumes of data automatically.
Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges
• Will be the foundation for adapting to changing customer demands in terms of DER, electric vehicles and changing customer loading.
Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment
This is a medium priority when compared to the level of AM objectives being met, however, ODS is a major piece of system analytics for any future fully integrated bi-directional grids.
Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness
• Single source of data allowing for easier analysis and reporting, reducing time or eliminating effort spent on connecting disparate data sources • Data-based condition asset replacement resulting in more cost effective asset replacement • Greater interoperability with existing systems to improve business efficiency • Alternative to this system would be to use/purchase an off the shelf system that cannot be customized directly. One alternative was to use a system that would cost $100,000 in OM&A per year. Without all of the additional combined system integration functionality. • Ability to identify system losses on a daily / feeder level basis for the entire system (all the time). Currently this would be limited to pilot projects in limited areas for a limited period. These pilot projects to find losses normally were in targeted areas and would be labour / equipment intensive. Use the equipment assets already deployed and utilize the currently available data to determine if there is energy diversion or metering failure/errors.
Analysis of Project & Alternatives – Net Benefits Accruing to Customers
• Not expected to result in significant cost savings, however, the improved reliability from better asset management and more informed and efficient business decisions will provide a net benefit to customers • Proactive asset replacement using real Meter Data and feeder loading information combined with weather information. • Automated Alerts to internal staff regarding an asset going outside of a pre-defined limit. Traditionally this type of alert was limited to a Transformer Station or Municipal station. We are looking to have this available for ALL assets deployed by OPUCN. • Automated alerts sent to customers regarding consumption usage above a set threshold or a threshold that the customer would like to specify.
Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages

• Better visualisation of asset conditions will result in risk-based asset replacement reducing the duration of outages as these will be completed on schedule versus unscheduled. OPUCN will assess each outage with our ODS and the impact of the energy consumption due to a power outage. Outage information from the OMS when supplied to the ODS will be able to provide each customer a detailed history of outages and duration, through web presentment (online).
Project Alternatives (Design, Scheduling, Funding/Ownership)
The other alternative identified is to "do nothing," however, this alternative continues to spend time manually connecting data sets repeated as needed resulting in wasted effort and delayed decision making. Incomplete data sets with estimation based upon available information that is not consolidated in the ODS requires considerable effort to collate and evaluate.
Safety
The purpose of this project is to support data collection practices and does not relate to safety.
Cyber-Security, Privacy (where applicable)
Overall project will be reviewed in light of the recent OEB cyber-security framework to ensure that it is in compliance with the framework and OPUCN cyber-security policies.
Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)
Not Applicable
Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)
This system will be able to integrate to a future ADMS system.
Environmental Benefits (where applicable)
Not Applicable
Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)
Not Applicable
Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)
Not Applicable
Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity
This system will be able to integrate to a future ADMS system.

C. Category-Specific Requirements – System Service (5.4.3.2.C)
Assessment of Customer Benefits Based on Project Objectives and Cost Impact

Upgrades to the ODS will help to provide more information to the customer when combining OMS, SCADA, CIS and GIS systems. Information to assist in reducing line losses, therefore reducing costs to customer for energy by determining and comparing consumption for energy delivery point meters to consumed point customers.
Information on Regional Electricity Infrastructure Requirements Identified in the Regional Planning Process
Not Applicable
Description of how Advanced Technology has been Incorporated (where applicable)
The ODS system is integrated to the AMI system, SCADA, CIS, E-mail, Interactive Phone Voice Recognition (IVR), GIS and OMS, and portable electronic devices (meters, remote sensors) where all sources of data supply utilizing existing available systems. AMI information sent to ODS daily for interval data. SCADA information per feeder collected and sent to ODS and stored. E-mail output from BI-Analysis for event outside of set normal sent as SMS to crews for review during the day and after hours.
Identification of any Reliability, Efficiency, Safety and Coordination Benefits or Affects
Continued investment in the ODS system to combine and house all ODS. One system to collect all data, the result will be in better efficiency and better co-ordination. Efficiency improvement by moving the existing link to the MDMR and the settlement system to one system instead of being in separate systems.
Identification and Explanation of the Factors Affecting Implementation Timing/ Priority
The ODS system implementation will be affected by source data system upgrades, GIS, OMS, SCADA, CIS for data collection and automation. Resourcing planning with OPUCN IT group is the largest constraint for implementing any upgrades/ changes in the ODS system
Analysis of Project Benefits and Costs Comparing to a) Doing Nothing and b) Technically Feasible Alternatives
Doing nothing, or remaining in status quo will not gain efficiencies. The ODS system will provide collection of multiple data sources to one system and will improve the predictive capability failure rates. Feasible alternatives would be to utilize other COTS solutions that we would need to integrate to our systems. The challenge with COTS solutions is the inability to customize and get the exact outputs and information processes in a timely fashion. COTS solutions typically have larger utilities as major contributors (in the USA) and the overall costs quoted are higher than the current project costs.

A. General Information (5.4.3.2.A)					
Project/Activity	Repair, Improvements and Upgrades of OT and Smart Grid Infrastructure				
Project Number	SS-11				
Investment Category	System Service				
	2021	2022	2023	2024	2025
Capital Cost	$41,000	$39,000	$43,000	$31,000	$40,000
Capital Contribution	N/A	N/A	N/A	N/A	N/A
Net Cost	$41,000	$39,000	$43,000	$31,000	$40,000
O&M Cost	2021	2022	2023	2024	2025
	-	-	-	-	-
Customer Attachments and Load					
The total number of customers impacted and the connected load will be determined when the specific project is determined.					

Start Date	2021-2025	In-Service Date	2021-2025	
Expenditure Timing for the Planning Horizon	2021Q1	2021Q2	2021Q3	2021Q4
	$10,188	$10,188	$10,188	$10,188

Project Summary

This project is a part of OPUCN’s efforts towards improving service reliability with its smart grid and OT system. During the period of 2021-2025, OPUCN will repair, improve and upgrade existing OT and Smart Grid Infrastructure.

Just as MS Batteries and Battery Chargers are critical to the operation of MS equipment, batteries and battery charger are critical to the OT and Smart Grid system devices. Batteries and battery chargers provide back-up power to these devices that communicate, monitor and operate equipment including overhead remote switches and underground remote switches. Without reliable batteries and chargers, during an outage, these devices would not be able to provide critical information to the control room operator about the condition of the system (e.g. which feeders have an outage) and would not be able to isolate and restore power to the distribution system.

This project will include repairing and replacing batteries of existing devices. During 2021-2025, OPUCN is expected to have approximately 90 enclosures, communication modules and data concentrators that each rely on batteries for backup power. Typical lifespan of these batteries is expected to be three to five years.

Also, this project will include replacing damaged equipment, upgrading firmware, improving communication and functionality of existing devices. This project will include existing automated overhead switches, radio communication systems, vault communication system, underground switches, smart fault indicators data concentrators and other existing smart grid devices.

Risk Identification & Mitigation

Resource Risk – Resource to complete the required design and installation is important for successful completion of the project. OPUCN has resources and experience available in-house and also through approved, experienced contractors, to complete the repairs and improvements.

Budget Risk – During initial assessments, an amount has been set aside to cover reactive repairs and replacement. This may pose a risk of incurring additional cost and scheduling risk due to additional scope.

Comparative Information on Expenditures for Equivalent Projects/Activities

There is no comparison as OPUCN has not undertaken a project in the past to repair, upgrade and improve existing smart grid and OT system devices.

This program was introduced in 2020.

Historical Costs ($ '000)						Forecast Costs ($ '000)				
2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
-	-	-	-	-	25	41	39	43	31	40

REG Investment Details including Capital and OM&A costs

As this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.

Leave to Construct approval under Section 92 of the OEB Act

This project is below 50 kV and therefore Leave to Construct is not required, as per OEB.Reg. 161/99.

Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material

Figure 70- Example of a failed Radio Communication Box that failed to communicate due to moisture ingress (Outside)

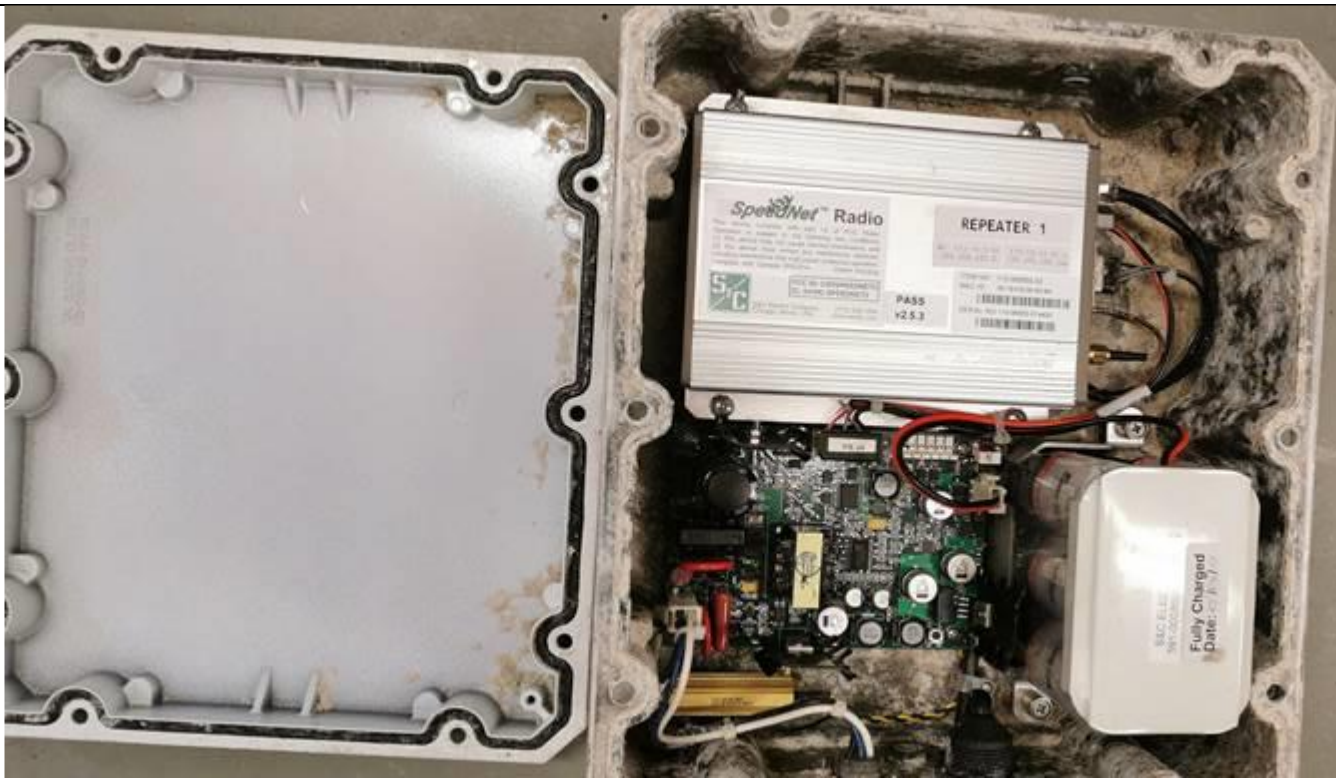


Figure 71- Example of a failed Radio Communication Box that failed to communicate due to water ingress (Inside)

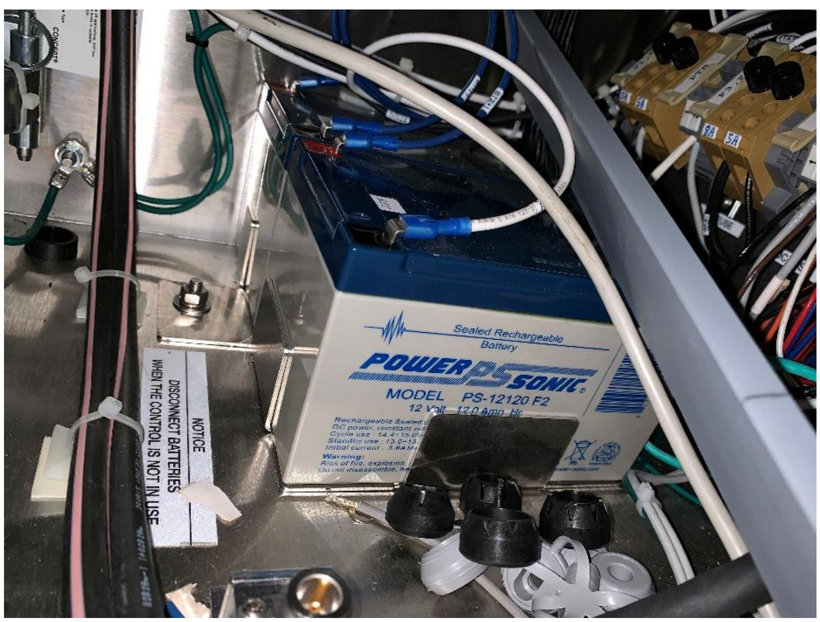


Figure 72- Example of a battery used

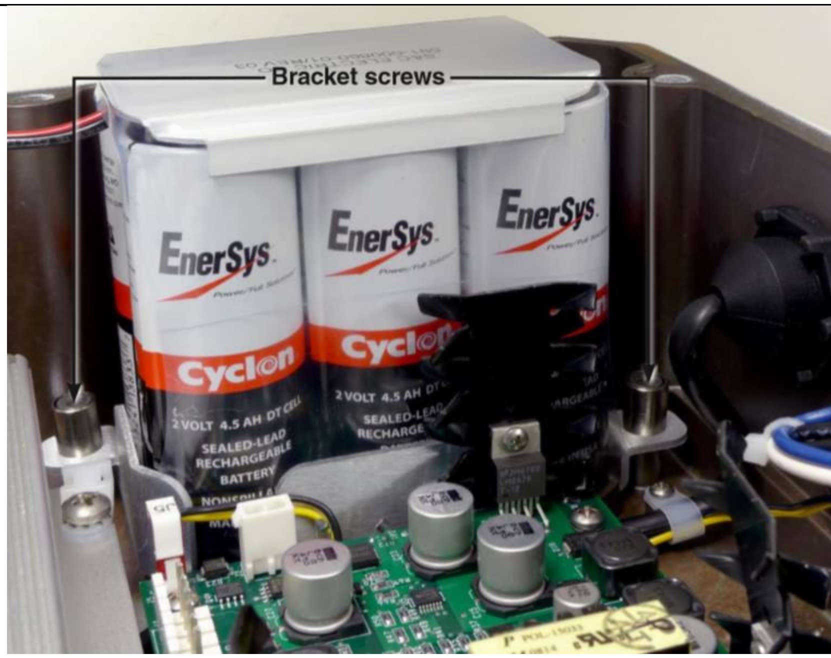


Figure 73-Example of battery used

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)
Efficiency, Customer Value & Reliability – Investment Main Driver
Reliability and operational efficiency is the key driver for this project. This project will ensure smart grid and OT devices work reliably during a power outage and that these devices will communicate and aid in the outage restoration process. This project will help OPUCN to ensure all existing devices will continue to reduce the outage duration through reliable smart grid devices.
Efficiency, Customer Value & Reliability – Investment Secondary Driver
Not applicable.
Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets
The investment objectives is to mitigate the risk of service reliability and operational efficiency by ensuring reliable operating smart grid devices. Targets include OEB's annual scorecard for OPUCN. Specific operational efficiency targets include "Average Number of Hours that Power to a Customer is Interrupted", "Average Number of Times that Power to a Customer is Interrupted", "Total Cost per Customer" and "Total Cost per Km of Line".
Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment
Information used to support this investment include recent events of battery and communication device failures. When these events occurred, the functions of the smart grid and OT devices (e.g. remote switching and automated power restoration) were rendered useless as there was no control power or communication available for them to function. According to feedback from OPUCN's customers, approximately 88% of customers surveyed want OPUCN to invest in smart grid technologies including system automation, making grid technology one of the top five priorities to customers.

This project is supported in OPUCN's Grid Modernization Plan (see this specific project in Section 10 Project Descriptions and Benefits) which identifies that it is critical to invest in the OT data infrastructure. Without investing in repairing, replacing and upgrading existing smart grid and OT data infrastructure, the OT data infrastructure will not be able to operate as intended for smart grid devices to improve reliability and improve operational efficiency. This project is supported in OPUCN's Grid Modernization Plan (Section 9 – Project Cost and Impact Scores) which identifies that it is mandatory to repair the OT system.
Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges
The project will support smart grid devices including automated switching to restore power in case of sustained power outage by implementing Fault Detection, Isolation and Restoration capability – which will help to make the grid ready for the ADMS implementation in future.
Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment
The project has been determined as a high priority due to the scoring of OT data infrastructure in the Grid Modernization Plan by METSCO in Section 9 – Project Cost and Impact Scores of the Grid Modernization Plan. This project is also considered a high priority as it meets most of OPUCN's AM objectives identified in Section 5.3.1.
Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness
<u>Replace only batteries</u> This option would mitigate risk of batteries failing and rendering the communication devices and smart grid devices useless. <u>Do nothing</u> This option would not mitigate any risks of batteries reading end of TUL and failing nor devices failing. <u>Replace batteries and repair, upgrade OT infrastructure</u> This option would mitigate risk of batteries failing and rendering the communication devices and smart grid devices useless. This option would also address locations where communication devices fail to communicate (e.g. enclosure is no longer waterproof or signal strength is weak).
Analysis of Project & Alternatives – Net Benefits Accruing to Customers
The net benefits accruing to Customers will be better service reliability due to reliable control power and communication for smart grid devices.
Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages
The repair, improvement and upgrading of smart devices will be able to provide reliable fault restoration as this project will ensure smart devices which perform fault restoration will have reliable control power and communication.
Project Alternatives (Design, Scheduling, Funding/Ownership)
There are no other practical and cost-effective design or funding alternatives, or co-ownership options available. This project received a high priority based on meeting AM objectives.
Safety
By providing reliable control power and communication to smart grid devices, this project ensures existing smart grid devices will operate safely as intended and provide status information to control staff .

Cyber-Security, Privacy (where applicable)
Not Applicable
Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)
Not Applicable
Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)
The controller for the smart devices will provide additional functionality in communication with the existing automatic restoration software and with multiple other SCADA devices to achieve advance level of coordinated Fault Detection, Isolation and Restoration capability.
Environmental Benefits (where applicable)
Reliable smart devices will reduce the need of requiring dispatching of crew (truck) during normal and in case of outages. The avoided truck rolls therefore will help to reduce GHG emission.
Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)
Not Applicable
Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)
Not Applicable
Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity
The controller for the smart devices will provide additional functionality in communication with the existing automatic restoration software and with multiple other SCADA devices to achieve advance level of coordinated Fault Detection, Isolation and Restoration capability.

C. Category-Specific Requirements – System Service (5.4.3.2.C)
Assessment of Customer Benefits Based on Project Objectives and Cost Impact
According to OPUCN's 2019 Distribution System Plan Customer Engagement Report, this project will cost a portion of a monthly average cost of 15.3 cents (overall total cost of system service projects), which the majority (60%) of customers surveyed supported (see Figure 14 – System Service Investment Chart). In addition, 88% of customers surveyed (see OPUCN's 2019 Distribution System Plan Customer Engagement Report, Figure 2 – Customer Priority Table) want OPUCN to invest in smart grid technologies, making grid technology one of the top five priorities to customers. Customer will be benefit from the advantages of smart grid devices (improve overall operational efficiency) as this project will provide reliable control power and communication to existing and new smart grid devices. Without a reliable OT data

infrastructure which includes control power (provided by batteries) and communications, smart grid devices cannot function and their benefits can not be realized.
Information on Regional Electricity Infrastructure Requirements Identified in the Regional Planning Process
Not Applicable
Description of how Advanced Technology has been Incorporated (where applicable)
This project ensures existing smart grid devices are functioning reliably.
Identification of any Reliability, Efficiency, Safety and Coordination Benefits or Affects
The investment in ensuring reliable control power and communication for smart devices will improve system reliability and visibility. It will also reduce the operational cost as ability to perform switching from control room will reduce the need to dispatch and engage line crew.
Identification and Explanation of the Factors Affecting Implementation Timing/ Priority
The project has been given a high priority because providing reliable control power and communication is a prerequisite for the functioning of smart grid and OT devices. When properly functioning, these devices offer a high benefit for improving operational efficiency, reliability and visibility. Some examples include automated power restoration and fault detection. OPUCN has a number of batteries which have past their TUL. OPUCN will provide appropriate weightage for vintage of the existing devices in selecting location to leverage the opportunity for asset renewal.
Analysis of Project Benefits and Costs Comparing to a) Doing Nothing and b) Technically Feasible Alternatives
Replacing only batteries but not addressing the communication devices will ensure reliable control power but will not address areas where communication devices are not reporting reliably back to other smart grid and OT devices and control room operators. Devices will not function reliably and continue without improving operational efficiencies and grid visibility. By doing nothing, OPUCN will allow smart devices to not function reliably and continue without improving operational efficiencies and grid visibility. This is not a proactive approach for grid modernization.

A. General Information (5.4.3.2.A)					
Project/Activity	44kV Line Extension - Ritson Rd - Winchester Rd E and Conlin Rd E				
Project Number	SS-12				
Investment Category	System Service				
	2021	2022	2023	2024	2025
Capital Cost	-	-	$375,000	-	-
Capital Contribution	N/A	N/A	N/A	N/A	N/A
Net Cost	-	-	$375,000	-	-
O&M Cost	2021	2022	2023	2024	2025
	-	-	-	-	-
Customer Attachments and Load					
Approximately 6,000 customers, 50MW					

Start Date	2023	In-Service Date	2023

Expenditure Timing for the Planning Horizon	2021Q1	2021Q2	2021Q3	2021Q4
	-	-	-	-

Project Summary
This project will extend the existing 44kV circuit (165M7) with approximately 12 taller poles framed to accommodate new 44kV line with 3-556kcmil AL. The project will also include the installation of one new SCADA operated 44kV switch to provide remote monitoring and control of the switching device. Design, construction and installation will comply with the latest standards and regulations including Ontario Regulation 22/04 (O.Reg. 22/04). By completing the overhead line extension, OPUCN plans to provide redundancy to improve the level of operational efficiency and maintain reliability.
Risk Identification & Mitigation
Scheduling Risks – This project is subject to scheduling risks with respect to external contractors and with other major projects but are prioritized based on condition of assets and failure risks. The majority of the design work and Municipal Consent(s) will be completed a year ahead of construction so that construction may begin in Q1 to mitigate this risk. Schedules are also determined the year before and progress meetings are held to ensure construction stays on track.
Comparative Information on Expenditures for Equivalent Projects/Activities
There are no direct comparative information for this project, however, the design, installation and construction will be similar to the "OH Line Renewal" program. The average cost in constructing a 75' pole with 44kV circuit is about $20K-$25K depending on site conditions which was considered in estimating the forecasted cost for this project.
REG Investment Details including Capital and OM&A costs
As this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.
Leave to Construct approval under Section 92 of the OEB Act
This project is below 50 kV and therefore Leave to Construct is not required, as per O.Reg. 161/99.
Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material
Project scope and map for the 44kV line extension at Ritson Rd N/ Winchester Rd E and Ritson Rd N/ Conlin Rd E are shown in the following:

SS-12: 44kV Line Extension - Ritson Rd - 72m South of Given Rd to Winchester Rd E and 116m north of Conlin Rd E
Scope: 444m - 3 phase 44kV (8+3 Spans), 12 Poles, 1-44kV Remote Load Break Switch

Figure 74: SS-12 44kV Line Extension Ritson Road Area Map

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)
Efficiency, Customer Value & Reliability – Investment Main Driver
System Service is the driver for this project aimed at providing redundancy in the distribution system to improve operational efficiencies and to maintain reliability. Redundancy will mitigate the impact on reliability performance including SAIDI and SAIFI.
Efficiency, Customer Value & Reliability – Investment Secondary Driver
There are no secondary drivers.
Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets
This project will improve operational efficiencies by providing redundancy in the distribution system and will ensure that impact to power supply reliability during power outages is mitigated.
Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment

The source and nature of the information used to justify the investment is "good utility practice." In planning and designing the 44kV line extension, considerations are given to reliability and grid modernization. The new pole line will be upgraded to provide a three-phase tie to adjacent circuit so that operational efficiency and reliability can be enhanced. A SCADA remote load break switch will also be installed to provide remote monitor and control of the feeder section. Third party work/relocations are also taken into account so that work may be co-ordinated as much as possible.
Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges
This program will maintain or improve the operational efficiency and reliability of the system by creating redundancy and future proofing the design by incorporating an advance switch with load breaking capability.
Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment
This program receives a high priority based on the level of AM objectives it meets identified in Section 5.3.1 of this DSP. Completion of this project will provide redundancy on the 44kV system in north Oshawa. The risk associated with the deferral of this investment is much less than some of the other OH Line Renewal investments that are mandatory and thus this project has been prioritized accordingly throughout the DSP.
Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness
Completion of the 44kV line extension program will improve system operation efficiency and maintain system reliability by creating a redundant system and providing a remote load break switch that can be remotely operated from the Control Room. New overhead design and industry practice will be introduced based on a more robust standards and current regulations providing a safer and more reliable overhead distribution system.
Analysis of Project & Alternatives – Net Benefits Accruing to Customers
Customers supplied by the feeders will benefit from this project through the reduction of the risk of longer outage times during outage situations.
Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages
Providing distribution system redundancy and remote switching will provide a more reliable system and will reduce the risk of longer outages.
Project Alternatives (Design, Scheduling, Funding/Ownership)
The project alternative that was considered for this investment is to "do-nothing," however, this option would not provide any improvement in operational efficiencies.
Safety
New design of switch, remote switching functionality and the real-time status information through SCADA will improve safety for the line crew. The installation of automatic and remote switches eliminates exposing staff to arc-flashes that may occur due to operating defective overhead switches. The installation will be built in compliance with O.Reg. 22/04 and new standards to ensure safety for the general public.
Cyber-Security, Privacy (where applicable)

The communication with SCADA operated switches will be implemented using OPUCN's dedicated fiber or a secure wireless network for SCADA communication loop which will ensure (PR.DS-2 OEB Cybersecurity Framework) Data-in-transit is protected as a Security Control. This ensures that only authorized staff have access to critical information that operates power delivering equipment. Access to the control system will be managed according to LDC's IT/OT standards in compliance to NIST cyber security standards and OEB's cyber security framework.
Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)
OPUCN meets quarterly with the City, Region and all other utilities to discuss projects, timelines and co-ordinate efforts. In addition to this, designs are sent to each of these parties for each individual project which also aids in co-ordination. The controller for the SCADA operated switches will be procured using specification that includes, but not limited to, secure communication using DNP3 protocols, compliance to applicable industry standards including IEEE and NIST, to meet the interoperability requirements. This will ensure devices will be able to communicate with Control Room SCADA system and other IEDs.
Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)
The controller for the SCADA operated switches will provide additional functionality and will be provisioned to form a communication backbone to a network of multiple SCADA operated switches.
Environmental Benefits (where applicable)
Installation of SCADA operated switches will enable remote operation of switches by control room staff, without requiring dispatching of crew(s) /truck during normal and in case of outages. The avoided truck rolls therefore will help reduce GHG emission.
Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)
Not Applicable
Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)
Not Applicable
Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity
The controller for the SCADA operated switches will provide additional functionality and will be provisioned to form a communication backbone to a network of multiple SCADA operated switches.

C. Category-Specific Requirements – System Service (5.4.3.2.C)
Assessment of Customer Benefits Based on Project Objectives and Cost Impact
Customers will benefit due to a more reliable system and faster restoration that will be achieved with the redundant system and new SCADA operated switch. This project will help OPUCN reduce the risk of longer outage duration through remote switching of the 44kV distribution. System Operators will receive fault detection alerts indicating when fault conditions have occurred

downstream of overhead switches which further reduces outage durations. The remote switches will provide ability to perform remote switching without dispatching line crew, improving operational efficiency and reduce operating cost.
Information on Regional Electricity Infrastructure Requirements Identified in the Regional Planning Process
Not Applicable
Description of how Advanced Technology has been Incorporated (where applicable)
The controller for the SCADA operated switches will provide additional functionality and will form a communication backbone to a network of multiple SCADA operated switches.
Identification of any Reliability, Efficiency, Safety and Coordination Benefits or Affects
This program will provide redundancy and improve operational efficiencies and maintain system reliability. It will also help with operational cost as it will reduce the need to dispatch and engage line crew to perform manual switching operations. There will be an added level of safety due to remote operation as field staff will not be required to operate switches manually.
Identification and Explanation of the Factors Affecting Implementation Timing/ Priority
The project has been given a high priority because it offers a high benefit for improving operational efficiency, reliability, visibility and meeting AM objectives. OPUCN meets quarterly with the City, Region and all other utilities to discuss projects, timelines and co-ordinate efforts. In addition to this, designs are sent to each of these parties for each individual project which also aids in co-ordination.
Analysis of Project Benefits and Costs Comparing to a) Doing Nothing and b) Technically Feasible Alternatives
The project alternative that was considered for this investment is to “do-nothing,” however, this option would not provide any improvement in operational efficiencies.

A. General Information (5.4.3.2.A)					
Project/Activity	Facilities				
Project Number	GP-01				
Investment Category	General Plant				
	2021	2022	2023	2024	2025
Capital Cost	$100,000	$100,000	$100,000	$100,000	$100,000
Capital Contribution	N/A	N/A	N/A	N/A	N/A
Net Cost	$100,000	$100,000	$100,000	$100,000	$100,000
O&M Cost	2021	2022	2023	2024	2025
	-	-	-	-	-

Customer Attachments and Load

Not Applicable

Start Date	2021-2025	In-Service Date	2021-2025
Expenditure Timing for the Planning Horizon	2021Q1	2021Q2	2021Q3	2021Q4
	$25,000	$25,000	$25,000	$25,000

Project Summary

These investments will address on-going requirements to maintain the upkeep and safe working condition of OPUCN's facilities and support required business needs. Forecast capital expenditures are based on 2021-2025 average historical expenditures on facilities and third-party identified leasehold improvements (see Appendix L for Building Condition Assessments).

Risk Identification & Mitigation

Safety/Productivity Risk: The type of work undertaken in this project could affect the work environments of employees. Construction work that is particularly invasive should be done after business hours where possible to mitigate impacts.

Scheduling Risk: The execution of work in the Facilities project is based on historical expenditure and Building Condition Assessments. Other sources of spending not included in the plan often surface over the budget period which introduce scheduling risks to the original plan. OPUCN will mitigate the risk of scheduling in each year by routinely reviewing detailed plans and upcoming unplanned additions. This exercise will aid in levelling the expenditure year over year while also enabling the team to prioritize and proceed with identified work within the necessary timeline.

Comparative Information on Expenditures for Equivalent Projects/Activities

$ '000

Year	2015	2016	2017	2018	2019	2020
Historical Charges	108	219	49	111	106	360

The additional initiatives (both equipment and construction or decommission projects) are a result of investments that were not previously made. There is no comparative data going back to 2015, or more recently for these type of projects, however, average historical expenditures for facilities and leasehold improvements were used to estimate future cost.

2020 is a budget cost which includes the following additional investments required to be completed to meet business needs:

- Barcode Technology
- Fuel Pumps and Fuel Line Removal
- MS12 Demolition
- HVAC Units in Distribution, Main Office and Metering

REG Investment Details including Capital and OM&A costs

As this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.
Leave to Construct approval under Section 92 of the OEB Act
This project is below 50 kV and therefore Leave to Construct is not required, as per OEB.Reg. 161/99.
Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material
Refer to the Building Condition Assessment (BCA) in Appendix L.

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)
Efficiency, Customer Value & Reliability – Investment Main Driver
The driver of these initiatives is in General Plant Investment Category and is aimed at addressing "essential needs" to support the business, and to mitigate the high level of risk that is present if we do not undertake. Program drivers can include change in work requirements and staff reorganization.
Efficiency, Customer Value & Reliability – Investment Secondary Driver
There are no secondary drivers.
Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets
The investment objectives of this program is aimed reliability, improved efficiency, accuracy, and employee throughput.
Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment
Given that we are in an aged facility, the equipment and structures are aged, deteriorating, and unreliable and therefore, the maintenance costs are increasing. This investment was developed to support the current facilities needs.
Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges
A proactive approach to supporting an ageing building will ensure that we continue having reliable and safe facilities so that necessary work can be completed to support the reliability of the electrical system.
Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment
This program meets majority of the AM objectives identified in Section 5.3.1 and considered a high priority as the projects in this investment are essential in order to support business needs. Without adequate facilities to support structure, company performance can be negatively impacted, and customer expectations for accuracy and expediency will not be met.
Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness
Renewal/Replacement of unreliable equipment ensures that operation and maintenance costs are minimized and system operations stay as efficient as possible. Planned replacement of our facilities infrastructure incurs a lower cost than reacting to a catastrophic failure while also ensuring that our team is subject to the safest work environments possible while on the job.
Analysis of Project & Alternatives – Net Benefits Accruing to Customers
Having reliable equipment avoids any delays in service request(s) or outage response.

Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages
There is no direct impact on reliability performance, however, this will mitigate the risk of reactive work which could affect OPUCN efficiency in delivering service.
Project Alternatives (Design, Scheduling, Funding/Ownership)
The project alternatives considered for this investment is a reactive model where in case of facilities equipment, these will not get replaced until complete failure. This introduces increased reliability concerns and increased O&M costs. As for construction or decommissioning initiative programs, reactive approach will have an impact on service and can begin to deteriorate as well as product containment (theft) can become a reality.
Safety
Planned replacement of equipment mitigates any catastrophic failure which may threaten the safety of employees and the public.
Cyber-Security, Privacy (where applicable)
Not Applicable
Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)
Not Applicable
Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)
Not Applicable
Environmental Benefits (where applicable)
This initiative will replace older equipment, and enhance our facilities management capability to better service the overall needs of the business while supporting the environment.
Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)
Not Applicable
Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)
Not Applicable
Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity
Not Applicable

C. Category-Specific Requirements – General Plant (5.4.3.2.C)
Results of Quantitative and Qualitative Analyses
OPUCN conducted a thorough inspection of the office and facilities equipment and determined investments required to ensure the existing office space continues to provide efficient and effective operational support. Please refer to the BCA for the result of the assessment.
Business Case Documenting the Justifications for Expenditure, Alternatives, Benefits (Long Term/Short Term), Cost Impacts
The BCA in Appendix L provides the justification for the expenditure. The ageing building we occupy now requires upgrades to provide a safe environment for those working. Without these repairs and upgrades, the efficiency of our day-to-day operations may suffer. Also, the indicated construction and decommission initiatives are critical as buildings and infrastructure, such as MS12 and the Fuel Pumps, may begin to deteriorate causing safety and environmental issues.

A. General Information (5.4.3.2.A)					
Project/Activity	Fleet Replacement Program				
Project Number	GP-02				
Investment Category	General Plant				
	2021	2022	2023	2024	2025
Capital Cost	$530,000	$420,000	$100,000	$440,000	$95,000
Capital Contribution	N/A	N/A	N/A	N/A	N/A
Net Cost	$530,000	$420,000	$100,000	$440,000	$95,000
O&M Cost	2021	2022	2023	2024	2025
	-	-	-	-	-
Customer Attachments and Load					
Not Applicable					

Start Date	2021-2025	In-Service Date	2021-2025

Expenditure Timing for the Planning Horizon	2021Q1	2021Q2	2021Q3	2021Q4
	$150,000	$30,000	-	$350,000

Project Summary

OPUCN plans to replace 1 single bucket truck, 2 digger trucks, and 5 light duty vehicles, a reach truck, and a forklift truck. The existing trucks are nearing end-of-service life or are becoming unreliable units on the fleet.

- Investments in 2021 include a Digger Derrick Truck and a Reach Truck.
- Investments in 2022 include a Single Bucket Truck and a Forklift Truck.
- Investments in 2023 include two ½ ton Pickup Trucks.
- Investments in 2024 include a Digger Derrick Truck, and a Sedan.
- Investments in 2025 include a Cargo Van and a ½ ton Pickup Truck.

Risk Identification & Mitigation

In order to mitigate risk that vehicle delivery will be delayed, OPUCN will request quotes early in the year for light duty fleet to ensure they are delivered within the same year. For large fleet, the quotes and order will be requested a year or more in advance to accommodate lead times. In order to mitigate the risk that vehicles will not fulfill on-the-job requirements, OPUCN has adopted a fleet management committee with representation from the distribution, safety, engineering, and management teams to make final decisions on replacements and new vehicle acquisitions based on operational requirements.

Comparative Information on Expenditures for Equivalent Projects/Activities

$ '000

Year	2015	2016	2017	2018	2019	2020
Historical Expenditures	461	132	503	368	341	545

- Investments in 2015 included a Freightliner double bucket, a cargo van, and two ½ tonne pickup trucks.
- Investments in 2016 included a metering city express van, a medium-duty stations service vehicle, and a medium-duty dump truck.
- Investments in 2017 included the purchase of a material handling trailer, a pole trailer, a light-duty truck, and a 52' single bucket truck.
- Investments in 2018 included a 50' single bucket truck.
- Investments in 2019 included the purchase of a medium-duty dump truck, three light-duty pickup trucks, a light-duty pickup truck with a double cab, and a medium-duty underground service vehicle.
- Investments in 2020 include a Single Bucket Truck, one ½ ton Pickup Truck and two ¾ ton Pickup Trucks. 2020 is a budget cost.

Capital expenditure within this program varies from year to year depending on the type of fleet required to be replaced as per the Fleet Management Policy and up-to-date maintenance records.
REG Investment Details including Capital and OM&A costs
As this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.
Leave to Construct approval under Section 92 of the OEB Act
This project is below 50 kV and therefore Leave to Construct is not required, as per OEB.Reg. 161/99.
Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material
Refer to Fleet Management Policy in Appendix R.

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)
Efficiency, Customer Value & Reliability – Investment Main Driver
The driver of this project is General Plant Investment Category associated with addressing the risk of vehicle failure due to asset's end of TUL and operational effectiveness.
Efficiency, Customer Value & Reliability – Investment Secondary Driver
There are no secondary drivers.
Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets
Operational efficiencies and ensuring vehicles are safe and reliable during daily operation.
Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment
This program is in accordance with OPUCN's Fleet Management Policy: • OPUCN created a policy in 2019 to address vehicle replacements which states that light duty fleet will be replaced within 8 years or 200,000kms and heavy duty fleet will be replaced in 10 years or 10,000 hours. Any vehicle can be evaluated for replacement based on physical condition, departmental needs, changing regulations, etc. • Review of the maintenance records and utilization logs may defer or advance replacement timing and smooth annual investments.
Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges
• Having a fleet that is constantly available ensures that necessary reactive and maintenance work can be completed to support the reliability of the system. • All vehicles that routinely leave the yard are equipped a system that collects GPS, speed, and distance data for analytical and safety use. All new vehicles will have this system installed so the team can continue to analyze vehicle use and any safety issues that arise.
Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment

This program meets majority of the AM objectives identified in Section 5.3.1 and considered a high priority for supporting business needs. Without a proper fleet maintenance, reactive work can fall behind thus increasing risks to safety and reliability, and increasing costs.
Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness
Consistent replacement and maintenance of units on the OPUCN fleet will ensure that life cycle costs and risks of catastrophic failure remain low. Planned replacement of our fleet ensures that our team is using the most efficient equipment possible while on the job.
Analysis of Project & Alternatives – Net Benefits Accruing to Customers
Having a reliable fleet avoids any delays in customer service request or outage response.
Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages
Fleet replacement planning ensures that vehicles are available for reactive and planned work. Without access to reliable vehicles, reactive response time could suffer and frequent of outages could increase if planned work is not completed on time.
Project Alternatives (Design, Scheduling, Funding/Ownership)
Lease Model – OPUCN considered and analyzed a leasing model. Analysis proved that this model would increase O&M significantly and posed a variety of risks which included penalties for modifications to the vehicles (beacons, etc.), penalties for additional mileage, and maintenance not including wheels and brakes. This model introduced increased O&M costs and lifecycle costs when compared to the owned model.
Safety
Planned replacement of fleet mitigates any catastrophic failure which may threaten the safety of employees and the public.
Cyber-Security, Privacy (where applicable)
Not Applicable
Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)
Not Applicable
Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)
Not Applicable
Environmental Benefits (where applicable)
This program will replace older vehicles with new vehicles which will meet the latest emissions and energy efficiency standards.
Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)
Not Applicable

Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)
Not Applicable
Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity
Not Applicable

C. Category-Specific Requirements – General Plant (5.4.3.2.C)
Results of Quantitative and Qualitative Analyses
<u>'Do Nothing' Approach:</u> Deferring investment and extend the use of the existing fleet beyond its useful life. This approach would increase the risk of operational downtime and catastrophic failure leading to prolonged periods without vehicles. Without reliable vehicles OPUCN runs the risk of experiencing severe reliability and productivity issues. Vehicles which are unreliable will cause increased O&M costs. <u>Hybrid Plan:</u> In the hybrid plan a variety of indicators are used to determine if a vehicle is ready for replacement while also considering the lifecycle cost. Rather that waiting for catastrophic failure or making early investment based on condition criteria, this method uses a condition criteria guideline while also considering subjective criteria including the usefulness to the company, the utilization of the vehicle, the changing operational needs, overall condition assessments, safety concerns, and/or changing regulatory guidelines. The advantages to this plan is the ability to holistically look at the vehicle and make an informed decision based on multifaceted information. The disadvantages could be an increase in analysis that may not inform a decision. It is important that the information tracked continues to be effective and explanatory to avoid over analyzation resulting in fogged decisions. <u>Condition-Based Plan</u>: Investments would be based solely on strict condition criteria thresholds which trigger immediate replacement such as kilometers, engine hours, or age. The advantage of this strategy is that the fleet would be held to the highest standard and be in top repair. The disadvantage is the possibility of increased lifecycle costs and the absence of other criteria during the decision making process such as utilization, changing regulations, or the overall usefulness of a vehicle to the company. Without the ability to holistically assess vehicles before they are replaced the risk of overspending is present.
Business Case Documenting the Justifications for Expenditure, Alternatives, Benefits (Long Term/Short Term), Cost Impacts
To effectively manage Fleet assets OPUCN has developed a Fleet Management Policy, found in Appendix R, which outlines the roles and responsibilities of the committee and the suggested condition criteria for replacement considerations. This Policy follows the Hybrid Approach as outlined above to take advantage of the holistic approach to fleet management. The suggested criteria for replacement of vehicles is as follows: • Mileage • Engine hours • Age • Routine Fleet Assessment results; • Maintenance costs; • Changing emissions, weight, and safety regulations; and • Usefulness to the company.

For the purpose of this DSP, OPUCN has created a replacement plan based on historical expenditures and the criteria mentioned above. The Fleet Management Committee has the ability to make decisions to retain vehicles beyond the predicted replacement or to remove them from service prior to their predicted replacement.

A. General Information (5.4.3.2.A)					
Project/Activity	Major Tools and Equipment				
Project Number	GP-03				
Investment Category	General Plant				
	2021	2022	2023	2024	2025
Capital Cost	$100,000	$100,000	$100,000	$100,000	$100,000
Capital Contribution	N/A	N/A	N/A	N/A	N/A
Net Cost	$100,000	$100,000	$100,000	$100,000	$100,000
O&M Cost	2021	2022	2023	2024	2025
	-	-	-	-	-

Customer Attachments and Load

Not Applicable

Start Date	2021-2025	In-Service Date	2021-2025
Expenditure Timing for the Planning Horizon	2021Q1	2021Q1	2021Q1	2021Q1
	$25,000	$25,000	$25,000	$25,000

Project Summary

The purpose of this ongoing charge is to replace major tools and equipment that has reached end-of-life due to substandard performance and functional inefficiencies. Equipment includes on-the-job tools, safety equipment, radio equipment, and other major tools that outfit work vehicles.

The program is also intended to purchase new equipment to improve the operational efficiency of the field crew, lower operational costs, or reduce potential safety risks. There is additional room in the project budget to allow for unplanned replacement of tools and equipment due to premature failure.

The tools to be purchased include: testing equipment, battery operated equipment, rubber goods, pulling equipment, construction tools, troubleshooting equipment, safety equipment, radio equipment, and other major tools that outfit work vehicles.

All purchases are completed on an as-needed basis depending on the type of work required.

Risk Identification & Mitigation

Budgeting Risks: In the historical period Tools and Equipment purchases were consistently over budget. In the forecast period budget was increased to ensure this risk no longer exists and the

Defective Tool Risks: Procuring defective tools could present safety and reliability risks. In order to mitigate this, OPUCN inspects tools before they are used and in some cases send major tools and equipment to third parties for inspection. Major Tools and Equipment go for routine maintenance and inspection to third parties while they are in use by OPUCN employees to ensure they are safe to use and/or providing accurate information.

Comparative Information on Expenditures for Equivalent Projects/Activities

Year	Actual	Budget
2015	$ 54,337.64	$ 50,000.00
2016	$ 51,357.70	$ 50,000.00
2017	$ 63,009.77	$ 50,000.00
2018	$ 63,533.62	$ 50,000.00

2019	$ 102,996.74	$ 50,000.00
2020		$ 100,000.00
2021		$ 100,000.00
2022		$ 100,000.00
2023		$ 100,000.00
2024		$ 100,000.00
2025		$ 100,000.00

The additional cost being proposed for the forthcoming five years when compared to the previous five years is due to the fact that in the preceding five years, attempts have been made to ensure the overall projects remain within budget. This has resulted in some crews not having access to the tools they need to most efficiently perform their tasks and delaying the replacement of some tools until more budget becomes available. In addition, new equipment installed in the distribution system and improvement in safe work practices (i.e. reduce the risk of repetitive strain injuries) would require new tools and equipment.

REG Investment Details including Capital and OM&A costs

As this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.

Leave to Construct approval under Section 92 of the OEB Act

This project is below 50 kV and therefore Leave to Construct is not required, as per OEB.Reg. 161/99.

Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material

The following is the list of tools and equipment that OPUCN will be replacing or procuring during the forecast years:

Tool
Sitcks
Rubbers
Multi Testers (Phase, Pot, Etc)
Travellers
Spider Ropes
Tension Machine Ropes
Rotation Meters
Secondary Beast (Testers)
Flukes
Battery Tools
Primary Ammetres
Battery Load Testers
VLF Testers
10K Meggers
3 Phase Metering Testers
Hoists
Grips

Ground Pounders
Tampers
Stripping Tools
Grounds
Generators
Belt and Spurs
Various Hand Tools
Hydraulic Drills

Images of some of the tools and equipment are shown below for reference:

Figure 75: Battery Load Tester

Figure 76: Ground Rod Pounder

Figure 77: 10k Megger

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)
Efficiency, Customer Value & Reliability – Investment Main Driver
General Plant is the main driver for this project that involves replacing non-system equipment that has reached end-of-life due to substandard performance and functional inefficiencies.
Efficiency, Customer Value & Reliability – Investment Secondary Driver
There are no secondary drivers.
Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets
This project main objective is to support daily operations to ensure performance measures targets are met including operational efficiency and safety.
Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment
OPUCN has used input from staff, best utility practices, regulation, and recommendations from manufacturers to justify this investment.
Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges
Having access to the proper tools in working order allows crews to perform their tasks in the most efficient manner. This allows them to respond to system interruptions faster, thus reducing the overall duration of the system interruption and improving reliability. Properly calibrated and functioning testing equipment can help crews identify potential deficiencies in the distribution network and perform preventative maintenance to eliminate or reduce the duration of the system interruption that would have been introduced had the asset failed. New tools and equipment will be procured with additional functionality to allow us to better support the overall needs of the business with respect to reliability, and sustainability.

Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment
This is high priority investment meeting most of the AM objectives identified in Section 5.3.1 to improved business efficiencies and effectiveness which will distribution and operations work. Tools and equipment are purchased on an as-needed basis. Continuous investment in the proper tools is required to avoid tool failure which would not allow crews to maintain the distribution system in a timely manner.
Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness
Access to the appropriate tools in good working condition allows crews to complete their tasks with the best workmanship in the shortest time resulting in shorter task timelines and improved operational efficiency.
Analysis of Project & Alternatives – Net Benefits Accruing to Customers
Access to the appropriate tools in good working condition allows crews to complete their tasks with the best workmanship in the shortest time resulting in shorter task timelines and improved operational efficiency. This reduces overall costs per task and improves reliability by ensuring all construction is completed to the best quality and reduces restoration time during system interruptions.
Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages
When OPUCN staff have access to safe and reliable tools, it allows them to restore system following an outage in an expedient manner and also shortens the duration of the planned outages
Project Alternatives (Design, Scheduling, Funding/Ownership)
There are three scenarios considered as each piece of equipment is identified for replacement or purchase. Those three scenarios are: 1. Do Not Replace – Should the number of tools identified in need of replacement exceed the number required to perform the tasks, the tool will be decommissioned and not replaced. This is the default scenario. 2. Upgrade – for tools where an option for material improvements to their operational efficiency, safety, or reliability can be demonstrated, the old tool will be replaced with the newer technology and the old will be decommissioned or scrapped. 3. Like-for-Like Replacement – where the current tool is meeting all the requirements and no further improvements are available, and a replacement is required to maintain a number required for efficient operation, the tool will be replaced with a similar tool. Each tool that is identified for replacement is evaluated against the above three scenarios based on information from subject matter experts, third-party vendors, good utility practices and regulations.
Safety
If safe, reliable, and up-to-date tools and equipment are not provided, it can introduce substantial safety-related impacts for OPUCN staff.
Cyber-Security, Privacy (where applicable)
Not Applicable
Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)

Not Applicable
Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)
Tool and equipment purchases are performed on an as-needed basis. Should future technology be introduced into the distribution system with special tool or equipment requirements, those tools will be evaluated on a case-by-case basis.
Environmental Benefits (where applicable)
Not Applicable
Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)
Not Applicable
Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)
Not Applicable
Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity
Should future technology be introduced into the distribution system with special tool or equipment requirements, those tools will be evaluated on a case-by-case basis.

C. Category-Specific Requirements – General Plant (5.4.3.2.C)
Results of Quantitative and Qualitative Analyses
There are three scenarios considered as each piece of equipment is identified for replacement or purchase. Those three scenarios are: 1. Do Not Replace – Should the number of tools identified in need or replacement exceed the number required to perform the tasks, the tool will be decommissioned and not replaced. This is the default scenario. 2. Upgrade – for tools where an option for material improvements to their operational efficiency, safety, or reliability can be demonstrated, the old tool will be replaced with the newer technology and the old will be decommissioned or scrapped. 3. Like-for-Like Replacement – where the current tool is meeting all the requirements and no further improvements are available, and a replacement is required to maintain a number required for efficient operation, the tool will be replaced with a similar tool. Each tool that is identified for replacement is evaluated against the above three scenarios based on information from subject matter experts, third-party vendors, good utility practices and regulations.
Business Case Documenting the Justifications for Expenditure, Alternatives, Benefits (Long Term/Short Term), Cost Impacts
Due to the case-by-case basis of this program, actual expenses will vary annually based on the tool and equipment replacement requirements. OPUCN has used input from staff, best utility practices, regulation, and recommendations from manufacturers to justify this investment.

A. General Information (5.4.3.2.A)					
Project/Activity	Customer Information System (CIS) Acquisition				
Project Number	GP-04				
Investment Category	General Plant				
	2021	2022	2023	2024	2025
Capital Cost	$736,000	-	-	-	-
Capital Contribution	N/A	N/A	N/A	N/A	N/A
Net Cost	$736,000	-	-	-	-
O&M Cost	2021	2022	2023	2024	2025
	-	-	-	-	-
Customer Attachments and Load					
All Customers					

Start Date	2021	In-Service Date	2021
Expenditure Timing for the Planning Horizon	2021Q1	2021Q2	2021Q3	2021Q4
	-	$450,000	$236,000	$50,000

Project Summary

Acquiring a Customer Information System (CIS) is a critical project. This is primarily due to being heavily reliant on a third party to host the existing CIS which poses a significant risk if this third party consultant were to cease activity or its business relationship with OPUCN were to end.

We rely extensively on our CIS for customer billing, data management, interfacing with our Interactive Voice Response (IVR) and several other Application Program Interface(s) (API). Currently, OPUCN does not own the CIS software in use. In order to improve efficiency and business continuity acquiring our own CIS is imperative. The acquisition will remove risk from our current operating model and will allow OPUCN to establish a footprint to operationalize and advance customer service improvements.

The project involves the acquisition of CIS software and IT equipment to host the software in house. The following table outlines the details of the capital investment required to proceed with this project.

Category	**Description**	**Capital Expenditure**
IT Equipment	Hardware	$50,000
	Licencing/SQL/Vmware/Veeam/AVG/Certificates	$123,000
IT Equipment Sub Total		**$173,000**
CIS Software Acquisition	Software	$410,000
	Project Management	$146,000
	Technical Administration Fee	$7,000
CIS Software Acquisition Sub Total		**$563,000**
TOTAL		**$736,000**

Risk Identification & Mitigation

Scheduling Risk – This project is subject to scheduling risk with respect to external contractors and with other major projects but in order to mitigate this risk, OPUCN will request quotes, and perform the proper procurement policy (RFQ/RFP) for each requirement prior to commencing.

Resource Risk – Timely consultation among the team members ensures proper resource allocation to complete the work on schedule.

Compatibility/Data Migration Risk – When integrating new systems into existing operations it is important to consider compatibility and the issues that may be experienced during a data migration. OPUCN will to the best of their ability mitigate this risk by ensuring the new CIS system acquired is compatible with existing systems and will not pose any risks to the customer data during migration.

Comparative Information on Expenditures for Equivalent Projects/Activities

There is no comparative data for this initiative.

REG Investment Details including Capital and OM&A costs

As this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.

Leave to Construct approval under Section 92 of the OEB Act

This project is below 50 kV and therefore Leave to Construct is not required, as per OEB.Reg. 161/99.

Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material

The preferred option for this project is to purchase a CIS and host it in-house. The CIS acquisition will allow for an O&M savings of up to 16% as this will not be leased from a third party consultant. This option will also allow us to mitigate the risk of being heavily reliant on a third party should they cease operations or our business relationship ends. Acquiring a CIS would allow us full control of the system and configurations with the ability to provide technical in-house support. The following schematic shows how the existing CIS system is integrated with OPUCN systems and how the new CIS system will be integrated with OPUCN systems.

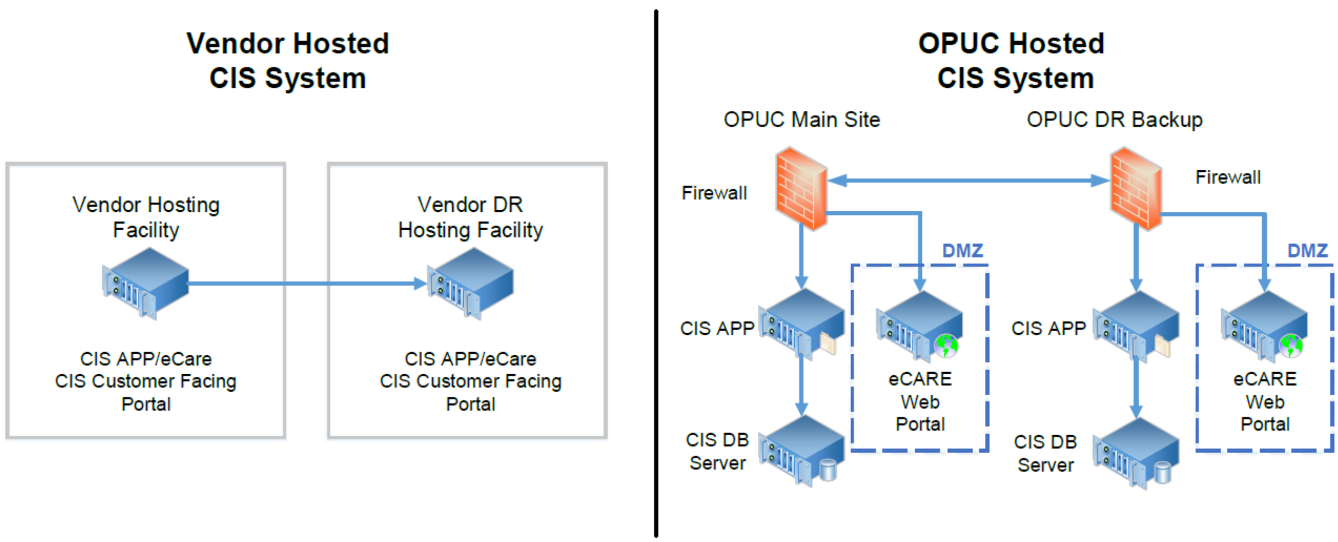


Figure 78: CIS Alternative Hosting Model Comparison

The existing CIS system being used, although not owned by OPUCN, has been a good fit for our operation historically. Although other options will be explored, if OPUCN were to acquire the existing CIS system to host in house it will minimize implementation costs and reduce the probability of data migration issues due to compatibility.

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)
Efficiency, Customer Value & Reliability – Investment Main Driver
The driver for this project is in General Plant Investment Category and aims at to improving by lowering our risks of being dependent on a third party consultant.
Efficiency, Customer Value & Reliability – Investment Secondary Driver
There are no secondary drivers.
Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets
The primary objective of this investment is to align with customer interests and to improve overall quality of customer service and customer communications with the aim of improving OPUCN's customer satisfaction performance target.
Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment
In a 2018 Customer Satisfaction survey, it was noted that providing several communication channels to meet customer need was key to improving the customer experience. This requires an improved quality of customer service by having a reliable and secure CIS. The other sources and nature of information utilized by OPUCN to justify this investment is through compliance with OEB Cybersecurity Framework and risk analysis.
Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges
This new CIS system will be integrated to current systems such as the OMS and should be compatible with future systems such as an Advanced Distribution Management System (ADMS).
Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment
This investment meets critical AM objectives identified in Section 5.3.1 and there is a high level of prioritization for this project as it will enhance our customer service through in-house billing and will provide opportunities to create cost savings through elimination of the Application Service Provider (ASP) model.
Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness
This initiative will result in cost efficiencies as the CIS will be hosted in-house which allows us to do in-house billing. Technical support will also be provided internally which will improve our operational efficiency and cost-effectiveness with O&M savings of up to 16% annually.
Analysis of Project & Alternatives – Net Benefits Accruing to Customers
Investment in the acquisition of a new CIS will provide a more robust service offering to customers. This investment will allow a better ability to respond to changes, enhanced customer service ability and better responsiveness.

Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages
The purpose of this system is data collection and does not directly affect the reliability performance which includes the frequency and duration of outages.
Project Alternatives (Design, Scheduling, Funding/Ownership)
There are three project alternatives considered on how the CIS should be implemented during the forecast years: 1. Do Nothing – This is a default option. The current systems will remain status quo and will still be at risk if the third party were to cease activity or the business relationship with OPUCN were to end. There will be no opportunities for long term O&M cost savings. 2. Acquire the CIS hosted by a third party – This will provide OPUCN control of the system but will not mitigate the privacy risk. There are no O&M cost savings that will be realized in this scenario. 3. Acquire the CIS hosted in-house – This will allow OPUCN full control of the system and configurations with the ability to obtain technical in-house support. Risks will be further mitigated and a significant O&M cost savings can be realized.
Safety
Acquiring a new CIS does not contribute to safety issues.
Cyber-Security, Privacy (where applicable)
OPUCN emphasizes the importance of security. IT will pay a key role in this project ensuring the new system will adhere to the current OEB Cyber Security Framework.
Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)
Not Applicable
Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)
An in-house CIS will allow us to securely integrate with our current operating systems. This will also provide the OMS real time information reflecting the current state of the network.
Environmental Benefits (where applicable)
Not Applicable
Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)
Not Applicable
Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)
Not Applicable

Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity
An in-house CIS will allow us to securely integrate with our current operating systems. This will also provide the OMS real time information reflecting the current state of the network.

C. Category-Specific Requirements – General Plant (5.4.3.2.C)
Results of Quantitative and Qualitative Analyses
Acquisition of a CIS system will lower privacy risks and will provide opportunities for cost efficiencies in the future. Our Quantitative and Qualitative analysis reviewed three options; the 'Do Nothing' Approach, Acquire CIS hosted by a Third Party, and Acquire CIS hosted In-House. The results of this analysis proved that the third option, Acquire a CIS hosted In-House, was the more cost effective, efficient, and strategically advantageous option to choose.
Business Case Documenting the Justifications for Expenditure, Alternatives, Benefits (Long Term/Short Term), Cost Impacts
We rely extensively on our CIS for customer billing, data management, interfacing with our Interactive Voice Response (IVR) and several other API's. For efficiency and business continuity acquiring our own CIS is imperative. The acquisition will de-risk our current operating model and will allow OPUCN to establish a footprint and advance customer service improvements as well as mitigate our exposure to privacy risks. Owning our own CIS and hosting on site will secure customer information should the third party contractor cease to exist. The following chart illustrates the high-level cumulative yearly expenditure (Capital + O&M) for all 3 project options considered. Based on this chart, acquiring the CIS and hosting it in-house provides the highest cost benefit providing cost savings in the long run starting 2025. For the 'Do Nothing' Approach, the costs will continue to be operational. Acquiring a CIS hosted by a third party has a $500K capital cost but an operational cost that is comparable to the 'Do Nothing' Approach. By Acquiring a CIS hosted In-House the capital investment is higher, at $736K, but the operational costs decrease significantly on an annual basis when compared to the 'Do Nothing' approach.

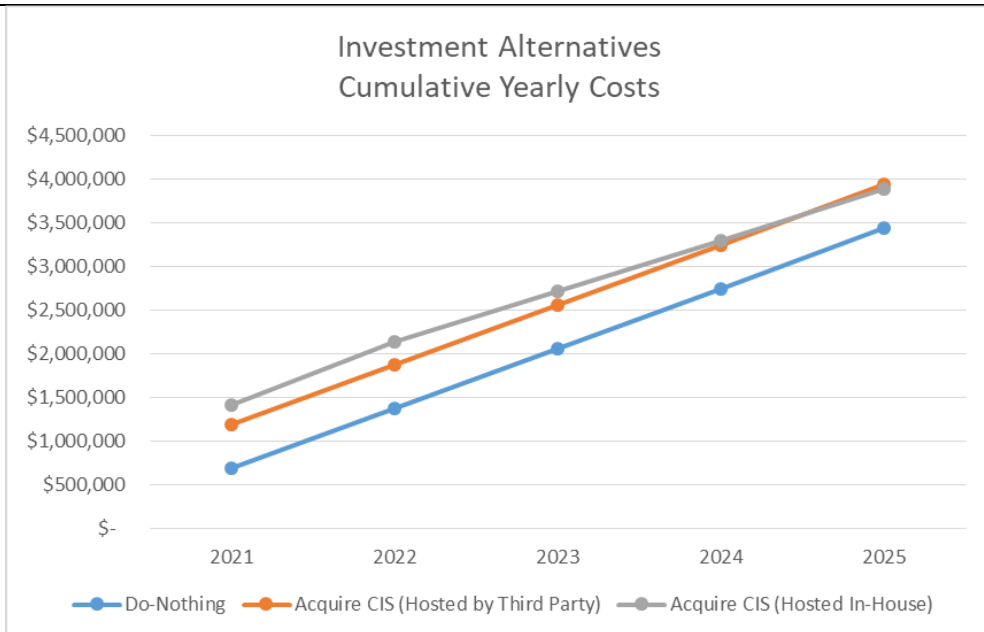


Figure 79: Cumulative Expenditure (O&M and Capital) Comparison of 3 CIS Alternatives

The following chart indicates the estimated Capital and annual O&M costs associated with all of the alternatives.

	'Do Nothing'	**Acquire CIS Hosted by a Third Party**	**Acquire CIS Hosted in House**
IT Equipment	$0	$0	$173,000
CIS Software Aquisition	$0	$500,000	$563,000
Capital Subtotal	**$0**	**$500,000**	**$736,000**
Software Hosting (Vendor)	$688,000	$584,000	$0
Software Maintenance on customer-owned Software (Vendor)	$0	$104,000	$104,000
In-House Server Maintenance	$0	$0	$148,000
In House FTE Work (Estimate)	$0	$0	$430,000
O&M Subtotal	**$688,000**	**$688,000**	**$578,000**

In the future we foresee the use of additional systems that would require integration with the CIS system. When these systems are hosted in house we find that integration with other systems is easier and less cost prohibitive. Since we the company has grown we are able to manage these systems in house.

A. General Information (5.4.3.2.A)					
Project/Activity	Office Systems				
Project Number	GP-05				
Investment Category	General Plant				
	2021	2022	2023	2024	2025
Capital Cost	$257,000	-	-	$48,500	-
Capital Contribution	N/A	N/A	N/A	N/A	N/A
Net Cost	$257,000	-	-	$48,500	-
O&M Cost	2021	2022	2023	2024	2025
	-	-	-	-	-

Customer Attachments and Load

Not Applicable

Start Date	2021	In-Service Date	2021
Expenditure Timing for the Planning Horizon	2021Q1	2021Q2	2021Q3	2021Q4
	-	$57,000	$200,000	-

Project Summary

OPUCN plans to procure and upgrade the following office systems:

- Investments in 2024 includes routine *Financial System Upgrades* to upgrade the system to a current version and to ensure that this is supported by a Microsoft product.
- Investment in 2021 includes a *Document Management System* which will provide the ability to capture any type of document from any source (ie: paper, records such as maps, drawings, manuals, electronic files such as host generated reports, client statement streams, emails, IVR recordings, etc.), index and compress them for secure archival and future recall-providing a single cohesive repository for all document management, workflow, archival and business continuity needs.

Risk Identification & Mitigation

1. Resource Risk – Staff dedicated to office system upgrades may be required on other projects
    a. Stagger IT upgrade projects to limit project overlap of internal resources
2. Requirement to upgrade current office system due to operating system obsolescence prior to implementation of full upgrade
    a. Maintain communication with vendors and move up timeline for upgrade as required
3. Scheduling Risk – There is a perceived risk in delivering the project on-time
    a. In order to mitigate project risk, OPUCN will request quotes, and perform the proper procurement policy (RFQ/RFP) for each requirement prior to commencing.

Comparative Information on Expenditures for Equivalent Projects/Activities

There are no comparable projects for this investment.

Historical Costs ($ ‘000)						Forecast Costs ($ ‘000)				
2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
-	-	-	-	-	55	257	-	-	-	-

Investments in 2020 includes the routine Financial Systems upgrade and procurement of a People Systems software.

REG Investment Details including Capital and OM&A costs
As this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.
Leave to Construct approval under Section 92 of the OEB Act
This project is below 50 kV and therefore Leave to Construct is not required, as per OEB.Reg. 161/99.
Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material

A *Document Management System* which will provide the ability to capture any type of document from any source (ie: paper, records such as maps, drawings, manuals, electronic files such as host generated reports, client statement streams, emails, IVR recordings, etc.), index and compress them for secure archival and future recall-providing a single cohesive repository for all document management, workflow, archival and business continuity needs.

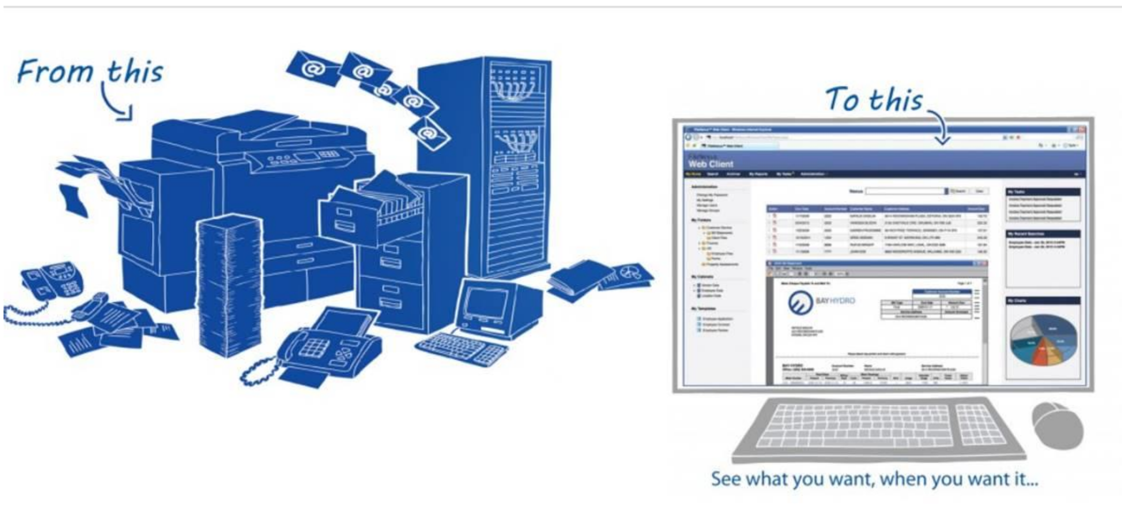


Figure 80: Document Management System Graphic

The Document Management System infrastructure consists of a single server that will host the Application and SQL Database as per diagram below. The Application and SQL VMs will be backed up on a regular schedule to Local and Disaster Recovery (DR) Network-Attached Storage (NAS), along with nightly backups of the Document Management Data. Client PCs will access the application and we will leverage existing scanning devices in our environment.

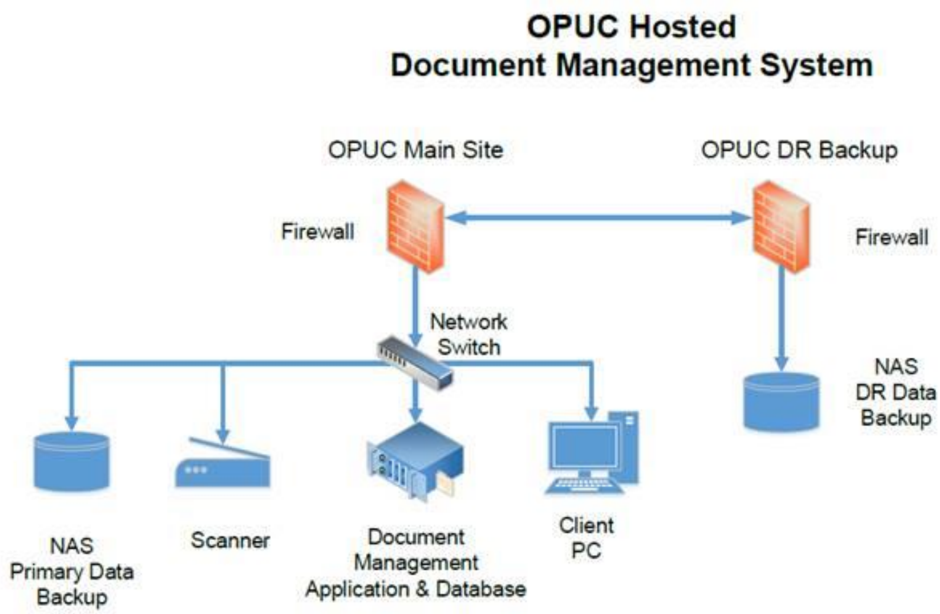


Figure 81: OPUCN Hosted Document Management System Schematic

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)
Efficiency, Customer Value & Reliability – Investment Main Driver
The driver for this project is in General Plant Investment Category with the purpose to maintain and improve operational efficiencies by upgrading the infrastructure with latest technology thereby eliminating aged and unsupported systems.
Efficiency, Customer Value & Reliability – Investment Secondary Driver
There are no secondary drivers.
Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets
The investment objective is to reduce operating costs and improve efficiency
Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment
Office systems requires upgrade due to changing technology and ensuring that the office systems are compatible with current Microsoft products and support. Additional office systems will be required to provide business support in ensuring that all data are retained.
Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges

The Document Management System which will provide the ability to capture any type of document from any source, index and compress them for secure archival and future recall-providing a single cohesive repository for all document management, workflow, archival and business continuity needs. This will upgrade our current paper process in retaining data and information.
Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment
This investment meets several AM objectives identified in Section 5.3.1 to improve business efficiency and effectiveness as office systems must be reliable to provide continued business support and has been categorized as medium priority.
Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness
Expected to allow OPUCN to provide a more efficient way of retaining and collecting data and information.
Analysis of Project & Alternatives – Net Benefits Accruing to Customers
Reduce operating costs and create more efficiencies related to: • Labor Savings • Printing Costs • Photocopier Costs • Lost & Misfiled Documents • Email Management • Storage Costs • Improved Customer Service
Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages
This project supports the office systems that support employees at OPUCN. This project does not directly affect the reliability performance including frequency and duration of outages.
Project Alternatives (Design, Scheduling, Funding/Ownership)
“Do Nothing” approach is not a practical or cost effective solution as no efficiencies will be realized.
Safety
This project is not directly related to safety.
Cyber-Security, Privacy (where applicable)
Enhanced Security vs physical printed paper which can become a liability. Sensitive printed files are more easily compromised. OPUCN would ensure that the Data Management Repository would support compliance, audit and regulatory requirements. There is also the possibility of loss of data in the event of a disaster. The new system will be compliant with the requirements of the OEB Cybersecurity Framework.
Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)
Not Applicable
Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)

Not Applicable
Environmental Benefits (where applicable)
The document management system will minimize the number of documents being printed.
Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)
Not Applicable
Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)
Not Applicable
Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity
Not Applicable

C. Category-Specific Requirements – General Plant (5.4.3.2.C)
Results of Quantitative and Qualitative Analyses
Continued upgrade to the existing office systems is required to support business needs. Additional office systems will provide improvement in business processes and system efficiencies.
Business Case Documenting the Justifications for Expenditure, Alternatives, Benefits (Long Term/Short Term), Cost Impacts
Office system upgrade is a standard requirement to ensure that the systems are current and are able to support business needs. Additional office systems such as the document management system will provide efficiencies to the current paper-based filing systems. Currently, OPUCN current method of filing is archaic, expensive not very secure and time consuming. There are several benefits to implementing a Document Management System such as the productivity gains would provide a complete pay back within months of the initial deployment not to mention the environmental benefits of eliminating paper and liability of a data breach.

A. General Information (5.4.3.2.A)					
Project/Activity	IT Systems Upgrade				
Project Number	GP-06				
Investment Category	General Plant				
	2021	2022	2023	2024	2025
Capital Cost	$251,500	$230,500	$494,250	$186,000	$418,250
Capital Contribution	N/A	N/A	N/A	N/A	N/A
Net Cost	$251,500	$230,500	$494,250	$186,000	$418,250
O&M Cost	2021	2022	2023	2024	2025
	$26,800	$26,800	$29,800	$29,800	$29,800
Customer Attachments and Load					
Not Applicable					

Start Date	2021-2025	In-Service Date	2021-2025

Expenditure Timing for the Planning Horizon	2021Q1	2021Q2	2021Q3	2021Q4
	$175,000	$25,000	$25,000	$26,500

Project Summary

- Upgrade and planned refresh of retired hardware including laptops, desktops, networking gears, storage capacity, UPS and battery systems, phone systems, data back-up and the server infrastructure.
- Equipment & Consulting services for network and systems enhancement/upgrade including domain controller, email systems and network segmentation.

Risk Identification & Mitigation

- Many of the system upgrade and implementation task may require specialized skill set which is not available internally that may delay the implementation of the project.
  - Use external resources to fill in the gap and speed up the implementation process.
- Risk of going over budget due to inflation and the lower exchange rate since most of the equipment purchased from USA based vendor and the product is quoted in USD$.
  - The mitigation strategy is to find an alternative local sources, and if that is not available then plan to purchase equipment when the foreign exchange rate is higher.
- Delayed equipment delivery since most of the equipment sourced from foreign vendors. Historically, delivery takes longer than anticipated time.
  - To mitigate the risk, OPUCN will plan to order equipment earlier to ensure on time delivery or find the alternative local sources.
- OPUCN continues to focus on security and privacy as required to comply with all applicable laws, standards and best IT security practices.
- Ensure that current and future EOSL (end of serviceable life) equipment is replaced on schedule.

Comparative Information on Expenditures for Equivalent Projects/Activities

Year	Actual	Budget
2015	$ 117,549.00	$ 130,000.00
2016	$ 93,294.00	$ 130,000.00
2017	$ 140,960.00	$ 80,000.00
2018	$ 291,481.00	$ 280,000.00
2019	$ 127,000.00	$ 80,000.00
2020		$ 314,000.00
2021		$ 251,000.00
2022		$ 230,500.00
2023		$ 494,250.00
2024		$ 186,000.00
2025		$ 418,250.00

2015	2016	2017	2018	2019
104,672	79,976	187,535	282,572	126,791

The above table depicts the capital expenditures and budget for 2015 – 2019. During this time frame, project projections and spending was fairly low, with minimum allocations for system upgrades, maintenance, and disaster recovery as it relates to mitigating end of supportable life, supporting effective disaster recovery and maintaining cybersecurity standards relating to OEB Framework and Industry best practices. The table below depicts required activities and related expenditures by year for the 2020 to 2025 timeframe. 2020 is a budget cost and part of historical expenditure within this DSP.

Project		2020	2021	2022	2023	2024	2025
New IT Equipment Upgrades (work stations & laptops)		87000	89000	90500	92000	94000	96000
Network Segmentation project		30000	0	0	0	0	0
Storage System Refresh		0	0	115000	25000	0	0
Switches & Routers/ Firewall upgrade		0	91000	0	0	0	40000
UPS System Refresh and Batteries		0	9000	0	0	34000	0
Data Backup Refresh		67000	0	0	25000	0	0
Phone System Refresh		0	0	0	50000	0	250000
Domain Controller and Email System Upgrade		50000	0	0	0	0	0
Servers Upgrades in Production and DRP - EOSL		60000	40000	0	275000	28000	0
Mobile Phone Refresh		20000	22500	25000	27250	30000	32250
	Total	**314000**	**251500**	**230500**	**494250**	**186000**	**418250**

REG Investment Details including Capital and OM&A costs

As this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.

Leave to Construct approval under Section 92 of the OEB Act

This project is below 50 kV and therefore Leave to Construct is not required, as per OEB.Reg. 161/99.

Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material

Not Applicable

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)
Efficiency, Customer Value & Reliability – Investment Main Driver
The driver is in the General Plant Investment Category aimed at maintaining and improving operational efficiencies by upgrading the infrastructure with latest technology thereby eliminating aged and unsupported systems. Equally, upgrades directly support control requirements outlines in the OEB Cyber Security Frame
Efficiency, Customer Value & Reliability – Investment Secondary Driver
There are no secondary drivers.
Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets
Reliability and operational performance improvements. Substantially reduce the risk of equipment failure and downtime.
Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment
This is based on the best practices to enhance the reliability and the overall performance of the OPUCN IT infrastructure.
Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges
Procurement of the new hardware infrastructure to meet emerging business needs. Upgrade will also maximize the ability to port existing assets as well as ensure the future extensibility and portability of future systems that will be deployed.
Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment
This program meets multiple AM objectives identified in Section 5.3.1 and is a high priority that will maintain and improve operational efficiencies. This is also an essential investment to address business requirements and cybersecurity.
Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness
OPUCN has received alternatives quotations from three different vendors. OPUCN will be reviewing the alternatives and adopt a selection process based upon best fit, cost effective and most preferred vendor.
Analysis of Project & Alternatives – Net Benefits Accruing to Customers
Improved systems/network reliability, operational efficiencies and cost efficiencies. Maintaining legacy systems is more costly than upgrading to newer more efficient systems.
Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages
The investment in a new system will improve the ability to respond to changes, increase reliability and performance of the customer facing systems thereby enhancing customer service ability, better responsiveness and timely updates to customers and employees.
Project Alternatives (Design, Scheduling, Funding/Ownership)
The project alternative that was considered is to “do-nothing,” however, maintaining legacy systems is more costly and limits ability to utilize new technological developments in support of business needs.
Safety

This project does not directly relate to safety.
Cyber-Security, Privacy (where applicable)
OPUCN continues to focus on security and privacy as required to comply with all applicable laws, standards and best IT security practices. Project initiatives directly support Cyber Security requirements as mandated by the OEB Cyber Security Framework as well as Industry best practices.
Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)
Not Applicable
Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)
Procurement of the new hardware infrastructure to meet emerging business needs. Upgrade will also maximize the ability to port existing assets as well as ensures the future extensibility and portability of future software deployment.
Environmental Benefits (where applicable)
Not Applicable
Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)
Not Applicable
Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)
Not Applicable
Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity
Not Applicable

C. Category-Specific Requirements – General Plant (5.4.3.2.C)
Results of Quantitative and Qualitative Analyses
New hardware will enable the end user to work faster and more efficiently, increasing the return on investment (ROI). Similarly, older systems that crash regularly, or otherwise keep end users from working efficiently will contribute to productivity issues. Hardware is typically purchased with a maintenance/warranty period that is defined based on normal wear and tear that contributes to poor performance.
Business Case Documenting the Justifications for Expenditure, Alternatives, Benefits (Long Term/Short Term), Cost Impacts

Although there is a capital investment involved, leveraging refreshed systems could enable OPUCN to save over the long-term through reduced maintenance and support cost and improved efficiency and staff productivity.

If we were to 'Do Nothing' there is a higher probability of system failure and cybersecurity incidents. Vendors often will not extend warranties beyond the serviceable life which increases support risks. The business operation could be negatively impacted if systems are not maintained and/or replaced. If IT systems are not upgraded OPUCN would expect additional maintenance fees or higher than usual upgrade costs in the long-term.

Appendix B: Asset Condition Assessment (2019)

METSCO

MAKING IT POSSIBLE

Prepared For:

OSHAWA PUC NETWORKS INC.

ASSET CONDITION ASSESSMENT REPORT 2018

Prepared by

P-18-173

April 2019

Disclaimer

This 2019 report has been prepared by METSCO Energy Solutions Inc. ("METSCO") for Oshawa PUC Networks Inc. ("OPUCN"). Neither OPUCN, nor METSCO, nor any other person acting on their behalf makes any warranty, expressed or implied, or assumes any legal responsibility for the accuracy of any information or for the completeness or usefulness of any process disclosed or results presented, or accepts liability for the use, or damages resulting from the use, thereof. Any reference in this report to any specific process or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement or recommendation by OPUCN or METSCO.

Asset Condition Assessment Report 2018

Final Report

April 2019

Experts:

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Executive Summary

This Asset Condition Assessment report contains calculations of current condition of Oshawa PUC Network Inc's (OPUCN) distribution assets, based on the data supplied by the utility in the fourth quarter of 2018. In addition to assessing the condition of assets with available information, the report recommends an asset replacement strategy to maintain the health of the distribution system and ensure a continuous service for OPUCN's customers.

This report summarizes the results of an Asset Condition Assessment (ACA) study carried out by METSCO Energy Solutions Inc. (METSCO) on behalf of OPUCN. The underlying study's main objectives were to generate Health Indices with current condition data of in-service assets deployed in the electricity distribution system and recommend replacement plans. As OPUCN moves towards a risk-based asset management strategy to determine the optimal timing and scope of investment into asset renewal, an ACA is prepared to determine the condition of the utility's asset base. The ACA is the first step in implementing a risk-based asset management framework that is aligned to ISO 5500X standards. A brief outline of implementing a risk-based asset management framework is documented in Section 2. The first step towards the implementation of a risk-based asset management approach is to develop a baseline assessment tool, namely the asset Health Index, that could be employed to measure and benchmark the health and condition of assets going forward. METSCO developed a comprehensive methodology and documented it in Section 3 of the report for assets comprising the scope of this analysis. The methodology in this report has been updated to METSCO Energy Solutions Inc.'s Health Index Formulation to better reflect the accuracy of an asset's condition for further risk management analysis.

The Asset Condition Assessment is based on data compiled in Q4 2018 and covers the following classes of assets owned by OPUCN:

- Distribution Assets
    - Poles
    - Overhead Primary Conductors
    - Underground Primary Cables
    - Transformers
    - Primary & Smart Switches
    - Switchgears
    - Cut-out arrestors
    - Elbows
    - Reclosers
    - Vaults & manholes
- Station Assets
    - Power Transformers
    - Circuit Breakers
    - Switchgears
    - Relays & RTUs

- Battery & Chargers
- Ground Grids
- Fences
- Buildings

For each asset group the Health Index is calculated using the data provided by the utility. Assets are classified in one of five conditions: Very Good, Good, Fair, Poor, or Very Poor. The results of the Asset Condition Assessment are summarized in Figure 0.1.

Figure 0.1: Health Index results

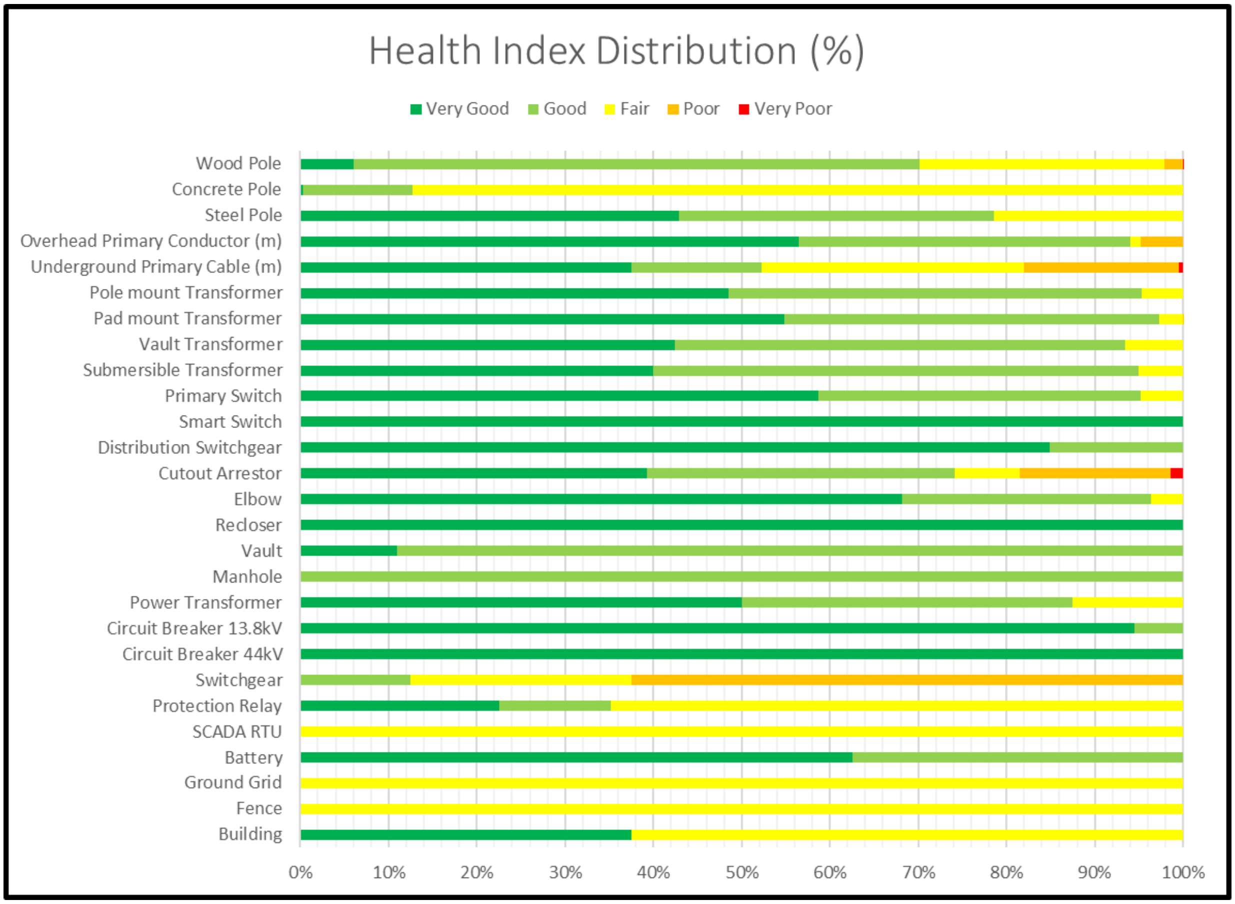

Table 0-1 presents the summary of the Health Index results. For each asset class the following details are given: the total population, average Health Index and the Health Index distribution. The Health Index Formulation (HIF) is derived from METSCO's experience, OPUCN's asset management objectives, the available data and the most material parameters that determine the timeline of expected end of life. For each asset in the following subsections, a Data Availability Indicator (DAI) is presented. The DAI is a percentage of availability of condition parameter data for an asset, as measured against the condition parameters considered in the Health Index Formulation. DAI of 100% for an asset indicates presence of values for all condition parameters defined in the Health Index Formulation and is therefore a measure of the success in meeting its intentioned data collection. OPUCN's current collection of data parameters results in a 100% DAI for the HIF.

The majority of OPUCN's system is in Fair or better condition, which suggests OPUCN's past renewal investments were effective in maintaining the system health. However, there are some assets that can benefit from an increase in asset renewal to improve the age distribution and the condition of the asset class. This may result in a decrease in cost associated with reactive failures and may reduce the number of assets with a condition graded below Fair.

Following our engagement, METSCO's chief recommendation is that OPUCN consider aligning its Health Index Formulation to the Best Practice Health Index Formulation, through the addition of incremental end of life criteria that can supplement the current inspection processes. To assist OPUCN in taking immediate steps towards asset renewal, METSCO has also provided a recommended asset replacement plan for asset renewal, reflective of the current ACA's results. The asset replacement plan is a baseline that identifies the projected quantities of assets that would likely require replacement over the next short-term planning period (years 2019 to 2025) to improve the asset category's Health Index and maintain the overall system health.

Table 0-1: Asset Condition Assessment overall results

Asset Category	Pop.	Health Index Distribution					Avg. Health Index
		Very Good	Good	Fair	Poor	Very Poor	
Wood Pole	9,570	6%	64%	28%	2%	0%	73%
Concrete Pole	869	0%	12%	87%	0%	0%	66%
Steel Pole	14	43%	36%	21%	0%	0%	72%
Overhead Primary Conductor (m)	519,869	56%	38%	1%	5%	0%	86%
Underground Primary Cable (m)	460,325	37%	15%	30%	18%	0%	69%
Pole mount Transformer	2,513	49%	47%	5%	0%	0%	84%
Pad mount Transformer	3,765	55%	42%	3%	0%	0%	85%
Vault Transformer	394	42%	51%	7%	0%	0%	84%
Submersible Transformer	20	40%	55%	5%	0%	0%	83%
Primary Switch	1,001	59%	36%	5%	0%	0%	87%
Smart Switch	15	100%	0%	0%	0%	0%	100%
Distribution Switchgear	33	85%	15%	0%	0%	0%	96%
Cutout Arrestor	2,830	39%	35%	7%	17%	1%	80%
Elbow	7,192	68%	28%	4%	0%	0%	90%
Recloser	4	100%	0%	0%	0%	0%	0%
Vault	146	11%	89%	0%	0%	0%	84%
Manhole	120	0%	100%	0%	0%	0%	83%
Power Transformer	16	50%	38%	13%	0%	0%	83%
Circuit Breaker 13.8kV	72	94%	6%	0%	0%	0%	96%
Circuit Breaker 44kV	16	100%	0%	0%	0%	0%	100%
Switchgear	8	0%	13%	25%	63%	0%	43%
Protection Relay	71	23%	13%	65%	0%	0%	75%
SCADA RTU	8	0%	0%	100%	0%	0%	60%
Battery	8	63%	38%	0%	0%	0%	89%
Ground Grid	16	0%	0%	100%	0%	0%	67%
Fence	8	0%	0%	100%	0%	0%	60%
Building	8	38%	0%	63%	0%	0%	75%

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1 Introduction

This Asset Condition Assessment (ACA) study is carried out by METSCO Energy Solutions Inc. (METSCO) on behalf of Oshawa PUC Network Inc. (OPUCN). The core objective of METSCO's engagement was to generate Health Indices with current condition data of in-service assets deployed across OPUCN's service territory and recommend replacement plans.

The ACA methodology underlying this study assessed multiple categories of assets present in OPUCN's distribution system. Adoption of the recommended ACA methodology would require periodic asset inspections and recording of their condition to identify those most at risk. Additionally, computing the Health Index for distribution assets requires identifying end-of-life criteria for various components associated with each asset type. Each criterion represents a factor that is influential in determining the component's current condition relative to conditions reflective of potential failure. These components and tests shown in the tables are weighted based on their importance in determining a given asset's end-of-life.

The asset classes covered in the report include the following:

- Distribution Assets
  - Poles
  - Overhead Primary Conductors
  - Underground Primary Cables
  - Transformers
  - Primary & Smart Switches
  - Switchgears
  - Cut-out arrestors
  - Elbows
  - Reclosers
  - Vaults & manholes
- Substation Assets
  - Power Transformers
  - Circuit Breakers
  - Switchgears
  - Relays & RTUs
  - Battery & Chargers
  - Ground Grids
  - Fences
  - Buildings

The information contained within this report represents data available in Q4 2018. The report is organized into four sections including this introductory section:

- Section 2 outlines the fundamentals of an evidence-based strategic asset management plan, summarizing standards PAS-55 and ISO 55000/55001/55002, and providing an overview of METSCO's methodology and the ACA process;

- Section 3 describes the Condition Assessment methodology framework and assessment of an asset's age, condition and data collection process;
- Section 4 summarizes our recommendations for OPUCN on data collection improvements for building on the current Health Index frameworks;
- Section 5 summarizes the recommended asset replacement strategy based on the Asset Condition Assessment, without consideration of additional factors such as an asset management plan, resource capacity, or budgetary constraints.

2 Strategic Asset Management Plan

In developing the ACA for OPUCN, METSCO ensured that the methodology was aligned to existing asset management industry standards, including ISO 5500X. Industry standards assist organizations in aligning their processes to one that is recognized internationally. This is further detailed in Section 2.1.

The ACA approach implemented for OPUCN is designed to act as a part of a broader risk-based asset management framework to allow the utility to identify assets for replacement in accordance with industry standards for asset management. This is further discussed in Section 2.2.

The ACA approach described in this report reflects OPUCN's current available data and is modified from the ideal Health Index formulation. The recommended ACA model for OPUCN is further explained in Section 2.3.

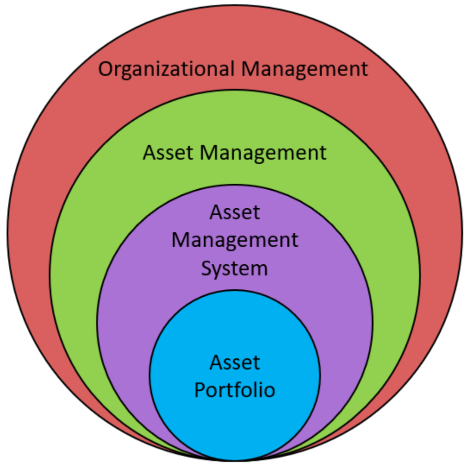
2.1 Industry Standard for Asset Management Planning

The Industry Standard for Asset Management Planning is outlined in standards documents comprising the ISO 5500X framework. Asset Management (AM) generally applies to one of three groups of entities: those looking to establish an asset management system, those seeking to realize more value from an existing asset base, and those seeking to review an asset management system already in place to explore opportunities for improvement. Given this breadth of potential utilization pathways, ISO 5500X is broadly applicable across organizations of different types, adjusting, as necessary, for the purpose, operating context, and financial constraints.[1]

Any item or entity that adds value to the organization can be considered an asset. This can be actual or potential value, expressed in a monetary or other form (i.e. public safety). The hierarchy of an organizational AM framework includes several elements showcased in Figure 2.1. An asset portfolio that contains all known information regarding the assets sits as the core of an organization. Around the asset portfolio is the AM system, which represents a set of interacting elements to establish policy, objectives, and the processes to achieve those objectives. An AM system is comprised of AM practices, which are executed in a coordinated fashion to realize the maximum value of an organization's assets. Finally, the organizational management structure organizes and executes the elements of the underlying hierarchy.[1]

[1] ISO 55000 – Asset management – Overview, principles and terminology

Figure 2.1: Relationship between key Asset Management terms[1]



Asset management is fundamentally grounded in a risk-based evaluation approach. The overarching goal of an AM process it to quantify all risks affecting the assets by their probability and impact (where possible), and then seek to minimize these risks through execution of tasks through asset management operations. Rigorous application of AM processes can yield multiple types of benefits, including: realized financial profits, better defined, classified and managed risks across the asset base, more informed investment decisions, demonstrated compliance across the asset base, increased public and worker safety, and corporate sustainability (among others).[1]

Asset management processes are ideally integrated throughout an entire organization. This requires a well-documented AM framework that is shared between and understood by all relevant agents. In this way, the organization stands to benefit the most from its own on-hand resources, whether via technical experts, those operating and maintaining the assets, or those with an understanding of the financial operations and constraints on the organization. Organizations typically document the key AM principles in a Strategic Asset Management Plan (SAMP). The SAMP should be used as a guide for the organization to apply its asset management principles and practices to its specific-use cases. Distribution of the SAMP should be open within an organization and updated on a regular basis, in order to best quantify the most current and comprehensive asset management practices being implemented. Just as the asset base performance is subject to in-depth review, the asset management process and system should be periodically reviewed with the same rigor.[1]

A well-executed AM framework hinges on an organization's ability to classify its assets using comprehensive and efficient data collection and analysis procedures. This includes but is not limited to collection and storage of technical specifications, historical asset performance information, projected asset behaviour and degradation analysis, configuration of an asset or asset-group within the system, the operational relation of one asset to another, etc. In this manner, AM systems should be focused on the techniques and procedures in which data can be most efficiently extracted from its asset base and stored to allow for further analysis to take place. With more asset data on hand, better-informed decisions can be made to realize greater benefits and reduce the risk across the asset portfolio.[2]

AM practices can help quantify and drive strategic decisions. A better understanding of the condition of asset portfolio within an organization can enable fluid reorganization or changes in management processes to realize tangible benefits to the organization. This is largely due to AM being a fundamentally risk-based approach, which lends itself to use as a sound framework for creating financial plans driven by evidence from the field. AM practices should also have goals in mind when framing asset investments, changes in asset configuration, or acquisition of new assets. This can include better technical compliance, increased safety, increased reliability, or a more optimized financial expenditures to maintain the asset base. ISO 5500X states explicitly that all asset portfolio improvements should be assessed using a risk-based approach prior to being implemented.[2]

Finally, asset management should be considered a fluid, flexible process subject to continuous enhancements and revisions. Adopting a framework and an optimized set of practices does not bind the organization or restrict its agency in the future, as the operating strategic context evolves. With time, the goal of any asset management system is to continually improve and realize benefits within the organization through better management of its asset portfolio. Continually improved asset data and data collection procedures, updated Strategic Asset Management Plans (SAMPs), and further integration of asset performance analytics into all aspects of an organization's activities as it grows and changes over time should be the goal of any AM framework.[2]

An Asset Condition Assessment (ACA) represents the first step in fully integrating the AM framework outlined by ISO 55000. An organisation determines the current condition scores for each asset by evaluating a current set of available data related to the state of degradation of in-service assets within an asset portfolio. The level of degradation of an asset, knowledge of its configuration within the system, and its corresponding likelihood of failure feed directly into a risk-based assessment. The fundamental purpose of an ACA is to collect, consolidate, and present the results framed by the current organizational dynamics for the purposes of properly quantifying and managing the risks of its asset portfolio. An ACA should provide insights into the current state of an organization's asset base, the risks associated with further degradation, and approaches as to optimal utilization of obtained results to extract the maximum value from the asset portfolio going forward.

[2] ISO 55002 – Asset management – Management systems – Guidelines for the application of ISO 55001

2.2 Overview of METSCO's Methodology

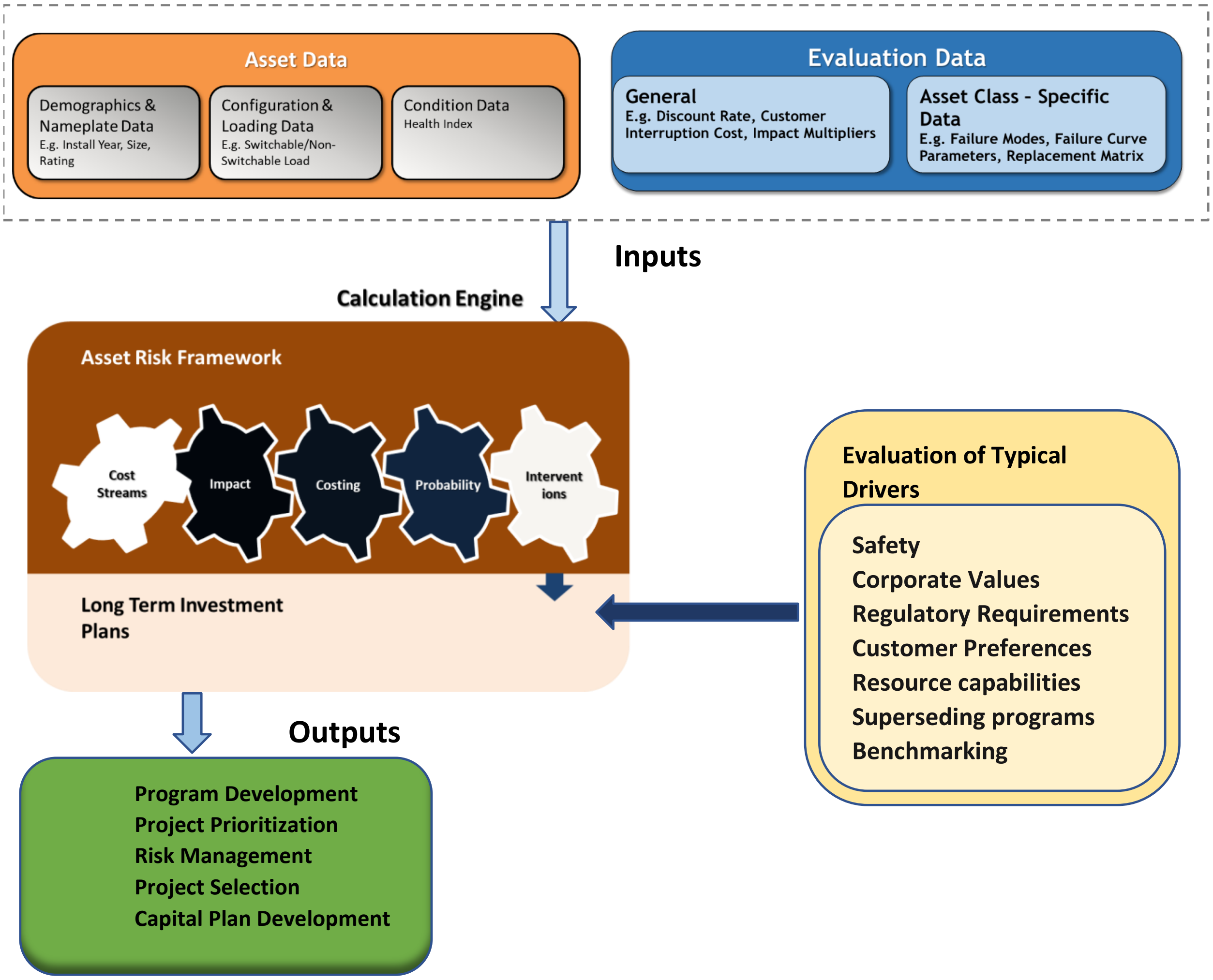
2.2.1 Overall Asset Management Strategy

Decisions involving investments into fixed assets play a major role in determining the performance of distribution systems. Most of investments in fixed assets are triggered by either declining performance in the areas of system reliability, power quality or safety; increasing operating and maintenance costs associated with aging assets; or anticipated growth in demand requiring capacity upgrades. Under any of these scenarios, investments that are either oversized or made too far in advance of the actual system needs may result in sub-optimal allocation of resources. On the other hand, investments not made in time when warranted by the system needs increase the risk of missing performance targets – thus also resulting in suboptimal capital allocations. Optimal operation of a distribution system is achieved when "right sized" investments into renewal and replacement (capital investments) and into asset repair, rehabilitation and preventative maintenance are planned and implemented based on a "just-in-time" approach. In summary, the overarching objective of an Asset Management Strategy is to find the right balance between capital investments in new infrastructure and operating and maintenance costs to sustain the existing plant – minimizing the combined total costs over the life of an asset.

METSCO is a proponent of Risk-Based Asset Management Strategies, which determine the risk of asset failure based on physical condition of an asset, commonly measured using numerical "Asset Health Indices". This approach computes the valuation of the asset risk based on consequences of asset failure and identifies the economically optimal risk mitigation alternative through an evaluation of all available options. Asset management covers the full life cycle of a fixed asset, from preparation of the asset specification and installation standards, through the scope and frequency of preventative maintenance during the asset's service life, – and finally, to the determination of the asset's end-of- life and retirement from service. At each stage of an asset's life cycle, decisions are made to achieve the right balance between achieving maximum life expectancy, enabling highest operating performance, and maintaining lowest initial investment (capital costs) and operating costs. The best-in-class asset management strategies employ integrated processes that allow optimal levels of financial and operating performance to be achieved, using transparent and objective criteria that can easily be audited and inspected by regulators.

The overarching objective is to develop a prioritized capital and preventative maintenance investment plans, which are implemented over periods of 10 to 25 years to optimize system performance. Corporate objectives and performance requirements are incorporated in the model by placing appropriate weights and costs on project drivers as shown in Figure 2.2.

Figure 2.2: Model to Identify Assets with Highest Risks



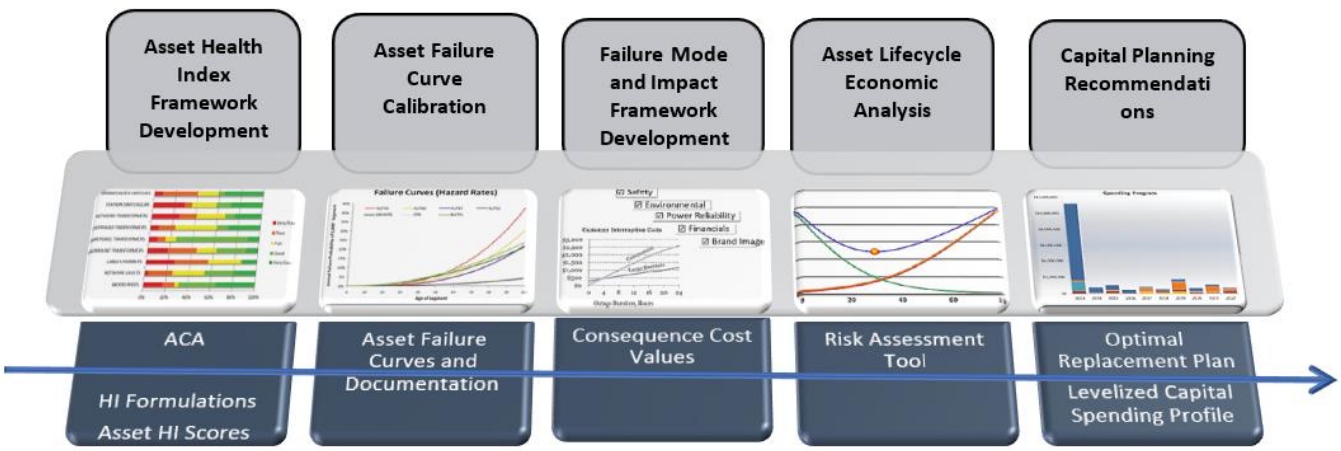
METSCO's overall asset management approach includes executing an assessment across the five components as presented in Figure 2.3. Under the asset Health Index (HI) framework development, an Asset Condition Assessment (ACA) is performed. An ACA is used to produce the HI, which represents a quantified condition score of a given asset. The HI score is ultimately calculated using asset age, inspection and historical performance data (as applicable). Using this technique, a utility may also choose to develop condition-based failure probability information – that is the likelihood of assets failing once degrading past a certain threshold.

Different asset classes and individual assets have different propensity to fail over time on the basis of their observed condition parameters, meaning different failure curves apply to them. Failure curves are calibrated by analyzing actual failure data against the age and/or condition parameters observed at the time of failure. Weibull analysis is a commonly used statistical methodology to develop the failure probability curves.

The calculated failure probability information is used in subsequent risk analysis to determine the likelihood of failure of an asset of a given age in a given year. Failure mode and impact component development calculates the consequence cost values for various asset failure modes – considering customer impacts, collateral damage impact, environmental impact, etc. Once the probability and impact of asset failure have been determined, the risk cost can be calculated, along with the life-cycle costs of the asset. Assets will be recommended for replacement at the point in time when an optimal balance is achieved between capital spending and risk level mitigated, avoiding premature retirements and preventing significant delays in addressing the most pressing problems.

The scope of this report only covers the Asset Health Index Framework Development component of the Overall AM Approach illustrated in Figure 2.3. The remaining components are identified to outline for OPUCN the future steps that can be taken to further enhance their Asset Management practices. However, the Asset Health Index Framework component represents the first step needed to be taken and is the foundation for the remaining identified four components of the Overall AM Approach.

Figure 2.3: Overall AM approach



2.2.2 Asset Condition Assessment Process

The major steps in the ACA are briefly discussed below:

1. Identify Asset Classes: Identify asset classes to be considered in the asset condition assessment study

   Typical asset classes in the distribution system include:

   - Station Transformers
   - Station Circuit Breakers
   - Station Batteries
   - Capacitors

- Controls and Protective Relays
- Overhead Primary Conductors
- Underground Primary Cables
- Distribution Transformers
- Switches
- Poles

2. Data Analysis:
   - Collect asset related data such as GIS records, asset demographics, inspection/testing records, etc.
   - Validate the accuracy of data, e.g. check for data discrepancies between files
   - Develop an adjusted "Health Index Formulation" (HIF) for each asset based on the available data, published best practice information and expert assessment of the data parameters which are reasonably obtained and are most indicative of asset end of life.
   - Identify additional asset data needed to determine and evaluate asset condition and assess the potential of collecting additional useful asset condition information to improve accuracy of the condition assessment results.
   - Recommend collecting additional data that is reasonably available (the methods to obtain additional data typically include inspection, testing, sampling, collection of paper records, field work to collect asset data, adopting advanced technology to record inspection/testing data, etc.).
3. Collect additional condition information specific to each asset class.
4. Calculate Data Availability Indicator (DAI): DAI is a percentage of availability of condition parameter data for an asset, as measured against the condition parameters considered in the adjusted HIF. DAI is calculated as a ratio of sum of weighted condition parameters score of available condition parameters to sum of weighted condition parameters score from the recommended HI formulation.

$$DAI = \left(\frac{\sum_{i=1}^{N} Weight_i * CPAF_i}{\sum_{i=1}^{N} Weight_i}\right) x\ 100$$

   Where *i* corresponds to the condition number, *N* is the total number of condition parameters considered in the HI calculation, and *CPAF* is the Condition Parameter Availability Factor which is equal to 1 if the condition parameter data is available for the asset otherwise equal to 0.

   DAI of 100% for an asset indicates successful population of values for all condition parameters defined in the adjusted Health Index Formulation for the asset and is therefore a measure of success in meeting its intentioned data collection targets. Typically, the targets for DAI are less than 100% for "sampled" assets such as cables and wood poles, or where the costs to collect additional data are not warranted such as for assets that represent lower risk of in-field failure (as opposed to proactive replacement). Sampling is done on assets where the asset population is significant and cannot be inspected within one year. Therefore, the best and latest available data is used as a representative sample of the total population. Sampling is a viable method to assess the condition of assets given the available condition parameters.

While Health indices can be calculated using a variety of combinations of available information, utilities seeking to improve their In addition, there is a data set representing the “Best Practice Health Index Formulation”, which an asset owner may be moving towards. In this case, a recommendation for process improvements may include suggestions to collect additional condition parameters defined in the Best Practice Health Index Formulation for the entire population of assets. With the new data collected, it is expected to increase the accuracy of ACA results.

5. Asset Condition Assessment:

A Health Index (HI) is an indicator of asset remaining life given as a percentage. A new asset should have a HI of 100% and an asset in very poor health should have a HI below 30%. Table 2-1 presents the HI ranges and the corresponding asset condition.

Table 2-1: Asset condition based on health index

Health Index	Condition	Description	Requirements
[85–100]	Very Good	Some ageing or minor deterioration of a limited number of components	Normal maintenance
[70–85)	Good	Significant deterioration of some components	Normal maintenance
[50–70)	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed depending on criticality
[30–50)	Poor	Widespread serious deterioration	Start planning process to replace or rehabilitate considering risk and consequences of failure
[0–30)	Very Poor	Extensive serious deterioration	Asset has reached its end-of-life; immediately assess risk; replace or refurbish based on assessment

To determine the condition for an asset, the Health Index formulation is developed using condition criteria that lead to an asset’s physical end of life and potential failure. Described modes of degradation are identified through failure analysis reports, subject matter experts and historical failure. A weight is assigned to each condition to indicate the amount of influence the condition has on the overall asset health. When presented with a HI Formulation such as:

Table 2-2: Health Index Calculation Example

#	Condition Criteria	Weight	Condition Grade	Factors	Maximum Score
1	Condition example 1	4	A,B,C,D,E	5,4,3,2,1	20
2	Condition example 2	6	A,C,E	5,3,1	30
3	Condition example 3	6	A,B,C,D,E	5,3,2,1	30
	MAX SCORE				**80**

Asset Health Indices are based on identification of aging mechanisms and failure modes of the assets and their sub-systems and are developed by placing appropriate weights on various parameters indicative of condition, to express the level of degradation of an asset's health along the way to its end-of-life.

The assigned weights are based on the parameter's criticality in determining the overall health and condition of the asset and depending on the ease or difficulty with which these condition parameters could be improved. For example, those that relate to their primary functions and cannot be easily improved without costly rehabilitation/ repair work are assigned higher weights than those that represent ancillary functions or can be improved without incurring high costs.

This assigning of weights for Health Indexing is a continuous improvement and is a continuing effort supported through METSCO's ongoing review of industry practices and techniques for asset inspections and testing. Historical utility surveys and literature search have been performed to support the development of best practice Health Indices. Ongoing efforts are continued at METSCO to further refine its best practice Health Index formulations to accurately reflect current asset construction and testing techniques.

Each condition is ranked from A to E and each rank corresponds to a numerical grade:

Grade	Condition
A – 5	Best Condition
B – 4	Normal Wear
C – 3	Requires Remediation
D – 2	Rapidly Deteriorating
E – 1	Beyond Repair

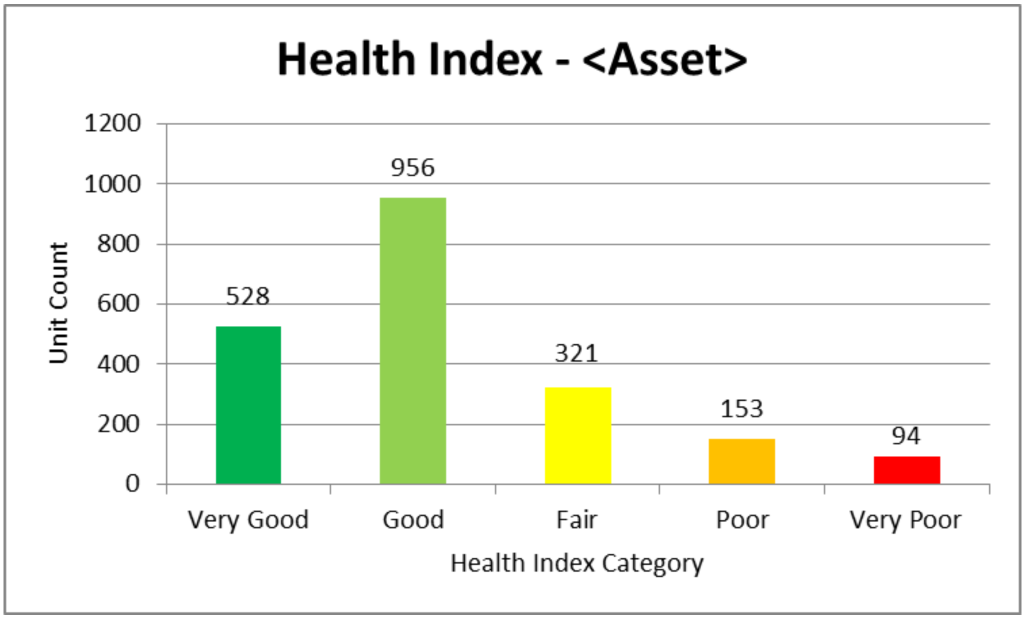
The Health Index is then calculated as follows:

$$HI = \left(\frac{\sum_{i=1}^{N} Weight_i * Numerical\ Grade_i}{Total\ Score}\right) x\ 100$$

Where *i* corresponds to the condition number, *N* is the total number of condition parameters considered in the HI calculation and the *HI* is a percentage representing the remaining life of the asset.

Figure 2.4 shows the example graph representation of HI conditions for an asset class categorizing assets into Very Good to Very Poor condition.

Figure 2.4: Asset Health Index Graph-Example

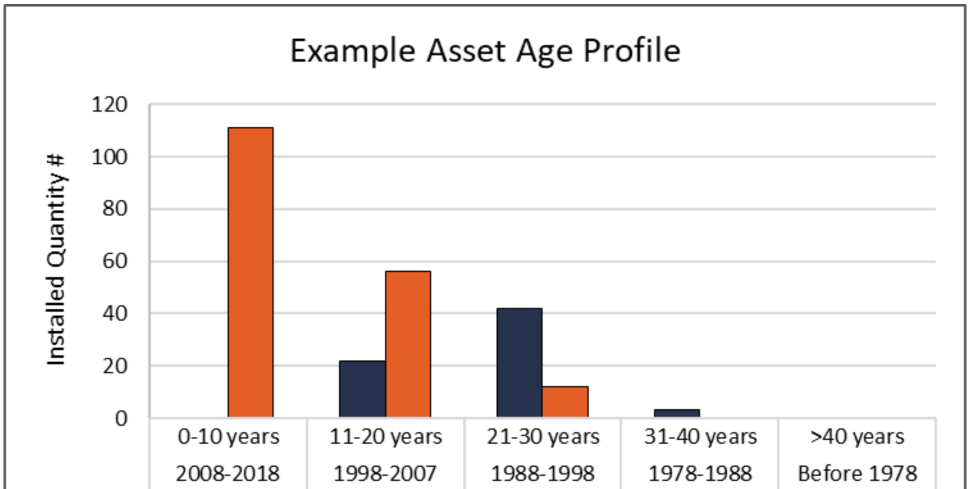


Note – the above graphic is illustrative only and does not represent any factual numbers of OPUCN's assets nor system.

6. Demographic Assessment:

A useful cross-reference to an HI is a representation of asset demographics. Assets are charted based on age from installation date, and other pertinent demographics such as material or manufacturer/type etc. Since many people still consider age when making replacement plans, it is important to document any significant variations between the age-based results and the condition-based HI. As an example, cables are known to have different life expectancies based on the technology available at the time of installation. In other cases, equipment produced by a certain manufacturer may be known to be reaching the end of life and failing at a higher-than-predicted rate. Figure 2.5 represents a typical demographic chart to represent the asset age data.

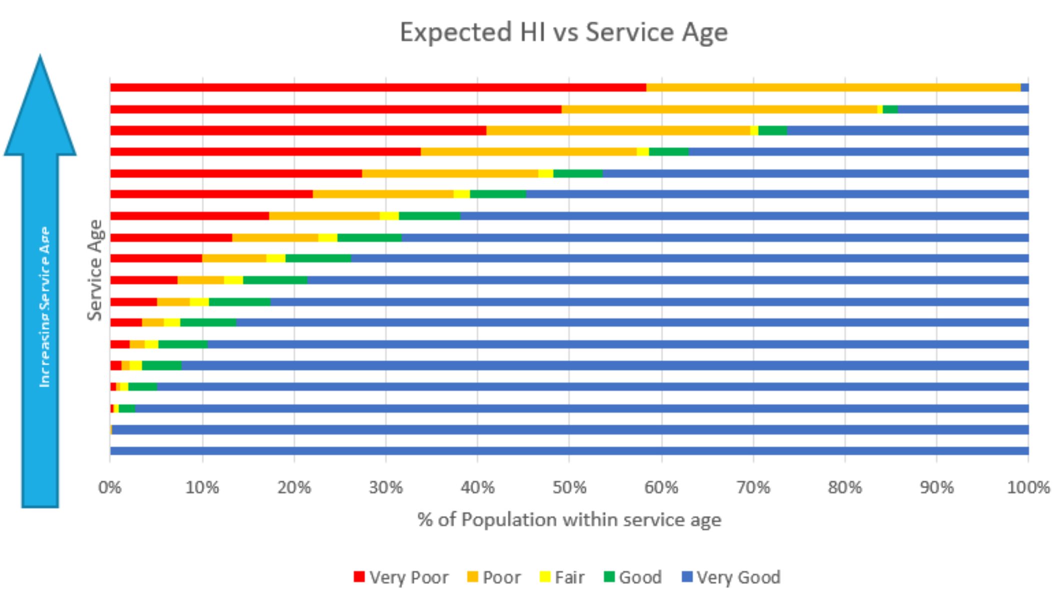
Figure 2.5: A Typical Demographic Chart



	0-10 years 2008-2018	11-20 years 1998-2007	21-30 years 1988-1998	31-40 years 1978-1988	>40 years Before 1978
Type 1	0	22	42	3	0
Type 2	111	56	12	0	0

Figure 2.6 presents an example of an expected relationship between the HI condition and service age. Based on past empirical studies, there is a general expectation that the HI conditions should gradually change from Very Good to Very Poor as the service age of an asset increases. However, deviations within and across specific asset classes may be present due to a number of potential drivers.

Figure 2.6: Expected HI Vs Service Age Trend-Example



7. Recommendations: The last stage of the ACA process entails providing recommendations for OPUCN based on the results of the ACA including a preliminary asset replacement for

sustainable system performance for the next seven years, as well as improvements on data collection process that are expected to increase the validity of HI results.

2.3 ACA Model for OPUCN

The ACA model for OPUCN's system utilized in this study is a function of both OPUCN's data availability and its asset management objectives. Data availability drives the parameter selection for each asset's Health Index as well as their respective index weighting. OPUCN's asset management objectives drives the criticality of assets.

The Health Index Formulation (HIF) for OPUCN includes the following modifications from the Best Practice Health Index Formulation (BHIF) driven by the distributor's specific circumstances:

1. Additional parameters were included for some assets that are usually not included within the BHIF. Additionally, certain related parameters have been merged together, whereas in the BHIF the parameter would ideally be divided into multiple parameters to highlight the criticality. An example of this is for wood poles where in the BHIF, "Wood Rot" and "Defects" would be separated whereas in the OPUCN it is merged as "Overall Condition" since that is how the available data is collected.
2. The weighting of each parameter is different in comparison to the BHIF. Although it deviates from the BHIF, the HIF implemented reflects OPUCN's historical asset performance and condition. Additionally, the weightings align with OPUCN's asset management objectives, identifying parameters that are critical for OPUCN's system and are targeted to reduce the associated risk. The HIF implemented at OPUCN is unique to its own system as every system varies and differs within Ontario. However, OPUCN understands the implemented HIF can continue to be improved upon and intends to be in alignment to the BHIF with respect to the collecting of condition criteria unique to each asset class.
3. The BHIF Health Index formula does not identify weights that will result in a summation score of 100, whereas, OPUCN favors to identify weights that will result in a sum score of 100. As a recap, weights are identified through historical asset failures and subject matter experts in relation to their overall contribution the asset's physical end of life. However, the current approach has limited effect on the final Health Index in comparison to the BHIF. The translation from Ranking to Numerical Grade is identified from 1 to 5 in the adjusted HIF, whereas the BHIF is identified with 0 to 4. Though the Numerical Grade both use a five-level grading, the adjusted HIF Numerical Grade aides the goal of having a total score of 100. However, both methods normalize the Health Index to a total score out of 100 and as such are effectively the same.

The BHIF is METSCO's Health Index Formulation to evaluate the condition and risk of an asset based on industry standard. The BHIF is a tested methodology and has been successfully implemented and used within asset management practices across Ontario. The BHIF was developed based on multiple consultations between subject matter experts on each asset class, identifying parameters that affect the overall condition of the asset and the severity of anticipated impact associated with those parameters. However, the BHIF is dependent on an ideal state of data collection and maturity of asset management. Therefore, the BHIF can be slightly modified to fit OPUCN's database and historical performance while also providing the valuable insight on the asset's condition.

3 OPUCN Asset Base Health Indices

3.1 Distribution Assets

3.1.1 Wood Pole

3.1.1.1 Condition Assessment Methodology

Being an organic material, wood is subjected to degradation processes that are different from other assets on distribution systems. The most critical degradation process for wood poles involves biological and environmental mechanisms such as fungal decay, wildlife damage and physical stress due to effects of weather. Computing the Health Index of a wood pole requires developing the associated end-of-life criteria. Each criterion represents a factor in determining the asset's condition relative to potential failure.

The Health Index for wood poles is calculated by considering a combination of service age, visual inspections for defects and pole treatment. The best available data is considered for the Health Index calculations within this ACA. Table 3-1 summarizes the methodology to combine these criteria into an overall Health Index for wood poles.

Table 3-1: Wood Pole Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Service Age	8	A,B,C,D,E	5,4,3,2,1	40
2	Overall Condition	8	A,B,C,D,E	5,4,3,2,1	40
3	Component Condition	2	A,B,C,D,E	5,4,3,2,1	10
4	Pole Treatment	2	A,C,E	5,3,1	10
				MAX SCORE	**100**

Table 3-2 translates service age into a condition rating. Given that service age provides a reasonably good measure of the remaining life of the asset, and we employ it as a discrete assessment parameter.

Table 3-2: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 40 years
D	41 to 50 years
E	Over 50 years or Unknown

Different aspects of the wood pole are visually inspected by qualified staff during line patrols. OPUCN inspects a variety of components described below and utilizes a four-level grading system to rank the overall pole condition: Good, Fair, Fair-Poor, Poor. Visual inspection can detect the following types of wood pole damage:

- Fibre damage that may occur when wind hits a wood pole with force beyond the pole's bearing capacity;

- Animal and/or insect damage and infestation;
- Partial damage that may result when objects hit wood poles and reduce effective pole circumference. If the damage affects only a part of a pole's cross-section, the utility may keep the pole in-service while noting a reduced factor of safety;
- Mis-orientation from excessive transverse forces that may result in pole tilting as well as "stretching" (i.e. loosening) and breaking of guys and guying systems;
- Burning from conductor faults and insulator flashovers may damage the wood poles reducing the ability of these structures to withstand mechanical stress changes or causing their complete loss through fire incidents;
- Wood cracks that may hold moisture and cause decay or weaken the structures through freeze/thaw forces during winter; and
- Various types of wood rot in possible locations visually seen by the inspector.

Table 3-3 is used to translate visual inspection results into a condition rating.

Table 3-3: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	Pole is in "as new" condition
B	Pole has normal wear expected with age
C	Pole has many minor problems or a major problem that requires close attention and monitoring
D	Pole has many problems and the potential for its failure would rapidly escalate unless preventative maintenance is performed
E	Pole requires immediate replacement

Additionally, OPUCN inspects the component hardware found on poles. Incorporating the component hardware as a criterion to determine the Health Index of the pole is in alignment to OPUCN's asset management practices to assist in identifying deficiencies or non-standard hardware on poles that can be easily corrected.

Degradation of reduction in strength of insulator hardware may occur due to the following:

- Loss of galvanization and corrosion of steel members;
- Loss in strength due to fatigue;
- Loosening of hardware due to conductor vibrations; or
- Hardware failure during major storm events.

Close-up visual inspection can generally determine the extent of degradation. Different components of the pole line, including cross-arms, hardware, insulators and pole grounding are visually inspected by qualified staff during line patrols. By considering the results of these inspections, the health and condition of each component is scored in accordance with Table 3-4.

Table 3-4: Criteria for Component Condition

Condition Rating	Corresponding Condition
A	Component is in "as new" condition
B	Component has normal wear expected with age
C	Slight deficiencies visible on component
D	Moderate deficiencies visible on component
E	Extensive deficiencies visible on component

Since the rate of pole degradation is affected by the effectiveness of the preservative treatment, wood pole treatment is employed within the Health Index formulation. Table 3-5 is used to translate the wood pole's treatment to a condition rating.

Table 3-5: Criteria for Pole Treatment

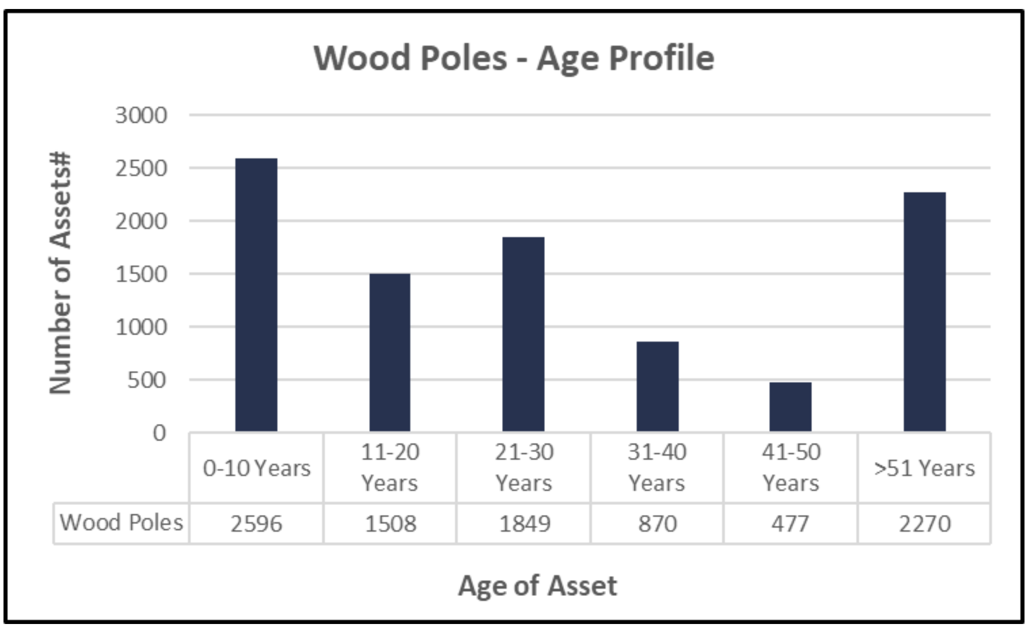
Condition Rating	Corresponding Condition
A	Fully treated
C	Butt treated
E	No treatment

3.1.1.2 Results of Analysis

Age Assessment

OPUCN currently owns 9570 wood poles in-service within its service territory. Figure 3.1 presents the age distribution. Through discussion with OPUCN, OPUCN believes poles with an unknown installation year are assumed to be 51 years or older. This accounts for 2.3% of total OPUCN poles. Asset service age is currently calculated with end year 2017.

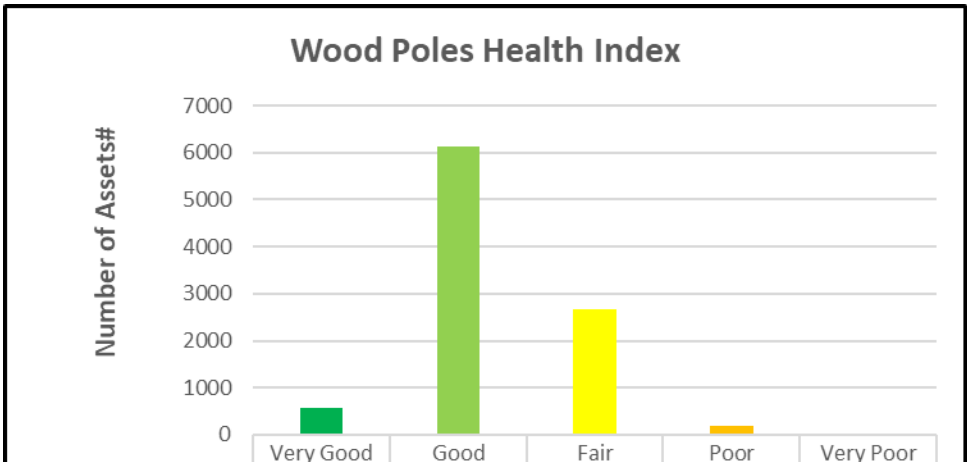
Figure 3.1: Wood Pole Age Demographic



Condition Assessment

OPUCN's pole inspections were completed by a third-party contractor and the results were used to calculate the Health Index based on the criteria provided in Table 3-1. The Health Index values were calculated for each wood pole asset using the best available data. The overall Health Index distribution is presented in Figure 3.2. In this analysis, wood poles with an unknown age have received a rating of "E" for service age.

Figure 3.2: Wood Pole Health Index Demographic



	Very Good	Good	Fair	Poor	Very Poor
Number of Assets #	581	6129	2662	196	2

Data Assessment

The Data Availability Indicator (DAI) is created to measure the reasonable collected data to date by the utility for completion regarding parameters used in the Health Index algorithm. The DAI for wood pole data is 100% with assumptions applied. Section 4 provides additional recommendations for data collections for Health Index formulation expansion.

3.1.2 Concrete and Steel Pole

3.1.2.1 Condition Assessment Methodology

Computing the Health Index of a concrete pole requires developing end-of-life criteria. Each criterion represents a factor in determining the asset's condition. The Health Index for concrete and steel poles is calculated by considering a combination of visual deficiencies and service age. The best available data is considered for the Health Index calculations within this ACA. Table 3-6 summarizes the methodology to combine these criteria into an overall Health Index for concrete and steel poles.

Table 3-6: Concrete and Steel Poles Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Service Age	8	A,B,C,D,E	5,4,3,2,1	40
2	Defects/Overall Condition	8	A,B,C,D,E	5,4,3,2,1	40
3	Out of Plumb	4	A,B,C,D,E	5,4,3,2,1	20
				MAX SCORE	**100**

Table 3-7 and Table 3-8 is used to translate service age into a condition rating. Since service age provides a reasonably good measure of the remaining life of the asset, it is employed as an assessment parameter.

Table 3-7: Criteria for Service Age – Steel Pole

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 40 years
D	41 to 50 years
E	Over 50 years or Unknown

Table 3-8: Criteria for Service Age - Concrete Pole

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 40 years
D	41 to 50 years
E	Over 50 years or Unknown

Different components of concrete and steel poles are visually inspected by qualified staff during line patrols. OPUCN inspects a number of components and utilizes a four-level grading system: Good, Fair, Fair-Poor, Poor. Table 3-9 is used to translate visual inspection into a condition rating. Table 3-10 is used to translate the concrete and steel pole components inspection results to a condition rating.

Table 3-9: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	Pole is in “as new” condition
B	Pole has normal wear expected with age
C	Pole has many minor problems or a major problem that requires close attention and monitoring
D	Pole has many problems and the potential for its failure would rapidly escalate unless preventative maintenance is performed or is replaced within a few years
E	Pole requires immediate replacement

Table 3-10: Criteria for Out of Plumb Condition

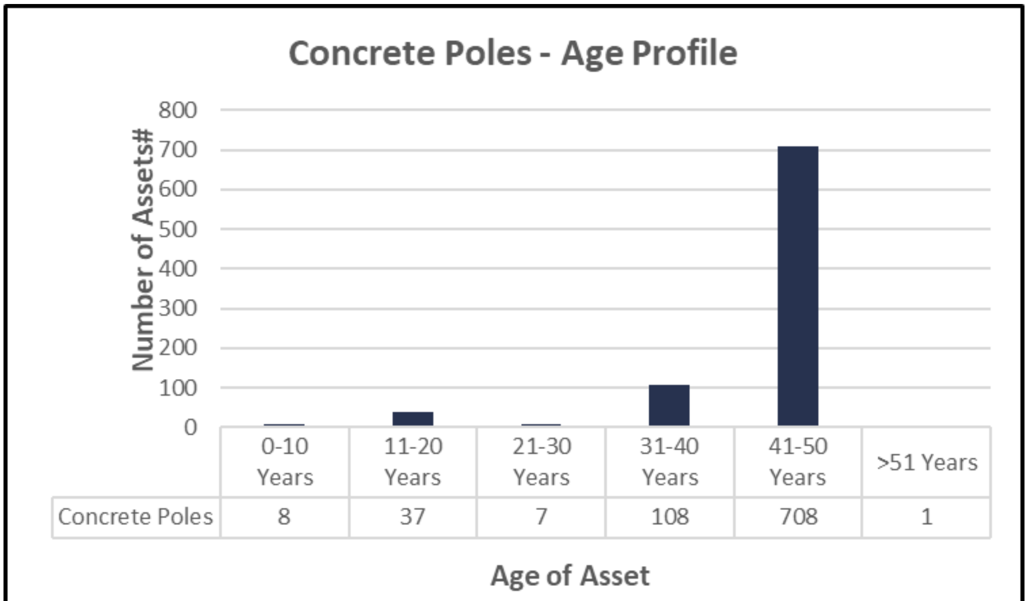
Condition Rating	Corresponding Condition
A	Pole in "as new" condition
B	Pole has normal wear expected with age
C	Pole out of Plumb - Slight
D	Pole out of Plumb - Moderate
E	Pole out of Plumb - Extensive

3.1.2.2 Results of Analysis

Age Assessment

OPUCN owns 869 concrete poles in-service within its service territory. Figure 3.3 presents the age distribution for concrete poles. Asset service age is currently calculated with end year 2017.

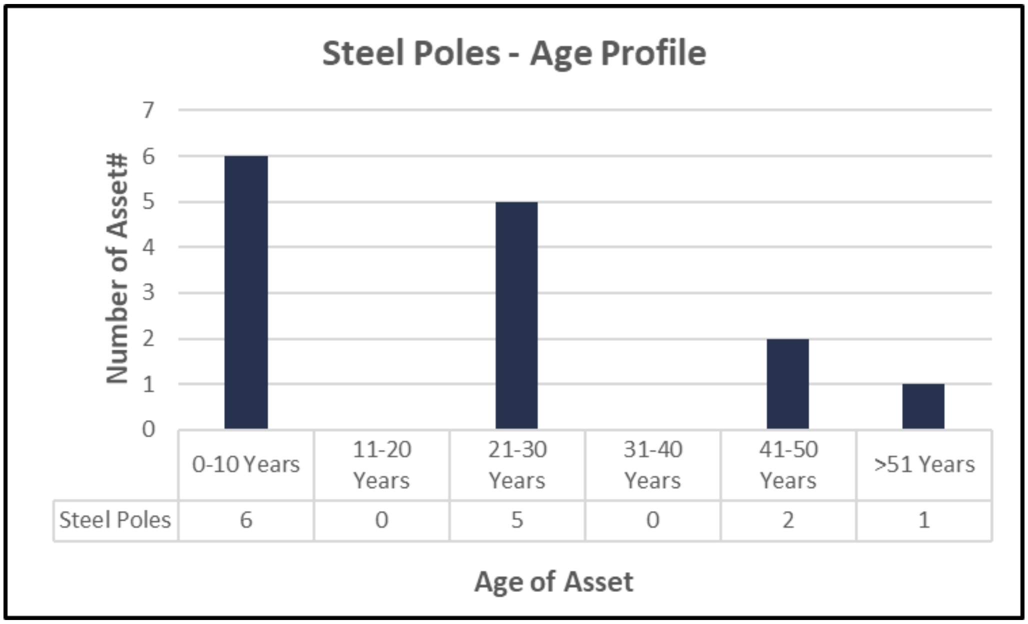
Figure 3.3: Concrete Pole Age Demographic



	0-10 Years	11-20 Years	21-30 Years	31-40 Years	41-50 Years	>51 Years
Concrete Poles	8	37	7	108	708	1

OPUCN owns 14 steel poles in-service within its service territory. Figure 3.4 presents the age distribution for steel poles. Asset service age is currently calculated with end year 2017.

Figure 3.4: Steel Pole Age Demographic



Condition Assessment

OPUCN's pole inspections were used to calculate the Health Index based on the criteria provided in Table 3-6. The Health Index values were calculated for each concrete and steel pole asset. The overall Health Index distribution is presented in Figure 3.5 and Figure 3.6.

Figure 3.5: Concrete Pole Health Index Demographic

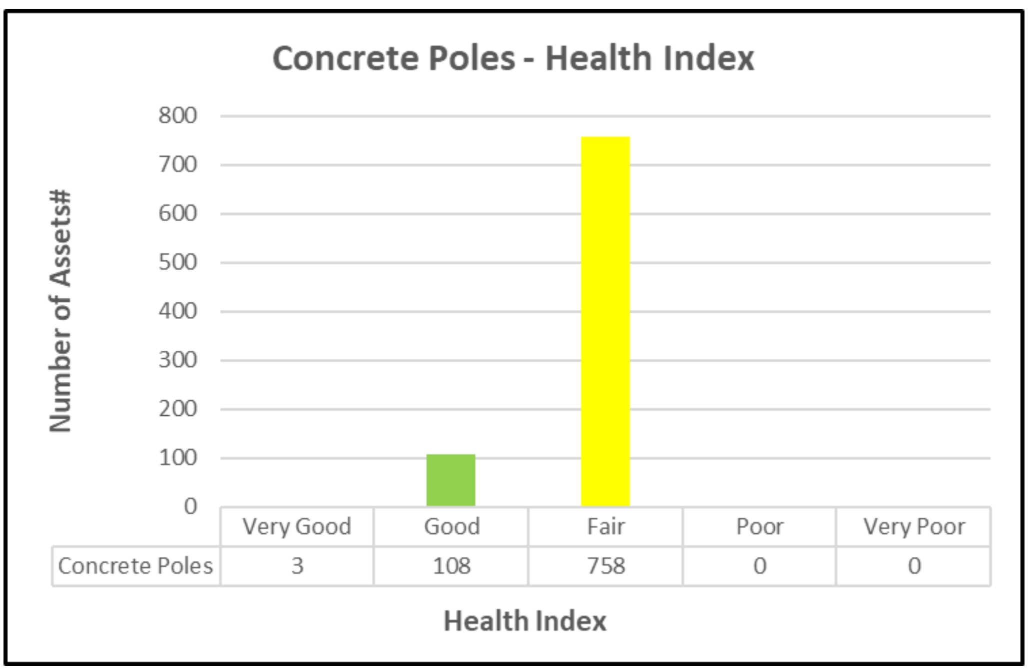
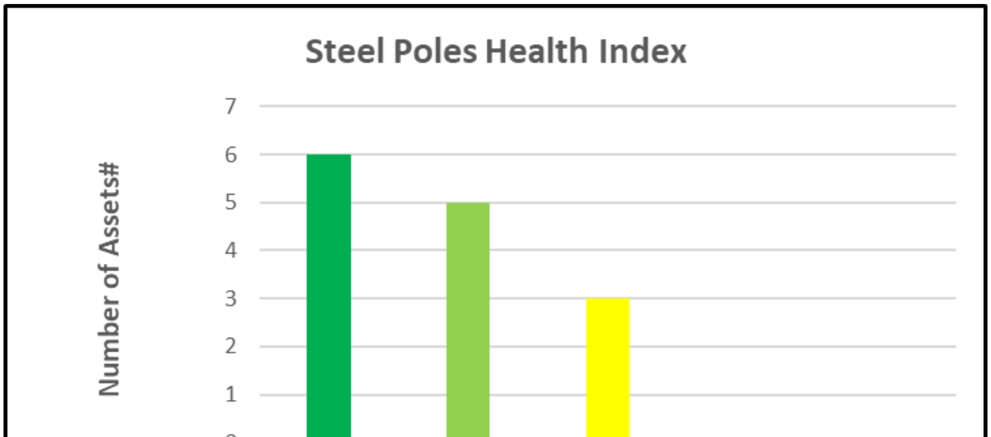


Figure 3.6: Steel Pole Health Index Demographic



	Very Good	Good	Fair	Poor	Very Poor
Number of Assets #	6	5	3	0	0

Data Assessment

The Data Availability Indicator (DAI) is created to measure the reasonable collected data to date by the utility for completion regarding parameters used in the Health Index algorithm. The DAI for concrete and steel pole data is 100% with assumptions applied. Section 4 provides additional recommendations for data collections for Health Index formulation expansion.

3.1.3 Overhead Primary Conductor

3.1.3.1 Condition Assessment Methodology

Although laboratory tests are available to determine the tensile strength and assess the remaining useful life of conductors, distribution line conductors rarely require testing. As a general observation, overhead primary conductors on distribution lines often outlive the poles and are not usually on the critical path to determine the end of life for a line section.

The only exception to the above rule might be where small copper conductors susceptible to frequent breakdowns are in use, or where line conductors are too small for line loads resulting in suboptimal system operation due to high line losses.

The Health Index for overhead primary conductors is calculated by considering a combination of service age and small conductor risk. The best available data is considered for the Health Index calculations within this ACA. Table 3-11 summarizes the methodology to combine these criteria into an overall Health Index.

Table 3-11: Overhead Primary Conductor Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Service Age	10	A,B,C,D,E	5,4,3,2,1	50
2	Small Conductor Risk*	10	A,E	5,0	50
				MAX SCORE	**100**

**Note: If Small Conductor Risk is present, the Health Index is divided by two to highlight the high risk of asset failure and condition.*

The service age provides a reasonably good measure of the remaining strength of conductors with the lack of visual inspection for cable defects. Table 3-12 is used to translate service age into a condition rating.

Table 3-12: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 30 years
C	31 to 50 years
D	51 to 70 years
E	71 years and older

Historical performance of small-sized conductors has exhibited a high safety concern to the public observed in multiple utilities across Ontario. Furthermore, the small-sized conductors do not align to the current best practice and industry standards for overhead conductor installation. Since small-sized conductors sometimes pose a serious safety risk, the value of this criteria is scored separately, presented in Table 3-13.

Table 3-13: Criteria for Small Size Conductor Risk

Condition Rating	Corresponding Condition
A	Absence of small sized conductors
E	Presence of small sized conductors (#4 to #6 copper)

3.1.3.2 Results of Analysis

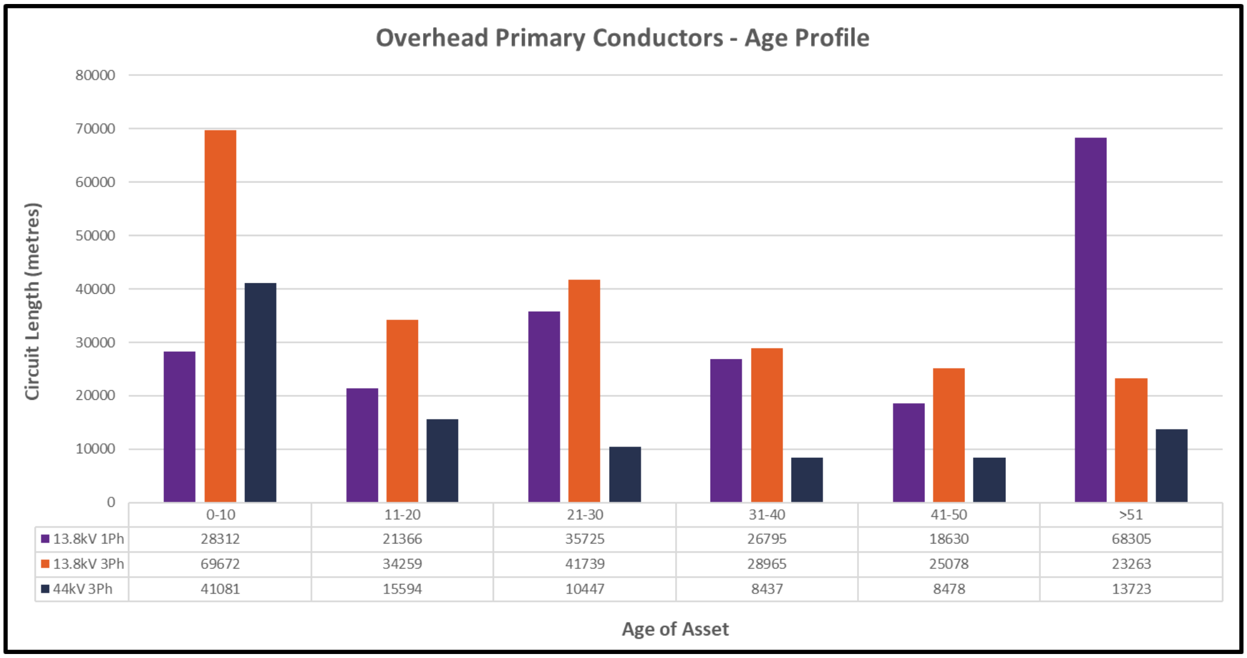
Age Assessment

OPUCN owns approximately 520 km of overhead primary conductors within its service territory. For overhead primary conductors with unknown service age, OPUCN applied two assumptions on the service age of the asset:

1) utilize the neighboring asset information within a 10-meter distance mapping to the oldest age of the poles (this accounts for 247kms or 47% of OPUCN total overhead conductors); and

2) where it was not possible to determine the age of the conductors by using neighboring asset information, the age of the conductor asset is fixed to 40 years old (this accounts for 24kms or 4.6% of OPUCN total overhead conductors). Figure 3.7 presents the age distribution for each major system voltage. Asset service age is currently calculated with end year 2017.

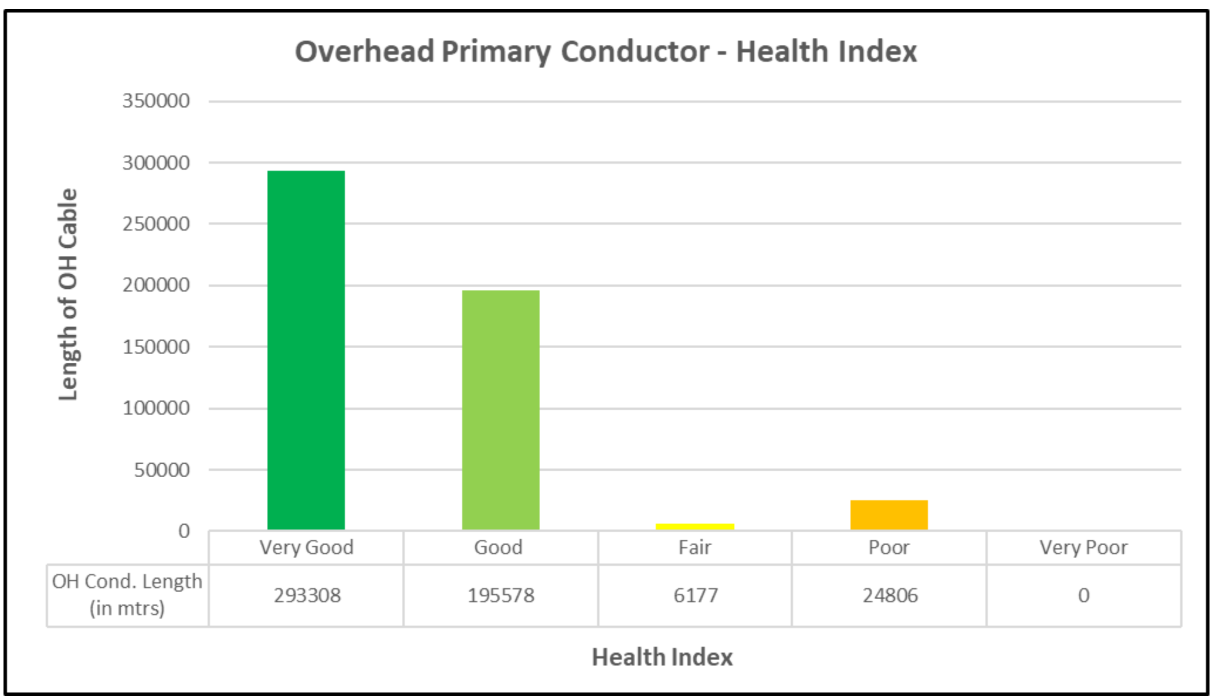
Figure 3.7: Overhead Primary Conductor Age Demographic



Condition Assessment

OPUCN's 2017 GIS conductor data was used to calculate the Health Index based on the criteria provided in Table 3-11. The overall Health Index distribution is presented in Figure 3.8.

Figure 3.8: Overhead Primary Conductor Health Index Demographic



Overhead Conductor Quick Sleeves

Sleeves are used to splice overhead primary conductor lines for circuit separation and for connecting two different primary conductor materials which are adjacent. OPUCN employs two types of sleeves: quick sleeves and compression sleeves. The jaws found in the quick sleeve clamp down on the primary conductors as tensile stress is applied to hold conductor wires together.. However, they may not last the entire life of the conductors they are installed on, as demonstrated by the failures. Compression sleeves are used as permanent splices in distribution systems. Compression sleeves are built to last for the entirety of the conductor's life, reducing the probability of potentially falling from an energized line. Compression sleeve integrity depends on several factors:

- Proper cleaning and roughening of the conductor strands
- Proper centering of the inner core within the sleeve
- Appropriate use of corrosion inhibitor

There are approximately 90 compression sleeves and 100 quick sleeves on 44kV primary overhead conductor lines in the OPUCN network, however, the total number of sleeves on the 13.8kV network is currently unknown.

Data Assessment

The Data Availability Indicator (DAI) is created to measure the reasonable collected data to date by the utility for completion regarding parameters used in the Health Index algorithm. The DAI for overhead primary conductor data is 100% with assumptions applied. Section 4 provides additional recommendations for data collections for Health Index formulation expansion.

3.1.4 Underground Primary Cable

3.1.4.1 Condition Assessment Methodology

Distribution underground primary cables are among the more challenging assets on electricity systems from a condition assessment and asset management perspective. Although test techniques such as partial discharge testing have become available over the recent years, it is still very difficult and expensive to obtain accurate condition information for buried cables. The adopted approach to managing cable systems has been to monitor cable failure rates and quantify the potential failure impact. The failure impacts of the cables are monetized in relation to (but not limited to) reliability, safety, environment, and operations. When the costs associated with in-service failures become higher than the annualized cost of cable replacement, the cables are then determined to be at their end of their economic useful life and should be replaced.

The Health Index for underground primary cable is calculated by considering the service age and the evidence of historic failures. The best available data is considered for the Health Index calculations within this ACA. Table 3-14 summarizes the methodology to combine these criteria into an overall Health Index.

Table 3-14: Underground Primary Cable Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Service Age	11	A,B,C,D,E	5,4,3,2,1	55
2	Historic Rates of Circuit Failures	9	A,B,C,D,E	5,4,3,2,1	45
				MAX SCORE	**100**

The service age provides a reasonably good measure of the remaining strength of conductors with the lack of visual inspection for cable defects. Table 3-15 is used to translate age into a condition rating. Table 3-16 is used to translate historical failure rates of underground primary cable on each circuit within the last 5 years.

Table 3-15: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 15 years
B	16 to 25 years
C	26 to 35 years
D	36 to 45 years
E	46 years and older

Table 3-16: Criteria for Historic Failure Rates

Condition Rating	Corresponding Condition
A	Less than 0.5 failure per 10 km in the last 5 years
B	0.5 to 1.0 failure per 10 km in the last 5 years
C	1.0 to 1.5 failures per 10 km in the last 5 years
D	1.5 to 2.0 failures per 10 km in the last 5 years
E	2.5 or more failures per 10 km in the last 5 years

3.1.4.2 Results of Analysis

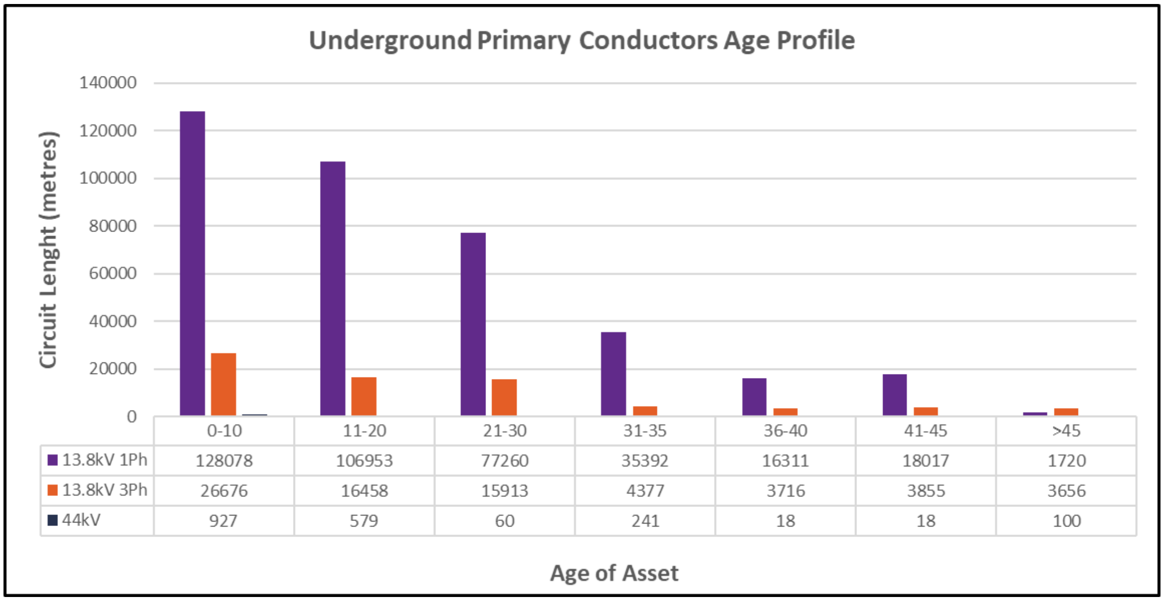
Age Assessment

OPUCN owns approximately 460.3 km of underground primary cable within its service territory. For the underground primary cables with unknown service age, OPUCN applied two assumptions on the service age:

1) utilize the neighboring asset information within a 10-meter distance mapping to the oldest age (this accounts for 5.5kms or 1.2% of OPUCN total underground cable); and

2) where it was not possible to determine the age of the conductors by using neighboring asset information, the age of the conductor asset is fixed to 25 years old (this accounts for 15kms or 3.3% of OPUCN total underground cable). Figure 3.9 presents the age distribution by system voltage. Asset service age is currently calculated with end year 2017.

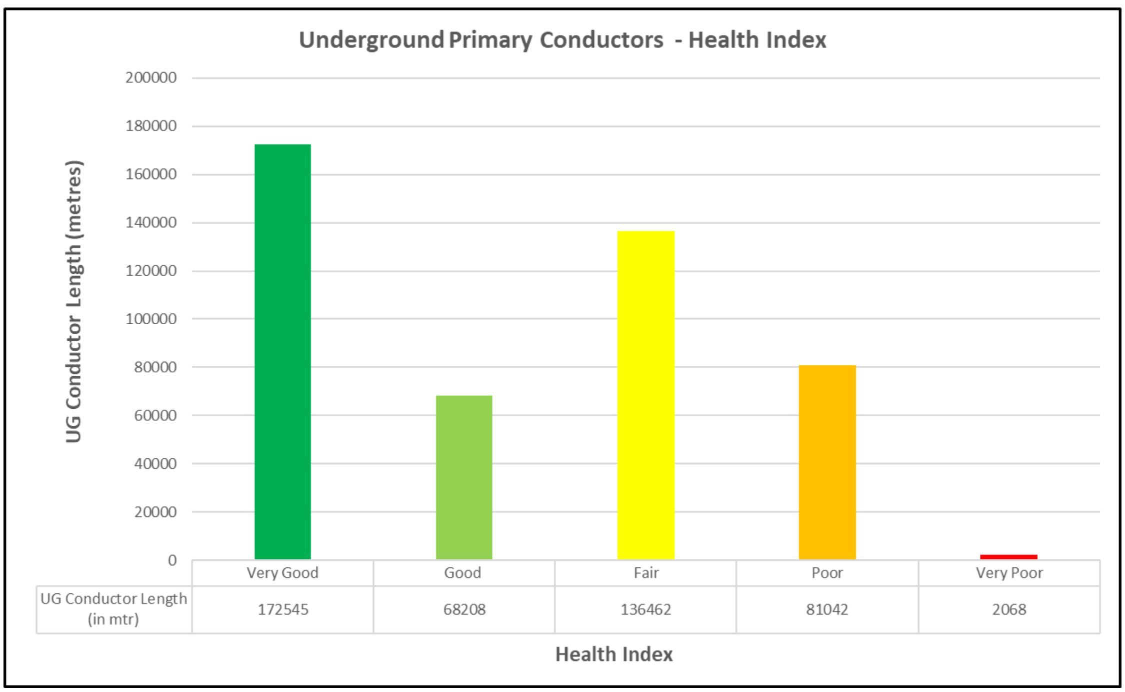
Figure 3.9: Underground Primary Cable Age Demographic



Condition Assessment

OPUCN's 2017 GIS conductor data was used to calculate the Health Index based on the criteria provided in Table 3-14. The overall Health Index distribution is presented in Figure 3.10 for each major system voltage.

Figure 3.10: Underground Primary Cable Health Index Demographic



Data Assessment

The Data Availability Indicator (DAI) is created to measure the reasonable collected data to date by the utility for completion regarding parameters used in the Health Index algorithm. The DAI for underground primary cable data is 100% with assumptions applied. Section 4 provides additional recommendations for data collections for Health Index formulation expansion.

3.1.5 Distribution Transformer

Four types of distribution transformers are assessed within this report:

- Pad mounted transformer
- Pole mounted transformer
- Submersible transformer
- Vault transformer

3.1.5.1 Condition Assessment Methodology

Generally, utilities replace distribution transformers as part of overhead or underground rebuild projects or when they are assessed as having a high risk of failure. Within the industry, apart from rust proofing, painting of the tanks, replacing a damaged bushing or repairing a leaky gasket, very little invasive preventative maintenance or testing is carried out on distribution transformers.

The Health Index for distribution transformers is calculated by considering a combination of service age, overall condition and loading history. The best available data is considered for the Health Index calculations within this ACA. Table 3-17 summarizes the methodology to combine these criteria into an overall Health Index.

Table 3-17: Distribution Transformers Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Service Age	6	A,B,C,D,E	5,4,3,2,1	30
2	Overall Condition	8	A,B,C,D,E	5,4,3,2,1	40
3	Peak Loading	6	A,B,C,D,E	5,4,3,2,1	30
				MAX SCORE	**100**

Since the service age provides a reasonably good measure of the remaining life of transformers, it is employed as an assessment parameter, Table 3-18.

Table 3-18: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	10 to 20 years
C	20 to 30 years
D	30 to 40 years
E	40 years and older

A visual inspection includes the following data entries:

- Presence of oil leaks
- Condition of cable terminations
- Presence of rust

Table 3-19 presents the condition rating based on the outstanding visual inspection issues for the distribution transformers. Additionally, the peak load in relation to the transformers rating can be utilized to assess the transformers' condition. A transformer exposed to longer durations or frequent peak loads above the manufacturer's rating will promote accelerated degradation of the transformer's internal components. Table 3-20 provides the condition rating based on loading level.

Table 3-19: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	No rust on tank/enclosure, no damage to bushings, no sign of oil leaks, padlocks in good condition on pad-mounted transformers
B	Only one of the following defects: Minor rust, or minor cracks in bushings or minor oil leak
C	Two or more of the above indicated defects present but do not impact safe operation
D	Tank/radiator badly rusted or major damage to bushing or major oil leak
E	Two or more of the above indicated defects

Table 3-20: Criteria for Peak Loading

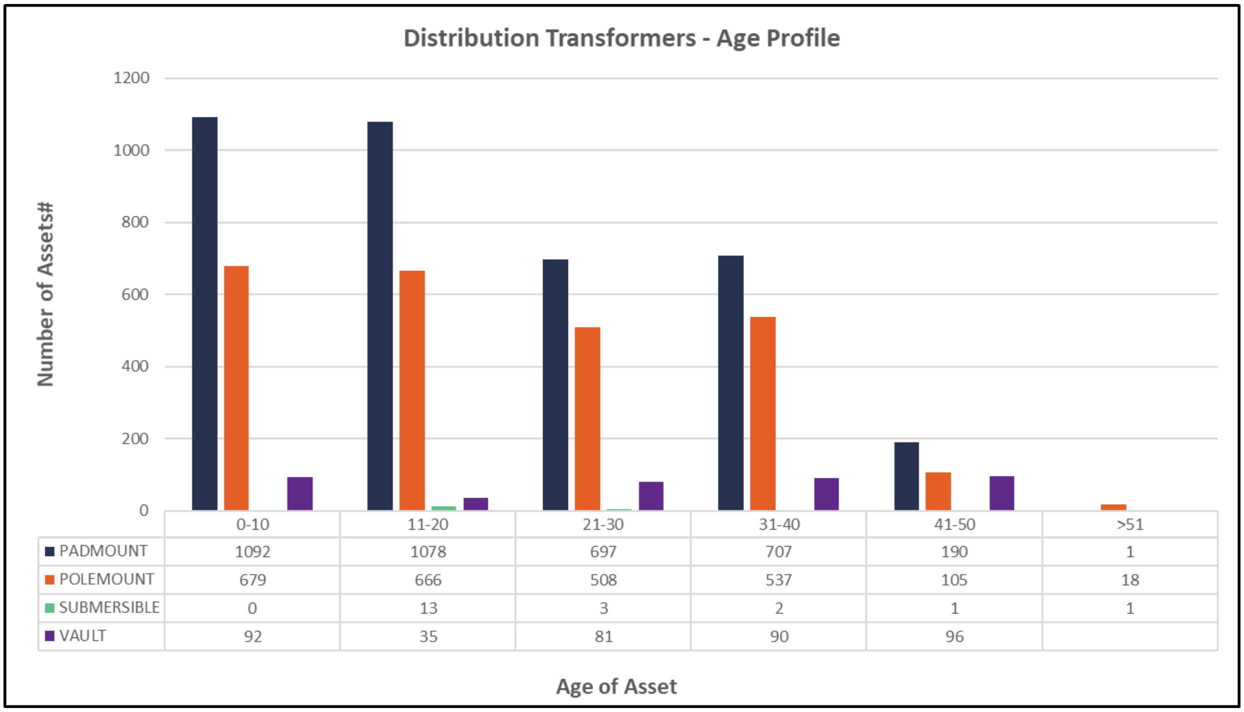
Condition Rating	Corresponding Condition
A	Peak load less than 50% of its rating
B	Peak load of 50% to 75% of its rating
C	Peak load of 75% to 100% of its rating
D	Peak load of 100% to 125% of its rating
E	Peal load of greater than 125% of its rating

3.1.5.2 Results of Analysis

Age Assessment

OPUCN owns 3765 pad mount transformers, 2513 pole mount transformers, 20 submersible transformers and 394 vault transformers within its service territory. For transformers with no known install dates, OPUCN applies the following assumptions in priority to back-fill the service age: date asset was received, manufacturer date. Figure 3.11 presents the age distribution by transformer types. Asset service age is currently calculated with year-end 2017.

Figure 3.11: Distribution Transformer Age Demographic



	0-10	11-20	21-30	31-40	41-50	>51
PADMOUNT	1092	1078	697	707	190	1
POLEMOUNT	679	666	508	537	105	18
SUBMERSIBLE	0	13	3	2	1	1
VAULT	92	35	81	90	96	

Condition Assessment

OPUCN's 2017 transformer inspections records and 2014 peak loading data was used to calculate the Health Index based on the criteria provided in Table 3-17. For transformers with peak loading percentage greater than 100% that require further analysis and data confirmation, OPUCN applies an assumption of a condition score of "D" to be assigned for the parameter peak loading. This accounts for 5% of the total OPUCN distribution transformers. The overall Health Index distribution is presented in Figure 3.12 to Figure 3.15 for each transformer type.

Figure 3.12: Pad Mount Transformer Health Index Demographic

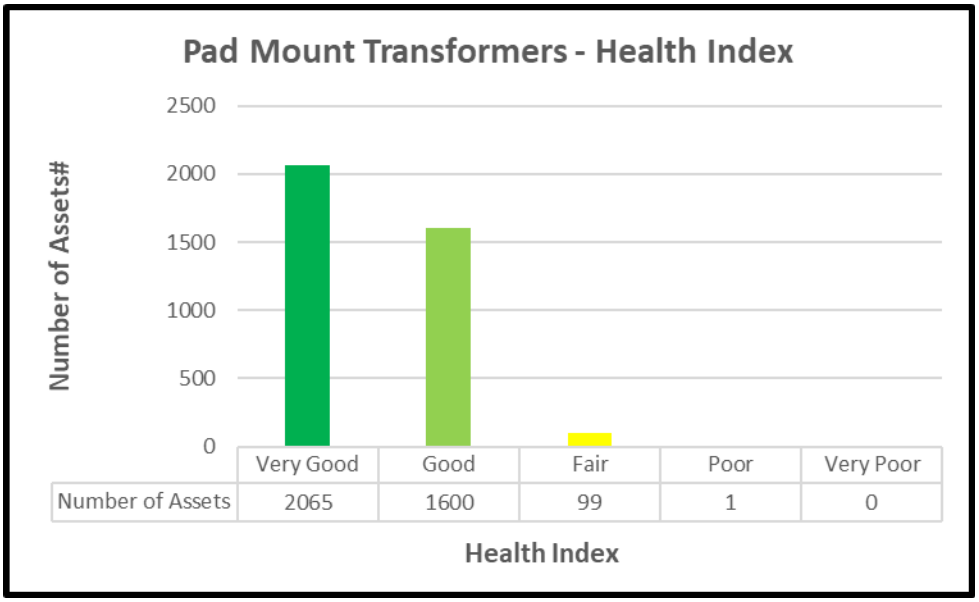


Figure 3.13: Pole Mount Transformer Health Index Demographic

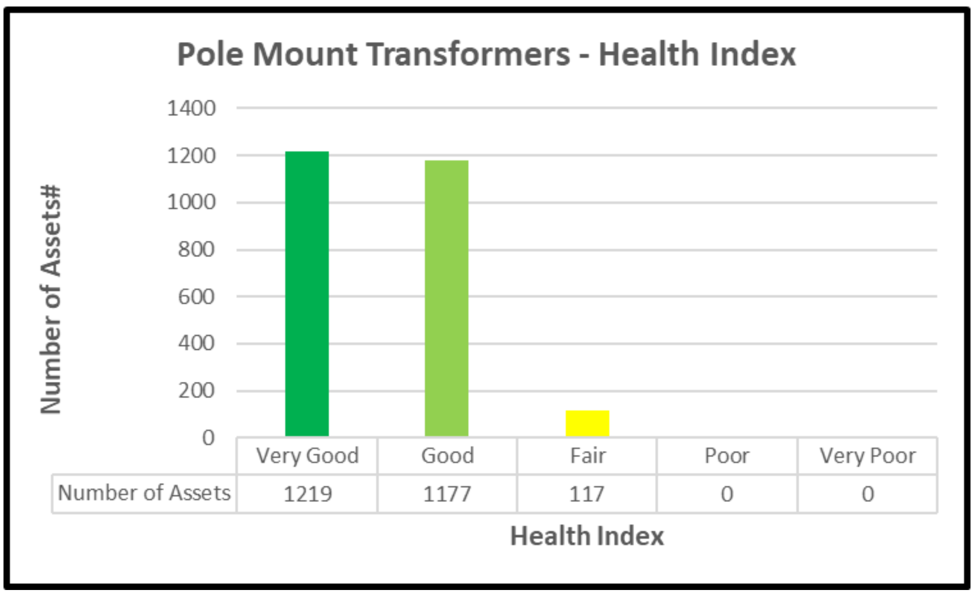


Figure 3.14: Submersible Transformer Health Index Demographic

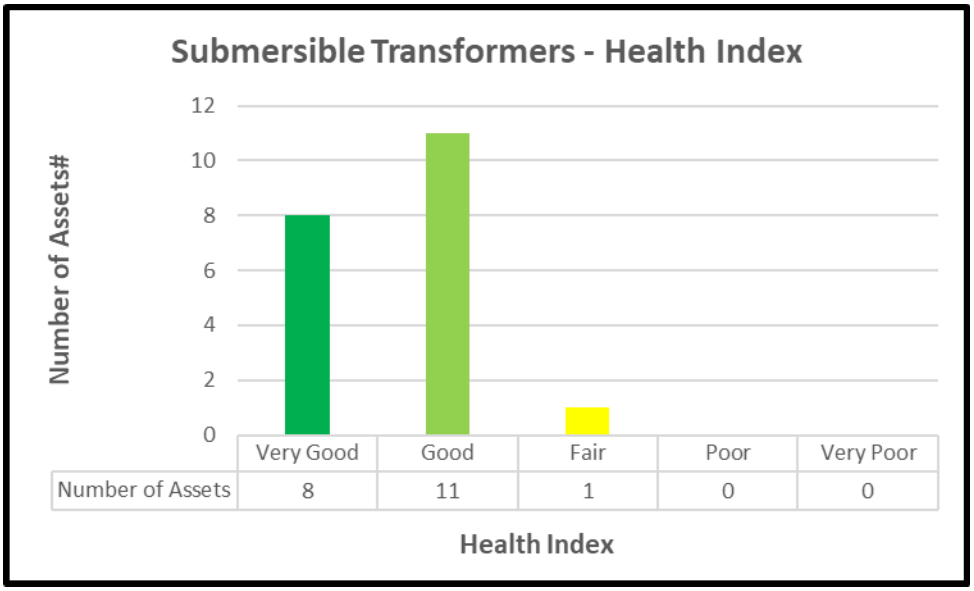
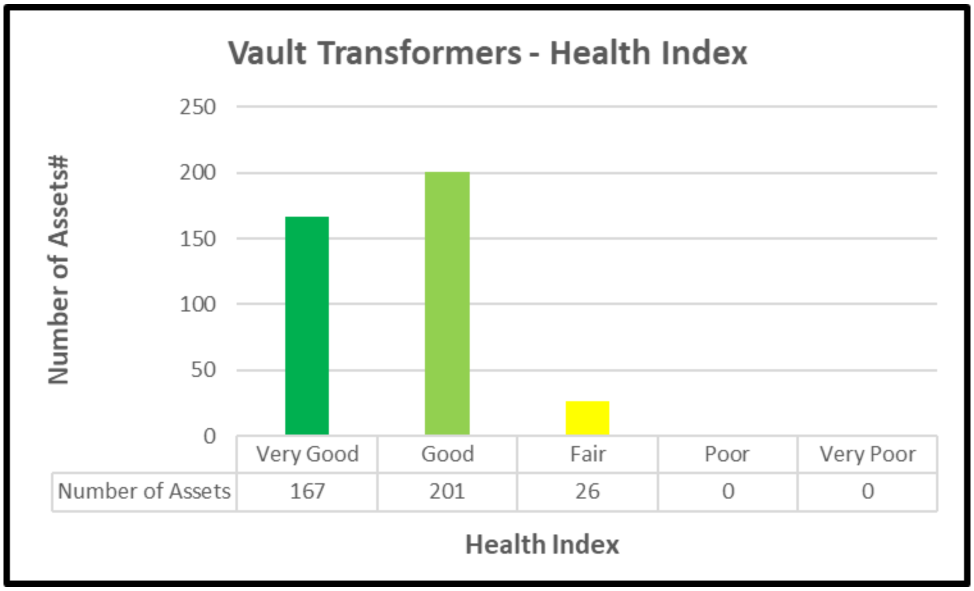


Figure 3.15: Vault Transformer Health Index Demographic



Data Assessment

The Data Availability Indicator (DAI) is created to measure the reasonable collected data to date by the utility for completion regarding parameters used in the Health Index algorithm. The DAI for transformer data is 100% with assumptions applied. Section 4 provides additional recommendations for data collections for Health Index formulation expansion.

3.1.6 Primary and Smart Switch

3.1.6.1 Condition Assessment Methodology

Disconnect switches provide the means of load disconnection and isolation for equipment, such as underground laterals or distribution transformers. The Health Index for primary and smart switches is calculated by considering a combination of service age and visual inspections for defects. The best available data is considered for the Health Index calculations within this ACA. Table 3-21 summarizes the methodology to combine these criteria into an overall Health Index.

Table 3-21: Primary and Smart switch Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Service Age	10	A,B,C,D,E	5,4,3,2,1	50
2	Overall Condition	10	A,B,C,D,E	5,4,3,2,1	50
				MAX SCORE	**100**

Since the service age provides a reasonably good measure of the remaining life of switches, it is employed as an assessment parameter, shown in Table 3-22.

Table 3-22: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	41 years and older

Visual inspections can provide a good indication of the physical condition of switches and are graded using Table 3-23.

Table 3-23: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	No rust and corrosion, operating mechanism in excellent condition and no hotspot detected
B	Only minor wear, no defects, or minor hotspot detected
C	No more than one of the above indicated defects present but does not impact safe operation or Intermediate hotspot detected
D	Two or more of above indicated defects, but they can be repaired, or serious hotspot detected
E	Two or more of the above indicated defects, but they cannot be repaired, or critical hotspot detected

3.1.6.2 Results of Analysis

Age Assessment

OPUCN owns a total of 1001 primary switches and 15 smart switches within its service territory. For primary switches with no known install dates, OPUCN applies the assumption that the assets are fixed to age 30, which accounts for 16% of OPUCN total primary switches. Figure 3.16

presents the age distribution for primary switches, and Figure 3.17 presents the age distribution for smart switches. Asset service age is currently calculated with end year 2017.

Figure 3.16: Primary Switch Age Demographic

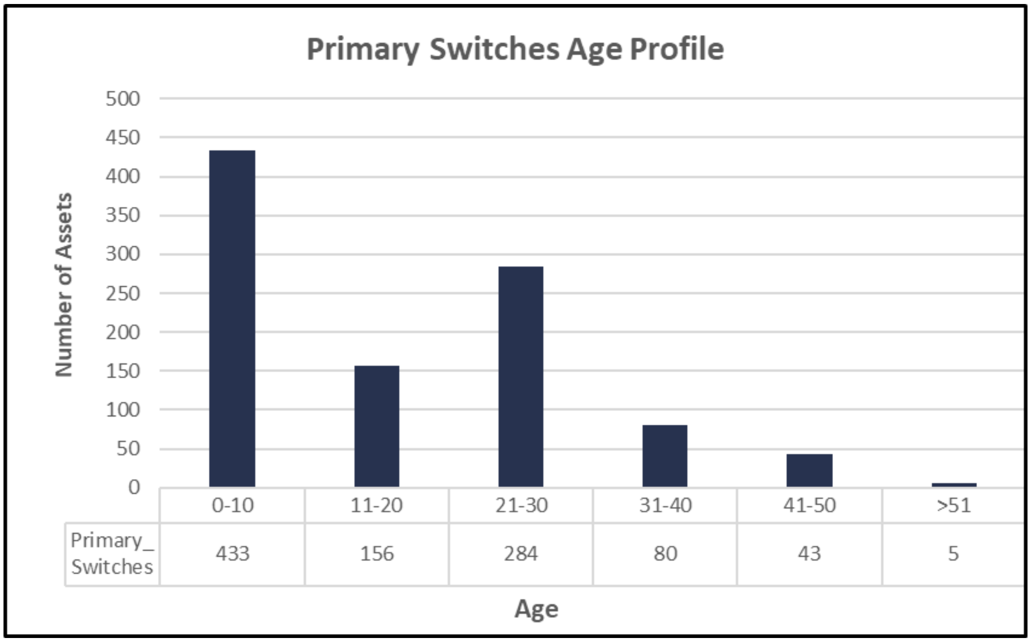
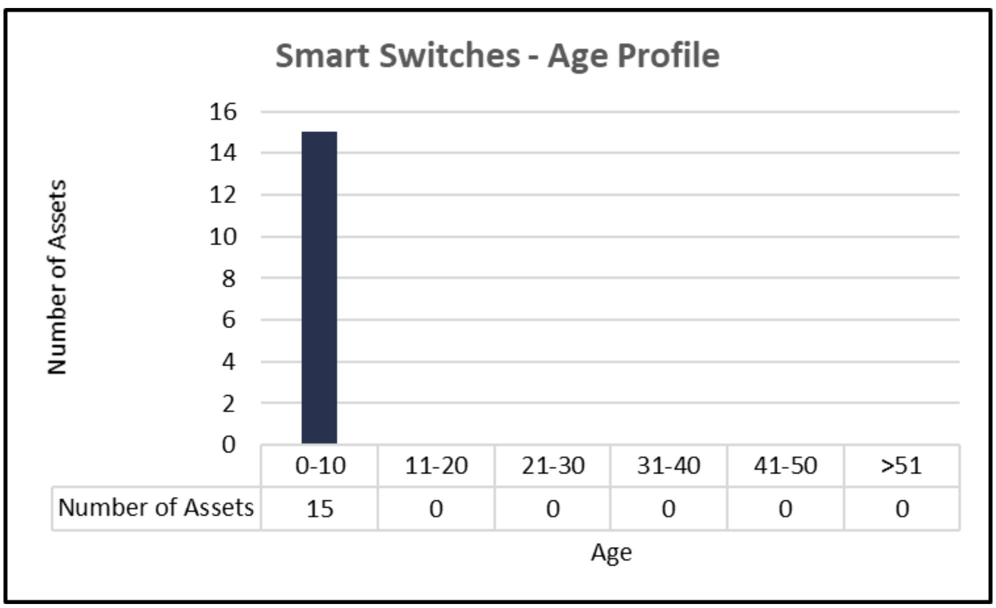


Figure 3.17: Smart Switch Age Demographic



Condition Assessment

OPUCN's 2017 switch visual inspections was used to calculate the Health Index based on the criteria provided in Table 3-21. The Health Index values were calculated for each asset with best available data. The overall Health Index distribution is presented in Figure 3.18 for primary switches and Figure 3.19 for smart switches.

Figure 3.18: Primary Switch Health Index Demographic

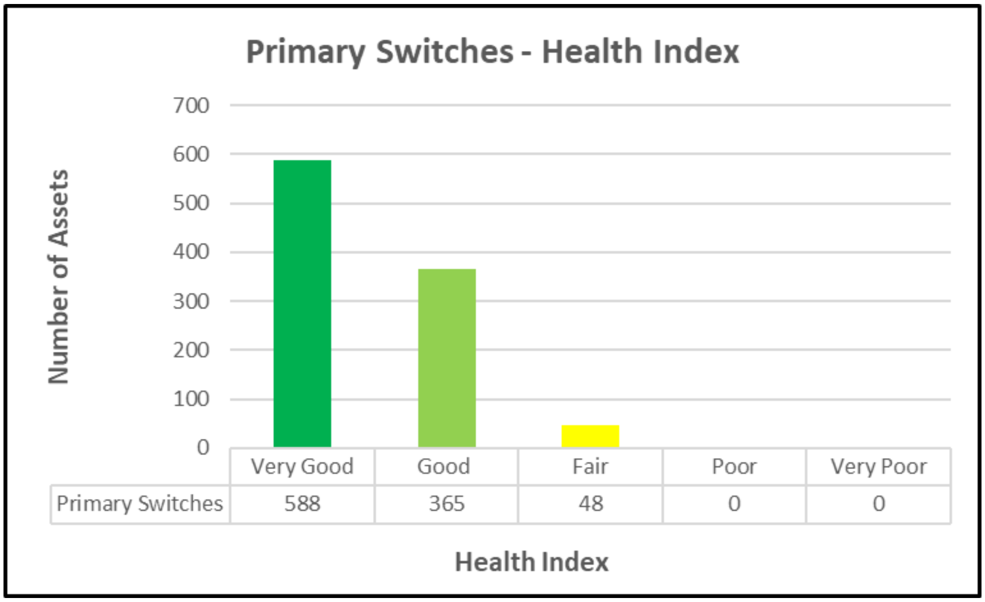
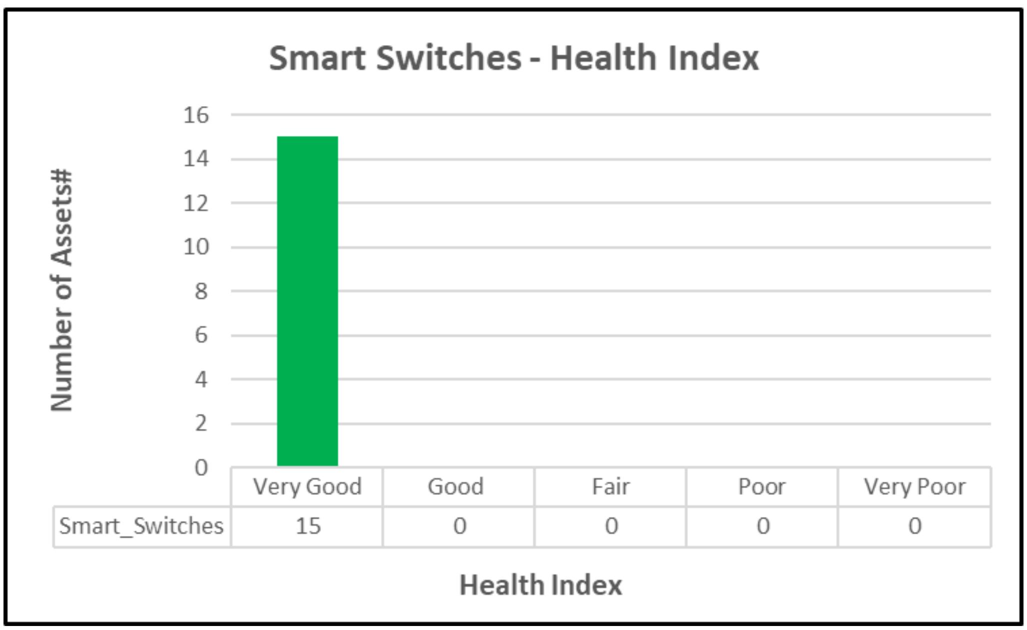


Figure 3.19: Smart Switch Health Index Demographic



Data Assessment

The Data Availability Indicator (DAI) is created to measure the current collected data to date by the utility for completion regarding parameters used in the Health Index algorithm. The DAI for switch data is 100% with assumptions applied. Section 4 provides additional recommendations for data collections for Health Index formulation expansion.

3.1.7 Switchgear

3.1.7.1 Condition Assessment Methodology

Switchgear is the second major sub-class of the switch asset group in OPUCN. OPUCN's asset management continues to manage the asset's risk of failure through regular visual inspections. The Health Index for switchgears, both pad and vault sub-types, is calculated by considering end of life criteria. Table 3-24: summarizes the methodology to generate the assets Health Index. Table 3-25: to Table 3-27: provide the criteria condition rating breakdown for switchgears.

Table 3-24: Switchgear Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Service Age	7	A,B,C,D,E	5,4,3,2,1	35
2	Component Overall Condition	9	A,B,C,D,E	5,4,3,2,1	45
3	Condition of Pad	4	A,C,E	5,3,1	20
				MAX SCORE	**100**

Table 3-25: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	41 years and older

Table 3-26: Criteria for Component Overall Condition

Condition Rating	Corresponding Condition
A	No rust and corrosion, operating mechanism in excellent condition
B	Only minor wear, no defects
C	No more than one of the above indicated defects present but does not impact safe operation or Intermediate hotspot detected
D	Two or more of above indicated defects, but they can be repaired.
E	Two or more of above indicated defects, but they cannot be repaired.

Table 3-27: Criteria for Condition of Pad

Condition Rating	Corresponding Condition
A	Condition of the pad is in excellent condition
C	Condition of the pad is in fair condition
E	Condition of the pad is in worst condition

3.1.7.2 Results of Analysis

Age Assessment

OPUCN owns 20 vault switchgears and 13 pad mount switchgears for a total of 33 in-service switchgears. Figure 3.20 and Figure 3.21 presents the age profile for vault and padmount switchgears, respectively.

Figure 3.20: Vault Switchgear Age Demographic

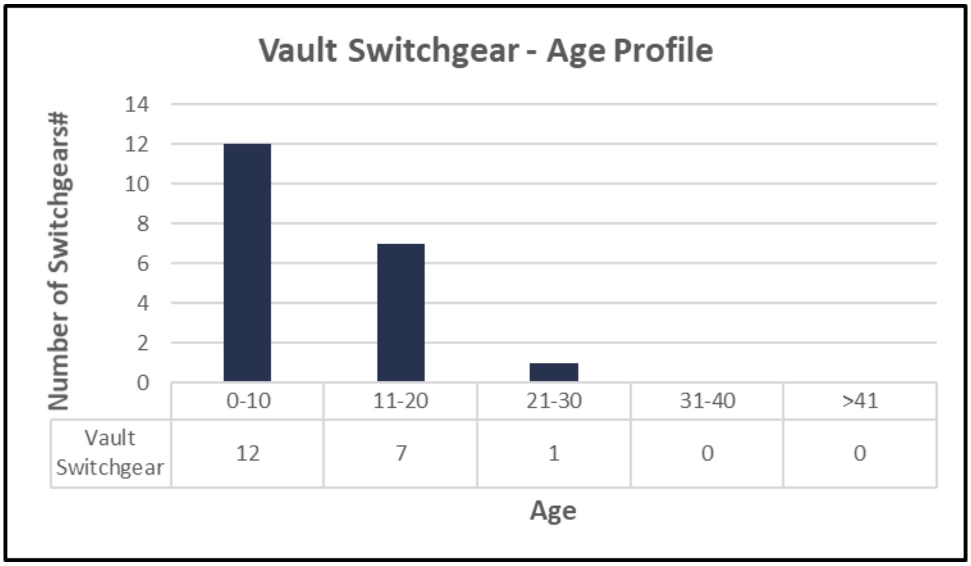
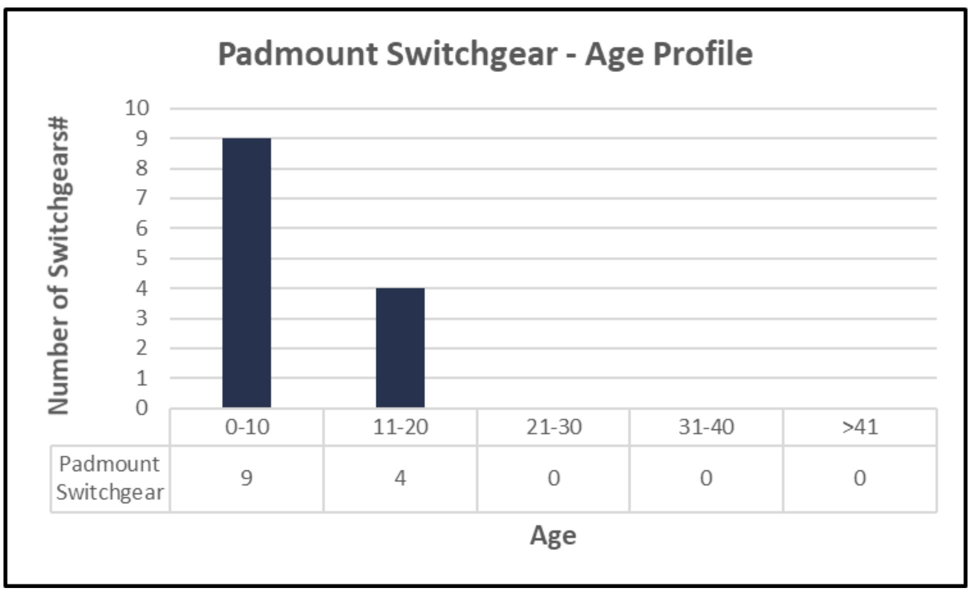


Figure 3.21: Padmount Switchgear Age Demographic



Condition Assessment

OPUCN's 2017 switchgear data was used to calculate the Health Index based on the end of life criteria identified. The overall Health Index distribution is shown in Figure 3.22 and Figure 3.23

for vault and padmount switchgears, respectively. OPUCN manages the failure risk through its maintenance programs and remedy actions. Currently, there are no in-service switchgears that are critical or at-risk of failing on the basis of data assessment.

Figure 3.22: Vault Switchgear Health Index Demographic

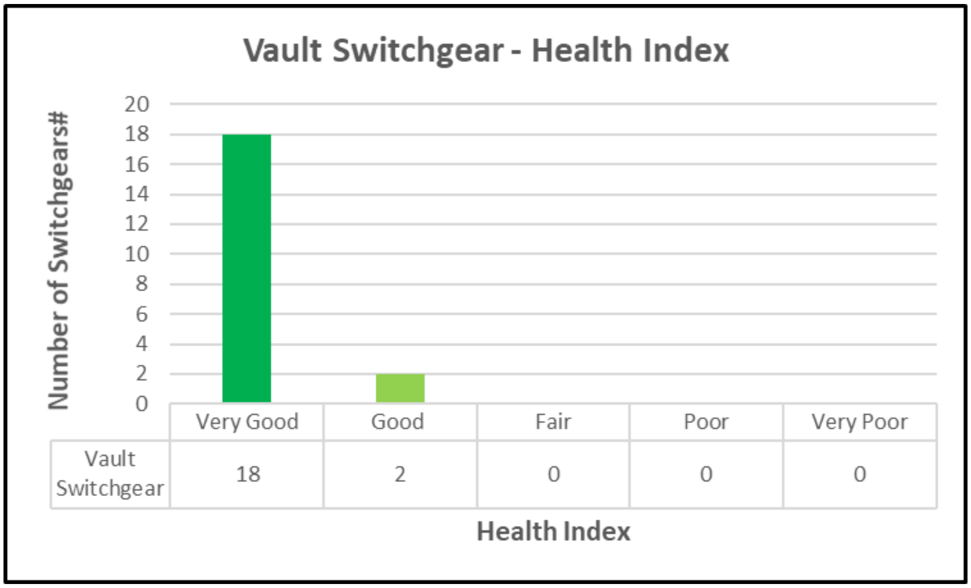
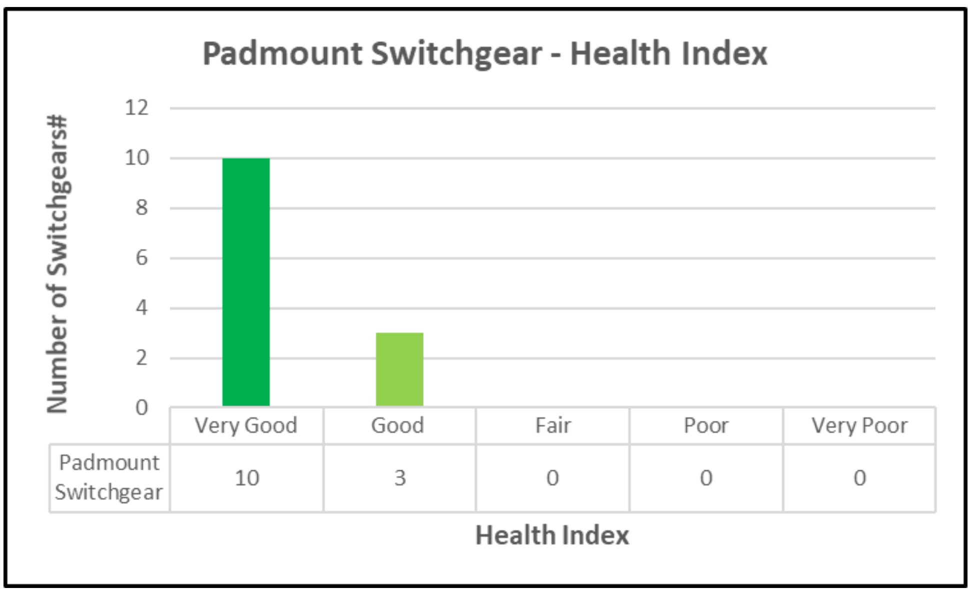


Figure 3.23: Padmount Switchgear Health Index Demographic



Data Assessment

The Data Availability Indicator (DAI) is created to measure the reasonably collected data to date by the utility for completion regarding parameters used in the Health Index algorithm. For the given asset class and attributes collected to date, the DAI is 100% with assumptions applied.

Section 4.0 provides additional recommendations for data collection for HI calculation improvement.

3.1.8 Cut-Out Arrestor and Insulator

3.1.8.1 Condition Assessment Methodology

The Health Index for cut-out arrestors is calculated by considering a combination of visual inspection records and service age. The best available data is considered for the Health Index calculations within this ACA. Table 3-28 summarizes the methodology to combine these criteria into an overall Health Index.

Table 3-28: Cut-out Arrestor Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Overall Condition	2	A,B,C,D,E	5,4,3,2,1	10
2	Service Age	8	A,B,C,D,E	5,4,3,2,1	40
3	Type of Material*	10	A,E	5,1	50
				MAX SCORE	**100**

**Note: If Type of Material is rated as 'E', the Health Index is divided by two to highlight the risk of unfavorable asset conditions. Furthermore, if Type of Material is rated as 'A', the Health Index Formulation readjusts to the former two condition criteria. See Table 3-31.*

Visual inspections are performed for cut-out arrestors, checking for the following items:

- Rust/Corrosion presence and/or contamination of insulator surface
- Damage to bushings
- Condition of operating mechanism and blades

In addition to the visual inspections, OPUCN undertakes Infrared (IR) Scans. Table 3-29 presents the condition rating based on the observed visual inspection deficiencies, including IR scan results. Since the service age provides a reasonably good measure of the remaining life of cut-out arrestors, it is employed as an assessment parameter, shown in Table 3-30.

Table 3-29: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	No rust or corrosion, operating mechanism and in excellent condition and no hotspot detected.
B	Only minor wear and no defects or minor hotspot detected.
C	No more than one of the above indicated defects present but does not impact safe operation or Intermediate hotspot detected.
D	Two or more of above indicated defects, but they can be repaired, or serious hotspot detected.
E	Two or more of the above indicated defects, but they cannot be repaired, or critical hotspot detected.

Table 3-30: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	41 years and older

Table 3-31: Criteria for Type of Material

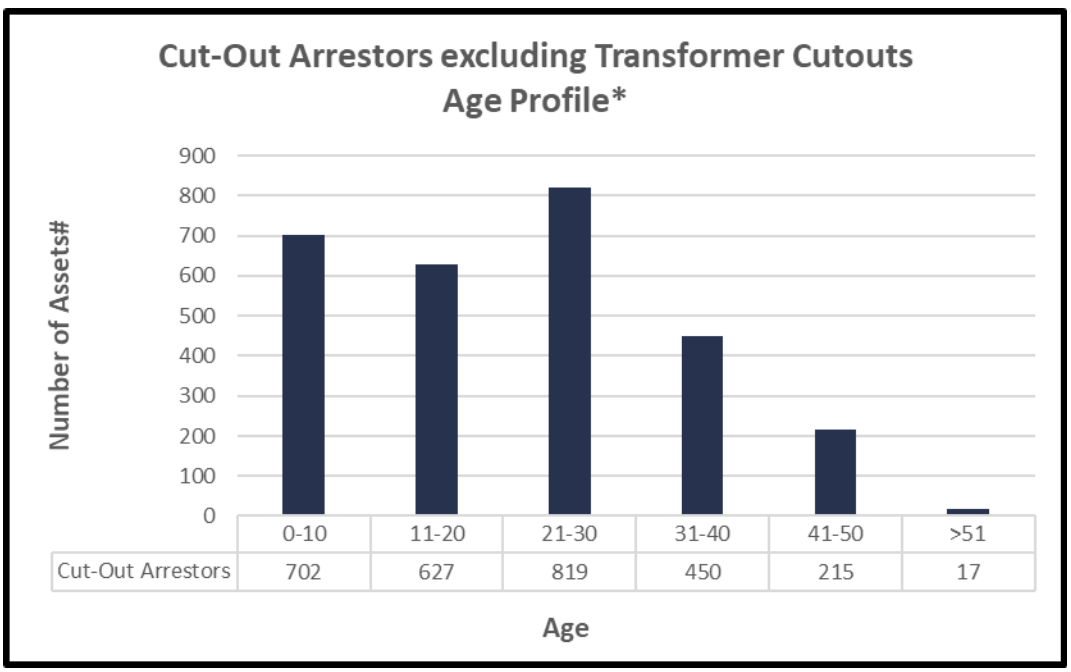
Condition Rating	Corresponding Condition
A	Polymer Cut-out Arrestor
E	Porcelain Cut-out Arrestor

3.1.8.2 Results of Analysis

Age Assessment

Based on current records and best available information, OPUCN identified 2830 cut-out arrestors and 3083 transformer cut-outs within its service territory. For the cut-out arrestors with unknown service ages, OPUCN applied the assumption of assigning a fixed age of 30 (~6% of total population). Figure 3.24 presents the age distribution. Asset service age is currently calculated with year-end 2017. Furthermore, the total number of OPUCN porcelain insulators is approximately 1726.

Figure 3.24: Cut-Out Arrestor Age Demographic

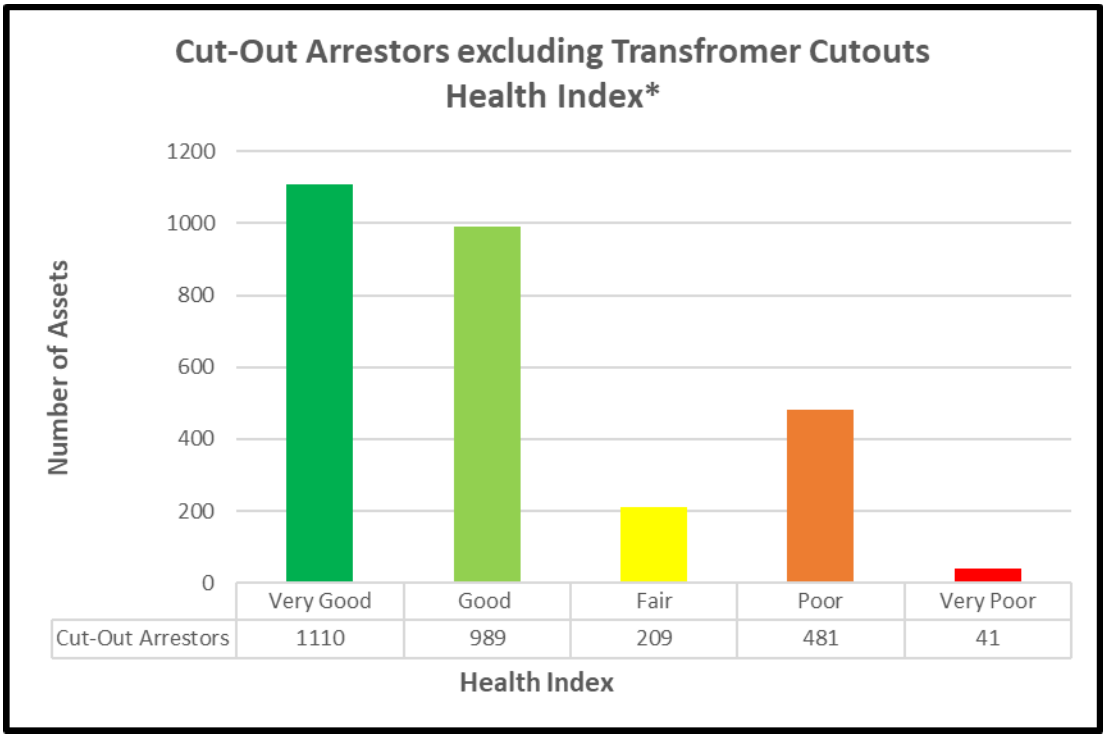


*This data includes approximately 540 porcelain riser cut-out arrestors (approximately 19% of the total OPUCN cut-out arrestors) excluding transformer cut-outs. The ages are best estimates by OPUCN subject matter experts.

Condition Assessment

OPUCN's 2017 visual inspection and IR scan data was used to calculate the Health Index based on the criteria provided in Table 3-28. The Health Index values were calculated for each asset with best available data. The overall Health Index distribution is presented in Figure 3.25.

Figure 3.25: Cut-Out Arrestor Health Index Demographic



*This data includes approximately 540 porcelain riser cut-out arrestors excluding transformer cut-outs, where OPUCN has categorized the assets as "Poor" or "Very Poor" condition based on the type of material, visual inspection and due to the number of failures in the field. The information for the porcelain cut-outs is best estimates by OPUCN's subject-matter experts.

Overhead Fuse Cut-Outs & Porcelain Insulators

Fuse cut-outs are pole-mounted switching devices, used to disconnect or reconnect pole mounted equipment to the line, such as distribution transformers or underground laterals. Porcelain insulated cut-outs have been in use in the electrical industry for many decades. Porcelain was also the material of choice for most other electrical equipment that required insulation, such as line insulators, arrestors and bushings. In the early 1980's large numbers of porcelain insulators began failing, particularly in cold climate regions. "Cement growth" (build-up of debris on surface) was causing insulators to crack due to moisture ingress and freeze/thaw cycling. The expansion and contraction of the adhesive interface which joined the porcelain to the hardware (connector) cause stresses on the porcelain. These stresses cause small cracks to appear in the porcelain which eventually lead to an electrical and/or mechanical failure of the porcelain insulator. Cracked porcelain cut-outs can also result in pole fires resulting in more extensive plant replacement.

Transmission insulators and distribution insulators had been the focus of the industry's attention throughout most of the 1980's and 1990's, resulting in expenditure of millions of dollars to rectify the problem of defective porcelain units. During the past several years, many utilities throughout North America have seen increasing failures of their porcelain insulated cut-outs. The mode of failure is very similar to that of insulators. Small cracks in the porcelain initially appear near the interface between the porcelain and hardware. These fractures eventually lead to a mechanical failure of the cut-out. Cement growth is the likely cause of the initial cracks.

The breakage of porcelain insulated cut-outs is a concern from a safety and reliability perspective. During cut-out operation the porcelain can break, causing the cut-out to separate into two parts. This creates a hazard to line personnel operating the cut-out and can cause outages to customers. The common industry solution to this problem has been replacement of porcelain-insulated cut-outs with polymer-insulated cut-outs.

OPUCN has been experiencing repeated failures of porcelain-fused cut-outs during the past several years. Some failures have resulted in electrical failure of the insulation, while other cases the insulator has cracked and broken resulting in pole fires. The failing cut-outs do present a high risk of injury to public or utility employees.

OPUCN has adopted a program beginning before 2014 under which porcelain cut-outs are being systematically replaced with polymer cut-outs to mitigate safety risks. This program will continue until all high-risk porcelain cutouts have been replaced. Currently, of the 2830 riser cut-out arrestors, there are 540 porcelain riser cut-out arrestors, which is approximately 19% of the total OPUCN cut-out arrestors excluding transformer cut-outs assumed. Additionally, there are 1175 porcelain transformer cut-out arrestors, which is approximately 38% of the total OPUCN transformer cut-out arrestors assumed. The information for the porcelain riser cut-outs and porcelain transformer cut-outs is not available in the OPUCN GIS System, however, OPUCN has been actively working on compiling a database since 2014.

3.1.9 Elbow

3.1.9.1 Condition Assessment Methodology

The Health Index for elbows is calculated by considering a combination of visual inspection records and service age. The best available data is considered for the Health Index calculations within this ACA. Table 3-32 summarizes the methodology to combine these criteria into an overall Health Index.

Table 3-32: Elbow Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Overall Condition	10	A,B,C,D,E	5,4,3,2,1	50
2	Service Age	10	A,B,C,D,E	5,4,3,2,1	50
				MAX SCORE	**100**

Visual inspections are performed for cutout arrestors, checking for the following items:

- Rust presence
- Visual damage and deficiencies
- Condition of operating mechanism

Table 3-33 presents the condition rating based on the observed visual inspection deficiencies. Since service age provides a reasonably good measure of the remaining life of the asset, it is employed as an assessment parameter. Since the service age provides a reasonably good measure of the remaining life of elbows, it is employed as an assessment parameter, shown in Table 3-34.

Table 3-33: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	No rust and no damage, operating mechanism in excellent condition
B	Only minor wear and no defects
C	No more than one of the above indicated defects present but does not impact safe operation
D	Two or more of above indicated defects, but they can be repaired
E	Two or more of the above indicated defects, but they cannot be repaired

Table 3-34: Criteria for Service Age

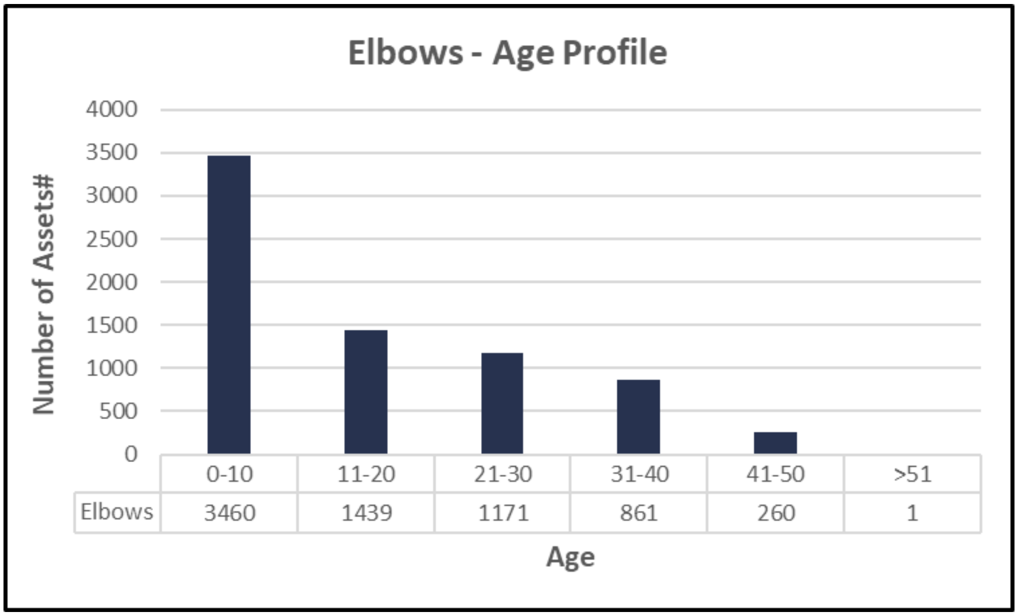
Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	41 years and older

3.1.9.2 Results of Analysis

Age Assessment

OPUCN owns 7192 elbows within its service territory. Elbows with unknown service age, OPUCN matches the elbow to the age of the pad mount transformer. The OPUCN assumption applies to 4842 elbows which is 67.3% of the total OPUCN elbows in-service. Additionally, if there was an unknown service age for the pad mount transformer, OPUCN applied an assumption of fixing the age to 25. This assumption applies to 29 elbows which is 0.4% of the total OPUCN elbows in-service. Figure 3.24 presents the age distribution. Asset service age is currently calculated with end year 2017.

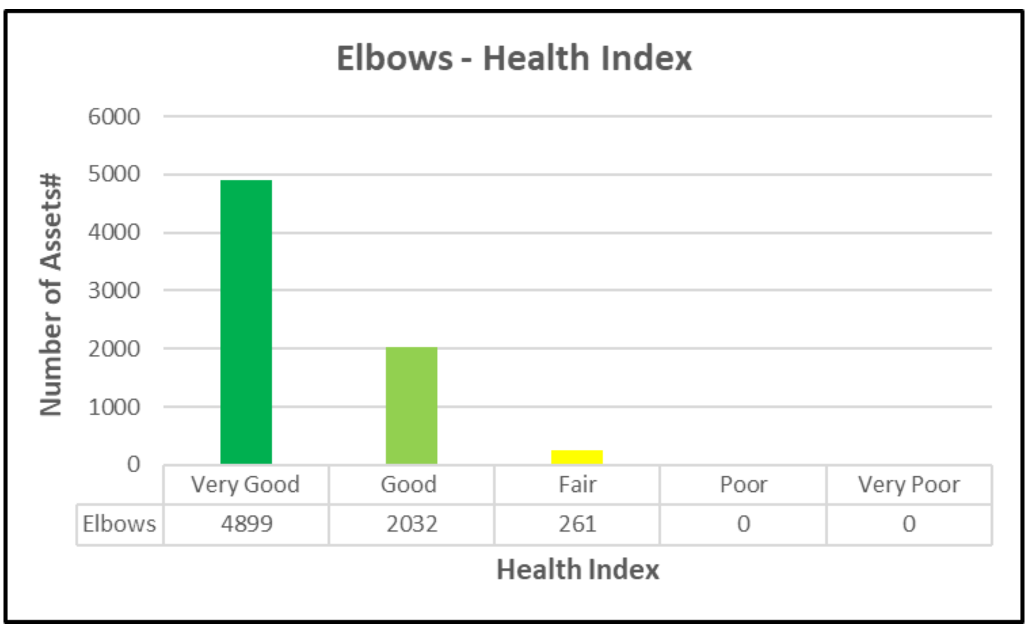
Figure 3.26: Elbow Age Demographics



Condition Assessment

OPUCN's 2017 asset data was used to calculate the Health Index based on the criteria provided in Table 3-32. The Health Index values were calculated for each asset with best available data. The overall Health Index distribution is presented in Figure 3.27.

Figure 3.27: Elbow Health Index Demographic



Data Assessment

The Data Availability Indicator (DAI) is created to measure the reasonable collected data to date by the utility for completion regarding parameters used in the Health Index algorithm. The DAI for elbow data is 100% with assumptions applied. Section 4 provides additional recommendations for data collections for Health Index formulation expansion.

3.1.10 Recloser

3.1.10.1 Condition Assessment Methodology

OPUCN owns four reclosers that are all in-service. Table 3-35: highlights the end of life criteria used to generate the Health Index for reclosers. Additionally, Table 3-36: and Table 3-37: present the condition grading criteria for each end of life criteria.

Table 3-35: Recloser Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Service Age	10	A,C,E	5,4,3,2,1	50
2	Overall Condition	10	A,C,E	5,4,3,2,1	50
				MAX SCORE	**100**

Table 3-36: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	41 years and older

Table 3-37: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	No rusting and any damage to the equipment
B	Only minor wear, no defects
C	No more than one of the above indicated defects present but does not impact safe operation
D	Two or more of above indicated defects, but they can be repaired
E	Two or more of above indicated defects, but they cannot be repaired

3.1.10.2 Results of Analysis

All four reclosers were installed in 2015 and have exhibited very little to none asset degradation. Therefore, all four reclosers are determined to be in Very Good condition and require no immediate rehabilitation, only continuous monitoring and inspections. The DAI for recloser data is 100% with assumptions applied.

3.1.11 Vault and Manhole

3.1.11.1 Condition Assessment Methodology

The Health Index for vaults and manholes is calculated by considering a combination of structural integrity, historical flooding and mitigation devices, and size and access of the civil assets. The best available data is considered for the Health Index calculations within this ACA. Table 3-38 summarizes the methodology to combine these criteria into an overall Health Index.

Table 3-38: Vaults and Manholes Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Structural Integrity	6	A,C,E	5,3,1	30
2	Flooding and mitigation	6	A,C,E	5,3,1	30
3	Size and access	8	A,C,E	5,3,1	40
				MAX SCORE	**100**

Table 3-39 to Table 3-41 represent the gradings for each criterion to evaluate the condition of OPUCN's vaults and manholes.

Table 3-39: Criteria for Structural Integrity

Condition Rating	Corresponding Condition
A	No deficiencies in the vault or manhole
C	Only minor deficiencies
E	Major deficiencies requiring immediate repairs/replacement

Table 3-40: Criteria for Flooding and Mitigation

Condition Rating	Corresponding Condition
A	No incidents of flooding at this location
C	Occasional flooding, working sump pumps and drains
E	Frequent flooding, no sump pumps or drains

Table 3-41: Criteria for Size and Access

Condition Rating	Corresponding Condition
A	Adequate ergonomic size and safe access to vault
C	Vault size slightly smaller than ideal, but adequate for safe working and reasonable access to vault
E	Vault size or access inadequate for safe working or worker rescue during an accident; immediate repairs/replacement

3.1.11.2 Results of Analysis

Condition Assessment

OPUCN owns 146 vaults and 120 manholes in service. OPUCN's 2017 inspection data was used to calculate the Health Index based on the criteria provided in Table 3-38. The Health Index values were calculated for each asset with best available data. The overall Health Index distribution for OPUCN's vaults and manholes are presented in Figure 3.28 and Figure 3.29, respectively.

Figure 3.28: Vault Health Index Demographic

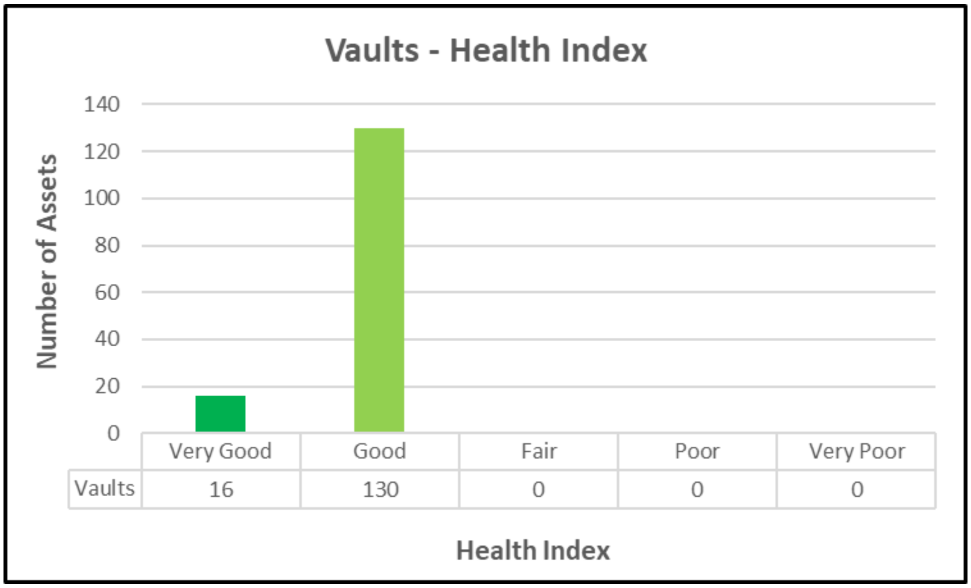
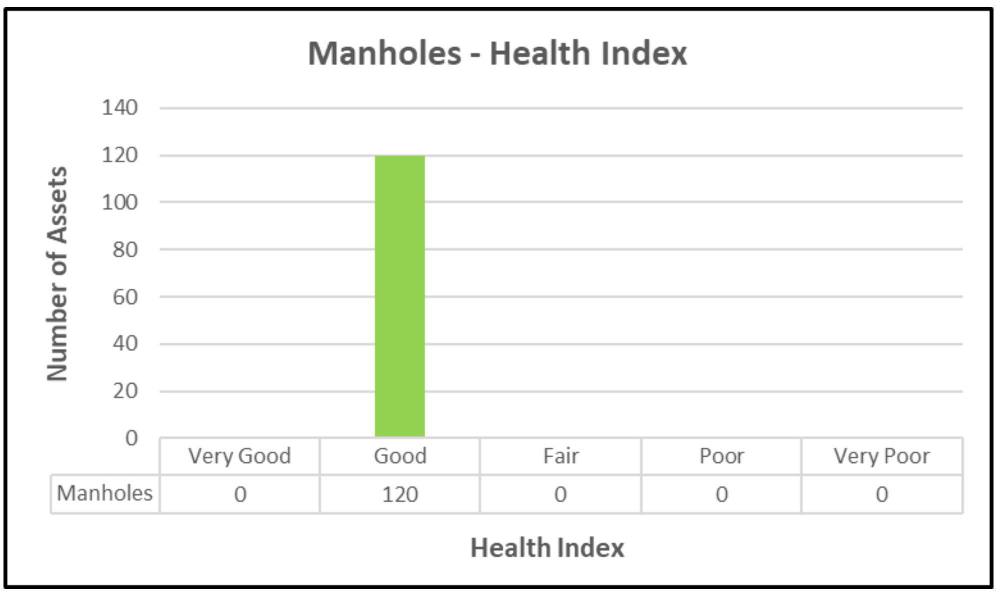


Figure 3.29: Manhole Health Index Demographic



Data Assessment

The Data Availability Indicator (DAI) is created to measure the current collected data to date by the utility for completion regarding parameters used in the Health Index algorithm. The DAI for vault and manhole data is 100% with assumptions applied. Section 4 provides additional recommendations for data collections for Health Index formulation expansion.

3.2 Station Assets

There are a total eight distribution substations owned and managed by OPUCN. These substations step down power from 44 kV to 13.8/8.0 kV. Each substation contains the following assets that are included within this report:

- Substation power transformer
- Substation circuit breaker
- Substation switchgear
- Substation protection relay and RTU
- Substation battery and charger
- Substation ground grid
- Substation fence and building

3.2.1 Power Transformer

3.2.1.1 Condition Assessment Methodology

Computing the Health Index of a transformer requires developing end-of-life criteria for its various components. Each criterion represents a factor in determining the component's condition relative to potential failure. The Health Index for substation power transformers is calculated by considering a combination of service age, analysis of test results, load history and visual inspection results. The best available data is considered for the Health Index calculations within this ACA. Table 3-42 summarizes the methodology to combine these criteria into an overall Health Index.

Table 3-42: Power Transformers Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Load History	6	A,B,C,D,E	5,4,3,2,1	30
2	Service Age	4	A,B,C,D	5,4,3,2	20
3	Overall Condition	2	A,B,C,D,E	5,4,3,2,1	10
4	Testing Analysis	8	A,B,C,D,E	5,4,3,2,1	40
				MAX SCORE	**100**

The rate of insulation degradation is directly related to the operating temperature, which is itself directly related to transformer loading levels. Peak loading level of transformers expressed in percent of nameplate rating can therefore be employed as an indicator of transformer health. OPUCN collects the substation load history monthly, recording the monthly peak load over the last twelve months. Table 3-43 presents the grades and ranges of load history.

Table 3-43: Criteria for Load History

Condition Rating	Corresponding Condition
A	Peak load less than 50% of its rating
B	Peak load of 50% to 75% of its rating
C	Peak load of 75% to 100% of its rating
D	Peak load of 100% to 125% of its rating
E	Peak load of greater than 125% of its rating

Table 3-44 presents the grading based on service age for substation power transformers. Since service age provides a reasonably good measure of the remaining life of the asset, it is employed as an assessment parameter.

Table 3-44: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 20 years
B	21 to 40 years
C	41 to 60 years
D	60 years and older

Visual inspections can provide a good indication of the physical condition of transformers. Table 3-45 presents the grading for visually inspected components.

Table 3-45: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	Station transformer is externally clean and corrosion-free. All monitoring, protection and control, pressure relief, gas accumulation and silica gel devices, and auxiliary systems mounted on the station transformer are in good condition. No external evidence of overheating or internal overpressure. No sign of oil leaks and forced air cooling fully functional. Appears to be well maintained with service records readily available.
B	Normal signs of wear with respect to the above characteristics.
C	One or two of the above characteristics are unacceptable.
D	More than two of the above characteristics are unacceptable – repairable.
E	More than two of the above characteristics are unacceptable – damaged beyond repair.

A combination of electrical, physical and chemical tests is performed to establish preventive maintenance procedures, avoid premature failure and costly shutdown and plant maintenance such as oil reclamation or replacement. Table 3-46 presents the grading for power transformers test analysis. The Weidmann Annual Test results are considered for the condition assessment.

Table 3-46: Criteria for Test results

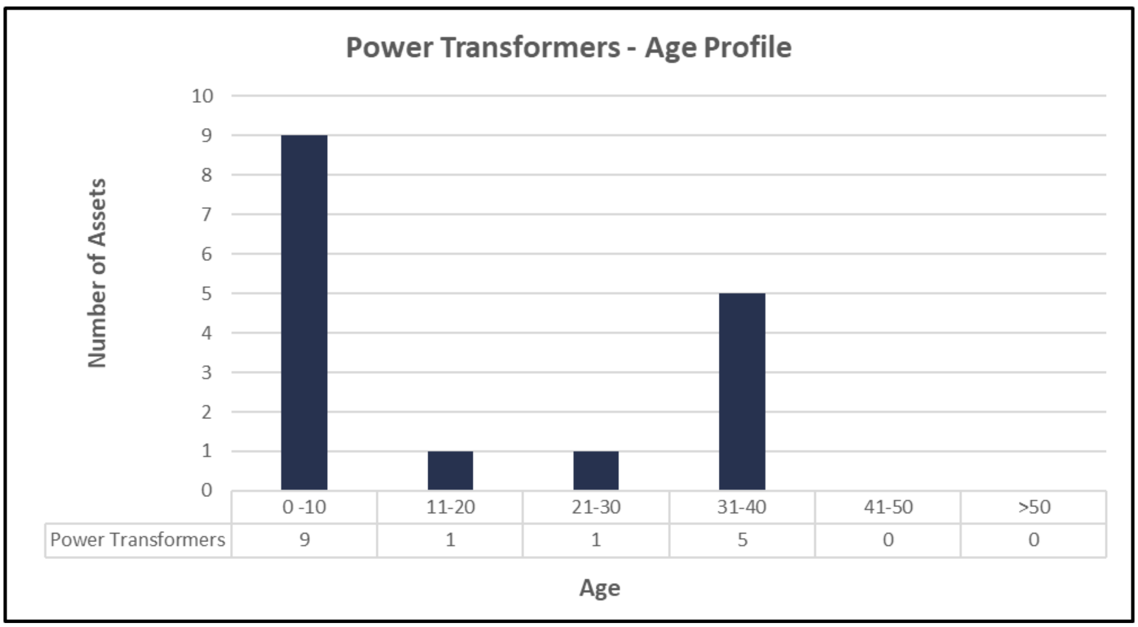
Condition Rating	Corresponding Condition
A	Test results indicate excellent installation condition, no indication of moisture, arcing, overheating or degradation of paper.
B	Tests indicate normal aging, no concerns about insulation health
C	Tests indicate slightly above average but stable moisture content or presence of arcing overheating related gases
D	Some of the tests indicates significant concerns about insulation condition or presence of significant arcing overheating related gases
E	Two or more of the tests indicate rapidly deteriorating insulation condition or presence of significant arcing overheating of two or more related gases

3.2.1.2 Results of Analysis

Age Assessment

OPUCN operates 16 in-service substation power transformers. Figure 3.30 presents the age profile of power transformers in-service. Power transformer MS14-T2 is the oldest power transformer at OPUCN. Asset service age is currently calculated with end year 2017.

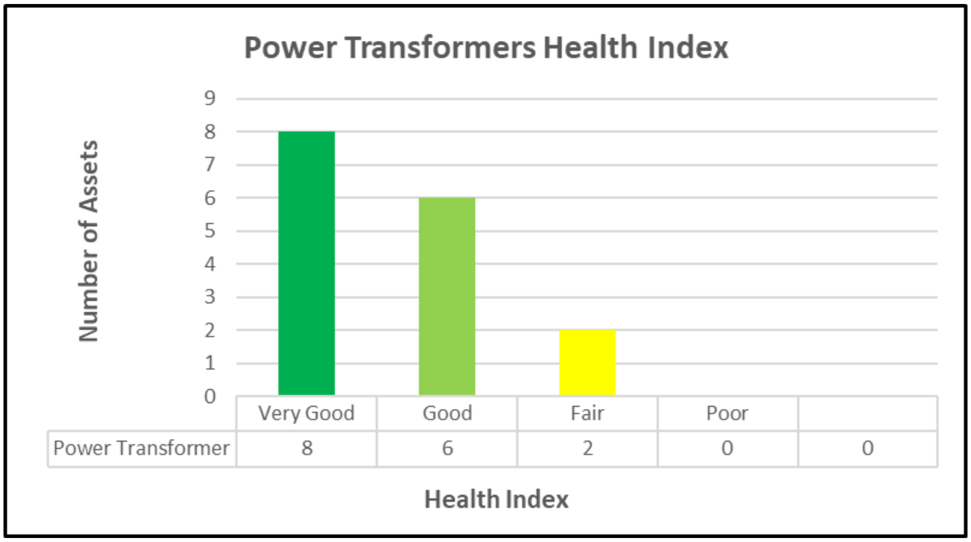
Figure 3.30: Power Transformer Age Demographic



Condition Assessment

Based on the condition assessment criteria defined and best available data, the Health Index score is summarized in Figure 3.31 for OPUCN owned power transformers. Majority of OPUCN's power transformers are in good condition.

Figure 3.31: Power Transformer Health Index Demographic



3.2.2 Circuit Breaker

Computing the Health Index of a circuit breaker requires developing end-of-life criteria for its various components. Each criterion represents a factor critical in determining the component's condition relative to potential failure. The Health Index for substations circuit breakers is calculated by considering a combination of service age, test results and visual inspections. The best available data is considered for the Health Index calculations within this ACA. Table 3-47 summarizes the methodology to combine these criteria into an overall Health Index.

Table 3-47: Circuit Breaker Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Service Age	5	A,B,C,D,E	5,4,3,2,1	25
2	Test Results	8	A,B,C,D,E	5,4,3,2,1	40
3	Overall Condition	7	A,B,C,D,E	5,4,3,2,1	35
				MAX SCORE	**100**

Service age provides a reasonably good measure of the remaining life of circuit breakers. Table 3-48 and Table 3-49 provides the grading for outdoor circuit breakers and indoor circuit breakers service age, respectively.

Table 3-48: Criteria for Service Age – indoor circuit breaker

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	41 years and older

Table 3-49: Criteria for Service Age – outdoor circuit breaker

Condition Rating	Corresponding Condition
A	0 to 7 years
B	8 to 15 years
C	16 to 24 years
D	25 to 32 years
E	33 years and older

Various tests can be interpreted by an expert to rank the overall condition of breaker system. Table 3-50 presents the grading for test results. The Weidmann Annual Test and OPUCN monthly test results are considered for the condition assessment. Additionally, Table 3-51 presents the grading for the overall condition circuit breakers with visual inspections.

Table 3-50: Criteria for Test results

Condition Rating	Corresponding Condition
A	Tests results indicate excellent condition of contacts, operating mechanism, insulation condition and controls
B	Normal aging, each of the four indicators within specific limits
C	One of the above four indicators is slightly beyond the specified limits
D	Two or more of the above four indicators beyond the specified limits
E	Two or more of the indicators beyond the specifications and cannot be brought to comply with the specifications

Table 3-51: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	No rust on tank/radiator, no damage to bushings, no sign of oil leaks, forced air cooling fully functional
B	Only one of the following defects: Minor rust, or minor cracks in bushings or minor oil leaks
C	Two or more of the above indicated defects present but do not impact safe operation
D	Tank/radiator badly rusted or major damage to bushing or major oil leak
E	Two or more of the above indicated defects of the cooling fans do not work

3.2.2.1 Results of Analysis

Age Assessment

OPUCN operates 16 44kV and 72 13.8kV circuit breakers in service. The age profile of circuit breakers is shown in Figure 3.32 and Figure 3.33. Asset service age is currently calculated with end year 2017.

Figure 3.32: Circuit Breaker (44kV) Age Demographic

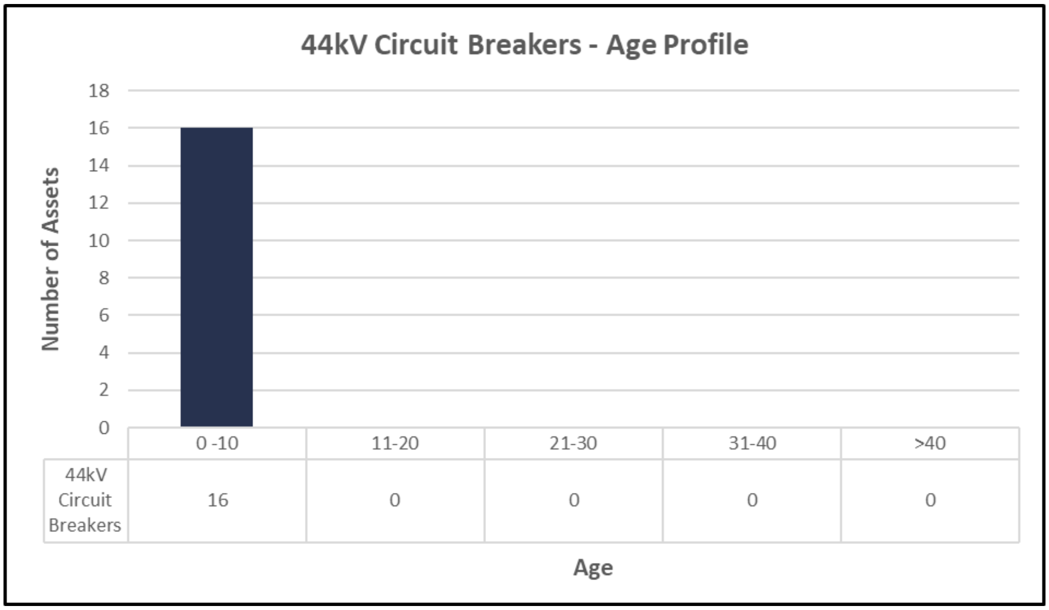
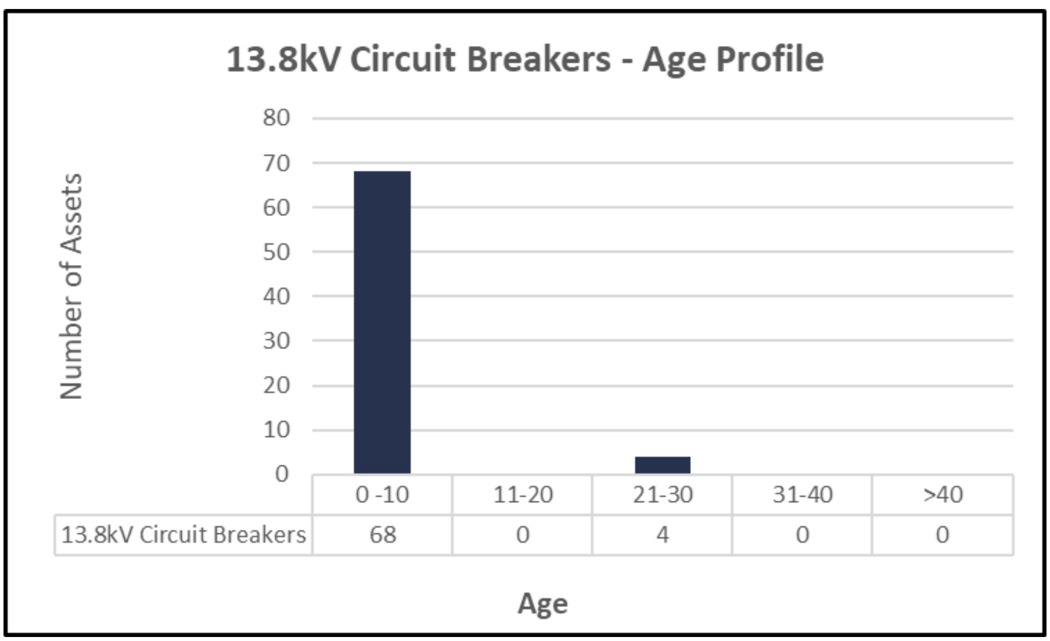


Figure 3.33: Circuit Breaker (13.8kV) Age Demographic



Condition Assessment

Based on the condition assessment criteria defined and best available data, the Health Index score for circuit breakers is summarized in Figure 3.34 and Figure 3.35.

Figure 3.34: Circuit breaker (44kV) Health Index Demographic

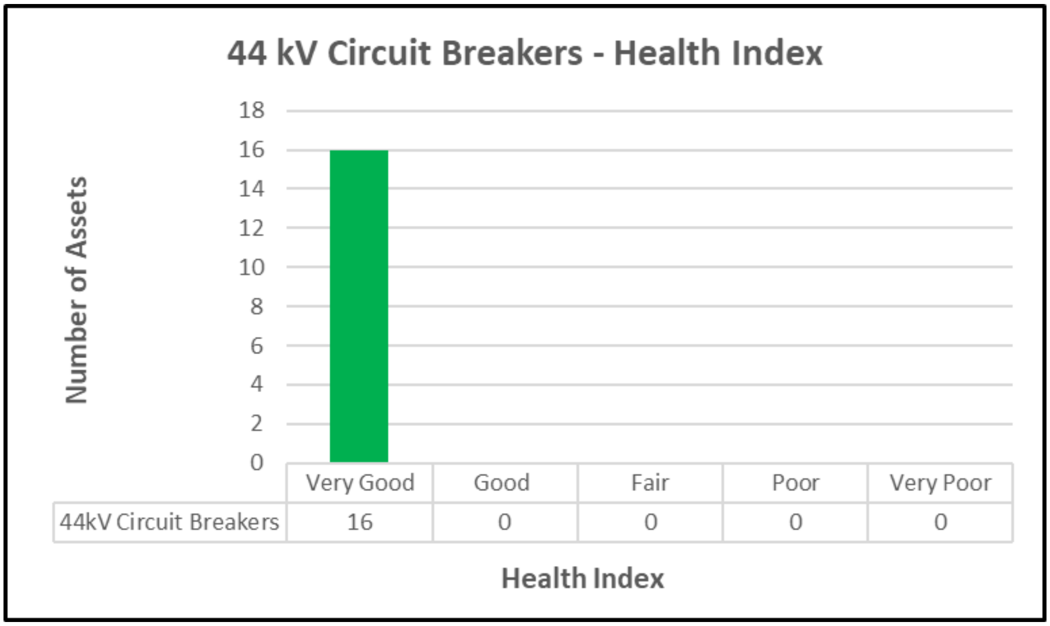
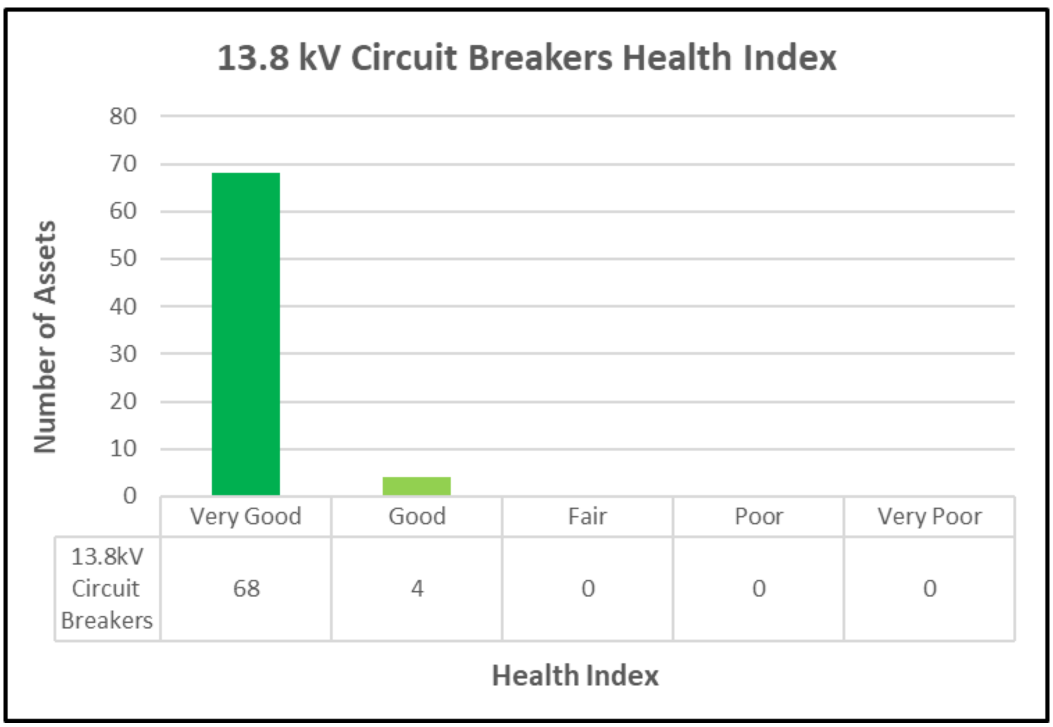


Figure 3.35: Circuit breaker (13.8kV) Health Index Demographic



3.2.3 Switchgear

Computing the Health Index of a switchgear requires developing end-of-life criteria. Each criterion represents a factor critical in determining the asset' condition relative to potential failure. The Health Index for switchgears is calculated by considering a combination of service age and visual inspections. The best available data is considered for the Health Index calculations within this ACA. Table 3-52 summarizes the methodology to combine these criteria into an overall Health Index.

Table 3-52: Switchgear Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Service Age	10	A,B,C,D,E	5,4,3,2,1	50
2	Overall Condition	10	A,B,C,E	5,4,3,2,1	50
				MAX SCORE	**100**

Table 3-53 and Table 3-54 provide the grading breakdown for each end-of-life condition criteria for switchgears.

Table 3-53: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	41 years and older

Table 3-54: Criteria for Overall Condition

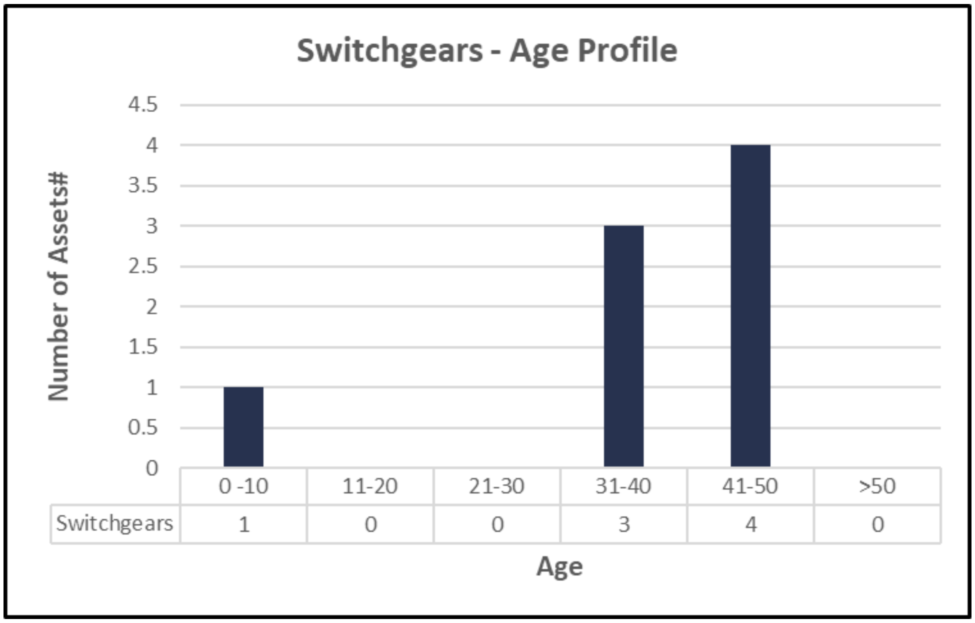
Condition Rating	Corresponding Condition
A	No rust and corrosion, operating mechanism in excellent condition
B	Only minor wear, no defects
C	No more than one of the above indicated defects present but does not impact safe operation. No intermediate hotspot detected.
D	Two or more of above indicated defects but can be repaired.
E	Two or more of above indicated defects but cannot be repaired.

3.2.3.1 Results of Analysis

Age Assessment

OPUCN owns eight switchgears in service. Figure 3.36 presents the age profile of switchgears in-service at OPUCN. Asset service age is currently calculated with end year 2017.

Figure 3.36: Switchgear Age Demographic

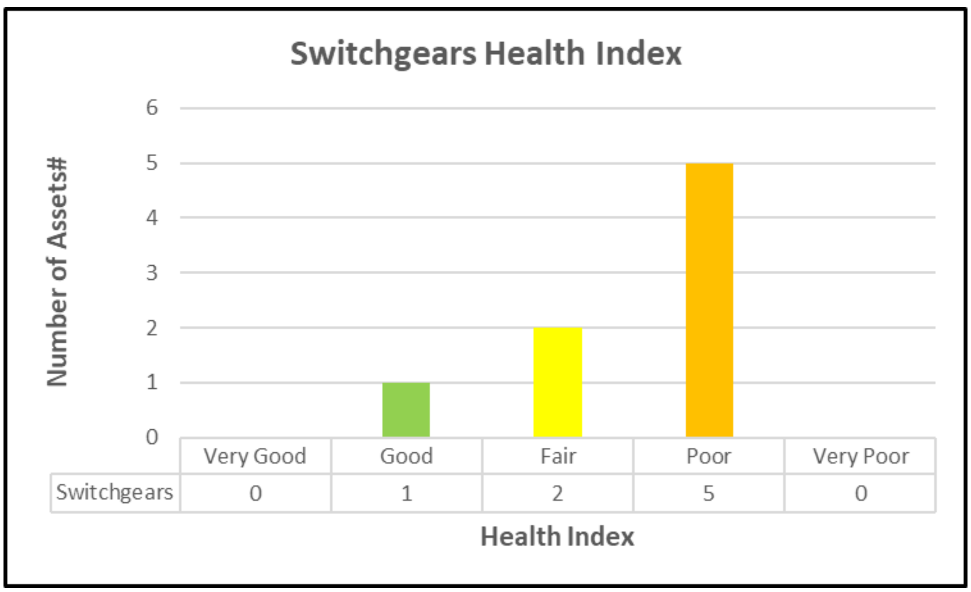


	0 -10	11-20	21-30	31-40	41-50	>50
Switchgears	1	0	0	3	4	0

Condition Assessment

Based on the condition assessment criteria defined and best available data, the Health Index score for protection relays and SCADA RTUs is summarized in Figure 3.37.

Figure 3.37: Switchgear Health Index Demographic



	Very Good	Good	Fair	Poor	Very Poor
Switchgears	0	1	2	5	0

3.2.4 Protector Relay and RTU

The Health Index for substations protection relays and RTUs is calculated by considering a combination of service age and test results. The best available data is considered for the Health Index calculations within this ACA. Table 3-55 summarizes the methodology to combine these criteria into an overall Health Index.

Table 3-55: Protector Relays and RTUs Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Service Age	10	A,B,C,D,E	5,4,3,2,1	50
2	Test Results	10	A,B,C,E	5,4,3,1	50
				MAX SCORE	**100**

Service age provides a reasonably good measure of the remaining life of protection relays and RTUs. Table 3-56 provides the grading for protection relays service age.

Table 3-56: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 3 years
B	4 to 6 years
C	7 to 10 years
D	11 to 15 years
E	16 years and older

Calibration tests can be interpreted by an expert to rank the overall condition of protection relays. Table 3-57 presents the grading for test results.

Table 3-57: Criteria for Test results

Condition Rating	Corresponding Condition
A	Excellent operating condition, calibration well within specified limits
B	Normal aging, calibration within the specified limits
C	Frequent calibration required, but it is possible to meet specified limits
E	Not possible to calibrate the relays to bring settings to specified limits

3.2.4.1 Results of Analysis

Age Assessment

OPUCN owns 71 protection relays and eight RTUs in service. Figure 3.38 presents the age profile of protection relays in-service at OPUCN. Figure 3.39 presents the age profile of RTUs. Asset service age is currently calculated with end year 2017.

Figure 3.38: Protection Relay Age Demographic

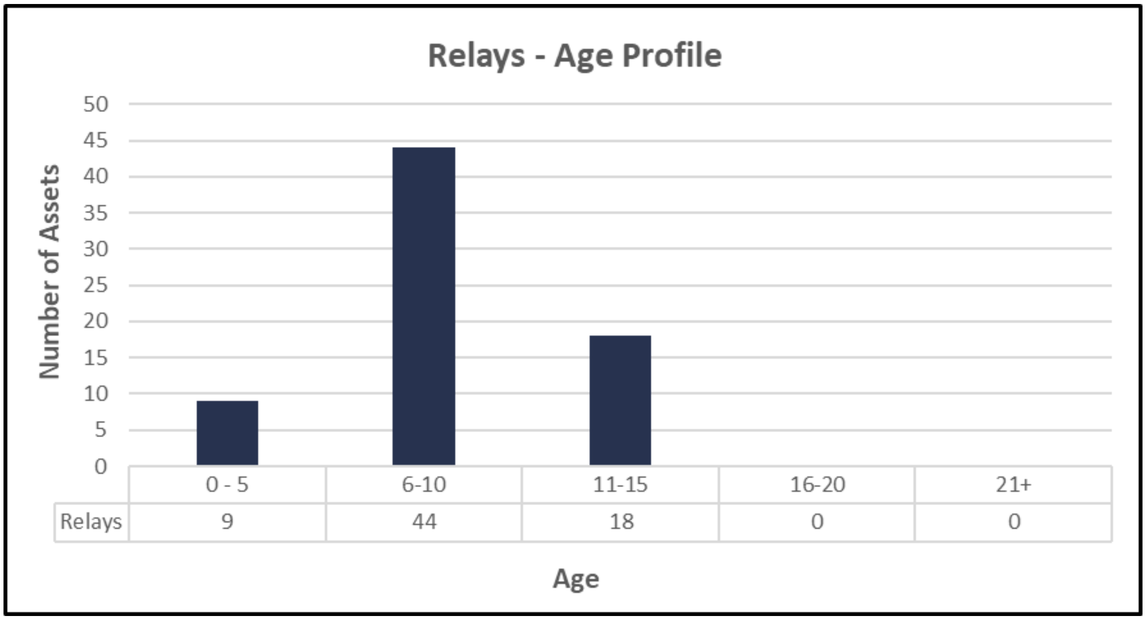
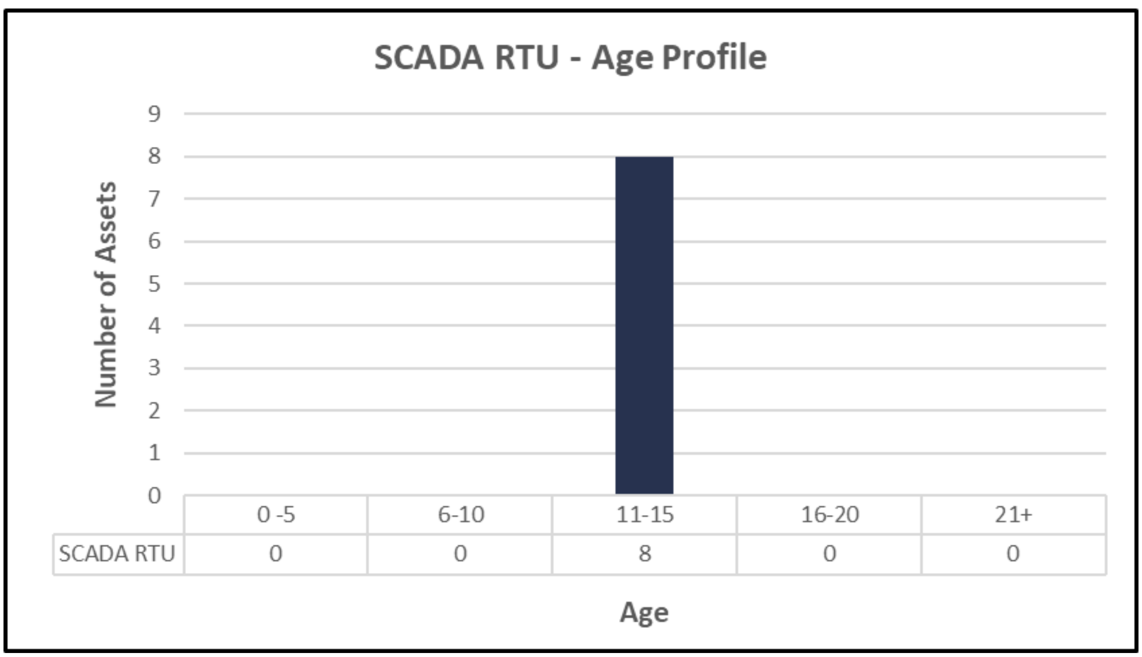


Figure 3.39: SCADA RTU Age Demographic



Condition Assessment

Based on the condition assessment criteria defined above and best available data, the Health Index score for protection relays and SCADA RTUs is summarized in Figure 3.40 and Figure 3.41.

Figure 3.40: Protection relay Health Index Demographic

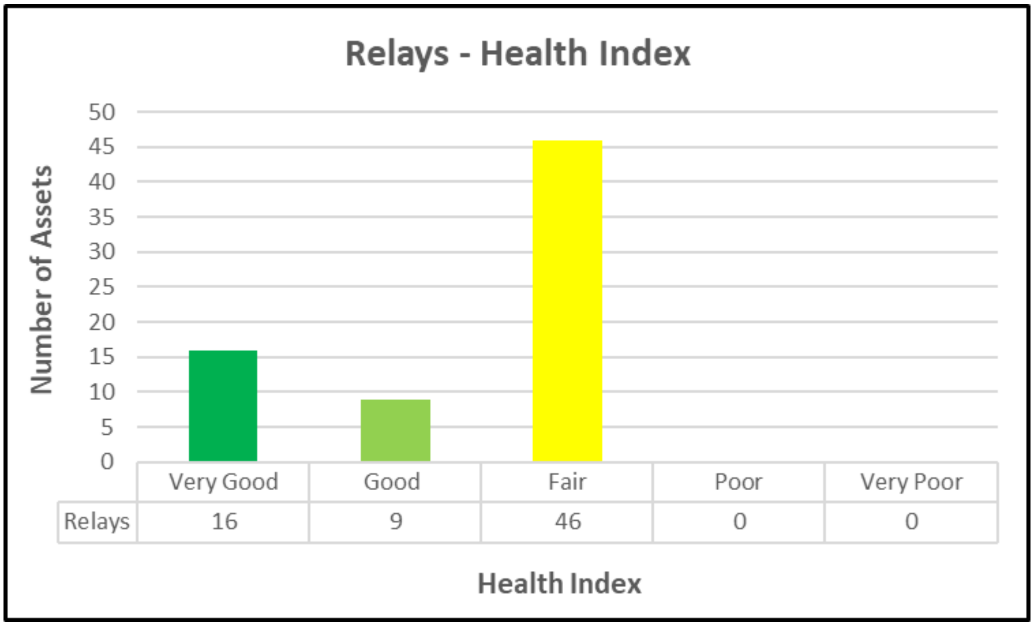
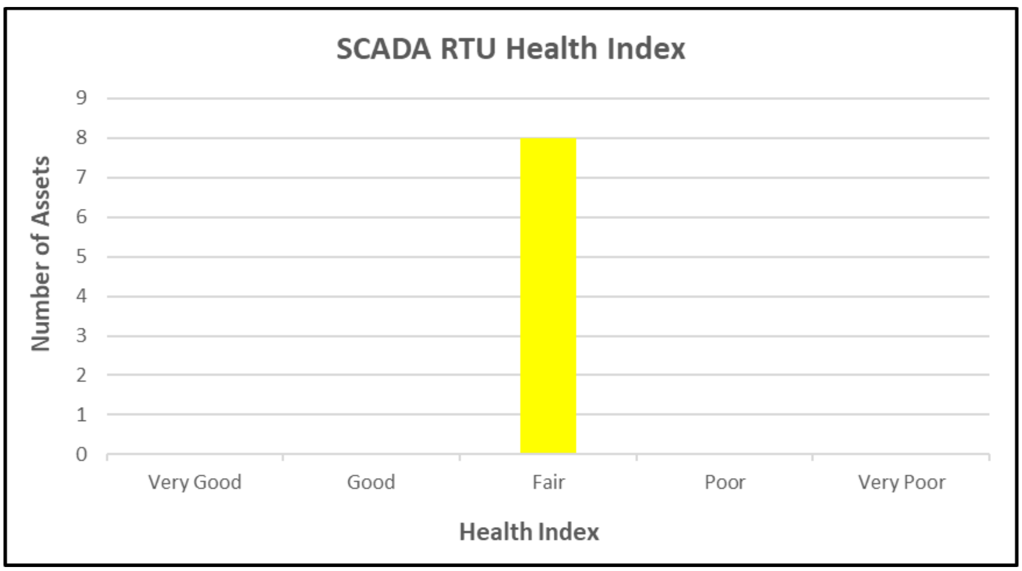


Figure 3.41: SCADA RTU Health Index Demographic



3.2.5 Battery and Charger

The purpose of substation batteries is to provide power for critical control functions such as trip coils of circuit breakers. Batteries are carefully sized to store adequate energy for system operation during an AC power failure. Both the electrodes and electrolyte in control batteries undergo aging with repeated charge and discharge cycles, which result in gradual reduction of battery storage capacity. The end of life is reached when the battery is no longer able to retain adequate charge for required functions. Battery chargers can experience component failures, but these can be easily replaced and as a result the charger often outlasts the battery. The Health Index for substations batteries is calculated by considering a combination of service age and test results. The best available data is considered for the Health Index calculations within this ACA. Table 3-58 summarizes the methodology to combine these criteria into an overall Health Index.

Table 3-58: Battery Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Service Age	10	A,B,C,D,E	5,4,3,2,1	50
2	Test Results	10	A,C,E	5,3,1	50
				MAX SCORE	**100**

Since different types of batteries can have significantly different life expectancy, age related scoring needs to be measured in terms of "Effective Life Expectancy". Table 3-59 provides the grading for station batteries effective life. Table 3-60 presents the grading for battery test results.

Table 3-59: Criteria for Service Age

Condition Rating	Corresponding Condition
A	Less than 25% of Effective Life Expectancy
B	Less than 50% of Effective Life Expectancy
C	Less than 75% of Effective Life Expectancy
D	Less than 100% of Effective Life Expectancy
E	More than Effective Life Expectancy

Table 3-60: Criteria for Test results

Condition Rating	Corresponding Condition
A	Battery capable of storing full rated energy
C	Battery stores marginally less than full rated energy, but still adequate for required functions
E	Battery stores significantly less than the full rated energy, inadequate for required functions

3.2.5.1 Results of Analysis

Age Assessment

OPUCN maintains eight batteries and chargers, one for each substation with majority of them being under 10 years old. Figure 3.42 and Figure 3.43 present the age profile of batteries and chargers, respectively. Asset service age is currently calculated with end year 2017.

Figure 3.42: Battery Age Demographic

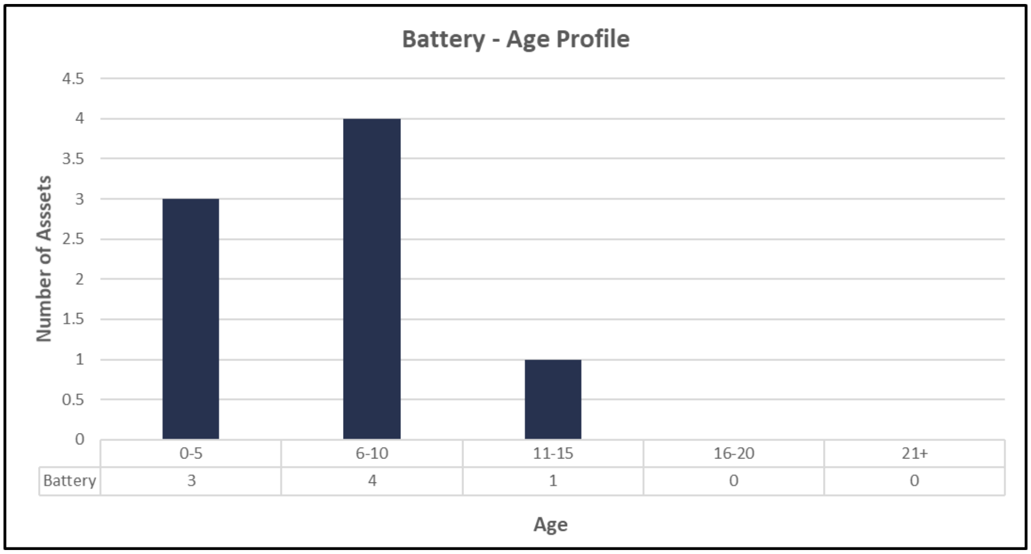
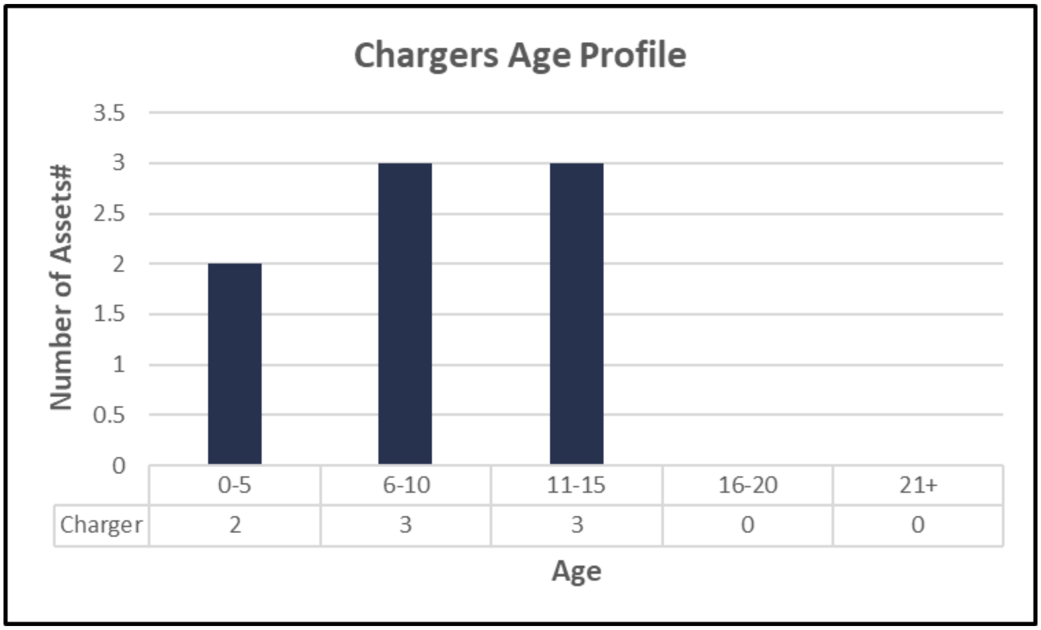


Figure 3.43: Charger Age Demographic



Condition Assessment

Based on the condition assessment criteria defined and best available data, the Health Index score for batteries and chargers is summarized in Figure 3.44 and Figure 3.45, all considered 'Very Good'.

Figure 3.44: Battery Health Index Demographic

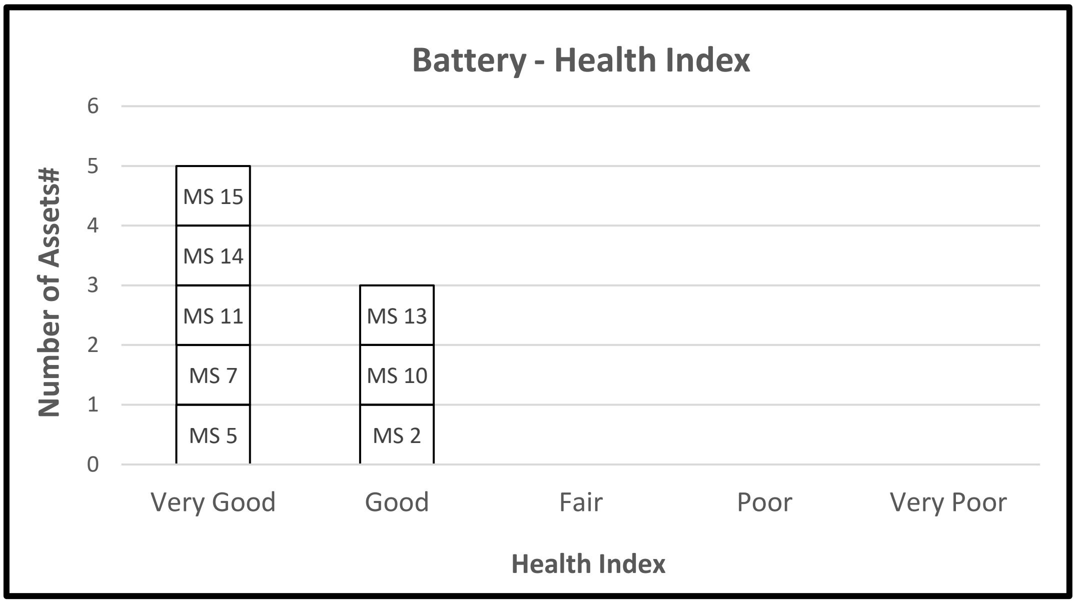
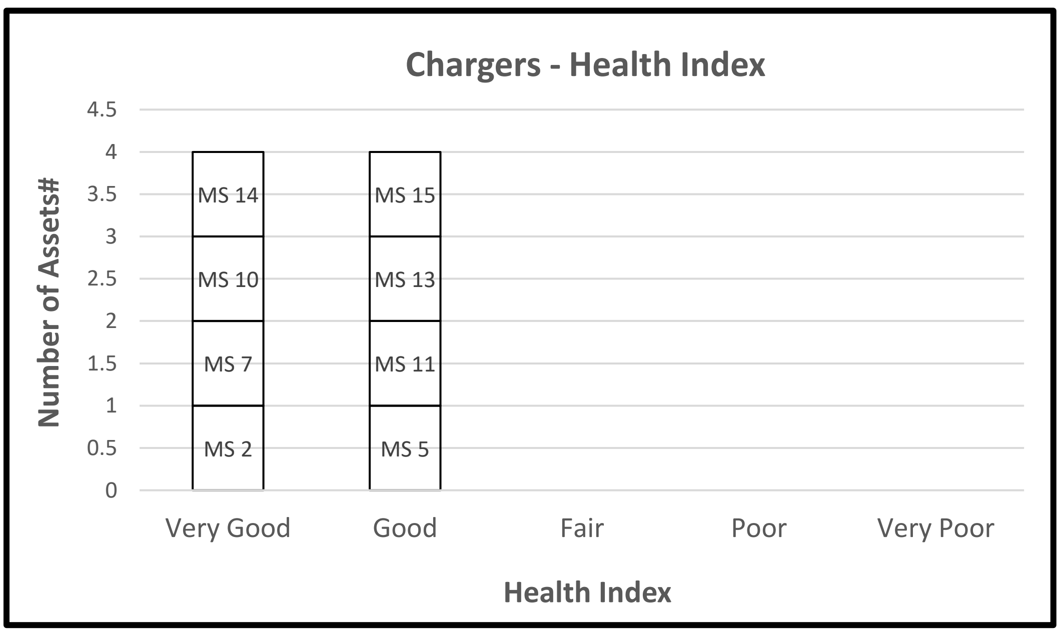


Figure 3.45: Charger Health Index Demographic



3.2.6 Ground Grid

The Health Index for substations ground grids is calculated by considering a combination of service age, visual inspections and testing. The best available data is considered for the Health Index calculations within this ACA. Table 3-61 summarizes the Health Index algorithm for station ground grids.

Table 3-61: Ground Grid Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Service Age	5	A,B,C,D,E	5,4,3,2,1	25
2	Electrode resistance test	8	A,C,E	5,3,1	40
3	Condition of surface stone	7	A,C,E	5,3,1	35
				MAX SCORE	**100**

Service age provides a reasonably good measure of the remaining life of station grids. Table 3-62 provides the grading for ground grid service age. Additionally, Table 3-63 and Table 3-64 provide the additional grading for the remaining identified condition criterions for the Health Index algorithm.

Table 3-62: Criteria for Service Age

Condition Rating	Corresponding Condition
A	Ground Electrode less than 10 years old
B	Ground Electrode between 10 and 20 years old
C	Ground Electrode between 20 and 30 years old
D	Ground Electrode between 30 and 40 years old
E	Ground Electrode more than 40 years old

Table 3-63: Criteria for Electrode resistance test

Condition Rating	Corresponding Condition
A	Ground electrode resistance and GPR within safe limits, all electrode components pass integrity test
C	Ground electrode resistance and GPR within safe limits but a few electrode components do not pass integrity test
E	Ground electrode resistance or GPR not within safe limits or many electrode components do not pass integrity test

Table 3-64: Criteria for Condition of surface stone

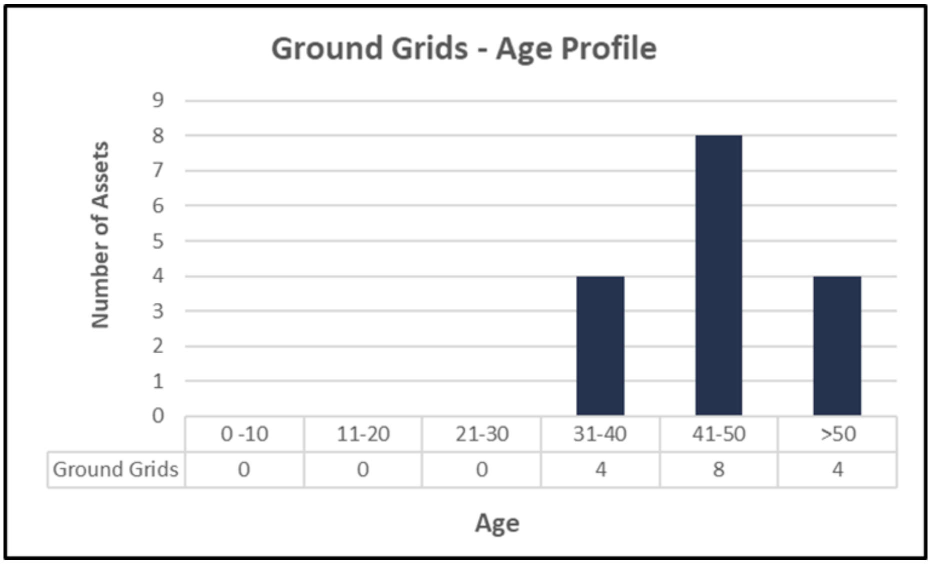
Condition Rating	Corresponding Condition
A	Resistivity of surface stone >3000 Ohm-m, no sign of vegetation growth
C	Resistivity of surface stone marginally less than <3000 Ohm-m, but no sign of vegetation growth
E	Resistivity of surface stone significantly less than <3000 Ohm-m, and signs of vegetation growth

3.2.6.1 *Results of Analysis*

Age Assessment

OPUCN operates and maintains 16 substation ground grids. Figure 3.46 presents the age profile of ground grids in-service at OPUCN. Asset service age is currently calculated with end year 2017.

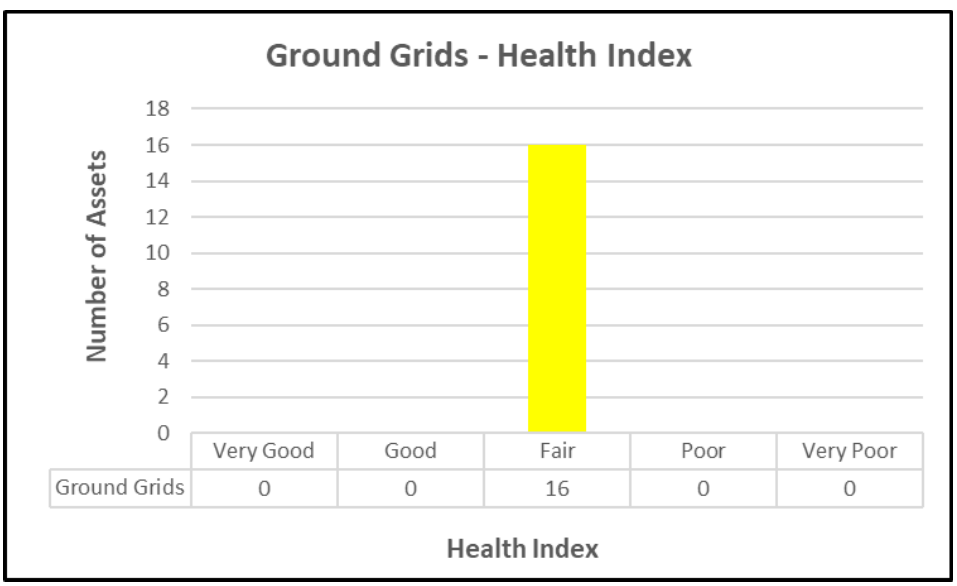
Figure 3.46: Ground Grid Age Demographic



Condition Assessment

Based on the condition assessment criteria defined and best available data, the Health Index score for ground grids is summarized in Figure 3.47.

Figure 3.47: Ground Grid Health Index Demographic



3.2.7 Fence & Building

The Health Index for substations fences and buildings is calculated by considering only visual inspections. Table 3-65 highlights the Health Index algorithm for both fences and buildings. The assets are considered individual within this report but use the same Health Index algorithm.

Table 3-65: Fence and Buildings Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Overall Condition	20	A,C,E	5,3,1	100
				MAX SCORE	**100**

Table 3-66 highlights the condition grading table used for both station fences and station buildings.

Table 3-66: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	No deficiencies
C	Only minor deficiencies
E	Major deficiencies requiring immediate attention

3.2.7.1 Results of Analysis

Condition Assessment

Based on the condition assessment criteria defined and best available data, the Health Index score for fences and buildings is summarized in Figure 3.48 and Figure 3.49.

Figure 3.48: Fence Health Index Demographic

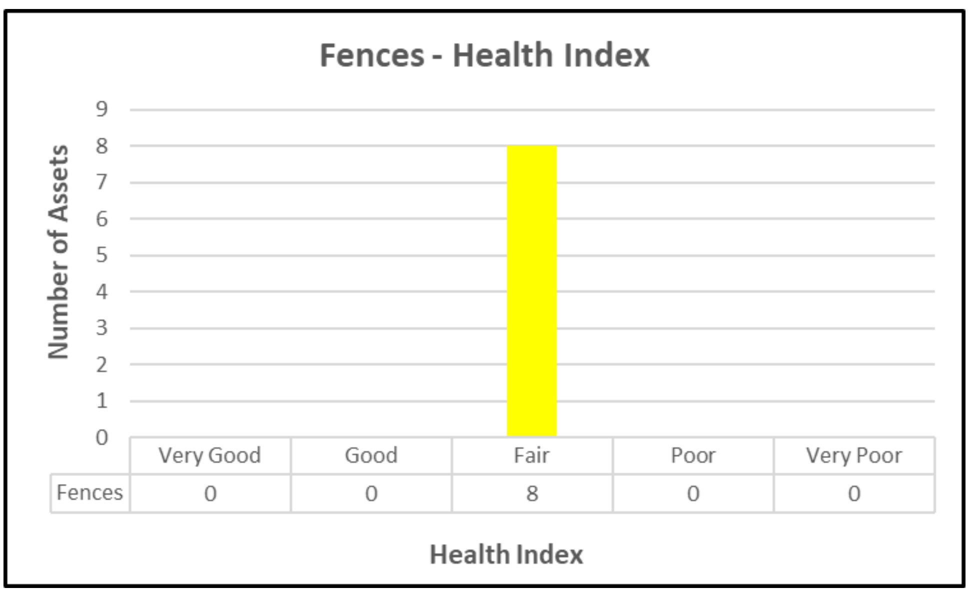
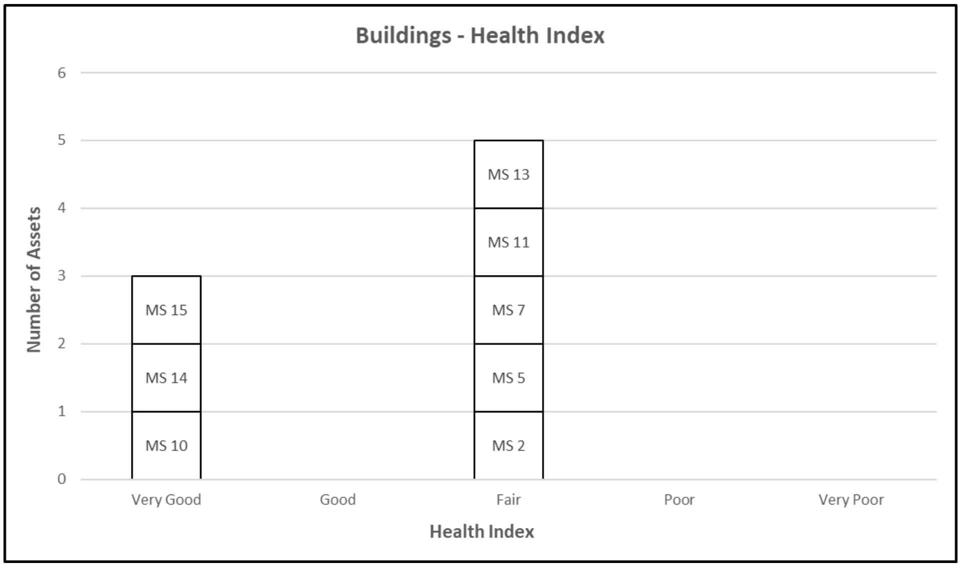


Figure 3.49: Building Health Index Demographic



Data Assessment

The Data Availability Indicator (DAI) is created to measure the reasonable collected data to date by the utility for completion regarding parameters used in the Health Index algorithm. The DAI for all station asset data is 100% with assumptions applied. Section 4 provides additional recommendations for data collections for Health Index formulation expansion.

4 Recommendations

Recommendations for further data points that can be collected are aggregated into this section and are provided for each asset group. Improvements can always be made to further justify the asset renewal, capital and operational expenditures, maintenance activities, or to enhance the ACA framework. Additionally, keeping records of asset condition is a good operating practice, as it may assist in planning and assessing the quality of in-service assets being replaced.

METSCO recommends that OPUCN incorporate a five-level grading scheme for any asset condition inspections, where applicable to bring its practices closer to the ISO5500X recommended approaches. A five-level grading scheme will allow for more discrepancy between assets and their respective Health Index values that will be used for prioritizing assets. Furthermore, METSCO recommends for OPUCN to perform annual validations of its ACA model for continuous improvements of the Health Index algorithms. There are several algorithms used by OPUCN that are not in alignment with the industry standard that can be realigned. Furthermore, additional algorithms have not yet fully been matured or developed and require additional data parameters. As OPUCN progresses with its asset inspection and data collection efforts, OPUCN is expected to be able to fully develop its ACA model.

As always, the decisions regarding enhancements to the testing, inspection and index calculation methodologies should incorporate the balance of financial considerations related to incremental costs of these tests, and the anticipated value of insights (e.g. value of risks mitigated) that these investments would bring about.

4.1 Pole

We recommend for OPUCN to continue periodically testing their poles for remaining strength and collecting visual indicators based on the OEB-recommended inspection cycle to capture the most recent asset condition. Table 4-1 identifies asset condition criteria that affect the life expectancy for this asset class. A priority classification in terms of criteria contributing to the life expectancy for the asset is provided below and can be used as a guideline for OPUCN to further enhance their Health Index Formulation. Furthermore, we recommend for OPUCN to refine the current HIF framework that separates the Overall Condition criteria into two sub-criteria (Wood Rot and Defects). The drawback with aggregate data is the underlying data may be lost moving forward and can be difficult to identify the main reason why a pole has an Overall Condition score of Poor. With the data split, should the HI of the pole be low, a system planner would be able to easily identify the reasons and make any necessary changes to prevent future assets experiencing similar degradations.

Table 4-1: End-of-Life Criteria for Poles

Criteria	Reasoning	Priority
Remaining Pole strength	Pole strength is blended in the general overall condition within OPUCN ACA data. METSCO recommends separating the associated strength parameters from the overall condition for further visibility and use in the HI formula. Measuring the strength of the in-service pole provides a valuable benchmark on the poles condition. This parameter is regarded to be the best parameter to use for identification of the pole's condition as the visual component of the pole may be only a slight representation of what is within the pole and affecting its strength.	**High**
Wood Rot	Wood rot is identified in the general condition comments part of the inspection process. METSCO recommends separating the associated "rot" fields away from the general "defects" field for further visibility and use in the HI formula.	**Medium**
Out of Plumb	Identifying poles that are already leaning present a higher risk to safety. Severely leaning poles should be targeted for replacement. Easily identifiable through pre-determined inspection cycles.	**Medium**

4.2 Overhead Primary Conductor

The Health Index for overhead primary conductors is determined with the use of two criteria: age and small conductor risk, both of which are found in the current HIF. Due to this fact, there are no immediate recommendations to be made regarding the HIF. Small conductor risk is a criterion as it is sometimes identified as having increased risk of becoming brittle and failing. OPUCN notes there are no small conductor's in-service, resulting in the HIF to be age dependent. However, if small conductors are in-service, it is recommended to update the Health Index values to accurately represent the current condition of the asset.

4.3 Underground Primary Cable

Table 4-2 identifies additional condition criteria that affect the life expectancy for underground primary cables and can contribute to the HIF. A priority in terms of criteria contributing to the life expectancy for the asset is provided and can be used as a guideline for OPUCN to further enhance their HIF.

Replacing underground cable can be a high capital expense for any utility especially if it is direct buried. We recommend that OPUCN consider the additional condition criteria moving forward to expand the HIF to assist with prioritization of asset replacement. Additionally, we recommend for OPUCN to reach out to external vendors that can provide these services to assist OPUCN to better understand the condition of their underground cable and what are optimal intervention methods to manage cable performance.

Table 4-2: End-of-Life Criteria for Underground Primary Cables

Criteria	Reasoning	Priority
Cable Failure	Identifying water tree samples throughout the service territory and varying age, the utility would be able to have an improved view on cable condition within the system. Sampling the distribution system would be a viable alternative. Currently, OPUCN collects historical cable failures, which may represent a good indication of the performance of cables in the surrounding areas.	**High**
Field Testing	Many test labs are offering partial discharge (PD) measurements to assess the condition of cables in service. Partial discharge testing of cables is performed online without disrupting the plant or facilities or offline when required. The data obtained from partial discharge test can provide critical information regarding the quality of cable insulation and its impact on cable system health.	**High**
Condition of Concentric Neutral	Corrosion of concentric neutrals is another mode of degradation. Insulation degradation and cable failures can be accelerated if cable jacket is damaged allowing moisture to enter into the insulation system. Concentric neutral corrosion is a major problem particularly on unjacketed cables or when the neutrals of the cable are exposed to excessive moisture over time. The corrosion can lead to premature cable failures and / or cause touch potential risks. Time Domain Reflectometry (TDR) tests are performed to determine the degree of corrosion on concentric neutral cables.	**Medium**
Loading History	Cable degradation can also occur due to overheating under overloading or short circuit conditions. Over stressing of insulation during voltage surges can also lead to cable failures.	**Low**

4.4 Distribution Transformer

OPUCN identifies and collects the major parameters that can be incorporated into a Health Index algorithm for distribution transformers. Additionally, OPUCN collects data through visual inspection cycles as well as IR scans and manages the asset risks through its maintenance routine.

4.5 Primary Switch, Smart Switch & Switchgear

Table 4-3: identifies asset condition criteria that affect the life expectancy for this asset class. A priority in terms of criteria contributing to the life expectancy for the asset is provided and can be used as a guideline for OPUCN to further enhance their Health Index Formulation. Currently, OPUCN collects data through visual inspection cycles as well as IR scans and manages the asset risks through its maintenance routine. However, we recommend for OPUCN to refine the current HIF framework that separates the Overall Condition criteria into multiple sub-criteria. The drawback with aggregate data is the underlying data may be lost moving forward and can be difficult to identify the main reason why the asset has an Overall Condition score of Poor. With the data fragmented, a system planner would be able to easily identify the reasons and make any necessary changes to prevent future assets experiencing similar degradations.

Table 4-3: End-of-Life Criteria for Switch & Switchgear

Criteria	Reasoning	Priority
Visual Inspection - Condition of Enclosure	Criterion affects life expectancy of switch. Identification of condition over time leads to degradation information of asset.	**Medium**
Visual Inspection - Condition of Interphase Barriers	Criterion affects life expectancy of switch. Identification of condition over time leads to degradation information of asset.	**Medium**
Visual Inspection and/or Corona testing - Condition of Terminations	Criterion affects life expectancy of switch. Identification of condition over time leads to degradation information of asset.	**Medium**
Visual Inspection - Condition of Blades	Criterion affects life expectancy of switch. Identification of condition over time leads to degradation information of asset.	**Medium**
Visual Inspection - Condition of Operating Mechanism	Criterion affects life expectancy of switch. Identification of condition over time leads to degradation information of asset.	**Low**
Visual Inspection - Condition of Pad (If applicable)	The civil infrastructure that holds the asset is an important component to look at as it contributes to the foundation of the asset and as a barrier to the outside environment.	**Low**

4.6 Cut-out Arrestor & Elbow

OPUCN recognizes the major parameters that can be incorporated into the HIF for each asset group. There no major recommendations being made towards the HIF.

4.7 Recloser

Table 4-4: and Table 4-5: identify the condition criteria that affect the life expectancy for each recloser type. A priority in terms of criteria contributing to the life expectancy for the asset is provided and can be used as a guideline for OPUCN to further enhance their Health Index Formulation.

Table 4-4: End-of-Life Criteria for Oil Insulated Recloser

Criteria	Reasoning	Priority
Visual Inspection – Condition of Oil	Criterion affects life expectancy of a recloser. Identification of oil quality over time leads to degradation information of an asset.	High
Visual Inspection - Condition of Tank	Criterion affects life expectancy of a recloser. Identification of condition over time leads to degradation information of an asset.	Medium
Visual Inspection - Condition of Terminations	Criterion affects life expectancy of a recloser. Identification of condition over time leads to degradation information of an asset.	Medium
Counter Readings	Criterion affects life expectancy of a recloser. Identification of operation use over time leads to degradation information of an asset.	Medium
Visual Inspection - Condition of Operating Mechanism	Criterion affects life expectancy of a recloser. Identification of condition over time leads to degradation information of an asset.	Low
Visual Inspection – Oil Leaks	Criterion affects life expectancy of a recloser. Identification of oil leaks over time leads to degradation information of an asset.	Medium

Table 4-5: End-of-Life Criteria for Vacuum Insulated Recloser

Criteria	Reasoning	Priority
Visual Inspection – Integrity of Vacuum Bottle	Criterion affects life expectancy of a recloser. Identification of condition over time leads to degradation information of an asset.	High
Visual Inspection - Condition of Enclosure	Criterion affects life expectancy of a recloser. Identification of condition over time leads to degradation information of an asset.	Medium
Visual Inspection - Condition of Terminations	Criterion affects life expectancy of a recloser. Identification of condition over time leads to degradation information of an asset.	Medium
Counter Readings	Criterion affects life expectancy of a recloser. Identification of operation use over time leads to degradation information of an asset.	Medium
Visual Inspection - Condition of Operating Mechanism	Criterion affects life expectancy of a recloser. Identification of condition over time leads to degradation information of an asset.	Low

4.8 Vault & Manhole

OPUCN identifies and collects the major parameters that can be incorporated into a HIF for vaults and manholes. However, METSCO recommends OPUCN to consider isolating the condition of the roof of the asset as a separate criterion as this component experiences the most wear and can be refurbished or renewed without needing to replace the whole structure.

4.9 Substation Power Transformer

Table 4-6: identifies the additional recommended condition criteria that affect the life expectancy for this asset class. A priority in terms of criteria contributing to the life expectancy for the asset is provided and can be used as a guideline for OPUCN to further enhance their Health Index Formulation. Moving forward, it is recommended to isolate testing results as individual criteria parameters into the Health Index Formulation in comparison to the current framework that aggregates all test results under one score. It is also advised for OPUCN to validate the data inputs and quality with respect to each of the identified end-of-life criteria in the current HIF. Additionally, METSCO recommends for OPUCN to refine the current HIF into a more detailed framework that explicitly highlights the end-of-life criteria rather than aggregating the sub-criteria into one criterion used in the HIF.

Table 4-6: End-of-Life Criteria for Power Transformer

Criteria	Reasoning	Priority
Infrared Scanning	To identify if the transformer is operating within normal temperature ranges – excess temperature would require further investigation.	**High**
Dissolved Gas Analysis	Increase of gas presence accelerates the degradation process. Identifying abnormal gas readings may present opportunity to intervene at an optimal time.	**High**
Oil Quality Test	Oil quality degradation affects the life expectancy of the asset. Continuous monitoring leads to degradation information over time.	**High**
Power Factor	Power factor assists in understanding how much a utility is required to generate the appropriate volt-amperes to supply real power to clients. More power required affects the whole distribution system and carries an increase in cost and risk.	**High**
Visual Inspection and/or Corona testing - Bushing Condition	Identifying defects to the bushings provides valuable condition data and more importantly if the issue is reoccurring after being addressed.	**Medium**
Visual Inspection - Main Tank Corrosion	Identifying presence of corrosion compromises the strength of the tank. Both the location and degree (low, medium, high) of rust presence should be captured over time.	**Medium**
Visual Inspection - Cooling Equipment	Identifying presence of corrosion/wear compromises the equipment. Both the location and degree (low, medium, high) of rust/wear presence should be captured over time.	**Medium**
Visual Inspection - Oil Tank Corrosion	Identifying presence of corrosion compromises the strength of the tank. Both the location and degree (low, medium, high) of rust presence should be captured over time.	**Medium**
Visual Inspection - Foundation	Identifying presence of wear compromises the foundation. Both the location and degree (low, medium, high) of wear presence should be captured over time.	**Low**

Field testing - Grounding	Identification of wear over time provides condition data of the grounding unit found in station transformers.	**Low**
Visual Inspection - Gaskets and Seals	Identification of wear over time provides condition data of the gaskets/seals found in station transformers.	**Low**
Visual Inspection - Connectors	Identification of wear over time provides condition degradation data of the asset.	**Low**
Visual Inspection - Oil Leaks	Identification of oil leaks, or residue and markings of oil leaks on equipment provides condition degradation data on the asset. Continuous problems would be addressed immediately for safe operation of asset.	**Low**
Visual Inspection - Oil Level	Identifying the oil level is within acceptable range of operation from previous inspection.	**Low**

4.10 Circuit Breakers

Table 4-7: identifies asset condition criteria that affect the life expectancy for this asset class. A priority in terms of criteria contributing to the life expectancy for the asset is provided and can be used as a guideline for OPUCN to further enhance their Health Index Formulation. Moving forward, it is recommended to isolate testing results as individual criteria parameters into the Health Index Formulation. Similarly seen for other assets, METSCO recommends for OPUCN to refine the current HIF into a more granular framework that explicitly highlights the end-of-life criteria rather than aggregating the sub-criteria into one criterion used in the HIF.

Lastly, OPUCN has recently installed SF6 circuit breakers. Though the condition of the assets has yet to be collected, METSCO provides OPUCN the asset criteria recommendations believed to be incorporated within a HIF.

Table 4-7: End-of-Life Criteria for SF6 Circuit Breakers

Criteria	Reasoning	Priority
SF6 Gas Analysis	Criterion affects life expectancy of a circuit breaker. Identification of gas quality over time leads to degradation information of an asset.	**High**
Visual Inspection - Condition Bushing Insulators	Criterion affects life expectancy of a circuit breaker. Identification of condition over time leads to degradation information of an asset.	**Medium**
Visual Inspection - Condition of Operating Mechanism	Criterion affects life expectancy of a circuit breaker. Identification of condition over time leads to degradation information of an asset.	**Medium**
Timing/Travel tests	Criterion affects life expectancy of a circuit breaker. Identification of operation use over time leads to degradation information of an asset.	**Medium**
Contact Resistance Tests	Criterion affects life expectancy of a circuit breaker. Identification of operation use over time leads to degradation information of an asset.	**Medium**
Visual Inspection – SF6 Leaks	Criterion affects life expectancy of a circuit breaker. Identification of leaks over time leads to degradation information of an asset.	**Medium**
Visual Inspection – Contact Resistance Tests	Criterion affects life expectancy of a circuit breaker. Identification of condition over time leads to degradation information of an asset.	**Low**

4.11 Relays & RTUs

Table 4-8: identifies asset condition criteria that affect the life expectancy for this asset class. A priority in terms of criteria contributing to the life expectancy for the asset is provided and can be used as a guideline for OPUCN to further enhance their Health Index Formulation. Moving forward it is recommended to isolate testing results as individual criteria parameters into the Health Index Formulation.

Table 4-8: End-of-Life Criteria for Protection Relays & RTUs

Criteria	Reasoning	Priority
Mean Time Between Failures	Objective test performed on the asset to determine MTBF values. Removes the subjectivity from the condition parameter within the Health Index.	**High**
Service Age	Basic age information of the asset will be able to align to the asset's typical useful life.	**High**
Obsolescence	Strategy driven from asset management or through manufacturer quality audits.	**High**
Overall Condition	Identifying external defects such as corrosion, connection conditions, evidence of overheating, counter readings for number of operations provides condition information for the asset's overall feature.	**High**
Defect and Test Reports	Objective reports performed on the asset to determine defects and test results. Removes the subjectivity from the condition parameter within the Health Index.	**High**

4.12 Substation Switchgears

OPUCN utilizes an under-developed Health Index algorithm for its substation switchgears, however it complements the current data collection by OPUCN. Table 4-9 identifies asset condition criteria that affect the life expectancy for this asset class that METSCO recommends for OPUCN to collect. A priority in terms of criteria contributing to the life expectancy for the asset is provided. Each criterion is identified as 'High' since the current Health Index algorithm is currently under-developed. Furthermore, METSCO recommends for OPUCN to refine the current HIF into a more detailed framework that explicitly highlights the end-of-life criteria rather than aggregating the sub-criteria into one criterion used in the HIF.

Table 4-9: End-of-Life Criteria for substation Switchgears

Criteria	Reasoning	Priority
Metal Clad Cubicle and Components	Visual condition rating of the cubicle and components provides a good indication of the condition of asset	**High**
Breaker Truck Condition	Visual condition rating of the breaker truck provides a good indication of the condition of asset	**High**
Control & Operating Mechanism	Visual condition rating of the control and operating mechanism provides a good indication of the condition of asset	**High**
Time/Travel Tests	Defined test provides unbiased indication of how the asset is performing and its condition	**High**
Contact Resistance Tests	Defined test provides unbiased indication of how the asset is performing and its condition	**High**
Oil Leaks	Criteria used for oil-type switchgears	**High**
Oil Analysis Test	Criteria used for oil-type switchgears	**High**
Arc Chutes	Criteria used for air-type switchgears	**High**
SF6 Leaks	Criteria used for SF6-type switchgears	**High**
SF6 Gas Tests	Criteria used for SF6-type switchgears	**High**
SF6 Coil Signature Test	Criteria used for SF6-type switchgears	**High**
Vacuum Bottle Integrity	Criteria used for vacuum-type switchgears	**High**

4.13 Battery & Charger, Ground Grids, and Fences

OPUCN recognizes the major parameters that can be incorporated into a HIF for these asset classes. METSCO recommends OPUCN to continue monitoring the asset's condition through regular maintenance inspection cycles and collecting all necessary data to evaluate the asset's condition.

5 Asset Replacement Plan

5.1 Purpose

Based on the condition assessment of major assets employed in substations, overhead lines and underground distribution system, this section provides the projected quantities of assets that would likely require replacement for the next short-term planning years 2019 to 2025.

The following major classes of assets are considered:

- Distribution Assets
  - Poles
  - Underground Primary Cable
  - Transformers
  - Switches
  - Switchgears
  - Cut-Out Arrestors & Elbows
  - Vaults & Manholes
- Station assets
  - Power Transformers
  - Circuit Breakers
  - Switchgears
  - Relays
  - Battery & Chargers
  - Ground Grids

Overhead conductors typically outlive the poles which support them. Therefore, they are typically replaced when poles are being renewed, and as such are not presented within this section. The exception is if the overhead conductor were to be a small sized conductor that carried a large risk of failing prematurely. If the exception is met, it is advised for the overhead conductor segment to be replaced as soon as possible. The long-term trending approach considers expected aging and degradation for each asset and attempts to smooth investment requirements over the planning period.

5.2 Approach

The ACA provides the Health Index distribution for each asset. The Health Index is a percentage score between 0 and 100, used to assess the condition of an asset. The condition-based intervention approach is shown in Table 5-1. This is a general approach, which can vary between assets and based on budget constraints. For each asset type, a range of quantity of asset replacements in each year is estimated. However, the replacements are based on Health Index, testing and field inspection of assets performed on the samples. Continuous monitoring of the asset by inspectors will provide current asset's condition assessment.

Table 5-1: Health Index definition and intervention approach

Health Index (%)	Condition	Intervention Approach
85 - 100	Very good	None
70 - 85	Good	None
50 - 70	Fair	Replace within 3-10 years
30 - 50	Poor	Replace within 1-3 years
0 - 30	Very poor	Replace immediately

In addition to the condition of the assets, the asset's age, specifically the Typical Useful Life (TUL), can be a determining driver for asset renewal because as the asset reaches and passes the TUL, the rate at which the asset's condition deteriorates increases. Furthermore, visual inspection records may result in a calculated Health Index to be in a favorable condition for an asset reaching or exceeding its TUL. However, the asset may carry an increased risk of failing and quickly deteriorating from a favorable condition (Very Good/Good) to an unfavorable condition (Very Poor) within a short period of time. Minimum, maximum and TUL values for OPUCN are assumed based on the *Asset Depreciation Study for the Ontario Energy Board* in 2010[3], as summarized in Table 5-2.

Table 5-2: Useful life measures for selected asset classes

Asset Class	Min. UL	TUL	Max. UL
Wood pole	35	45	75
Concrete pole	50	60	80
Steel pole	60	60	80
Underground cable (TR-XLPE direct buried)	25	30	35
Pole-mount transformer	30	40	60
Pad-mount transformer	25	40	45
Submersible / Vault transformer	25	35	45
Primary overhead switch / Smart switch	30	45	55
Switchgear	20	30	45
Recloser	25	40	55
Power transformer	35	45	60
Circuit breaker	35	45	65
Digital relay	15	20	20
Battery	10	15	15
Charger	20	20	30
Vault	40	60	80
Manhole	50	60	80

[3] Asset Depreciation Study for the Ontario Energy Board, Kinectrics Inc., 2010

5.3 Pole

The age and Health Index demographics are depicted in Table 5-3 and Table 5-4, respectively.

Table 5-3: Age distribution for pole

Asset	0-10 Years	11-20 Years	21-30 Years	31-40 Years	41-50 Years	51+ Years
Wood Pole	2596	1508	1849	870	477	2270
Concrete Pole	8	37	7	108	708	1
Steel Pole	6	0	5	0	2	1

Table 5-4: Health Index distribution for pole

Asset	Very Good	Good	Fair	Poor	Very Poor
Wood Pole	581	6129	2662	196	2
Concrete Pole	3	108	758	0	0
Steel Pole	6	5	3	0	0

To manage the in-service equipment failure at the current condition levels and managing the asset age demographic, Table 5-5 provides the replacement recommendation for asset renewal of poles expected to reach the end of their useful service life within the next seven years.

The replacement plan for wood poles prioritizes those poles that are rated as Poor and Very Poor and are past the TUL of a wood pole. Based on the large number of poles past the TUL, it is recommended for OPUCN to replace a portion of poles each year to manage the risk of poles failing due to age. However, the condition data collected to date does not support that wood poles past the TUL are experiencing unfavorable conditions and require attention for replacement. METSCO recommends for OPUCN to conduct a visual inspection on a subset of wood poles past the TUL to determine if the wood poles are in fact in acceptable service conditions or require asset intervention (i.e. asset renewal).

It is expected that with good risk management, the TUL could be extended to 55 years, in which case a decrease of wood pole replacement per year can be determined. With an optimal and balanced risk management, benefits can be realized within the asset management process. Benefits may include favorable customer service satisfaction, as there is a reduced need for planned outages, a consistent and decreased renewal budget that will reflect in minimal bill impacts and maintains the service reliability of the system.

Table 5-5: Projected replacement for pole

Quantity of Assets Recommended for Replacement							
Year	2019	2020	2021	2022	2023	2024	2025
Wood Pole	326	320	320	320	320	330	330
Concrete Pole	4	7	7	7	7	8	9

5.4 Underground Primary Cable

The age and Health Index demographics are depicted in Table 5-6 and Table 5-7, respectively.

Table 5-6: Age distribution for underground primary cable

Asset	0-10 Years	11-20 Years	21-30 Years	31-40 Years	41-45 Years	45+ Years
Underground Primary Cable (m)	155,681	123,990	93,233	60,055	21,890	5,476

Table 5-7: Health Index distribution for underground primary cable

Asset	Very Good	Good	Fair	Poor	Very Poor
Underground Primary Cable (m)	172,545	68,208	136,462	81,042	2,068

To keep the current levels of condition for the asset class, Table 5-8 provides the replacement recommendation for asset renewal of underground primary cable expected to reach the end of their useful service life within the next seven years. The replacement plan for underground primary cables prioritizes those that are rated as Poor and Very Poor and are past the TUL. By year 2025, approximately 60% of the currently identified Poor and Very Poor cables are targeted for replacement. The pace allows for OPUCN to manage replacement costs and to gradually replace the defective underground cables. METSCO recommends testing cables for replacement using proven test techniques to validate the condition of the cable is unfavorable and should be replaced. This will further assist OPUCN in correctly selecting which cables are to be replaced and which can remain in-service without accumulating additional capital costs.

Table 5-8: Projected replacement for underground primary cable

Quantity of Assets Recommended for Replacement							
Year	2019	2020	2021	2022	2023	2024	2025
Underground Primary Cable (km)	7.05	7.3	7.05	7.2	7.3	7.05	7.05

5.5 Transformer

The age and Health Index demographics are depicted in Table 5-9 and Table 5-10, respectively.

Table 5-9: Age distribution for distribution transformer

Asset	0-10 Years	11-20 Years	21-30 Years	31-40 Years	41-50 Years	51+ Years
Pole-mount transformer	679	666	508	537	105	18
Pad-mount transformer	1092	1078	697	707	190	1
Vault transformer	92	35	81	90	96	0
Submersible transformer	0	13	3	2	1	1

Table 5-10: Health Index distribution for distribution transformer

Asset	Very Good	Good	Fair	Poor	Very Poor
Pole-mount transformer	1219	1177	117	0	0
Pad-mount transformer	2065	1600	99	1	0
Vault transformer	167	201	26	0	0
Submersible transformer	8	11	1	0	0

To manage the asset age demographic, Table 5-11 provides the replacement recommendation for asset renewal of transformers expected to reach the end of their useful service life within the next seven years. Continuous monitoring of the asset's condition throughout the years will identify if any further condition degradation continues and if it is necessary to be replaced.

Distribution transformers are often managed on a run to failure scenario, or are replaced as a part of larger, planned renewal projects to minimize service disruptions impacts and maximize efficiency. The run to failure case is particularly true for overhead distribution transformers. Both cases will influence the replacement rate that OPUCN will plan for in the short term. Furthermore, old pole-mount transformers are typically found on old or failed wood poles and are replaced simultaneously for efficiency.

Pad-mount transformers near busy intersections that are exposed to salt and exhibit accelerated rusting should be replaced as soon as possible prior to failure. Pad-mount transformer that are not fully enclosed present a safety risk to the public and therefore should be managed on a proactive replacement.

The replacement plan for distribution transformers largely prioritizes assets that are beyond the TUL since there are limited numbers of transformers found in the Poor and Very Poor category. However, it is recommended for OPUCN to continue to inspect transformers planned for replacement. It is recommended for a transformer to be replaced if the condition of the transformer has deteriorated, otherwise OPUCN should consider continuing to operate and maintain the existing asset until a later date.

Table 5-11: Projected replacement for distribution transformer

Quantity of Assets Recommended for Replacement							
Year	2019	2020	2021	2022	2023	2024	2025
Pole-mount transformer	56	38	38	38	38	38	38
Pad-mount transformer	51	50	50	50	55	55	55
Vault transformer	11	11	12	12	11	12	11
Submersible transformer	0	1	1	0	0	0	0

5.6 Switch

The age and Health Index demographics are depicted in Table 5-12 and Table 5-13, respectively.

Table 5-12: Age distribution for switch

Asset	0-10 Years	11-20 Years	21-30 Years	31-40 Years	41-50 Years	51+ Years
Primary switch	433	156	284	80	43	5

Table 5-13: Health Index distribution for switch

Asset	Very Good	Good	Fair	Poor	Very Poor
Primary switch	588	365	48	0	0

To reduce the amount of assets beyond their TUL, Table 5-14 provides the recommended replacement for asset renewal of primary switches expected to reach the end of their useful service life within the next seven years. The replacement plan for primary switches prioritizes those that are approaching or past the TUL.

Table 5-14: Projected replacement for switch

Quantity of Assets Recommended for Replacement							
Year	2019	2020	2021	2022	2023	2024	2025
Primary switch	16	11	8	5	5	4	4

5.7 Switchgear

The age and Health Index demographics are depicted in Table 5-15: and Table 5-16:, respectively.

Table 5-15: Age distribution for switchgear

Asset	0-10 Years	11-20 Years	21-30 Years	31-40 Years	41-50 Years	51+ Years
Vault Switchgear	12	7	1	0	0	0
Padmount Switchgear	9	4	0	0	0	0

Table 5-16: Health Index distribution for switchgear

Asset	Very Good	Good	Fair	Poor	Very Poor
Vault Switchgear	18	2	0	0	0
Padmount Switchgear	10	3	0	0	0

Based on the ACA and age analysis, there is no recommended replacements within the next seven years. Should the switchgears continue to receive frequent maintenance, it is expected the assets will continue to perform well during tests.

5.8 Cut-Out Arrestor and Elbow

The age and Health Index demographics are depicted in Table 5-17: and Table 5-18, respectively.

Table 5-17: Health Index distribution for cut-out arrestor and elbow

Asset	0-10 Years	11-20 Years	21-30 Years	31-40 Years	41-50 Years	51+ Years
Cut-Out Arrestor	702	627	819	450	215	17
Elbow	3460	1439	1171	861	260	1

Table 5-18: Age distribution for cut-out arrestor and elbow

Asset	Very Good	Good	Fair	Poor	Very Poor
Cut-Out Arrestor	1110	989	209	481	41
Elbow	4899	2032	261	0	0

Table 5-19 provides the recommended replacement for asset renewal expected to reach the end of their useful service life within the next seven years. Continuous condition monitoring should be considered to capture additional datapoints to identify assets that may experience accelerated degradation. The replacement plan for these assets prioritizes those that are rated as Poor and Very Poor or to mitigate high-impact failures.

Furthermore, OPUCN has approximately 1175 porcelain transformer cut-out arrestors and 543 porcelain riser cut-out arrestors in-service. The target year OPUCN has set to completely remove porcelain assets from service is 2025 due to the associated safety risks.

Table 5-19: Projected replacement for cut-out arrestor and elbow

Quantity of Assets Recommended for Replacement							
Year	2019	2020	2021	2022	2023	2024	2025
Cut-Out Arrestor	50	52	52	50	62	69	65
Elbow	5	10	10	15	15	15	15

5.9 Recloser

Reclosers are a new asset class introduced in OPUCN system within the last 10 years. Based on the ACA and age analysis, there is no recommended replacements for reclosers within the next seven years.

5.10 Vault & Manhole

The Health Index demographics for vaults and manholes are depicted in Table 5-20.

Table 5-20: Health Index distribution for vault

Asset	Very Good	Good	Fair	Poor	Very Poor
Vault	16	130	0	0	0
Manhole	0	120	0	0	0

Based on the ACA analysis, there is no recommended replacements for vaults and manholes within the next seven years.

5.11 Power Transformer

The age and Health Index demographics are depicted in Table 5-21 and Table 5-22, respectively. No power transformers are beyond the TUL nor experiencing extreme condition degradation.

Table 5-21: Age distribution for power transformer

Asset	0-10 Years	11-20 Years	21-30 Years	31-40 Years	41-50 Years	51+ Years
Power transformer	9	1	1	5	0	0

Table 5-22: Health Index distribution for power transformer

Asset	Very Good	Good	Fair	Poor	Very Poor
Power transformer	8	6	2	0	0

To maintain the condition of in-service equipment and to improve the age distribution, Table 5-23 provides the recommended replacement for asset renewal of power transformers expected to reach the end of their useful service life within the next seven years. Although all transformers were rated as Fair or better, there are few transformers identified that OPUCN may consider completing a refurbishment or renewal.

MS10-T2 has a recommended target year of 2019 due to the latest test results receiving a Poor rating for the *Test Parameter* criteria for the HIF. This power transformer's condition should be continued to be monitored in case it experiences further degradation. The remaining identified power transformers have also received a less than acceptable oil quality analysis and should be targeted for asset replacement or rejuvenation. In addition, thee identified transformers in the table will reach the TUL of 45 years. Assets that are past or approaching the TUL may have positive visual inspection records resulting in an assets health to be in Fair condition. However, the asset carries an increased risk of failing and can quickly deteriorate from Fair to Very Poor. Therefore, it is beneficial for OPUCN to replace the power transformer prior to failing.

In addition, power transformers MS7-T1 and MS5-T2 have an anticipated replacement within the next planning period as they will approach the TUL between 2025-2031.

Table 5-23: Projected replacement for power transformer

Quantity of Assets Recommended for Replacement							
Year	2019	2020	2021	2022	2023	2024	2025
Power transformer	MS10-T2				MS14-T2	MS14-T1	MS7-T2

5.12 Circuit Breaker

The age and Health Index demographics are depicted in Table 5-24 and Table 5-25, respectively.

Table 5-24: Age distribution for circuit breaker

Asset	0-10 Years	11-20 Years	21-30 Years	31-40 Years	41-50 Years	51+ Years
Circuit breaker – 13.8kV	68	0	4	0	0	0
Circuit breaker – 44kV	16	0	0	0	0	0

Table 5-25: Health Index distribution for circuit breaker

Asset	Very Good	Good	Fair	Poor	Very Poor
Circuit breaker – 13.8kV	68	4	0	0	0
Circuit breaker – 44kV	16	0	0	0	0

Based on the ACA and age analysis, there is no recommended replacements within the next seven years. Should the circuit breakers continue to receive frequent maintenance, it is expected the assets will continue to perform well during tests.

5.13 Substation Switchgear

The age and Health Index demographics are depicted in Table 5-26 and Table 5-27 respectively, for substation switchgears.

Table 5-26: Age distribution for switchgear

Asset	0-10 Years	11-20 Years	21-30 Years	31-40 Years	41-50 Years	51+ Years
Switchgear	1	0	0	3	4	0

Table 5-27: Health Index distribution for switchgear

Asset	Very Good	Good	Fair	Poor	Very Poor
Switchgear	0	1	2	5	0

To manage the condition of in-service equipment at current levels and to manage the asset deterioration, Table 5-28 provides the recommended replacement for asset renewal of substation switchgears expected to reach the end of their useful service life within the next seven years. In multiple station locations, both switchgear buses have deteriorated, and both should be replaced within a short period between each installation for resource efficiency and adequate system planning.

Table 5-28: Projected replacement for switchgear

Quantity of Assets Recommended for Replacement							
Year	2019	2020	2021	2022	2023	2024	2025
Switchgear	-	MS13	MS7	MS11	MS5	MS2	MS10

5.14 Relay and RTU

The age and Health Index demographics are depicted in Table 5-29: and Table 5-30:, respectively.

Table 5-29: Age distribution for relay and RTU

Asset	0-5 Years	6-10 Years	11-15 Years	16-20 Years	>20 Years
Relay	9	44	18	0	0
RTU	0	0	8	0	0

Table 5-30: Health Index distribution for relay and RTU

Asset	Very Good	Good	Fair	Poor	Very Poor
Relay	16	9	46	0	0
RTU	0	0	8	0	0

To manage the age distribution of the in-service equipment, Table 5-31: provides the recommended replacement for asset renewal of relays and RTUs expected to reach the end of their useful service life within the next seven years. Continuous monitoring of the asset's condition throughout the years will identify if any further condition degradation continues and if it is necessary to be replaced. The replacement plan targets those assets approaching the TUL.

Table 5-31: Projected replacement for relay and RTU

Quantity of Assets Recommended for Replacement							
Year	2019	2020	2021	2022	2023	2024	2025
Relay	0	0	2	3	1	1	1
RTU	0	0	0	1	1	1	1

5.15 Battery and Charger

The age and Health Index demographics are depicted in Table 5-32 and Table 5-33, respectively.

Table 5-32: Age distribution for battery and charger

Asset	0-5 Years	6-10 Years	11-15 Years	16-20 Years	>20 Years
Battery	3	4	1	0	0
Charger	2	3	3	0	0

Table 5-33: Health Index distribution for battery and charger

Asset	Very Good	Good	Fair	Poor	Very Poor
Battery	5	3	0	0	0
Charger	4	4	0	0	0

To improve the age distribution of in-service equipment, Table 5-34 provides the recommended replacement for asset renewal of batteries that may reach the end of their useful service life within the next seven years. Batteries should be tested periodically, and should they begin to degrade, it is optimal to replace the asset. Chargers should be replaced if their test performance degrades.

Table 5-34: Projected replacement for battery

Quantity of Assets Recommended for Replacement							
Year	2019	2020	2021	2022	2023	2024	2025
Battery	-	MS10	MS2	MS13	MS11	MS15	MS7

5.16 Ground Grids

The age and Health Index demographics are depicted in Table 5-35 and Table 5-36, respectively.

Table 5-35: Age distribution for ground grid

Asset	0-10 Years	11-20 Years	21-30 Years	31-40 Years	41-50 Years	51+ Years
Ground Grid	0	0	0	4	8	4

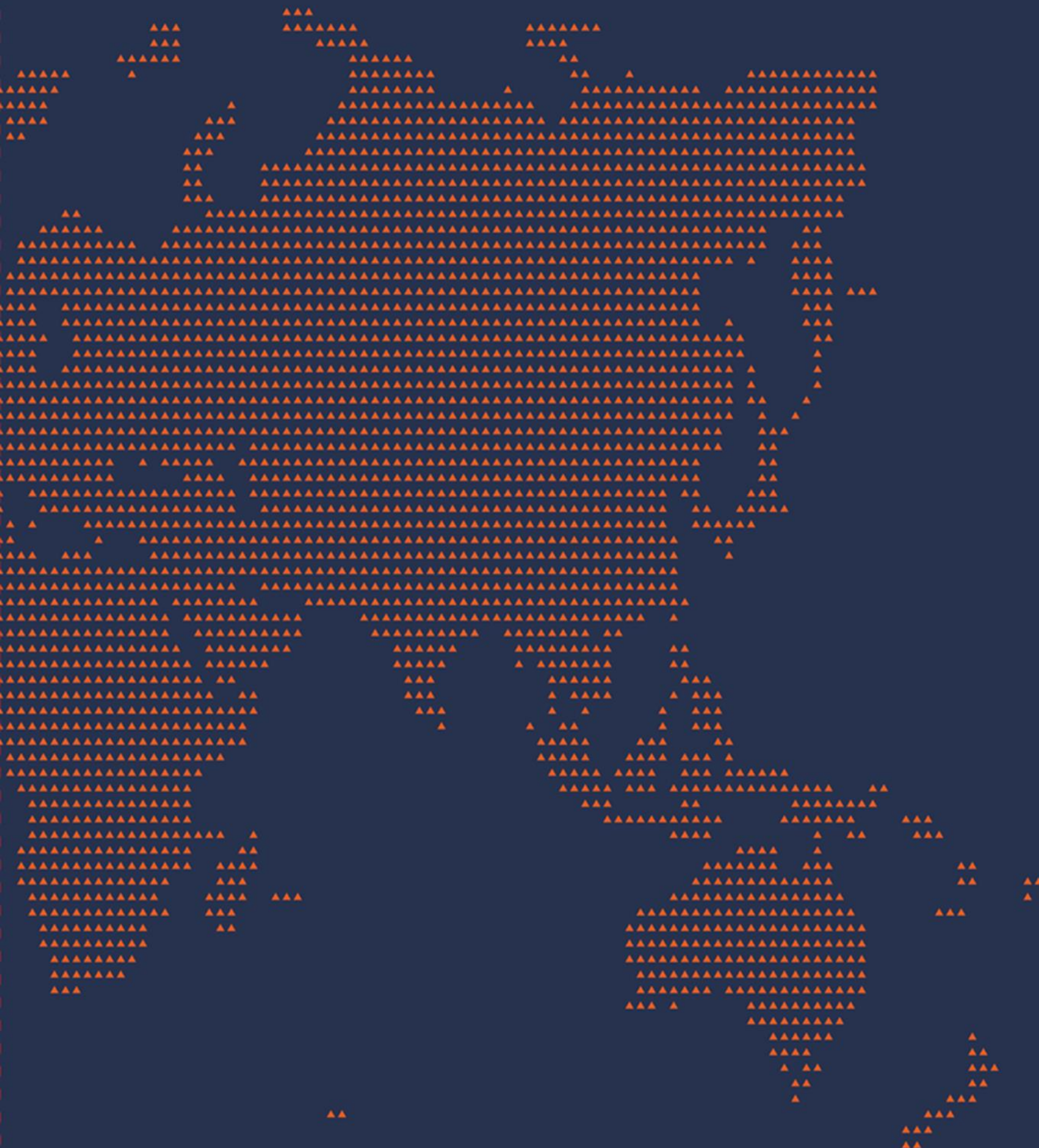
Table 5-36: Health Index distribution for ground grid

Asset	Very Good	Good	Fair	Poor	Very Poor
Ground Grid	0	0	16	0	0

Based on the ACA and age analysis, there are no recommended replacements within the next seven years. Should the ground grids continue to receive good maintenance, it is expected the assets will continue to perform well during tests. Should a ground grid receive a lower test result, an investigation should be completed to determine the root cause as well as appropriate remedial actions.

6 References

[1] International Organization for Standardization (2014). *ISO 55000*. Geneva: ISO.



Appendix C: Customer Engagement Report

Appendix C(i): Oshawa Power Distribution System Plan Customer Engagement Report

Distribution System Plan Customer Engagement Report

Prepared by: Sheila Risorto

January 30, 2020

Table of Contents

Executive Summary

During the 2019 Oshawa Power Distribution System Plan Customer Engagement process, Oshawa Power engaged the Oshawa community on the proposed factors of the 2020-2025 Distribution System Plan from October 1, 2019 through to December 8, 2019.

Oshawa Power has taken a multi-method approach to engaging customers, so it could understand the wide variety of opinions and views about what it takes to be seen as a successfully run LDC. Public engagement focused on education and awareness and included three feedback components:

- Implemented the Taking A.I.M. process (Applied Insights Methodology) online survey. A.I.M. is a method that creates two-way communication that allowed Oshawa Power to ask budgetary questions and also asked open ended questions to participants to gather feedback. Customers were able to ask questions and request responses from staff. The survey was made available in paper copy for those who did not have online access. Please see attached Taking A.I.M. report for further dialogue on the process to create the survey and accompanying tasks.
- Virtual Telephone Town Hall hosted on October 28, 2019; and,
- Four in-person public town halls hosted throughout the city where community members attended a presentation delivered by Oshawa Power's senior executive team, had open forum question and answer period and engage directly with Oshawa Power staff.

Please See **Appendix A Figure 8** for Customer Engagement Timeline covering January to December 2019

Communication Plan

In an effort to increase engagement, extensive promotion was used to encourage participation in the online survey using various mediums including:

- Created online survey
- Social media advertising on both Facebook and Twitter
- Newspaper notice/advertisement in 2 local newspapers
- Partnered with three local charities, local community centres and public library to expand social media reach
- Distributed media release
- Distributed postcard and flyers at 7 utility public events
- Email blast campaign to Oshawa Power online customers promoting the online survey
- Email blast campaign to Oshawa Power online customers informing customers of Telephone Town Hall and Public Town Halls
- Created a dedicated webpage on the Oshawa Power website for customers to obtain information about the Distribution System Plan, upcoming public events, and access to the online survey
- Created an information video and distributed through social media and post on webpage
- Created an online presentation and posted on webpage
- Promoted the initiative with Oshawa Power staff
- Information collaterals for takeaway in lobby
- Promoted in the Customer Service IVR welcome message in the call centre

- Conducted Virtual Telephone Town Hall during evening hours – October 28, 2019 7:30pm-8:30pm
- Hosted a Public Town Hall during evening hours at public library – November 5, 2019 5:30pm-7:30pm (Central Oshawa)
- Hosted three separate Public Information Sessions at three separate Oshawa Seniors Community Centres (OSCC) locations during business hours:
    - November 6, 2019 11am-1pm, OSCC John St Branch (Central Oshawa)
    - November 29, 2019 10am-12pm, OSCC Conant Branch (South Oshawa)
    - December 4, 2019 9am-11am, OSCC Delpark Homes Centre Branch (North Oshawa)

Attendance and Participation

Through the Online Survey, Virtual Telephone Town Hall and Public Town Halls Oshawa Power reached and engaged with over 12,000 Oshawa residents and businesses. Offering multiple methods of participation Oshawa Power was able to reach a cross section of customers that vary in age, income level, employment status and geography of Oshawa. Additionally, offering the survey in both an online and paper format addressed barriers for customer that may have mobility or internet access issues.

All of the engagement opportunities included an education and awareness component about the Distribution System Plan and Rate Application process, how rate payer dollars are allocated and next steps.

Oshawa Power reached:

- 9,798 listeners with a peak of 2,471 listeners on at one time during the one-hour Telephone Town Hall,
    - 189 listeners entered queue to ask a question and 22 went live
    - 4 polling questions were asked during the course of the live call
    - 93 customers opted out of the Telephone Town Hall ahead of time (0.19% of list provided)
- 1,240 completed A.I.M. surveys,
    - 26 customers asking to be contacted by an Oshawa Power employee
    - Over 900 comments were submitted
- Approximately 50 Oshawa residents attended the four public town halls and almost 80 questions were asked at the events to the senior executive team, questions listed in **Appendix B.**

Benchmarking

To measure customers responses a comparison of like questions from the 2019 online survey to the 2018 Customer Satisfaction Telephone Survey was completed:

- Oshawa Power is a well-respected company (83% online, 85% telephone), who is trusted and trustworthy (86% online, 90% telephone) and who is seen as an organization that spends money prudently (82% telephone).
- The customer base is an urban one. As such, there is a strong expectation that electricity is consistently delivered in a reliable and safe manner. As it relates to reliability, Oshawa Power

received excellent scores from respondents – 92% online, 91% telephone. Also, 88% online, 90% telephone respondents, agree OP's current standard of reliability meets their requirements.

Figure 1 – Oshawa Attribute Comparison Table

To what degree do you agree or disagree with the following attributes:				
Oshawa Power	**Online 2019**	**Telephone 2018**	**Telephone 2017**	**Telephone 2014**
Company to continue to be working with	87%	90%	88%	88%
Deals professionally with customers' problems	83%	86%	88%	86%
Pro-active in communicating changes and issues affecting Customers	81%	80%	77%	77%
Respected company in the community	83%	85%	90%	87%
Adapts well to changes in customer expectations	76%	79%	77%	78%
Is a trusted and trustworthy company	86%	90%	89%	85%
Accurate billing	86%	89%	88%	86%
Provides consistent, reliable electricity	92%	91%	90%	89%

The data from the Online Taking A.I.M. Survey with information for COS and DSP also shows the majority of respondents' support Oshawa Power's recommendations as they relate to System Renewal, System Service, General Plant, and Facility investments in order to maintain and increase the high level of reliability achieved today.

In the online survey Oshawa Power customers were given the opportunity to prioritize where they would like to see Oshawa Power spend money:

Figure 2 – Customer Priority Table

As an Oshawa Power customer could you tell us how important each of the following items is to you?			
Top 2 boxes 'Very + Somewhat important'	**Oshawa Power 2019**	**Oshawa Power 2018**	**Oshawa Power 2014**
Continuously improve the safety and reliability of the electricity network	95%	91%	86%
Remain focused on keeping costs low	95%		
Reduce response times to outages	94%	86%	80%
Look for ways to use technology to safeguard the electricity network or get more out of the equipment	92%	91%	
Provide good jobs in the community	91%		
Improve customer service	88%		
Invest in green energy technologies (energy storage, electric vehicles, etc.)	88%		
Invest in smart grid technologies (system automation)	88%	83%	75%
Invest in projects to reduce the environmental impact of the utility's operations	88%	76%	
Improve communications for billing and outages	87%	50%	
Educate the public as it relates to electricity safety	84%	73%	
Investing more in tree trimming to help reduce the number of outages		78%	68%
Provide more self-serve options on the website	78%	44%	40%
Provide sponsorships to support local programs and events	76%	48%	45%
Develop a smartphone application to allow you to view your electricity use and pay your bill	75%	50%	37%
Burying Overhead wires		64%	62%
Make better use of social media such as twitter	62%	29%	33%

The top five priorities are safety, reliability, keeping costs low, reduce response times, grid technology and be a good contributor to the local economy.

Online A.I.M. Survey

Beginning in 2014, Oshawa Power augmented their regular telephone-based Customer Satisfaction survey with supplemental questions to help gain insights into, or deal with, issues customers care about. For example, the 2014 telephone survey of 405 Oshawa Power customers were asked to prioritize investments for ten operational issues (See Figure 2). In 2017, 400 interviewees were asked to identify the importance of items as they relate to online access to various items, and in 2018, 402 interviewees were asked to prioritize operational planning items. (See Figure 2)

Oshawa Power embraced the Taking A.I.M. process (Applied Insights Methodology) to gather information and feedback from multiple sources. A process which gives customers multiple opportunities to "make their voice count." (See Taking A.I.M. Survey Report)

Through a joint on-site investigative type of review, fifty-eight (58) customer engagement activities were identified as customer interactive touchpoints that could provide information for the Cost of Service (COS) application.

There were 83 questions contained in the Online Taking A.I.M. COS DSP Survey with seven Chapters. Each chapter was designed to capture the survey respondent's information, insights, wisdom, feedback, or contact information on various subject areas. These areas were: About Oshawa Power, The Electricity Industry, Customer Priorities, Billing & Outages, Facilities & General Plant Capital Investments, Customer Care Operational Improvements and, Distribution System Plan (DSP) Capital Investments.

The A.I.M. process (Applied Insights Methodology) to create a two-way communication online survey that allowed for Oshawa Power to ask plan questions and also asked open ended questions to participants to gather feedback. The survey was made available in paper copy for those who did not have online access.

Oshawa Power spent the months leading up to the beginning of the campaign educating and informing residents at seven public events of the upcoming online survey and public town halls. Beginning October 1, 2019, the survey was actively advertised through social media campaigns, media release, newspaper ads, email campaigns and the customer service IVR welcome message in the call centre.

Results and Feedback

The survey was live from October 1, 2019 to December 8, 2019. Oshawa Power achieved:

- 1,240 completed A.I.M. surveys,
    - 26 customers asking to be contacted by an employee and were contacted
    - 305 respondents asked to be notified of any future public meetings regarding Oshawa Power's rate application
    - Over 900 comments were submitted

In the online survey details and cost of the Distribution System Plan were reviewed. Information was divided into the four main categories, the results were:

- **Facilities and General Plant Investments** - 58% of respondents supported Oshawa Power's recommendation, 30% wouldn't support an increase, and 11% answered 'Don't know'.

  - **Oshawa Power facility** – when asked separately about the Oshawa Power facility there are about 15% of the population who will not support any relocation. A total of 74% of online respondents can support the relocation and upgraded facilities.
- **System Access Investments** – 84% support these investments because they either help our community or they are mandated or both, and 15% do not support these investments
- **System Renewal Investments** - 62% of respondents indicated support for the recommended increase, 8% supported a lesser increase, 17% does not want any increase and 13% didn't know
- **System Service Investments** - 60% of respondents indicated support for the recommended increase, 9% supported a lesser increase, 19% does not want any increase and 13% didn't know

Figure 3 – Oshawa Power Recommendations Table

Base: Total Respondents 1,240	Support OP's recommendations #	Support OP's recommendations %
General Plant	713	58.3%
New Facility	912	73.5%
System Renewal	763	61.6%
System Service	739	59.6%

Virtual Telephone Town Hall

The Virtual Town Hall was held between 7:30pm-8:30pm on October 28, 2019. The Town Hall allowed participants:

- Join a city-wide conversation on the 5 Year Infrastructure Investment Plan;
- Learn more about the investment plan and rate application process
- Understand the industry and regulations
- Ask or listen in to budget-related questions and Oshawa Power's answers
- Answer polling questions on the investment plan and service delivered by Oshawa Power

Preparation was done ahead of time to create the scripting for the welcome message, recorded message for voice mails and the polling questions. Polling questions were selected that would provide rich feedback and encourage dialogue throughout the call. The Oshawa Power 5 Year Infrastructure Investment Plan Virtual Town Hall was advertised through social media, media release, website and an email campaign.

Beginning at 7:28pm on October 28, 2019, Oshawa Power customer account phone numbers (and community members who R.S.V.P.'d their phone number in advance) received a call inviting them to stay on the line to participate in the Town Hall.

Following opening remarks from President and CEO on the investment plan and the process, participants were invited to enter the queue to ask questions. Those on the line were asked polling questions throughout the event.

At the end of the Town Hall, listeners were informed that recording of the call would be available on the Oshawa Power website within one week. The recording and the full transcript was posted on Oshawa Power's dedicated Cost of Service webpage.

In addition, phone number that went directly to voicemail were left a pre-recorded message advising them that although they missed the call, they could still participate in the process and complete the survey.

Results and Feedback

The Virtual Telephone Town Hall hosted 9,798 listeners throughout the duration of call, with a peak of 2,471 listeners on at one time, and an average listen time of 14 minutes during the one-hour Telephone Town Hall,

- 189 listeners entered queue to ask a question and 22 went live
- 4 polling questions were asked during the course of the live call
- 93 customers opted out of the Telephone Town Hall ahead of time

You can listen to a recording of the Virtual Telephone Town Hall here or read the transcript here.

The Telephone Town Hall included four polling questions on the public's opinion on investing in self serve technology, distribution asset replacement, grid modernization and the Oshawa Power facility.

Virtual Town Hall – Polling Questions Summary

Question 1: Many customers have indicated that they would like to see more automated, self serve options allowing them to conduct their business with us at their convenience similar to the banking or retail shopping industry. Do you feel Oshawa Power should:

Figure 4 – Polling Question #1 Table

Answer	Responses	Percentage
Invest in new customer facing technology that will give customers self serve options to conduct their hydro account business at their convenience.	127	29.5%
I do not think it necessary to invest in self serve options at this time.	238	55.2%
Unsure or Undecided	66	15.3%

Question 2: The estimated useful life of distribution assets ranges between 10-50 years with the average life of approximately 30 years. As distribution assets get near end of life reliability begins to decline. Do you feel Oshawa Power should:

Figure 4 – Polling Question #2 Table

Answer	Responses	Percentage
Invest based on a 10-50-year life cycle to maintain reliability, accommodate growth and reduce outages.	264	75%
Run equipment to failure which will result in more frequent power outages and longer restoration times.	35	9.9%
Unsure or Undecided	53	15.1%

Question 3: Investing in grid modernization technologies that will assist us in detecting, locating and determine the cause of outages, will further reduce power outage duration, response times and save resources. Do you feel Oshawa Power should:

Figure 6 – Polling Question #3 Table

Answer	Responses	Percentage
Invest in grid modernization technologies that will expedite power restoration by providing critical information of cause and location.	191	62.6%
Invest only in replacing equipment as it reaches end of life and do not upgrade grid technology.	63	20.7%
Unsure or Undecided	51	16.7%

Question 4: Determining whether Oshawa Power should retro-fit or renovate an existing facility or build a new facility in Oshawa is a difficult decision. Do you feel Oshawa Power should:

Figure 7 – Polling Question #4 Table

Answer	Responses	Percentage
Invest and explore finding a more suitable facility that Oshawa Power would own and will accommodate the entire company to operate out of a single building and allow for future growth.	141	69.1%
Invest and retrofit the existing facility, even though it is not Oshawa Power's asset.	25	12.3%
Unsure or Undecided	38	18.6%

Public Town Halls

Oshawa Power hosted four different Public Town Halls. The first Town Hall was held during the evening at the McLaughlin Public Library on November 5, 2019. In total for all four events there were about 50 attendees.

The senior executive team presented a detailed summary of what Oshawa Power has accomplished since the last rate application, the rate application process and the cost of proposed projects. You can see the presentation here.

Attendees were able to ask questions throughout the presentation and invited to stay afterwards for further conversation.

Oshawa Power staff were on hand to assist any attendees with any account or service-related inquiries.

The same format was followed for the three sessions that were held at Oshawa Senior's Community Centres (OSCC). Sessions were held:

- November 6, 2019 11am-1pm, OSCC John St Branch (Central Oshawa)
- November 29, 2019 10am-12pm, OSCC Conant Branch (South Oshawa)
- December 4, 2019 9am-11am, OSCC Delpark Homes Centre Branch (North Oshawa)

See **Appendix B** for list of questions from the Public Town Halls.

Summary

Oshawa Power's active customer engagement campaign ran from October 1, 2019 to December 8, 2019. Utilizing relatively low-cost advertising methods Oshawa Power received a positive response in both survey and telephone town hall participation. The in-person town halls did not perform as well in terms of attendance however the attendees were engaged and inquisitive. Valuable open dialogue was generated from the in-person town halls.

In total, Oshawa Power was able to engage over 12,000 customers in Oshawa which is 20% of the customer base. With the multi-method approach to engaging customers Oshawa Power was able to reach out to a cross section of all customers that vary in age, income level and geography of Oshawa. Additionally, customers both online and not, were able to participate in completing a survey and providing feedback.

Consistent messaging from the Oshawa Power customers from all outreach formats is to manage costs and maintain safety and reliability of the infrastructure.

During the customer engagement campaign Oshawa Power customers were introduced to the investment levels proposed, the Distribution System Plan and Rate Application process, completed projects from current Distribution System Plan, and the current and proposed life cycle status of Oshawa Power assets.

Feedback gathered from the customer engagement campaign has been be provided to the Distribution System Plan team.

Please see the accompanying detailed report from the online survey *Taking A.I.M.* for further results of survey questions and customer feedback.

Appendix A

Figure 8 – DSP Engagement Timeline Table

DSP Customer Engagement Timeline										
	Owner	Jan-May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Jan
Phase One										
Create Surveys - Chapters 1-4	SR	complete								
Create survey webpage	SR	complete								
Social Media scheduled posts	SR	complete								
Create digital posters for library	SR	complete								
Phase Two										
Create Surveys - Chapters 3-7	SR/Utility Pulse					complete				
Create and Post info video							complete			
Create Flyers/postcards	SR		complete							
Share digital posters	SR		NA							
Information Pop Up booths @ libraries (staffed) RMG, SOCC, Donevan, Northview and Delpark	SR/Volunteers						NA	NA		
Summerfest (hand out flyers)	SR/Volunteers			complete						
Autofest (hand out flyers)	SR/Volunteers				complete					
Send Key Accounts Invitations	SR/Janet		NA							
Reach out to business groups/local clubs	SR/Lori D			complete						
Book and plan 4 Public Town Halls	SR					complete	complete	complete		
Require high level summary of last 5 years of increases and accomplishments DSP plan	DSP Team			complete						
Create presentation/story boards	SR			complete						
Reach out to 3 selected charities	SR					complete				
Phase Three										
Post survey to website	SR						complete			
Media Release							complete	complete		
Advertise on social and Google (newspaper?)	SR						complete	complete		
Email Blast Campaign							complete	complete		
Tag City of Oshawa social accounts	SR						complete	complete		
Create paper surveys	SR							complete		
Parkwood Basement Tours - key accounts presentation - special invitation	SR/PM/IL/JT/MS				NA					
Presentations to organized groups: Oshawa Chamber, BIA, Rotary Club	SR/PM/IL/JT/MS					NA	NA			
4 Public Town Halls	SR/PM/IL/MS						complete	complete		
Telephone Town Hall	SR/PM/IL/MS						complete			
Phase Four										
Present Charity cheques	SR/IL									complete
Consolidate collected feedback from events and surveys	SR/Utility Pulse								complete	complete
Prepare final report	SR/Utility Pulse								complete	complete

Appendix B

Listing of Public Town Hall Questions

There were approximately 50 attendees between the four events. Below is a summary of 80 questions asked during the sessions (duplicates have been removed):

1. 2004-Virtuall debt free to City – City Council one-time dividend $60M – where is debt?
2. Substation Upgrades – How does this differ from last five years? Would this ongoing?
3. Building is not owned by Oshawa Power, it is owned by the City, could we move to GM building or feeder plant?
4. Does new building have to be in the North?
5. Suggestion to move to GM Headquarters
6. The City owns Oshawa Power, raising rates sounds like another tax?
7. Conservation decreases profits and rate would increase – why can't the commodity charge be fixed?
8. Would you prefer 4% to City of 8% to a private entity?
9. What is the impact of GM leaving to Oshawa Power?
10. Are the solar generation programs over?
11. Will you be converting OH wires to UG?
12. Why are poles left behind after you replace them?
13. Are all new developments UG service?
14. Does automation monitoring advise of end of life?
15. Is grid connected to internet?
16. Are there plans to install EV chargers?
17. What is MS9?
18. Are there any reserve funds to deal with extreme weather damage to grid?
19. Who selects the architect for MS9?
20. Do you coordinate with City and other entities to only dig once for road work?
21. Will you run UG in storm sewers or overlay designs with other utilities?
22. How do you know end of life of assets?
23. Does ice affect autoswitches?
24. Is the dollar amount the rate impact per customer?
25. What was the status of end of life assets 5 years ago?
26. Once end of life is replaced will more become end of life?
27. Why weren't smart meter gradually installed?
28. Does the Durham incinerator sell hydro to us?
29. Do you have to build a new building or can you rent?
30. Don't make the new building look like MS9?
31. Are you subject to capital gains tax?
32. Can individuals submit questions to OEB?
33. How would number of customers affect residential bill?
34. Do all utilities submit a scorecard to OEB?
35. What is actual budget?
36. How are the impact costs calculated?
37. Can you send out charts that show end of life?

38. Do you have power to influence who moves in to Oshawa?
39. Where do sub-metering companies get their power from?
40. How many utilities in Durham?
41. Will we merge with another utility?
42. Will Zooshare help rates?
43. Is Pickering going offline?
44. Will Darlington be expanded?
45. Are animals causing outages?
46. What will happened to old building?
47. What about carbon footprint?
48. How do you plan for EVs?
49. How do you know about electric furnaces – car chargers?
50. Why different rates from summer to winter?
51. Can the grid handle electric vehicles?
52. What is the cost of EV at home?
53. What is rate impact?
54. What is submetering?
55. Where will a new building be?
56. What is the pole testing program?
57. Cheaper overnight EV charging?
58. What are some technologies that you are referencing?
59. Do you not have reserves for reactive work?
60. Do you have climate change plans?
61. What is the lifespan of UG cables?
62. Do new subdivisions have ducts or buried wires?
63. Can someone check my fuses?
64. You don’t own your building now?

Appendix C

2019 Taking A.I.M. Survey Charts

Figure 9 – General Plant Chart

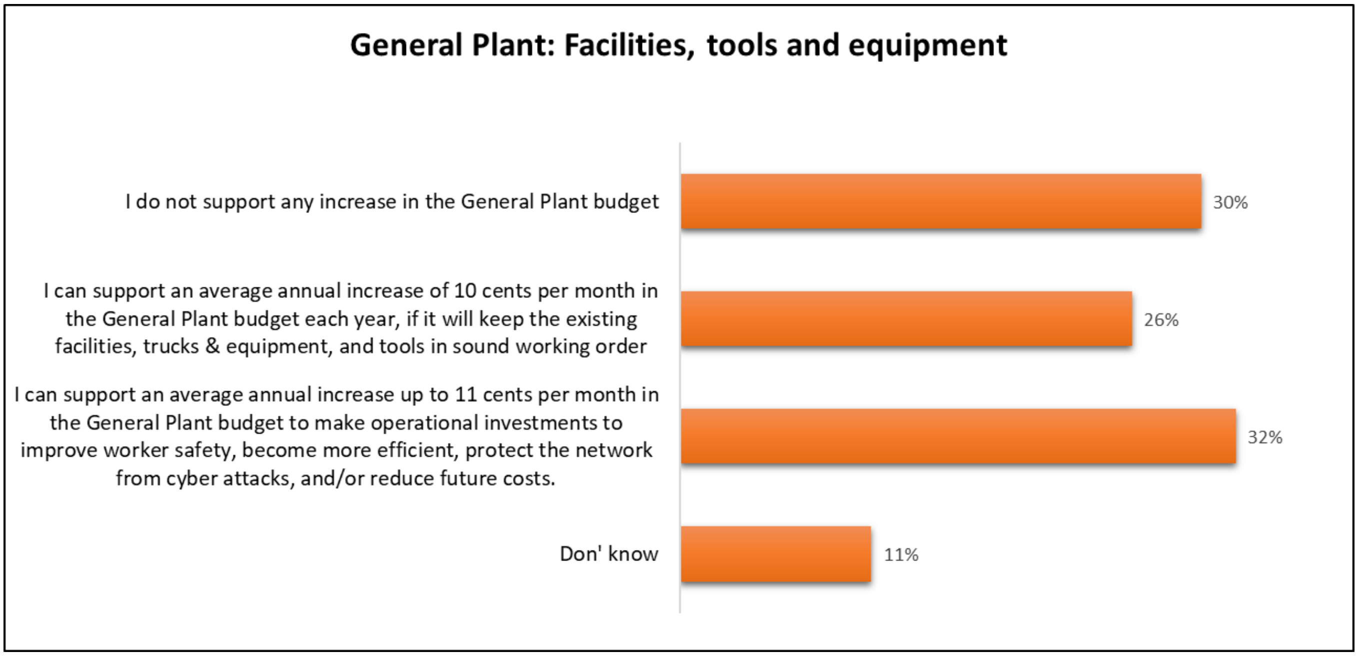


Figure 10 – Facility Choice Chart

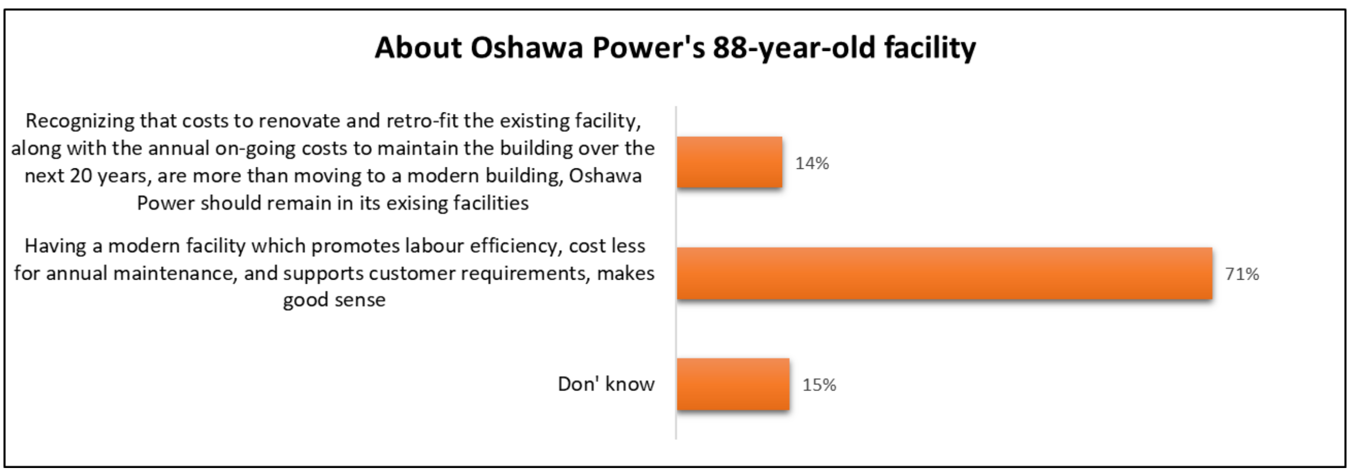


Figure 11 - Cost of Relocation Chart

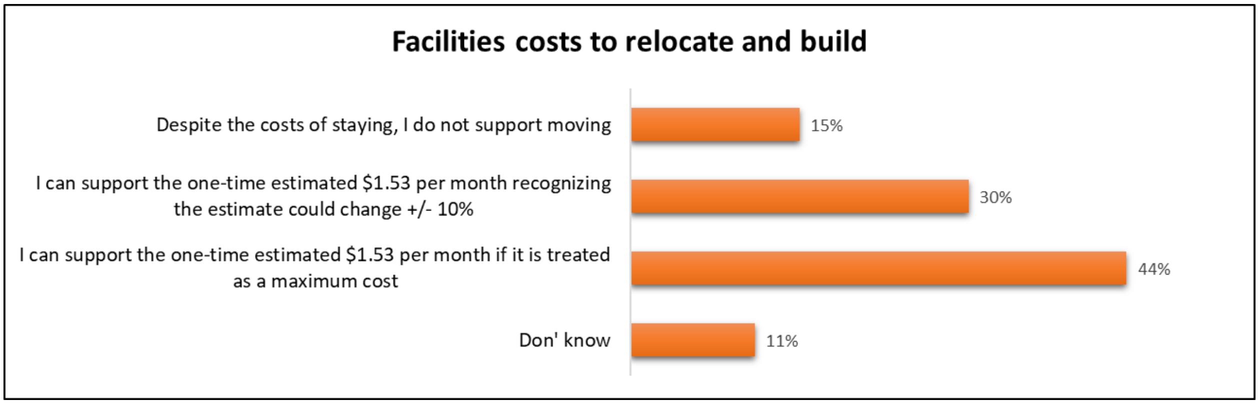


Figure 12 – System Renewal Investments Chart

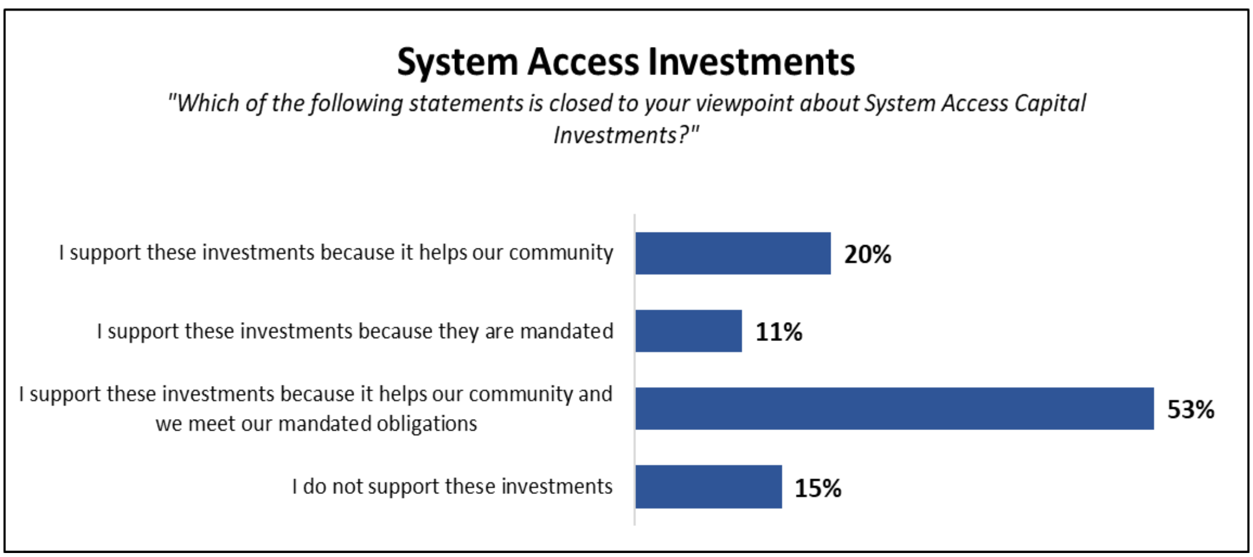


Figure 13 – System Access Investments Chart

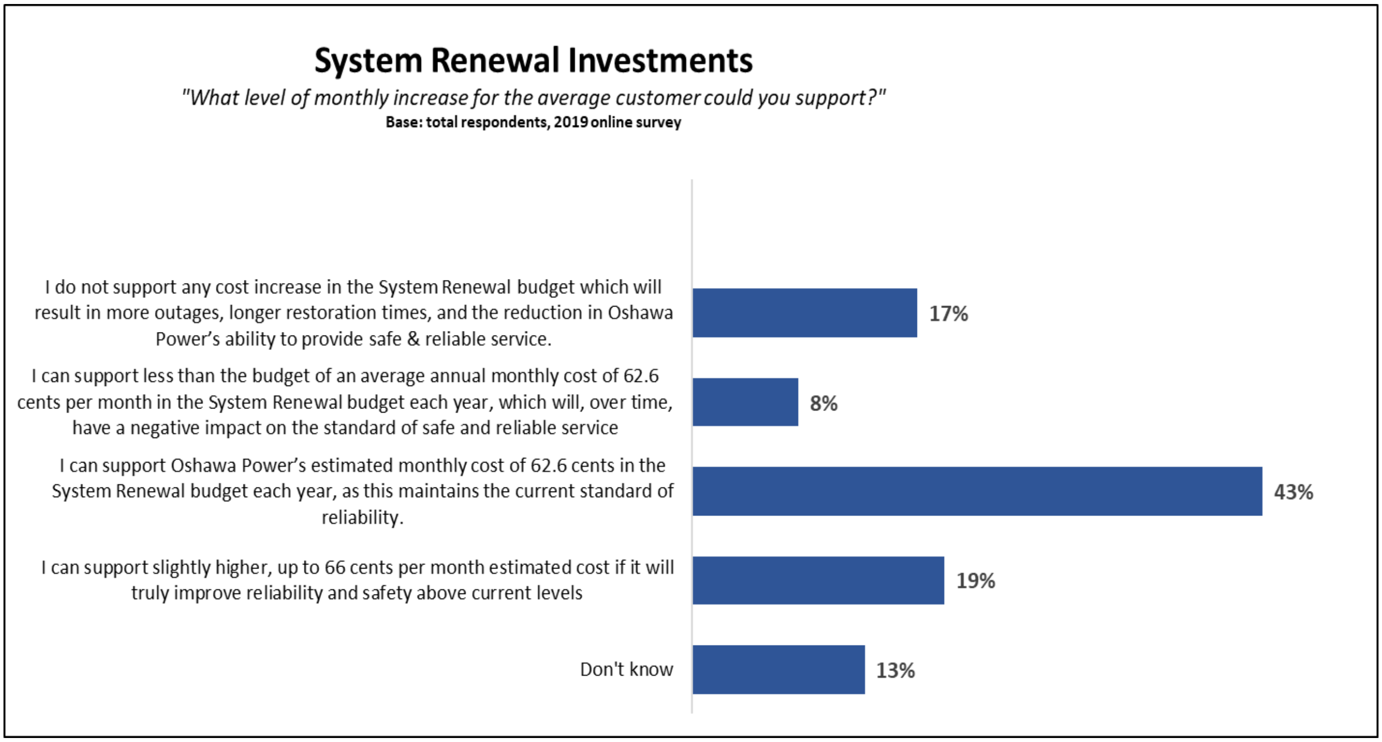
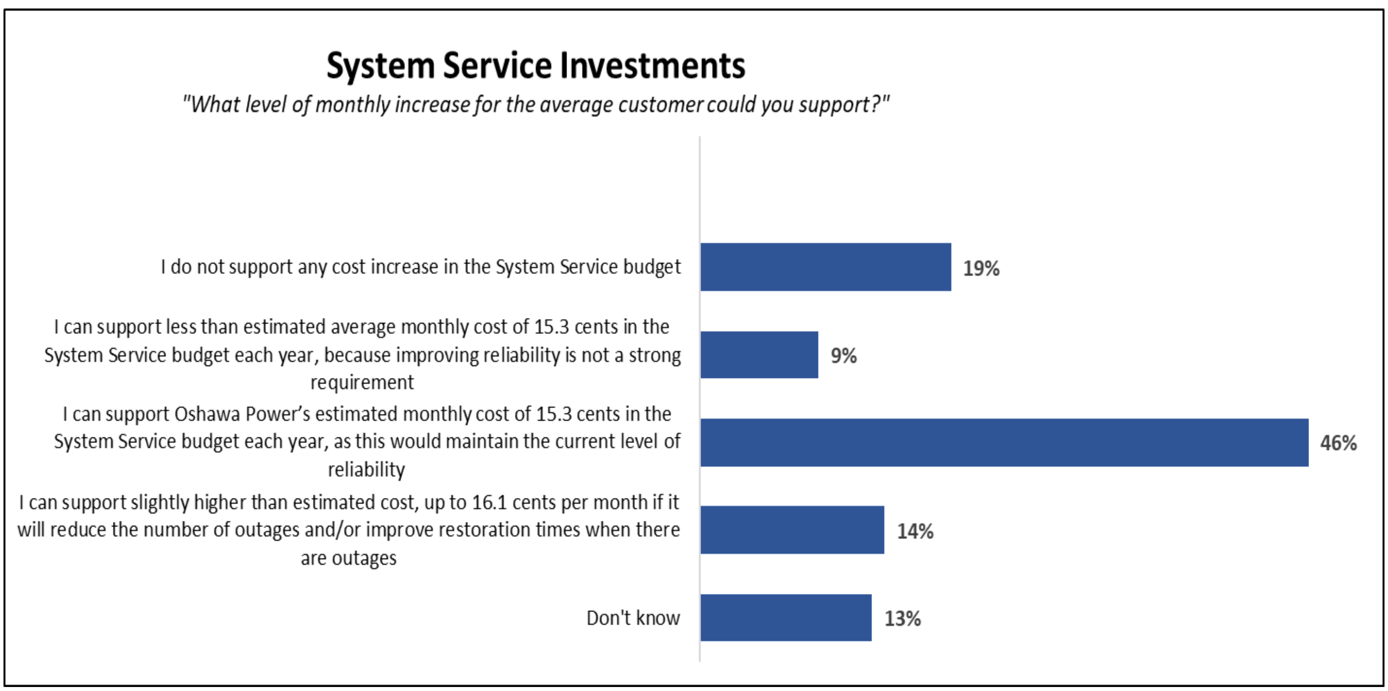


Figure 14 – System Service Investments Chart



Appendix C(ii): Taking AIM Report

Taking A.I.M.

(Applied Insights Methodology)
Capturing wisdom, information, insights, and feedback from customers

Oshawa Power

UtilityPULSE

Executive summary

The Age of Understanding

In a world where customers have experienced a tremendous range of emotions, as it relates to overall electricity costs over the past five years, the challenge for Oshawa Power (OP), and other LDCs as well, is to demonstrate it listens to its customers, it is responsive to changes in customer needs or requirements, but most importantly it cares about keeping costs low. However, customers are interested in knowing that OP is also focused on ensuring the electricity network is maintained, renewed and modernized in ways that are meaningful to its customers.

Oshawa Power has taken a multi-method approach to engaging customers, so it could understand the wide variety of opinions and views about what it takes to be seen as a successfully run LDC. Information, data, and feedback gathered from a customer population who are looking through a “lens of costs” tends to be more past-oriented rather than future-oriented. A written comment from one customer respondent: “*Yes, you are a wholly-owned subsidiary of the city of Oshawa, therefore the residents are your shareholders as well as your customers. We want reliable electricity supply without breaking the bank, as city taxes hurt us enough.”*

Most organizations and Oshawa Power is not an exception, want to believe people will make rational decisions. That is, when truthful information and facts are presented, a person will make a rational decision. This isn’t so; decisions are irrational. Findings from Oshawa Power’s Customer Engagement (CE) activities show 6% of online COS DSP survey respondents won’t support any increase for any reason. However, 41% of online COS DSP survey customer respondents would support all of Oshawa Power’s recommendations or something more than their recommendation, for System Renewal, System Service, General Plant, and Facilities. (See Oshawa Power Online COS DSP Survey - Chapter 7).

Base: Total Respondents 1,240	**No Increase #**	**No Increase %**	**Support OP’s recommendations #**	**Support OP’s recommendations %**
General Plant	370	29.8%	713	58.3%
New Facility	181	14.6	912	73.5%
System Renewal	212	17.1	763	61.6%
System Service	230	18.5	739	59.6%
Support No Increase (in all 4 areas)	71	5.7%		
Support OP recommendations (in all 4 areas)			503	40.6%

As it relates to a new facility, an overwhelming majority (70.9%) selected *"Having a modern facility which promotes labour efficiency, costs less for annual maintenance, and supports customer requirements, makes good sense."* as the statement which best reflects their view about the current 88-year-old facility. Only 13.8% thought OP should *"retrofit and stay,"* while 15.3% answered, 'Don't Know.'

Oshawa Power also understands that Customer engagement activities supporting their Cost of Service application (COS), such as online and telephone surveys, means customer respondents would be asked difficult questions --- all of which have complicated answers. As one senior-aged respondent said: *"For a senior, having lived in Oshawa for 60 years, to be faced with all this information and decision making, is a daunting task."* It isn't surprising then, on average, 12% of customer respondents selected 'Don't know' as their answer regarding the recommendations for investments, which affects costs, in System Renewal, System Service, General Plant, and Facilities. Despite the challenges of running an effective LDC operation, in a separate telephone interview, 87% of the interviewees 'agree somewhat + agree strongly' with the attribute that Oshawa Power *"Efficiently manages the electricity system."*

What were the Customer Engagement (CE) activities in support of the COS application?

1. Beginning in 2014, Oshawa Power augmented their regular telephone-based Customer Satisfaction survey with supplemental questions to help gain insights into, or deal with, issues customers care about. For example, the 2014 telephone survey of 405 Oshawa Power customers were asked to prioritize investments for ten operational issues. In 2017, 400 interviewees were asked to identify the importance of 10 items as they relate to online access to various items, and in 2018, 402 interviewees were asked to prioritize 12 operational planning items. (See Insights from Oshawa Power's telephone-based Customer surveys 2014-2018)

2. Oshawa Power embraced the Taking A.I.M. process (Applied Insights Methodology) to gather information and feedback from multiple sources. A process which gives customers multiple opportunities to "make their voice count." (See What is Taking A.I.M.)

3. Through a joint on-site investigative type of review, fifty-eight (58) CE activities were identified as customer interactive touchpoints that could provide information for the Cost of Service (COS) application. (See Insights from a review of Oshawa Power's Customer Engagement Activities)

4. There were 83 questions contained in the Online Taking A.I.M. COS DSP Survey with seven Chapters. Each chapter was designed to capture the survey respondent's information, insights, wisdom, feedback, or contact information on various subject areas. These areas were: About Oshawa Power, The Electricity Industry, Customer Priorities, Billing & Outages, Facilities & General Plant Capital Investments, Customer Care Operational Improvements and, Distribution System Plan

(DSP) Capital Investments. (See Insights from the Online COS DSP survey for Oshawa Power's Cost of Service Application)

5. 1,240 customer respondents participated in the online COS DSP survey containing DSP cost items. 19.3% of respondents had monthly bills less than $75.00 per month, 53.1% between $76-120, and 25.6% over $120 per month.
6. 290 "Wisdom from Customer" comments were made (See Wisdom from Customers)
7. 170 "General comments" were captured in the online COS DSP survey containing DSP items (See General Comments)
8. Customer respondents to the Online Taking A.I.M. Survey with seven chapters were also given an opportunity to request an Oshawa Power professional contact them because they had a specific question, issue, or concern they wanted to be addressed. Twenty-six customer respondents asked for follow up.
9. 21% of the 2018 telephone survey participants stated their annual household income was less than $50,000 per year.
10. Timing for the 2018 Telephone Customer survey was Q3.
11. Timing for the 2019 Online COS DSP survey with DSP information was Q3.
12. Oshawa Power held an extremely successful telephone town hall meeting Q3 (See separate report from Oshawa Power.)
13. Oshawa Power used its resources to reach out to its customer base publicly (See separate report from Oshawa Power.)

The findings in this report show Oshawa Power is a well-respected company (83% online, 85% telephone), who is trusted and trustworthy (86% online, 90% telephone) and who is seen as an organization that spends money prudently (82% telephone). The data from the Online Taking A.I.M. Survey with information for COS and DSP also shows the majority of respondents support Oshawa Power's recommendations as they relate to System Renewal, System Service, General Plant, and Facility investments.

The customer base is an urban one. As such, there is a strong expectation that electricity is consistently delivered in a reliable and safe manner. As it relates to reliability, Oshawa Power received excellent scores from respondents – 92% online, 91% telephone. Also, 88% online, 90% telephone respondents, agree OP's current standard of reliability meets their requirements.

The customer base does look at changes through the lens of costs and therefore has a deep desire to keep costs low. However, they also expect high standards of operations. Data from 3 telephone surveys tell us the number one suggestion for improvement is "reduce the price." Comments received through this Taking A.I.M. process indicate that seniors and customers on a fixed or low income are very concerned about rising costs. As one respondent said: *"That as a single person living alone, it is important* *to keep costs low. Some months my delivery charge is more than my usage fees."* But that is not all customers want, because 96% of online respondents said that "to continuously improve the safety and reliability of the electricity network" was a 'very important + important' item for Oshawa Power to focus on. Survey findings tell us that customers are concerned about rising costs AND they want continuous improvements in the safe, reliable delivery of electricity and in responding to outages. Oshawa Power doesn't live in an either/or world, i.e., keep costs low or improve the network; they live in an and/also world. Customers want both, which makes it a challenge to develop a balanced future-oriented plan. As one respondent said: *"[Oshawa Power] Been a reliable provider over the past 6 years, and small rate increases are to be expected to continue to provide this service."*

The reality is, LDC customers in Oshawa Power's territory, and throughout Ontario, know a glass of orange juice at $16 is over-priced. Wrapping their heads around whether an average of $4,991,700 annual System Renewal Budget is about right, is not easy. As a customer respondent commented: *"I wish I could tell you how, but this is not my area of expertise. I would say to maximize the existing infrastructure and be proactive about any aging components."*

A comment from a respondent of the Online COS DSP Survey captures the sentiment of many customers regarding the COS application: *"Good service at a reasonable rate. Try to avoid being wasteful. Spend on equipment and a well-educated staff."*

Our recommendations are:

1- Continue to take a thoughtful approach to capital investments. While keeping them essentially in line with inflation would be supported by the majority of customers, there will be a core of customers who will be unhappy with everything. Decisions are not made rationally by customers; they are made emotionally.

2- Recognize that a solid majority of online respondents supported Oshawa Power's recommended cost increase, though there are significant numbers of people who won't support any increase for any reason. Keeping costs reasonable has to continue to be a priority. However, 18% of online respondents supported a cost increase option for System Renewal, which was higher than Oshawa Power's recommendation. 14% of respondents supported a cost increase for System Service higher than OP's recommendation.

3- Doing anything with the 88-year-old facility will spark debate. But the reality is, 71% of respondents thought the following statement best represented their view about the old facility: *"Having a modern facility which promotes labour efficiency, cost less for annual maintenance, and supports customer requirements, makes good sense."* More importantly, 74% of residential respondents supported the *"$1.53 per month cost increase for a new facility*". 11% answered, 'Don't know,' and 15% did not support moving. Operational pragmatism is key to gaining and keeping support.

4- Dealing with the multitude of opinions and comments will be easier when developing a long-term plan for OP's facility is guided by the criteria identified as 'very + somewhat important' by online respondents:
    a. 96% Facilities are a safe and secure place to work
    b. 96% Valuable inventory, parts, and equipment are protected
    c. 94% The decision…be based on which option represents the best balance between keeping costs low, being efficient, and meeting customer longer-term energy needs
    d. 91% Facilities meet the needs of customers
    e. 88% The design of facilities encourages labour efficiency.

5- Oshawa Power's customer online COS DSP survey respondents are aware of the importance of technology. For example, 93% of online respondents rated the following as 'very + somewhat important'*: "Look for ways to use technology to safeguard the electricity network or get more out of the equipment."* 85% rated *"Invest in smart grid technologies (system automation)"* as 'very + somewhat important.' This level of support strongly suggests that the customer base is not anti-technology. However, any investment in technology must have an expected ROI.

6- From the perspective of customer care improvements customers would like Oshawa Power to undertake, here are the highest-ranking items:
    a. 77% An outage notifications system that automatically sends you a message by phone call, email or text
    b. 69% Accessing online account info for updates, move-outs, move-ins
    c. 69% Educating customers about energy conservation
    d. 65% Reviewing and paying your bill online.

7- Maintain the image of Oshawa Power as a high-quality company by communicating frequently, and ensuring everyone at OP re-enforces the "brand." In the 2018 telephone survey, Oshawa Power had an 85% Credibility & Trust Index score versus the Ontario benchmark of 81%. In a chaotic and confusing world, it is credibility and trust which will lead to support for the things and investments OP needs to do to meet the current and future needs of its customers.

A couple of key items about this assignment, we believe, should be mentioned. First of all, it was extremely important to OP that the language used in the survey mirrored their belief in the importance of treating customers as human beings. Second, there is a genuine interest in keeping costs reasonable as they produce a balanced-plan for ensuring the LDC meets or exceeds the current and future requirements of customers.

Seeking to understand is not the same as seeking permission. Oshawa Power's customers may not know a lot about the electricity industry or what Oshawa Power as a company is responsible for, but they do know the importance of electricity in their lives. The leadership of Oshawa Power understands, one of the best ways to ensure costs remain low, is to discover ways to be more successful today while preparing the organization to be successful again tomorrow in a changing industry, and a changing world. Seeking wisdom, information, insight, and feedback from its customers certainly help to ensure the future path of the organization meets the needs and wants of its customers. Oshawa Power, as an LDC with 58,000 customers, has undertaken many customer engagement activities to understand their customers' concerns and priorities.

By demonstrating that the COS rate application with its DSP cost information is built by people who are pragmatic, thoughtful, and informed, we believe Oshawa Power has the support of the majority of its customers. However, there will be staunch detractors and strong supporters. The 2018 telephone survey identified 5% of the respondents as 'At Risk', customers who are very dissatisfied with OP. But there were 30% of respondents who were identified as 'Secure', very satisfied and supportive of OP. When asked about whether a customer respondent had any additional comments about Oshawa Power or its COS application, one respondent provides guidance by simply stating: *"Honestly - I'm not sure right now - this has been a lot of information, but being a newer resident to Oshawa (7 months) - THANK YOU for asking the people to weigh-in... it is important to have the public feel that they are contributing to the future."*

Customers want lower prices with better service – despite knowing equipment wears out or fails and must be replaced. Oshawa Power shouldn't expect to get agreement from all of its customers regarding the COS rate application. But Oshawa Power will get support for what needs to be done because leadership can demonstrate they understand their customers – their needs, wants, and standards.

Sid Ridgley
UtilityPULSE
January 2020

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⁕ Insights from a Review of Oshawa Power's Customer Engagement Activities

As the first step in the TAKING A.I.M. (Applied Insights Methodology) process, UtilityPULSE conducted an onsite review of Oshawa Power's Customer Engagement (CE) activities. The review identified fifty-eight (58) CE activities as customer interactive touchpoints, which were sorted into the various levels of customer engagement: ❶Informing & information gathering, ❷Gathering feedback, ❸Capturing insights, ❹Gaining wisdom and ❺Customer empowerment.

Based on our experience, Oshawa Power has an extensive list of CE activities and showed an enthusiasm for doing more. They were also interested in using a range of methodologies for gathering feedback and opinion regarding their COS DSP application.

Conclusions based on the review of CE activities for the COS DSP submission:

1- Website reformatting would be required to host the Taking A.I.M. online COS DSP survey. Links to the survey also had supporting explainer videos which were produced by OP staff
2- OP would be augmenting their regular telephone survey and specialized COS DSP online COS DSP survey with a public telephone townhall
3- IVR technology could be used to encourage customers to participate
4- Additional face-to-face type community outreach activities would add to application data
5- Online COS DSP survey could and should include costs in $$
6- Online COS DSP survey should make good use of descriptor statements to gauge support for a policy or operational changes
7- The Fall 2018 Telephone survey would incorporate enhanced supplemental questions to:
    a. Determine Oshawa Power's communication effectiveness
    b. Probe for satisfaction as they relate to access to various services
    c. Gain a better understanding of customers' priorities and expectations
8- "Wisdom from Customers" would be a feature of the online COS DSP survey thereby giving respondents the opportunity to provide ideas which could save money or reduce costs
9- A "Hot Alert" function would also be a feature of the online COS DSP survey thereby giving respondents the opportunity to be contacted by the LDC for a specific issue and/or be kept apprised of any public meetings associated with the COS DSP application
10- Oshawa Power would use an incentive to encourage customers to respond to the online COS DSP survey.

The review and follow-up activities show Oshawa Power has a robust activity agenda to interact, collect information, gather feedback and insights from customers. Oshawa Power's investments in telephone surveys, online survey, public outreach programs have lead to significant changes for customers. For example:

1- After the 2014 survey, OP launched their social media strategy vis Twitter, Facebook and Linkedin
2- After the 2017 survey, OP lauched Customer Service Open Houses. While these events have a theme, they do represent an opportunity provide information and collect feedback
3- After the spring 2018 Electricity Safety Survey, OP launched an Annual Contractor Safety Day.
4- Following the Annual Contractor Safety Day, OP created a Contractor's Corner on the website for contractors and builders
5- Following the 2018 Large Commercial Customer survey, OP revamped thei key account strategy and now hold quarterly meetings
6- Findings from various surveys indicate that customers want speedy access to information. The website was substantially improved in 2018 to ensure it was mobile friendly and it included things such as a Contractor's Corner, Forms Section and TOU bar. In 2019 a Self Service Hub for customers was added
7- Staffing: To ensure increased flexibility to respond to customer needs, 4 part-time staff were added in 2018
8- Staffing: On an, as needed basis, OP will use Lunch and Learn type training sessions
9- Staffing: In 2017 a Marketing and Communications Analyst was added to the professional complement of OP. The position is measured by customer outreach events, brand reputation, digital followers and customer engagement
10- Staffing: In 2019 a Manager of Business Advocacy and Sustainability was added. This assignment is responsible for government relations, key account management, incentive application assistance, innovation projects.
11- Customer Service has a customer focus to ensure customers are getting answers to their questions or concerns of the day
    a. Weekly Scrum meeting in Customer Service to discuss current issues
    b. Montly departmental meetings
    c. Quarterly coaching meetings

12- In 2019, Bi-annual all employee meetings were launched ensuring that the "customer" is on the agenda.

❋ Insights from the Online COS DSP Survey for Oshawa Power's Cost of Service Application

About the respondents:

1- 1,240 customer respondents
2- 669 respondents elected to be entered in a draw to win one (1) of (5) prizes of $200 prepaid credit cards, 491 chose to have OP donate $5 to a charity and 78 elected to do neither the draw or charity
3- Respondents answered a set of preliminary identifying/demographic questions. [See Tab 4: Book of Online COS DSP Survey – Section 2 - "About You" questions]
   Here respondents identified their:
   a. Postal code
   b. Residential or Commercial customer status
   c. Responsibility level for paying the bill
   d. Identify the average amount of their bill.
4- Respondents also answered a set of closing questions giving respondents the opportunity to be contacted by the LDC for a specific issue and be kept apprised of any public meetings associated with the COS DSP application. [See Tab 4: Book of COS DSP Online COS DSP survey – Section 3 - "Hot Alert" questions]
5- The main online COS DSP survey was available from October 1 – 11:59 pm on December 8, 2019.

Online COS DSP Survey:

Chapter 1	"About your Oshawa Power"
Chapter 2	"The electricity Industry and Oshawa Power's role in it"
Chapter 3	"Customer priorities, which are the important ones?"
Chapter 4	"Customer insights about billing and outages"
Chapter 5	"Facilities and General Plant Capital investments"
Chapter 6	"Gathering insights about customer care operational improvements"
Chapter 7	"Distribution System Plan Capital investments"

Chapter 1 "About your Oshawa Power"

Purpose of this Chapter:

1- To provide respondents with information about the size of Oshawa Power
2- To gauge the level of respondent disposition, i.e., positive or negative, towards Oshawa Power as a company
3- To demonstrate Oshawa Power's desire to solicit feedback.

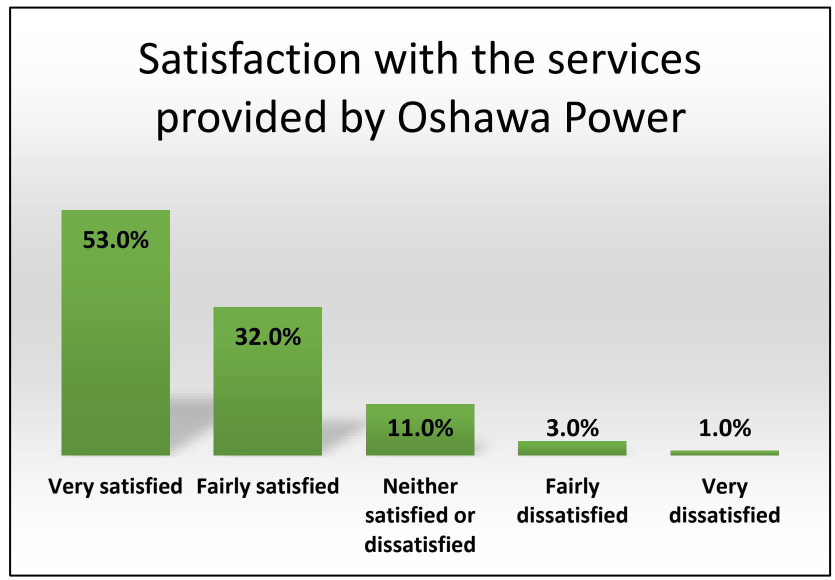
Primary theme:

Insights. Findings. Feedback.

Respondents of this chapter survey are quite supportive of Oshawa Power as a company. This survey also utilized a cross-over technique to compare online results with telephone survey results. There is tremendous consistency between the two methods.

A focus on satisfaction prompts the LC to continue to evolve in ways that make sense to those who pay the bills. A focus on satisfaction is a focus on effectiveness in the delivery of service to the customer.

The three most recent telephone surveys of residential and small commercial customers show that Oshawa Power consistently has been consistently higher than the Ontario Benchmark for LDCs.



Base: total respondents, 2019 online COS DSP survey

To what degree do you agree or disagree with the following attributes:				
Oshawa Power	**Online 2019**	**Telephone 2018**	**Telephone 2017**	**Telephone 2014**
Company to continue to be working with	87%	90%	88%	88%
Deals professionally with customers' problems	83%	86%	88%	86%
Pro-active in communicating changes and issues affecting Customers	81%	80%	77%	77%
Respected company in the community	83%	85%	90%	87%
Adapts well to changes in customer expectations	76%	79%	77%	78%
Is a trusted and trustworthy company	86%	90%	89%	85%
Accurate billing	86%	89%	88%	86%
Provides consistent, reliable electricity	92%	91%	90%	89%

Base: total respondents with an opinion: 2019 online COS DSP survey and 2014-2018 telephone surveys

Chapter 2 “The Electricity Industry and Oshawa Power’s role in it”

Purpose of this Chapter:

1- To help educate respondents about how the electricity system works in Ontario
2- To provide knowledge as to the role and responsibilities of Oshawa Power in the electricity sector

Primary theme:

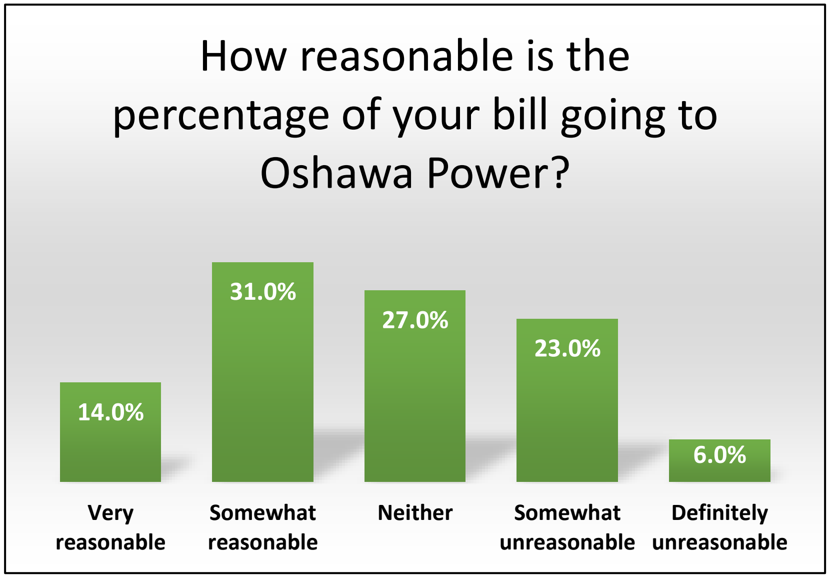
MAKE YOUR VOICE COUNT

Insights. Findings. Feedback.

Respondents were asked: “*Every item on your bill must be approved by the Ontario Energy Board. The charges you see on your electricity bill do not all go to Oshawa Power. For a residential customer using 750 kW of electricity per month, Oshawa Power only receives about 21% or $24.95 out of the approximate total bill of $122.62 to maintain the electricity network, build capacity to support economic growth, protect the network with cybersecurity measures, and so much more.*

In your view, how reasonable is the percentage given to Oshawa Power?”

Base: total respondents, 2019 online COS DSP survey



Oshawa Power’s ratings remain consistent year-over-year.

To what degree do you agree or disagree with the following attributes:				
Oshawa Power	**Online 2019**	**Telephone 2018**	**Telephone 2017**	**Telephone 2014**
Keeps its promises to its customers and community	83%	84%	86%	84%
Has a standard of reliability that meets expectations	88%	90%	90%	--
Delivers on its service commitments to customers	88%	89%	87%	86%
Is a company that is 'easy to do business with'	85%	85%	84%	86%
Quickly handles outages and restores power	90%	90%	86%	85%

Base: total respondents with an opinion: 2019 online COS DSP survey and 2014-2018 telephone surveys

Oshawa Power's ratings are also in line with the UtilityPULSE Ontario benchmark ratings. The Ontario benchmark ratings are derived from an independent study of Ontario LDC customers, conducted annually, who pay the bill, throughout the Province of Ontario.

To what degree do you agree or disagree with the following attributes:	Online Oshawa Power 2019	Telephone Ontario Benchmark 2019	Telephone Oshawa Power 2018	Telephone Ontario Benchmark 2018
Keeps its promises to its customers and community	83%	83%	84%	80%
Has a standard of reliability that meets expectations	88%	90%	90%	89%
Delivers on its service commitments to customers	88%	88%	89%	86%
Is a company that is 'easy to do business with'	85%	83%	85%	82%
Quickly handles outages and restores power	90%	88%	90%	86%

Base: total respondents with an opinion: 2019 online COS DSP survey and 2018 telephone surveys with Ontario benchmark comparators

Chapter 3 "Customer priorities, which are the important ones?"

Purpose of this Chapter:

1- To gather input from respondents about the priority level of various items which affect costs
2- To give respondents the opportunity to add to the priority item list when developing the Cost of Service application going to the Ontario Energy Board

Primary theme(s):

Insights. Findings. Feedback.

Customers will act primarily out of self-interest when asked to prioritize or to rank the importance of various LDC activities, which could affect costs. Oshawa Power has a 5-year history of soliciting input regarding what customers think are priorities or are important.

Times do change, technology does change, and customers' interests change. In 2014, Oshawa Power's telephone survey had a list of 10 items to be given a priority level. In 2018, the list grew to 12 items. For the 2019 online COS DSP survey, the list had 15 items. Just in case the list wasn't comprehensive enough, the online COS DSP survey had an open-ended question to capture any items or comments the respondent thought should be added.

Our 21 years of continuous research for Ontario LDCs tells us that priorities change by demographic and by location. For example, rural communities, especially those in northern Ontario, have poor access to the internet so investments that are linked to the internet get a low priority rating. Also, some items have an age bias. For example, items such as *"invest more in providing self-serve services on the website"* are rated very highly by younger respondents. Items such as *"educating customers about energy conservation"* have an income bias, with lower-income respondents rating it higher than respondents with higher household incomes.

None-the-less, gathering feedback about what is important helps Oshawa Power decision-makers determine where to invest or spend in the operations of the LDC.

As an Oshawa Power customer could you tell us how important each of the following items is to you?	
Top 2 box 'Very + Somewhat important'	**Oshawa Power**
Continuously improve the safety and reliability of the electricity network	95%
Remain focused on keeping costs low	95%
Reduce response times to outages	94%
Look for ways to use technology to safeguard the electricity network or get more out of the equipment	92%
Provide good jobs in the community	91%
Improve customer service	88%
Invest in green energy technologies (energy storage, electric vehicles, etc.)	88%
Invest in smart grid technologies (system automation)	88%
Invest in projects to reduce the environmental impact of the utility's operations	88%
Improve communications for billing and outages	87%
Educate the public as it relates to electricity safety	84%
Provide more self-serve options on the website	78%
Provide sponsorships to support local programs and events	76%
Develop a smartphone application to allow you to view your electricity use and pay your bill	75%
Make better use of social media such as twitter	62%

Base: total respondents with an opinion: 2019 online COS DSP survey

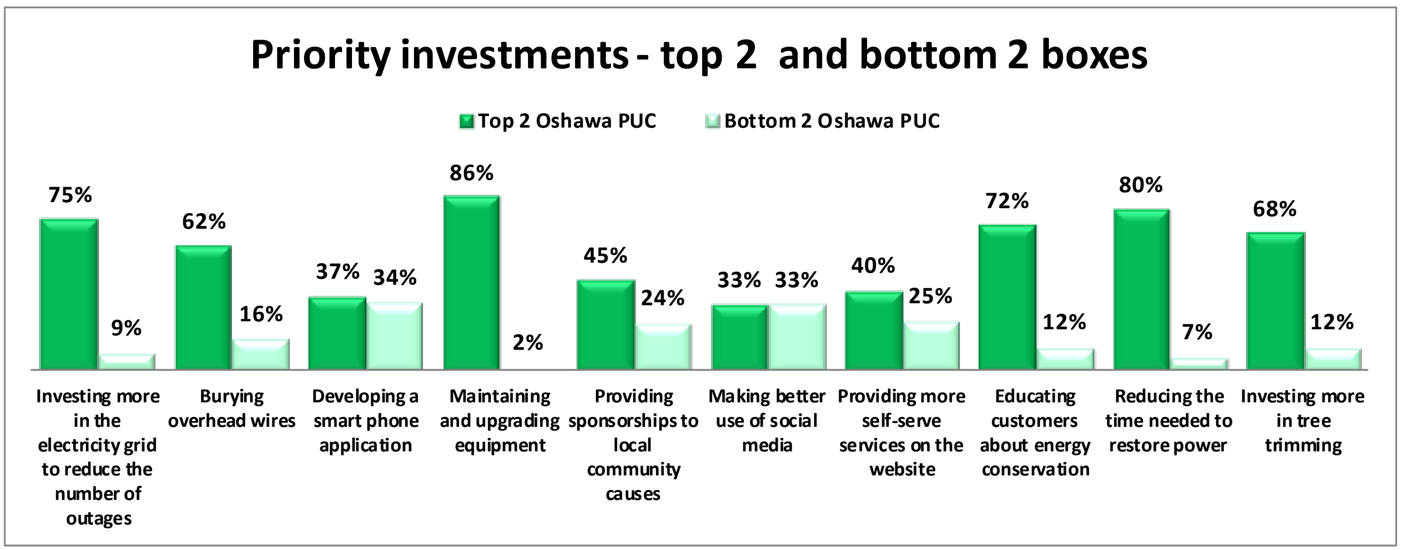
Note: See Wisdom from customers for responses to the open-ended question: *"Are there any priority items that you would like us to take into account when developing the Cost of Service application going to the Ontario Energy Board?"*

Priority Planning within the next 5 years (2018 Telephone survey)		
Top 2 Boxes: 'very high + high priority'	**Oshawa Power**	**UtilityPULSE**
Pro-actively maintaining and upgrading equipment	91%	89%
Reducing response times to outages	86%	83%
Investing more in the electricity grid to reduce outages	83%	80%
Investing more in tree trimming to help reduce the number of outages	78%	74%
Investing in projects to reduce the environmental impact of the utility's operations	76%	74%
Educating the public as it relates to electricity safety	73%	71%
Educating customers about energy conservation	70%	68%
Burying overhead wires	64%	60%
Developing a SMART phone application to allow you to view usage and pay your bill	50%	46%
Providing sponsorships to local community causes	48%	48%
Providing more self-serve services on the website	44%	37%
Making better use of social media (such as Twitter, Facebook, etc.)	29%	26%

Base: total respondents 2018 Telephone survey, UtilityPULSE data is an extract from the database

Priority Investments (2014 Telephone survey)		
Top 2 Boxes: 'Very high priority + High priority'	**Oshawa Power**	**UtilityPULSE**
Investing more in the electricity grid to reduce the number of outages	75%	74%
Burying overhead wires	62%	60%
Developing a smartphone application	37%	31%
Maintaining and upgrading equipment	86%	83%
Providing sponsorships to local community causes	45%	43%
Making better use of social media	33%	30%
Providing more self-serve services on the website	40%	38%
Educating customers about energy conservation	72%	74%
Reducing the time needed to restore power	80%	79%
Investing more in tree trimming	68%	58%

Base: total respondents 2014 Telephone survey, UtilityPULSE data is an extract from the database



Chapter 4 "Customer insights about billing and outages"

Purpose of this Chapter:

1- To gather feedback regarding various subjects such as e-billing
2- To determine to what degree customer respondents perceive Oshawa Power, as it relates to providing consistent, reliable electricity and handling outages
3- To determine to what degree customer respondents perceive Oshawa Power, as it relates to accurately billing its customers
4- To learn more about the preferred method(s) for contacting Oshawa Power when there is a billing issue or an outage

Primary theme(s):

Insights. Findings. Feedback.

Blackout (outages) and billing problems, we call them the "Killer B's," the two issues most likely to cause grief to utility customers. Ensuring power reliability has and will continue to be the key operational priority for electric utilities.

Bills and blackouts are a major component of the UtilityPULSE annual customer satisfaction survey; as such, there is a tremendous amount of comparison data available.

Our 21+ years of research tells us, the perception of LDC competency and value are linked to the frequency and duration of power outages. 88% of online respondents and 90% of telephone respondents with an opinion agree Oshawa Power *"quickly handles outages and restores power,"* and 89% online 88% telephone respondents agree Oshawa Power *"has a standard of reliability that meets expectations."*

To what degree do you agree or disagree with the following attributes:				
Oshawa Power	**Online 2019**	**Telephone 2018**	**Telephone 2017**	**Telephone 2014**
Oshawa Power provides consistent, reliable electricity.	92%	91%	90%	89%
Accurately bills its customers	86%	89%	88%	86%
Has a standard of reliability delivering electricity that meets your expectations	88%	90%	88%	n/a
Quickly handles outages and restores power	88%	90%	86%	85%
Makes electricity safety a top priority for employees and contractors	--	89%	89%	87%

Base: total respondents with an opinion, 2019 online COS DSP survey, and 2014-2018 telephone surveys

Bills

It is important to note; customers perceive billing problems much differently than administration. Typically, a LDC views billing problems as a processing issue. Customers, however, view “high bills” as a billing problem. The UtilityPULSE database for 2019 shows that 55% of telephone customer respondents who said they had a billing issue in the last 12 months cited “high bills” as the issue.

The chart below contains data from the recent online COS DSP survey and Oshawa Power’s 2018, 2017, 2014 telephone surveys.

84% of Oshawa Power respondents who said they had a billing problem (2018) indicated their preference is to contact Oshawa Power by telephone when there is an issue with their bill. In 2014, it was 94% of respondents who said their preference was to use the telephone. Times are changing.

Percentage of telephone survey respondents indicating that they had a Billing problem in the last 12 months			
	Oshawa Power	**National**	**Ontario**
2018	6%	9%	9%
2017	10%	12%	15%
2014	10%	16%	25%

Base: total respondents 2014-2018 telephone surveys

Billing issues have long been a major cause of customer inquiry and complaint. Not only are bills a key part of an LDC's revenue management processes, but they're also an essential element and touchpoint in their relationship with their customers. For many customers, it is one of the very few touchpoints they have with their LDC. Because of its nature, the bill is usually viewed by customers as wholly negative communication.

When customers with a billing problem want to contact Oshawa Power, the preference by a large margin is the telephone.

Preferred method to contact Oshawa Power when there is a billing issue		
	UtilityPULSE	**Oshawa Power**
Telephone	85%	84%
Email	4%	5%
Utility's website	3%	3%
Social media	1%	5%
In person	4%	3%

Base: total respondents 2018 Telephone survey, UtilityPULSE data is an extract from the database

Findings from the Oshawa Power 2014 telephone survey show that only 1% of customer respondents would contact the utility via the website and 3% via email.

However, times are changing, and there is a growing demand for LDCs to become proficient in outbound communications. That is to initiate contact with their customer. Data from the UtilityPULSE database shows there is an age bias on preference to receive notice about a billing issue. For example, older people prefer to receive a notice via the telephone while young people prefer email.

Oshawa Power's customers' preferred or primary method for Oshawa Power to contact them about billing issues are as follows:

Preferred method of communication to receive notice of a billing issue

	UtilityPULSE	Oshawa Power
Telephone	56%	52%
Voice Mail	2%	2%
Text	7%	11%
Email	34%	34%
Don't know	1%	0%

Base: total respondents 2018 Telephone survey, UtilityPULSE data is an extract from the database

E-billing is an opportunity area for every LDC in Ontario, Oshawa Power is no exception.

Take-up rates vary by such factors as urban-rural, economic status, access to high-speed internet and, age. Oshawa Power online respondents were asked to list their view on the top 3 barriers which get in the way of more customers moving to electronic billing.

89% of online COS DSP survey participants indicated that they received their bill electronically, while 11% said they did not. Oshawa Power took the survey as an opportunity to probe into the potential barriers stopping customers from moving to e-billing. Online respondents were asked to choose the top 3 reasons out of 7 potentials reasoning for barriers. It is important to note that 89% receiving their bill electronically is much higher than the total population. We believe the higher number is justified because online survey respondents have access to the internet and are more comfortable with technology.

Barriers for e-billing

In your view, what are the top 3 barriers which get in the way of more customers moving to electronic billing?	Oshawa Power Point Rankings
Some customers are not comfortable with technology	1922
Some customers do not have access to the internet	1436
Receiving the bill by mail is a reminder to pay	1094
Security concerns about receiving electronic billing	1082
Customers are not aware of the cost savings of e-billing help offset future cost increases	920
Customers are unaware of the environmental benefit of e-billing	602
It is more convenient to receive the bill by mail	384

Base: total respondents, 2019 online COS DSP survey

1

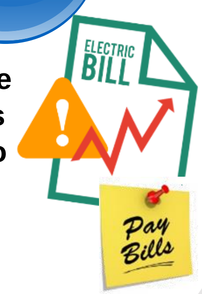
Some customers are not comfortable with technology

2

Some customers do not have access to the internet

3

Receiving the bill by mail is a reminder to pay



Blackouts/Outages

Outages aggravate customers. It could be said; some outages anger customers. The reality is there will be outages – some will, of course, be weather-related.

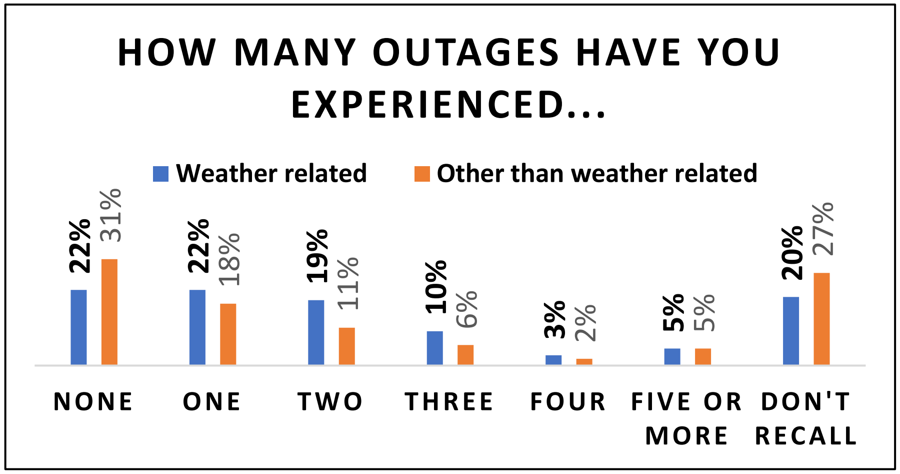
Percentage of Respondents indicating they had a Blackout or Outage problem in the last 12 months			
	Oshawa Power Telephone	National Benchmark	Ontario Benchmark
2018	47%	39%	44%
2017*	61%	37%	38%
2014	43%	47%	49%

Base: Base: total respondents 2014-2018 telephone surveys, Ontario and National benchmark comparators
Note (*): 2017 had a significant recall of outages due to a transformer issue affecting 17,000 customers

For online COS DSP survey respondents, Oshawa Power asked about the number of weather-related and non-weather-related outages that they had.

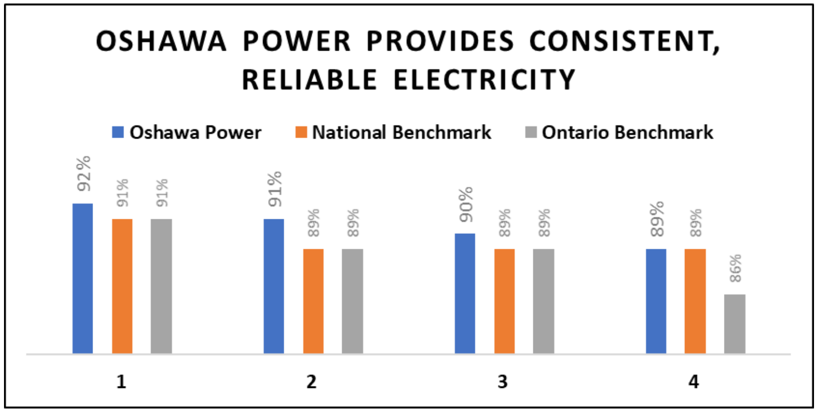
How many outages have your experienced that were…		
	Weather-related	Other than weather-related
None	22%	31%
One	22%	18%
Two	19%	11%
Three	10%	6%
Four	3%	2%
Five or more	5%	5%
Don't recall	20%	27%
None	22%	31%

Base: total respondents, 2019 online COS DSP survey



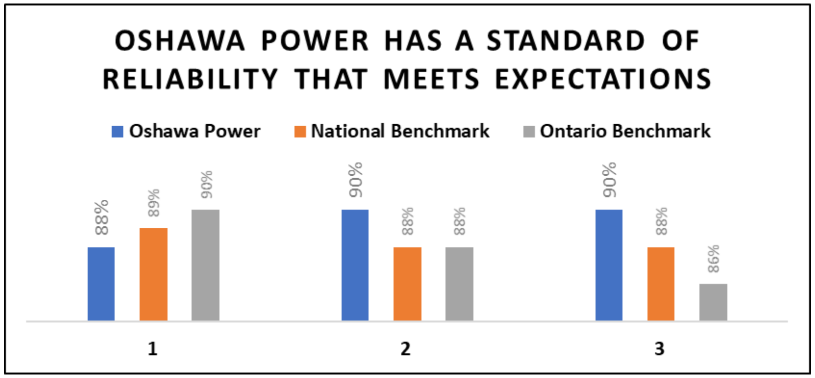
Quickly handles outages and restores power			
Survey Year/Type	**Oshawa Power**	**National Benchmark***	**Ontario Benchmark***
2019 Online	90%	88%	88%
2018 Telephone	90%	87%	86%
2017 Telephone	86%	87%	85%
2014 Telephone	85%	86%	83%

Base: total respondents
(*) Ontario and National benchmark comparators are derived from telephone surveys only



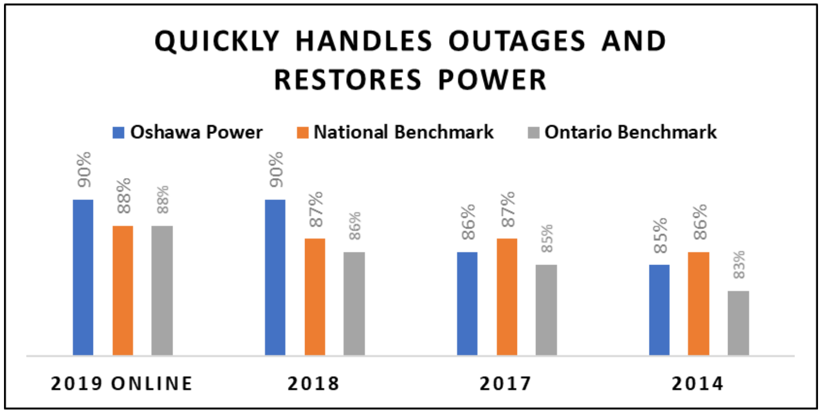
Oshawa Power has a standard of reliability that meets expectations			
	Oshawa Power	**National Benchmark***	**Ontario Benchmark***
2019 Online	88%	89%	90%
2018 Telephone	90%	88%	88%
2017 Telephone	90%	88%	86%

Base: total respondents
(*) Ontario and National benchmark comparators are derived from telephone surveys only



Oshawa Power provides consistent, reliable electricity			
Survey Year/Type	**Oshawa Power**	**National Benchmark***	**Ontario Benchmark***
2019 Online	92%	91%	91%
2018 Telephone	91%	89%	89%
2017 Telephone	90%	89%	89%
2014 Telephone	89%	89%	86%

Base: total respondents
(*) Ontario and National benchmark comparators are derived from telephone surveys only



Oshawa Power's overall effectiveness during outages	
Top 2 boxes 'Very + Somewhat Effective'	**Oshawa Power**
Responding to the power outage	84%
Restoring power quickly	84%
Using media channels for providing an update	44%
Providing information about the outage	49%
Maintaining information on the website	47%
Updating Social Media	35%

Base: total respondents, 2019 online COS DSP survey

Chapter 5 "Facilities and General Plant capital investments"

Purpose of this Chapter:

1- To determine levels of support for General Plant budget increase
2- To gain customers' perspectives as to what is considered to be important for a working facility
3- To capture a better understanding of what customers think about replacing Oshawa Power's current 88-year-old facility
4- To determine the level of support, from online respondents, regarding the proposed monthly increase to relocate and build a new facility

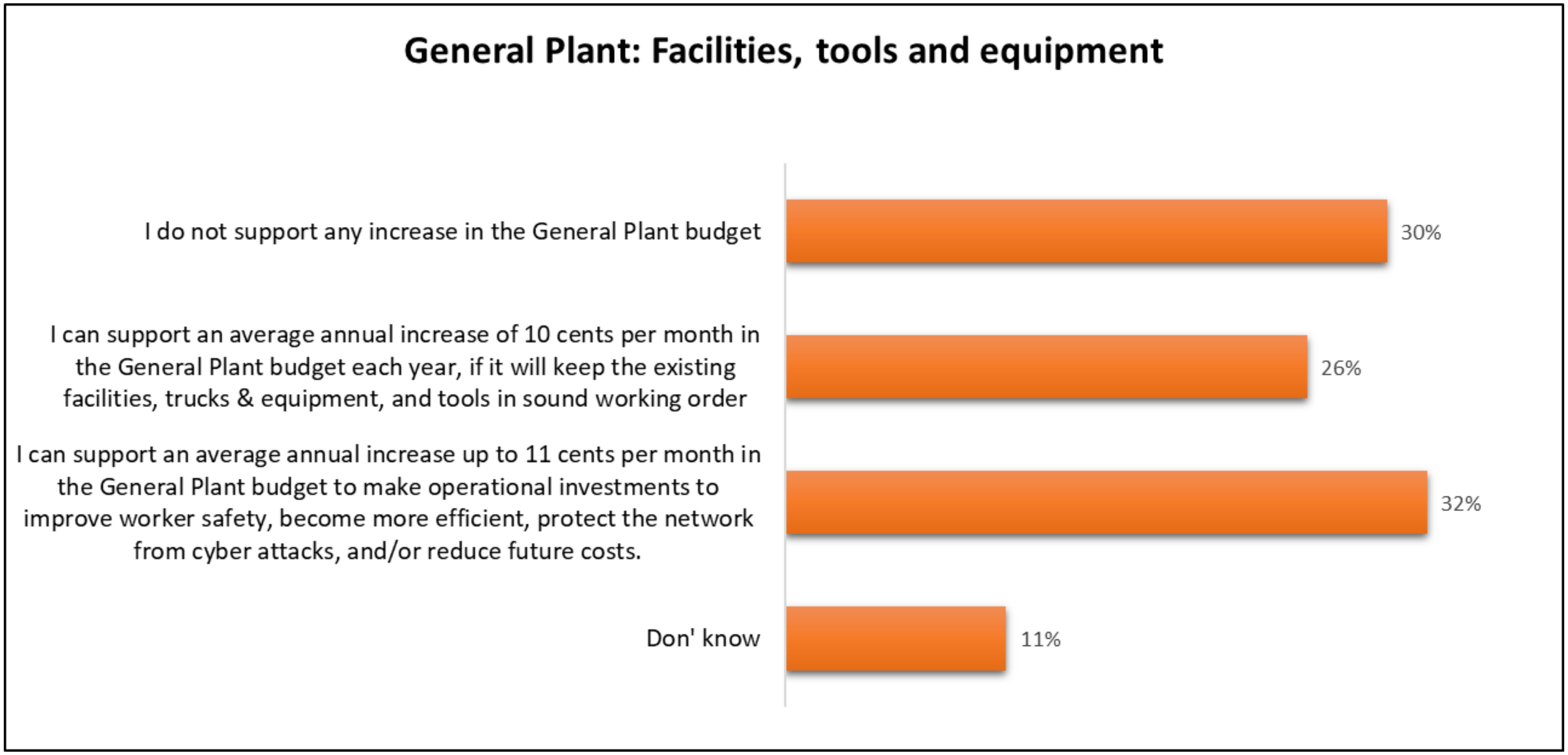
Primary theme(s):

Insights. Findings. Feedback.

Oshawa Power owns and manages $125 million in assets. Like all mechanical items, these assets have a life span, wear out, and at some point, need to be replaced. Oshawa Power invests about $1,129,000 per year on General Plant items.

Having the right tools & equipment, efficient workplaces, good trucks, and other rolling equipment, computers and software help your Oshawa Power professionals support day to day business and operational needs. Tools, equipment, trucks, etc. do wear out or become out-dated. In addition, modernizing security software to support cybersecurity measures and improving customer information systems is a high priority for Oshawa Power.

58% of respondents supported Oshawa Power's recommendation or a higher option, 30% wouldn't support an increase, and 11% answered 'Don't know'.



Base: total respondents, 2019 online COS DSP survey

About the current Oshawa Power facility:

Determining whether Oshawa Power should retrofit or renovate facilities or build new is a difficult decision with complex answers. Also, customers have a wide range of views regarding retrofitting or replacing facilities. A decision about facilities is a long-term decision and can involve a tremendous amount of investment. The reality is, facilities do need to be updated.

The data shows customer respondents take a pragmatic view towards retrofitting or replacement.

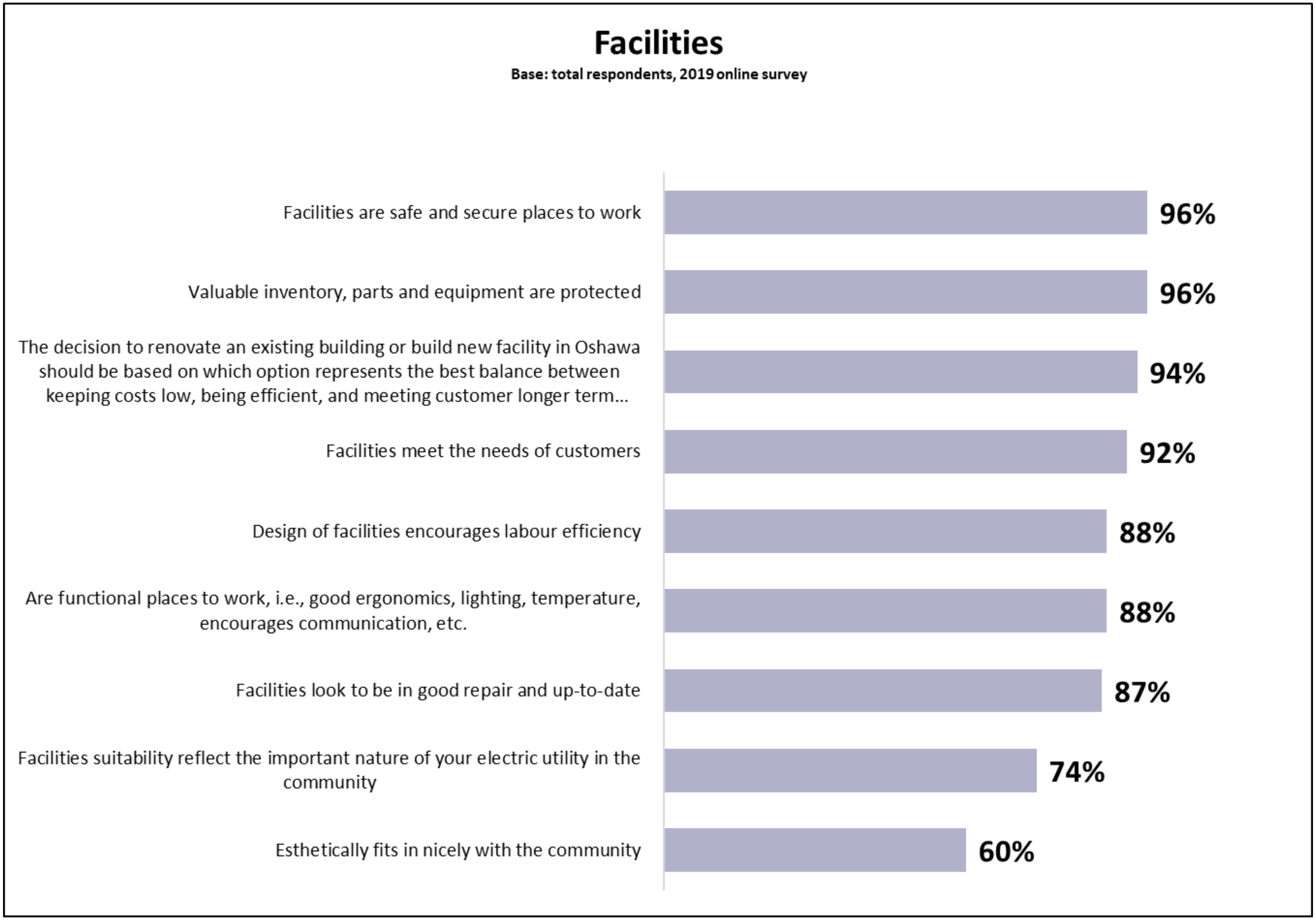
Respondents were asked: *The current Oshawa Power building opened on December 2, 1931, when Oshawa had a population of 23,439. Eighty-eight years later, Oshawa has a population of 159,458 and Oshawa Power has the privilege of serving over 58,000 customers. In addition, there has been much technological change in the industry. As such, the building no longer can meet the needs of your electricity utility.*

Determining whether Oshawa Power should retrofit or renovate an existing facility or build a new facility in Oshawa is a difficult decision.

Could you tell us how important each of the following items are in helping to make a long-term decision about Oshawa Power's facilities? How important…

Facilities	
Top 2 boxes 'Very important + Somewhat important'	**Oshawa Power Online**
Facilities are safe and secure places to work	96%
Valuable inventory, parts and equipment are protected	96%
The decision to renovate an existing building or build new facility in Oshawa should be based on which option represents the best balance between keeping costs low, being efficient, and meeting customer longer term energy needs	94%
Facilities meet the needs of customers	92%
Design of facilities encourages labour efficiency	88%
Are functional places to work, i.e., good ergonomics, lighting, temperature, encourages communication, etc.	88%
Facilities look to be in good repair and up-to-date	87%
Facilities suitability reflect the important nature of your electric utility in the community	74%
Esthetically fits in nicely with the community	60%

Base: total respondents, 2019 online COS DSP survey



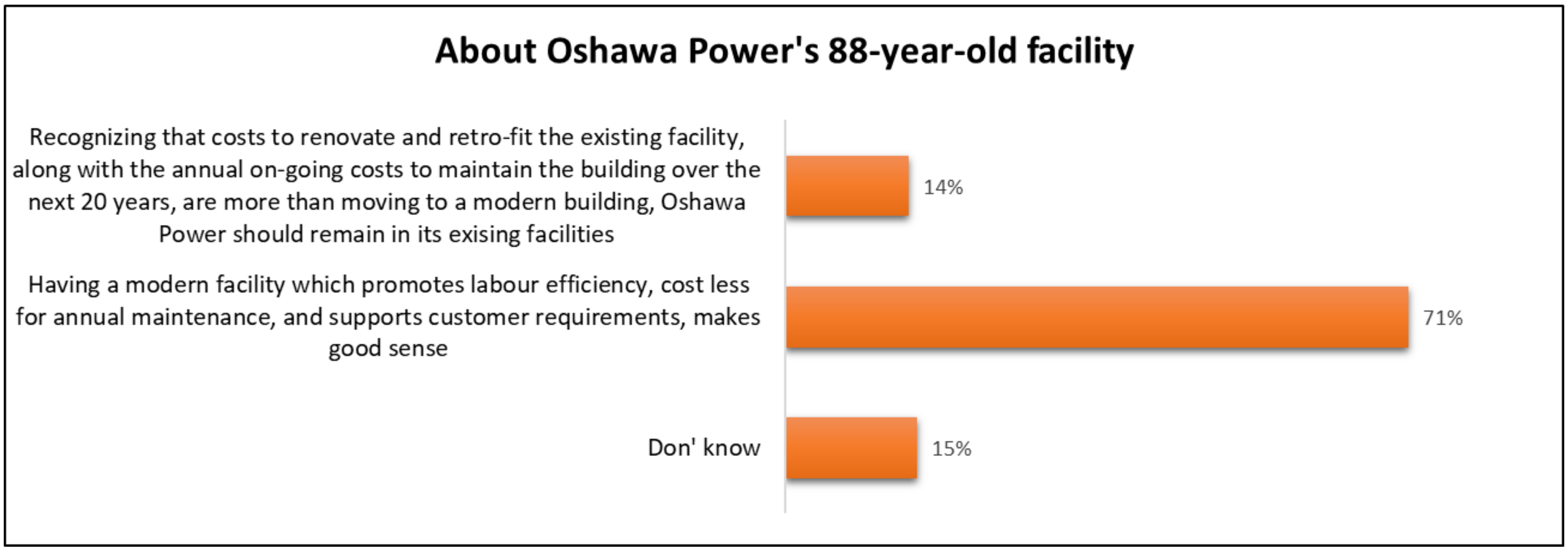
Base: total respondents, 2019 online COS DSP survey

Everyone knows, when talk of a facility is involved, there will be a myriad of viewpoints. Many of those viewpoints will be supported by strong levels of emotion.

Here are some of the written comments from online survey respondents, pro and con:

- *"No need to move from the current PUC building downtown. Offer more work from home options for the staff."*
- *"Environmental concerns (zero waste, reduction of greenhouse gasses) are of top concern right now, particularly with regard to renovation/building plans and maintenance. Thank you."*
- *"Sorry I do not support the move, I care about downtown Oshawa and prefer the beautiful Oshawa Power building to be permanently occupied/restored by OPUC"*
- *"The downtown location doesn't seem handy - you should move!"*
- *"If you decide to move, please consider Oshawa as the new location. Lots of available buildings / land and would bring. Ore jobs here to offset the damage done by GM leaving. I think you guys do an amazing job."*

Online respondents were asked which of the following statements best reflects their view about replacing Oshawa Power's 88-year-old facility.

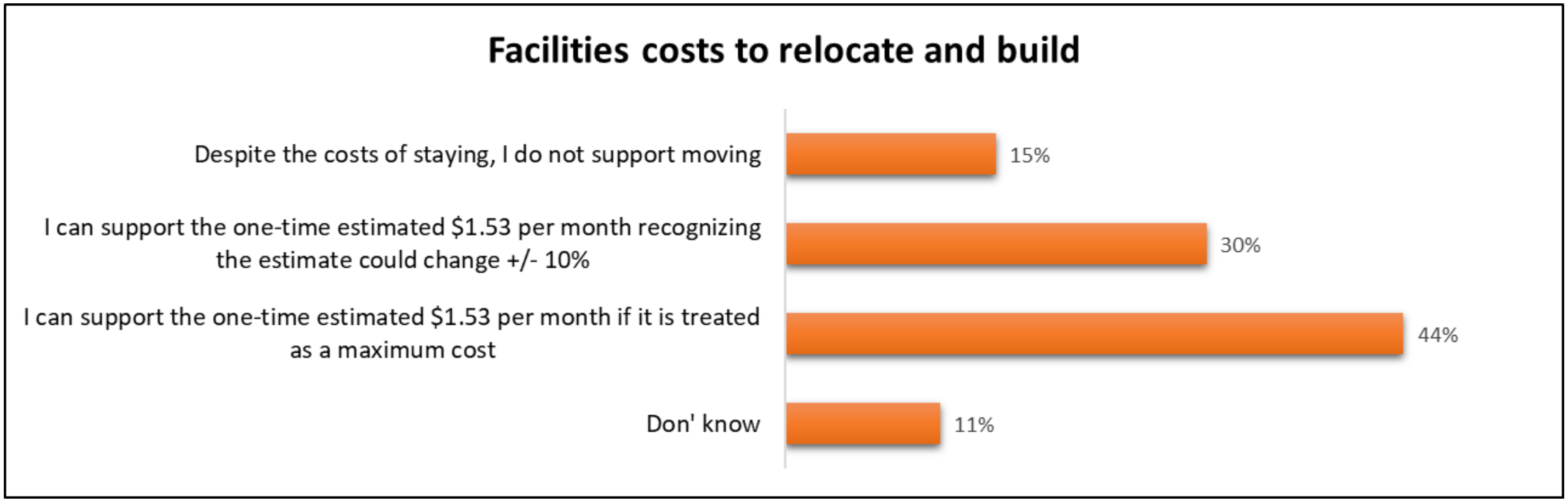


Base: total respondents, 2019 online COS DSP survey

Truth is not everyone is going to agree on what should be done. The truth is there will be many opinions. The challenge isn't about getting agreement; the challenge is getting support for a new building and relocating to a more efficient building, or spend the money to retrofit. The above question shows respondents chose the pragmatic statement about whether a new facility makes sense or not.

The above data shows, along with the chart below, there are about 15% of the population who will not support any move. A total of 74% of online respondents can support the move.

Respondents were asked: *To relocate and build a new facility that will accommodate our operational demands and growth in today's market will generate a monthly cost increase, beginning in 2022 of 1.53 per month. Which of the following statements best reflects your view about going to a modern facility?*



Base: total respondents, 2019 online COS DSP survey

In our view, there is an excellent level of support for building and relocating. However, there will be critics! Even if Oshawa Power decided to spend money to retrofit and stay, there would be critics!

Chapter 6 "Gathering insights about customer care operations"

Purpose of this Chapter:

1- To gather feedback regarding customer respondent satisfaction levels with the amount of information available for various topics
2- To gain a better understanding of desirable customer care operational improvements
3- To gauge the level of satisfaction with current levels of communication
4- To identify the current satisfaction levels regarding access to LDC services

Primary theme(s):

Insights. Findings. Feedback.

Oshawa Power, along with all other Ontario LDCs, is known as an influential brand company because they affect the daily lives of people and businesses. The safe, reliable distribution of electricity to homes and businesses is a job that makes life better, more interesting and meaningful for consumers and customers. However, the company has to consistently demonstrate that it cares about its customers and it can be trusted.

The importance of ensuring that customer care operations are meeting expectations while ensuring there is an effective marketing communications plan cannot be overstated.

Online respondents were asked: *Oshawa Power employees are focused on providing excellent customer care and are well aware that customer expectations about service will continue to rise.*

Thinking about the next 5 years, which of the following improvements would you like us to make?

Customer care operational improvements over the next 5 years… (online COS DSP survey)			
	Make this improvement	**Don't make this improvement**	**Don't know**
An outage notification system that automatically sends you a message by phone call, email or text	77%	15%	7%
Educating customers about energy conservation	69%	18%	13%
Access online account info for updates, move-outs, and move-ins.	69%	20%	11%
Reviewing and paying your bill online (through the utility's website)	65%	23%	12%
Reporting or inquiring about an issue through the website, e.g., billing question, outage problem	65%	23%	13%
Automating alerts when electricity usage exceeds a prearranged threshold	62%	25%	14%
Educating customer and the public about electricity safety	61%	26%	13%
A smartphone application that allows you to access your smart meter electricity usage information	55%	29%	16%
Automating alerts to remind you of your bill due date	48%	41%	12%
Comparing your electricity consumption with others in Oshawa Power's service territory	47%	38%	15%
Automating alerts to predict what your upcoming bill might be	39%	48%	14%
Having a web chat feature on the website	39%	43%	18%
Extended office hours	19%	60%	21%

Base: total respondents 2019 online COS DSP survey

Communication and Services Measurement

In a world where the vast majority of LDC customers feel time-pressed, the need for quality and timely information rises.

In consultation with our clients, in 2018, we developed the UtilityPULSE Communication Index score. Based on customer responses from Oshawa Power's telephone survey, they achieved a score of 79%, in-line with the UtilityPULSE database.

Satisfaction with information provided		
Top 2 Boxes: 'very + fairly satisfied'	**UtilityPULSE**	**Oshawa Power**
The amount of information available to you about energy conservation	82%	86%
The quality of information available when outages occur	73%	76%
The electricity safety education provided to the public	74%	78%
The timeliness and relevance of the information for things such as planned outages, construction activity, tree trimming.	78%	78%

Base: UtilityPULSE database, Oshawa Power 2018 telephone survey

Communication Score		
	UtilityPULSE	**Oshawa Power**
Communication Score	79%	79%

Base: UtilityPULSE database, Oshawa Power 2018 telephone survey

Convenience of Services Score

Again in 2018, we developed the UtilityPULSE Convenience of Services Score in response to client LDCs, including Oshawa Power, who were interested in knowing more about how satisfied customers were with access to various services.

Access to services		
Top 2 Boxes: 'very + somewhat satisfied'	**UtilityPULSE**	**Oshawa Power**
The availability of call-centre staff Monday to Friday	76%	77%
The 24/7 availability of system operators to respond to outages	77%	74%
The online self-serve options for managing your account	63%	64%
The online self-serve options for request services	56%	61%

Base: UtilityPULSE database, Oshawa Power 2018 telephone survey

Convenience of Services Score		
	UtilityPULSE	**Oshawa Power**
Convenience of Services Score	79%	79%

Base: UtilityPULSE database, Oshawa Power 2018 telephone survey

Based on customer responses from Oshawa Power's 2018 telephone survey, they achieved a 79% rating, in-line with the UtilityPULSE database.

Chapter 7 "Distribution System Plan Capital investments"

Purpose of this Chapter:

1- To gather insight into customer respondent preferences for proposed DSP capital investments
2- To provide another opportunity for customer respondents to provide ideas and insights into how the LDC could save money
3- To provide customer respondents with a mechanism to provide additional comments and be informed about any future public meetings regarding the COS application
4- To offer customer respondents with a mechanism to have an Oshawa Power professional contact them, we call these "Hot Alerts"
5- Note: respondents were given a summary with costs upon completion of this Chapter. With the summary, respondents were also given the opportunity to "go-back" and change their answers.

Primary theme(s):

Insights. Findings. Feedback.

Respondents struggle with answering questions associated with capital investments. They do so because the topic is complex with no easy answers. As stated earlier, customer respondents know a glass of orange juice at $16 is over-priced. Wrapping their heads around whether an average of $4,991,700 annual System Renewal Budget is about right, is not easy.

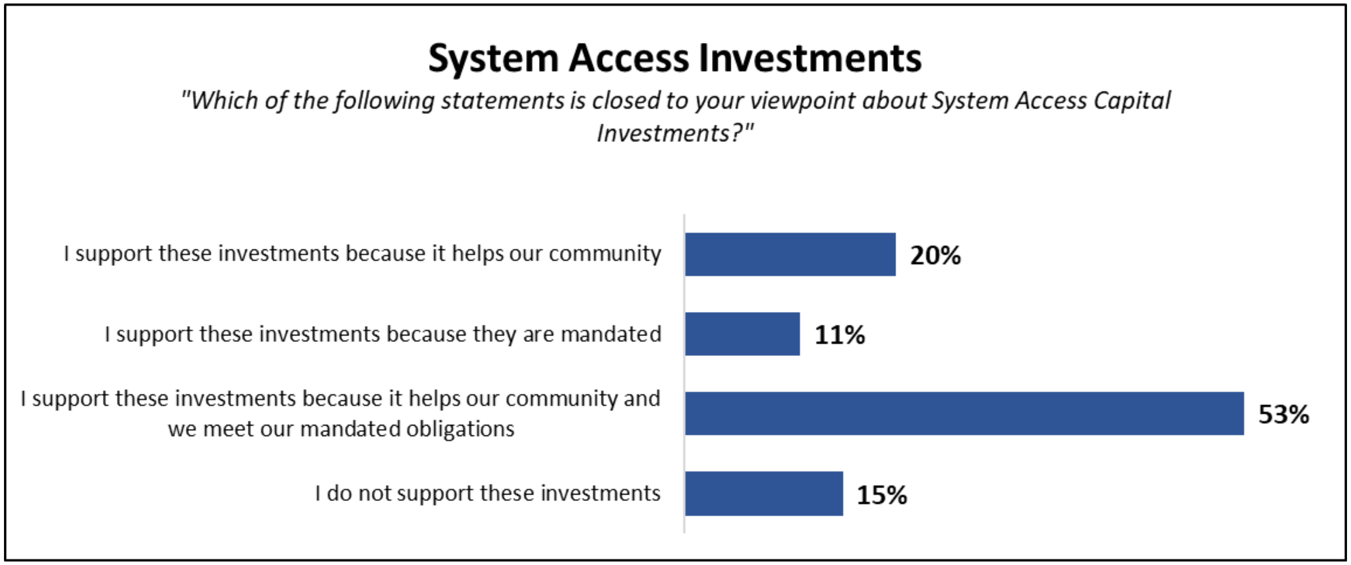
It is important for the reader to note that online respondents were given definitions of various terms being used, such as what capital investments are. Respondents also had available to them a comprehensive spreadsheet showing all of the numbers/costs for each capital investment area. Lastly, definitions, along with examples where available, were given to respondents about what is meant by the terms System Access, System Renewal and System Service.

System Access Investments:

System access investments are not a discretionary investment. We did, however, ask respondents about why they would support this type of increase. One respondent commented: *"Honestly, I feel system access costs should come from our taxes. We pay taxes to maintain access in our communities, such as road work; we shouldn't have to pay twice, once to build the roads and once directly to hydro to put access on the same road. We already pay so much for delivery charges of power to our homes, that the true cost of power is so small in comparison."*

Another said: *"Recommend new build homeowners absorb new power development requirements to establish their homes. The rest of us should not have to pay for this."*

Respondents were asked: *Oshawa Power, and every Local Distribution Company in Ontario, are mandated to provide customers with access to the existing electricity grid. The idea behind these projects is to help the community grow, i.e., residential and/or commercial development, fix transportation issues e.g., road widening, etc. For System Access projects examples click here. The average monthly cost increase for these types of investments is 49.3 cents per month for the average residential customer. Could you tell us which of the following statements is closest to your viewpoint about System Access Capital Investments:*



Base: total respondents, 2019 online COS DSP survey

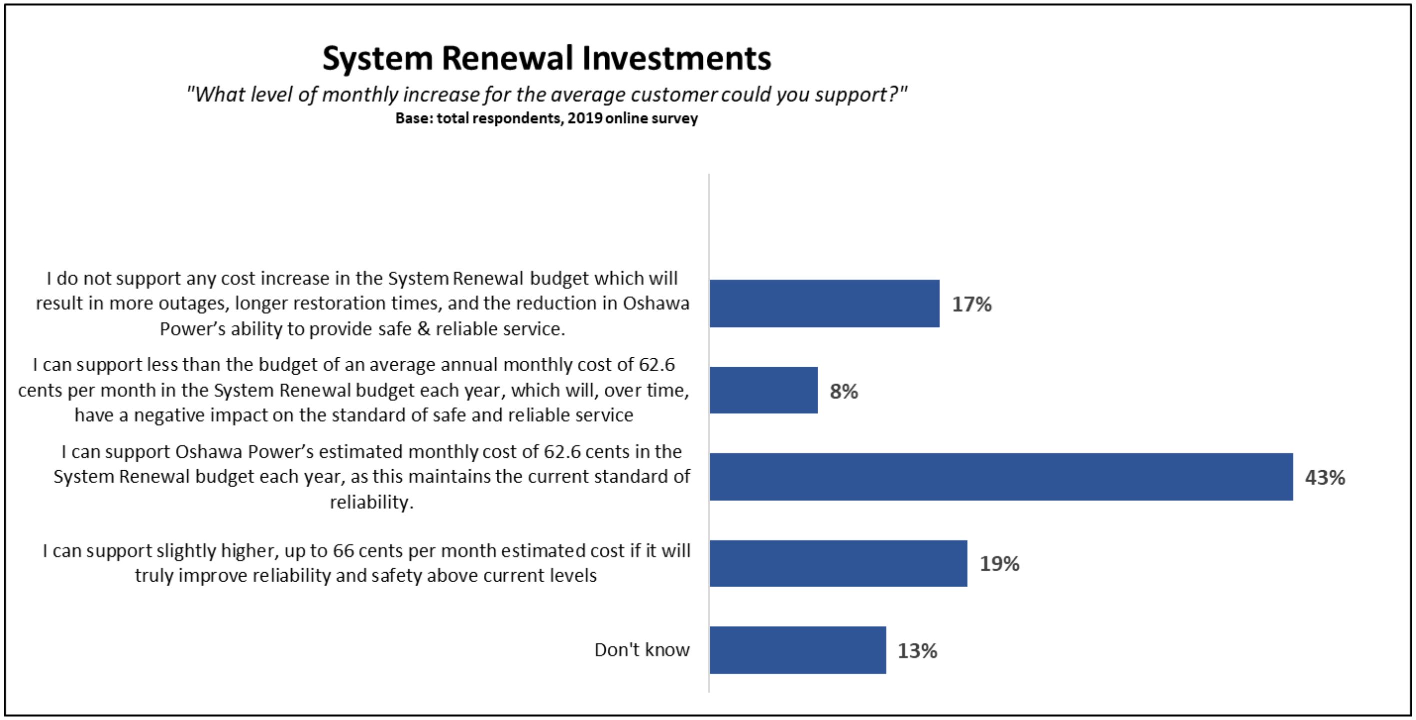
System Renewal Investments

Online respondents were asked:

Equipment such as poles, transformers, and other assets do wear out and must be refurbished or replaced. 90% of survey respondents from a recent telephone survey agreed with the statement that Oshawa Power has a standard of reliability that meets their expectations. 91% said, "Maintaining and upgrading equipment" was a 'very high or high priority'. 83% said, "Investing more in the electricity grid to reduce outages and to increase reliability and safety" was a 'very high or high priority'. For System Renewal project examples click here

Oshawa Power invests about $4,991,700 per year on System Renewal projects.

What level of monthly increase for the average customer could you support?



62% of online respondents indicated support for a 62.6 cent monthly increase (or higher)

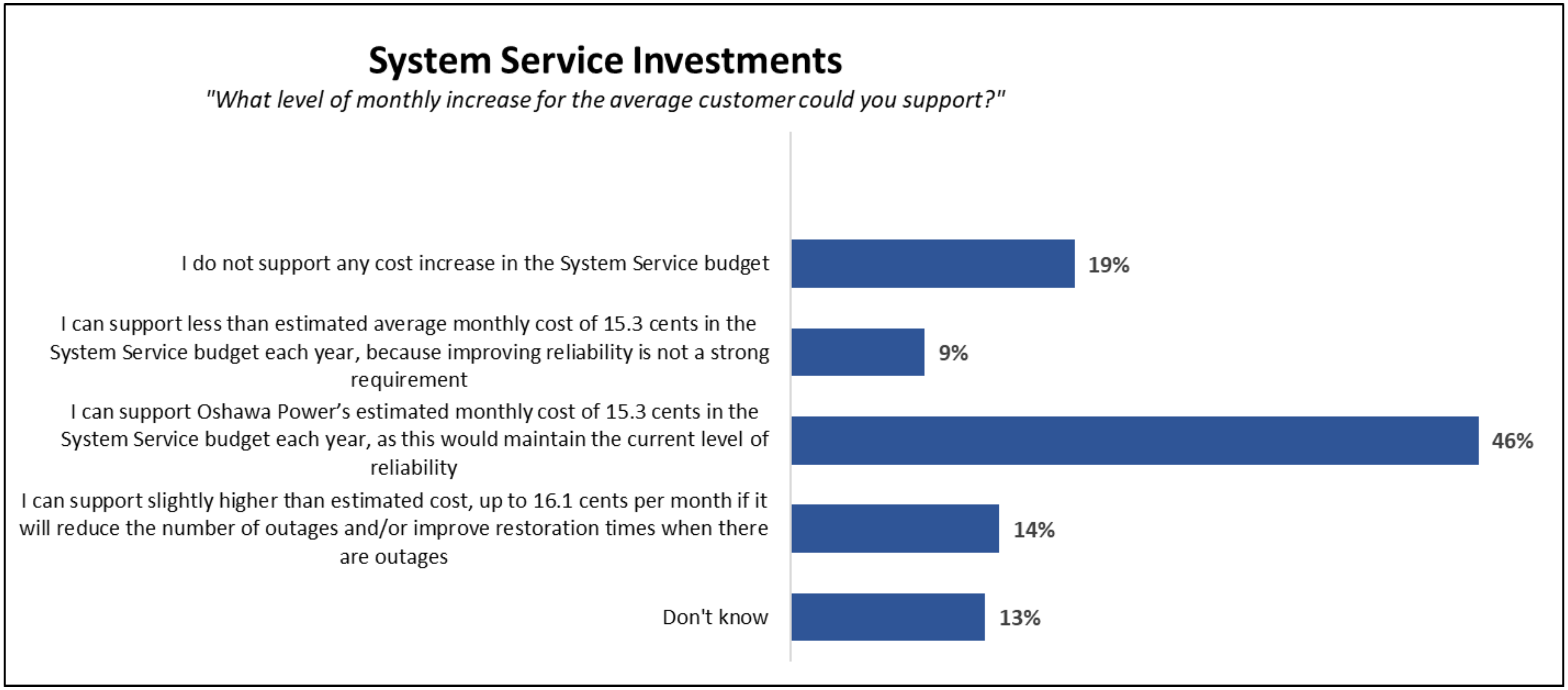
Base: total respondents, 2019 online COS DSP survey

System Service Investments

Online respondents were asked: *System Service investments are those required to ensure the electricity network has the capacity and reliability to meet current and future customer needs. These types of investments can represent replacing or adding new equipment, which improves reliability and helps reduce the impact of an outage on customers.*

Oshawa Power invests about $4,762,680 per year on System Service capital items

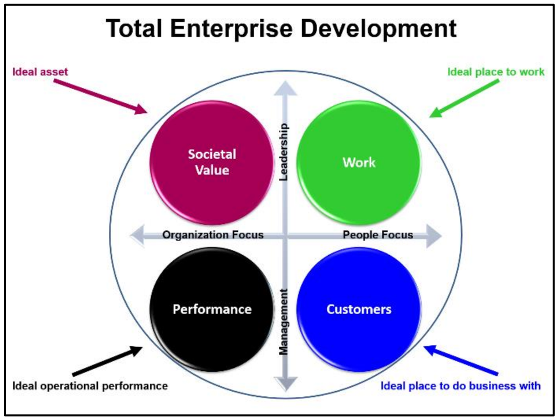
What level of monthly increase for the average customer could you support?



Base: total respondents, 2019 online COS DSP survey

Again, it should be noted that 60% of online respondents supported an increase of 15.3 cents per month or higher.

❋ Managing the whole enterprise from a Customer's perspective



For the 21 consecutive years UtilityPULSE has conducted its Annual Customer Satisfaction Survey for LDC clients in Ontario, the number one suggestion made by customer respondents to improve service was "reduce the price." Any other subject is a distant second.

Customer respondents view the performance of their LDC primarily through the lens of costs. Given the emotional roller-coaster LDC customers have gone through over the past few years, it is no wonder why customers see costs first and value second. Our UtilityPULSE research in 2015, 2016 and the early part of 2017, show, for most residential and small commercial customers, the cost increases for the energy side of their bill could not be reconciled with what was happening in their lives, e.g., 0-2% salary increases, 2% inflation costs, etc.

Successful LDCs and other enterprises know to keep costs low; the total enterprise must be performing at a high level. That is, employees need to be engaged because when they are not, increased costs and poor performance can be the result. Customers need to be engaged, in particular, feel they are valued. If not, complaints go up, and there is a cost increase to handle the additional volume. Operationally speaking the LDC has to perform at least to the standards in the industry even when higher than OEB requirements. Also, the LDC has to be seen as socially responsible and as a valuable asset to its owners and the customers it serves.

The UtilityPULSE annual telephone surveys contain various attributes when grouped give some insight into how customers perceive the successfulness of the enterprise. While many attributes could be measured which would provide some insight into Oshawa Power's success, the following represents how a customer respondent could look at their LDC. Customer respondents were asked to what degree they would agree or disagree with the following statements apply to Oshawa Power.

Total Enterprise Development	
Ideal place to do business with	**Oshawa Power**
Provides information to help customers reduce electricity costs	76%
Pro-active in communicating issues that affect customers	80%
Quickly deals with issues that affect customers	85%
Cost of electricity is reasonable when compared to other utilities	70%
Provides good value for your money	76%

Base: total respondents with an opinion, Oshawa Power 2018 telephone survey

Total Enterprise Development	
Ideal place to work	**Oshawa Power**
Deals professionally with customers problems	86%
Customer-focused and treats customers as if they're valued	84%
Makes electricity safety a top priority for employees and contractors	89%
Adapts well to changes in customer expectations	79%

Base: total respondents with an opinion, Oshawa Power 2018 telephone survey

Total Enterprise Development	
Ideal operational performance	**Oshawa Power**
Operates a cost-effective electricity system	78%
Efficiently manages the electricity system	87%
Delivers on its service commitments to customers	89%
Quickly handles outages and restores power	90%

Base: total respondents with an opinion, Oshawa Power 2018 telephone survey

Total Enterprise Development	
Ideal asset	**Oshawa Power**
Is a trusted and trustworthy company	90%
Is a socially responsible company	86%
Overall the utility provides excellent quality services	89%
A leader in promoting energy conservation	78%

Base: total respondents with an opinion, Oshawa Power 2018 telephone survey

Statistically the results shown above and to the side, are the same as the Fall 2018 UtilityPULSE database which is based on interviews with 2,328 customer interviews.

Oshawa Power, like many LDCs in Ontario, struggle with the comparison of costs with other non-electricity utilities and the perception of value.

Our years of research, tell us, the low perception of value is an industry wide problem.

Based on the results from customer interviews, Oshawa Power is a highly rated

❋ Wisdom from Customers:

An important feature of Oshawa Power's main COS DSP online survey was to provide every respondent with the opportunity to be contacted by an Oshawa Power representative; this was featured through the "Hot Alert" questions.

- Only 26 customer respondents asked to be contacted.

Customers want their voices to be heard, they do have ideas, and they want to be respected.

With this in mind, another feature of Oshawa Power's online COS DSP survey was to provide customer respondents with three opportunities to provide comments;

- the first was answering the question: *"Are there any priority or important items that you would like us to take into account when developing the Cost of Service application going to the Ontario Energy Board?"*
- the second and third were featured through two closing questions, the first being a "Wisdom from Customers" question: *"We are always looking for ways to reduce costs without compromising safety and reliability, what ideas do you have which might help reduce costs without compromising performance?"*
- the third, a "Make Your Voice Count" question: *"Do you have any additional comments about Oshawa Power or its Cost of Service Rate Application?"*

While the design of the survey was to capture ideas, feedback, and opinions about specific topics i.e., ways to reduce costs, etc. The reality is a respondent will write whatever is on their mind in any "bucket" available to them to do so. For example, if the respondent is a senior on a pension then "costs" will be part of every answer they provide. Or if a respondent thinks the CEO is paid too much, then that too may be part of every answer.

This makes the challenge of categorizing the verbatim comments extremely difficult. In addition, what a respondent wrote may require additional interpretation. In total, over 900 "comments/entries" were provided.

Every comment is meaningful. We encourage the reader to view the comments holistically.

First open-ended question: ***"Are there any priority or important items that you would like us to take into account when developing the Cost of Service application going to the Ontario Energy Board?"***

	TOTAL ----- (A)
Keep costs low/more affordable	43 19.6%
Environmental impact (e.g., global warming, reduce carbon footprint)	15 6.8%
Encourage/incentives for green energy/renewable energy (e.g., solar panels)	14 6.4%
Service reliability/less power outages	13 5.9%
Seniors discounts/incentives/reduce costs for seniors/keep seniors in mind	11 5.0%
Lower delivery costs/fees	9 4.1%
Administration overpaid/debt repayment/costs put on customers	7 3.2%
Improve safety/safety a top priority	6 2.7%
Develop an app for the phone (e.g., bills, monitor usage in real time)	5 2.3%
More ways to help us reduce usage	5 2.3%
Subsidies/breaks on the bill (e.g., for those on social assistance, for those making an effort to conserve)	4 1.8%
Maintain ownership/do not sell out	4 1.8%
Reduce tax/give tax credits	4 1.8%
Electric vehicle charging stations	4 1.8%

Update website (e.g., more user friendly)	4 1.8%
Better service (e.g., customer service, service maintained)	4 1.8%
Provide real time usage information	4 1.8%
Technology/smart technology (e.g., keeping up)	4 1.8%
Consideration for those who have electricity not gas in the homes	4 1.8%
Notification of outages/updates	3 1.4%
Transparency/justification of increases	3 1.4%
	1.4%
Not all seniors have computers/cell/smart phones (e.g., prefer bills in the mail)	2 0.9%
Threats of being cut off	2 0.9%
Rebates	2 0.9%
Maintain/use more nuclear power	2 0.9%
Bury cables/wires underground	2 0.9%
Infrastructure	2 0.9%
Other	22 10.0%
None/nothing/satisfied	57 26.0%
Don't know/refused	7 3.2%

Second open-ended question: ***"We are always looking for ways to reduce costs without compromising safety and reliability, what ideas do you have, which might help reduce costs without compromising performance?"***

	TOTAL ----- (A)
Cut staff/cut executive wages/cut pay increases to management/excessive benefits/pensions/lower overhead	39 10.7%
Do not increase rates/we pay enough/allow less fortunate access/force suppliers to reduce costs	28 7.7%
Invest in green energy/renewable energy	26 7.2%
Education/educate customers/the public (e.g., on social media, efficient usage)	20 5.5%
Be more efficient/planning effectively (e.g., budget management, oversight)	20 5.5%
Do not renovate/do not build a new building	12 3.3%
All cables should be underground/bury the cables	11 3.0%
Having too many employees on site/when few are required/train staff better	11 3.0%
Paperless billing/mandatory electronic statements/app	10 2.8%
Incentive to reduce usage/other ways to reduce household consumption	9 2.5%
Seniors should be taken into consideration (e.g., cannot afford, don't use smart phone/computers)	9 2.5%
Automation/use robots/AI	8 2.2%
Anything that they can do/rely on your expertise	8 2.2%

Improve infrastructure (e.g., modern)	8 2.2%
Technology/new advances	7 1.9%
Keep equipment/tool well maintained/upgrade when needed	7 1.9%
Reduce delivery costs/fees/'additional costs (e.g., debt repayment, taxes, costs of wind power)	7 1.9%
Improve website (e.g., not user friendly, considering going back to paper)	6 1.7%
Improve customer service	6 1.7%
Reduce waste	5 1.4%
Storage technology	5 1.4%
Remove smart meters/time of day usage/have a flat rate	5 1.4%
Provide customers with better tools (e.g., real time usage, when peak hours are, app to show how much it costs)	5 1.4%
Safety is the number one priority/despite the cost	5 1.4%
Get more government grants/money from government	4 1.1%
Lighting programs (e.g., LED technologies)	4 1.1%
Should join/merge with other power company	3 0.8%
Increase reliability	3 0.8%
No value for higher cost	3 0.8%
Create more online services/you can check yourself	3 0.8%
Cut fuel costs with a change in your fleet/don't have trucks idle	2 0.6%

Other payment options (e.g., pre-pay, Mastercard)	2 0.6%
Other	41 11.3%
None/nothing	52 14.3%
Don't know/refused	33 9.1%

Third open-ended question: ***"Do you have any additional comments about Oshawa Power or its Cost of Service Rate Application?***

	TOTAL ----- (A)
Rates are getting to be way too high/do not increase rates	38 11.0%
Poor/dislike survey (e.g., too long, badly designed, biased)	29 8.4%
Happy with/great service/you're the best	17 4.9%
Thank you (e.g., appreciate giving my opinion/feedback)	17 4.9%
Need more information	9 2.6%
Consider seniors (e.g., on a fixed income, trying to continue living in my home)	9 2.6%
Good survey (e.g., comprehensive, educational)	7 2.0%
Lower delivery charge/fees	6 1.7%
People who conserve should get a break/reward those who conserve	6 1.7%
Keep up the good work	5 1.4%
Small increases will happen/is expected/I can support increases	5

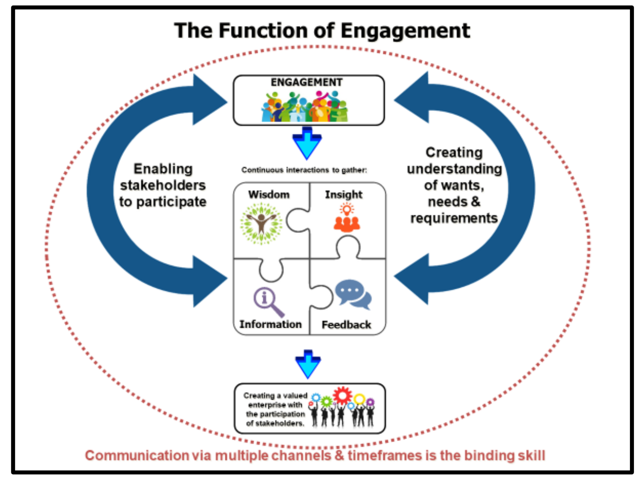
		1.4%
Website needs to be updated	5	1.4%
We have too many power outages	5	1.4%
Cut management salaries/bonuses	4	1.2%
Bring back the phone app/mobile app will be useful	4	1.2%
Alternative ways to find money than increasing our bills (e.g., civic buildings to turn down lights when closed...)	4	1.2%
Do not support new building/move	4	1.2%
Payments (equalized billing, auto payment, easier)	3	0.9%
I support a new building/you should move	3	0.9%
Electric vehicle charging	3	0.9%
Do not sell/out to a bigger company	3	0.9%
Should not have time of day usage/don't force me to do things in the evening	3	0.9%
Reliable	2	0.6%
Invest in green alternatives	2	0.6%
Maintain good infrastructure/maintain/replace equipment	2	0.6%
Environment concerns (e.g., zero waste, reduction in greenhouse gases, reduce pollution)	2	0.6%
You are going to do whatever you want anyway	2	0.6%
Give me a weekend/month free	2	0.6%
The costs are reasonable	2	

	0.6%
Other	41
	11.8%
None/nothing	134
	38.7%
Don't know/refused	17
	4.9%

❋ What is Taking A.I.M. (Applied Insights Methodology)

The purpose of engaging customers is to gather usable findings which help the LDC meet the needs and requirements of customers and other stakeholders while accelerating movement towards becoming a more effective and efficient organization with high levels of customer affinity. The goal is to ensure there is alignment between LDC plans and customer needs and expectations. The function of customer engagement is to create an understanding of wants, needs, and requirements. The key to getting meaningful input is to ensure customer respondents are enabled via multiple opinions & views methodologies.

An output, from Taking A.I.M. for Oshawa Power, is the production of this report, which we like to call “Oshawa Power’s Book on Customer Engagement.”



Unlike a single online or telephone survey, A.I.M. utilizes a multiple touch-point design to entice participation by customer-respondents who, like just about everyone in Ontario, is time-pressed. This multiple touch-point design helps to:

1- Keep the time requirements for respondents to a reasonable level
2- Identify, for the LDC, customer-respondent wants, needs and requirements
3- Clarify customer-respondent priorities by providing multiple opportunities to provide open-ended commentary
4- Identify the level of support for various capital and operational changes, including the associated costs.
5-

The Taking A.I.M. process helps the LDC to answer the following questions:

1- What are the customer-engagement (CE) activities that we have been doing?
2- What have we learned from those CE activities?
3- When going forward with a COS application which CE activities:
    a. Are best done with internal resources?
    b. Need to be enhanced?
    c. Should be completed by a 3rd party?
4- What are customers saying about what the priorities should be?
5- What are the challenges the LDC has identified for producing a successful COS application?
6- What level of community outreach can be achieved in the allocated timelines? What methods of outreach will be used?

7- What additional value, or synergy, can be achieved through the activities of producing a successful COS application?

One way to improve the effectiveness of various customer engagement activities is to determine the type of information the LDC is trying to gather.

Embedded in the Taking A.I.M. model are five levels of engagement.

For our purposes, the first four levels are Giving/Getting Information, Gathering Feedback; Capturing Insights; and Gaining Wisdom from respondents.

Understanding the type of feedback that is desired by the LDC helps ensure any survey work which is done, via telephone or online, is both effective and efficient for customer respondents.

By understanding the type of feedback from customer-respondents the LDC desires, a 5-phase project plan is then developed.

Taking A.I.M. Project Phases

Phase 1: Planning and Preparation (Partially done and is well underway)

- Conduct a review of current CE activities
- Identify ways to get the best from internal resources
- Project administration requirements

Phase 2: Customer Engagement Activities - Fieldwork

- Operationalize CE activities

Phase 2: Online COS DSP

- One online COS DSP survey with seven Chapters. Each chapter represents a different subject area

Phase 2: Telephone Survey

- Capitalize on the Fall 2018 telephone survey of Oshawa Power customers

Phase 2: Customer & Community Outreach (this is handled by OP personnel)

- Making the best use of activities

Phase 2: Support Activities

- Project administration
- Identify additional sources of data or information which can be used to help validate findings from Oshawa Power surveys, e.g., UtilityPULSE database, Ontario LDC benchmark
- Embed a “Hot Alert” function in every “Chapter” survey, i.e., give respondents the opportunity to speak to someone at Oshawa Power to voice their concerns or to have a problem solved
- Monitor and report on progress

Phase 3: Discussion, Analysis and Reporting for Internal Use

- Review findings with internal LDC personnel to help the alignment of plans

Phase 4: Report Development for COS DSP

- Survey data analyzed and reported in useable formats
- Provide 3rd party input into the completion of Appendix 2-AC

Phase 5: Post Project Review & Additional Recommendations

- Lessons learned
- Getting the most from the AIM

To further simplify and integrate various customer engagement online activities, four survey branding elements are used. These branding elements are used as visual cues for customer respondents as they relate to the purpose of their participation. For example, the branding element "Make Your Voice Count" was used on Oshawa Power's web page as a link to the online COS DSP survey. Oshawa Power went a step further and provided two (2) explainer videos to encourage participation in the survey. Individual questions within the online COS DSP survey also used the branding elements as visual prompts.

Taking A.I.M. the Online COS DSP survey Strategy

UtilityPULSE has been conducting customer research for Ontario's LDC community for over 21 years. Based on this experience, we have learned:

1- Long surveys (from a time perspective) have a high abandon rate, and to reduce the rate, we used a Chapter system to segment the subject matter. Each chapter has a different subject focus.

2- Respondents are mostly interested in giving feedback in the subject areas they are interested in, which means, areas they are not interested in typically attract higher levels of 'Don't know' selections.

3- Online surveys such as the COS DSP Survey which ask difficult questions that have complicated answers, often require an extensive amount of reading. Few respondents will take the time to read the supporting information. As a result, question design and scaling are impacted.

4- Question design for online should mimic question design found in other Oshawa Power research, for example, their regular telephone survey. This reduces the impact of one of the variables which can cause differences in findings. Though different methodologies i.e., online versus telephone, can impact scores, the reality is multiple methodologies can add to the richness of the data.

5- Decisions are not made rationally; they are made emotionally by human beings. To simplify decision making, five-point scales were used. For questions regarding planning, costs, or investments, respondents were given a maximum of 4 statements to choose from.

6- While different survey methods can produce different results, having consistency of question design, across multiple platforms, reduces one of the variables which can produce different outcomes.

Each Chapter of the online COS DSP survey has a different purpose and when combined, they become a wider story of gathering wisdom, information, feedback and insights from customer respondents. The mission and theme for each survey:

Online COS DSP Survey	Primary Theme
Chapter 1 *"About your Oshawa Power"*	Make Your Voice Count
Chapter 2 *"The Electricity Industry and Oshawa Power's role in it"*	Make Your Voice Count
Chapter 3 *"Customer priorities, which are the important ones?"*	Could You Help Us Decide
Chapter 4 *"Customer insights about billing and outages"*	Make Your Voice Count
Chapter 5 *"Facilities and General Plant Capital investments"*	Could You Help Us Decide
Chapter 6 *"Gathering insights about customer care operational improvements"*	Could You Help Us Decide
Chapter 7 *"Distribution System Plan Capital investments"*	Could You Help Us Decide
Wisdom from Customers *“Collecting ideas to reduce costs and comments about the COS rate application”*	Wisdom from Customers

Methodology

Telephone surveys:

The 2018 findings in this report are based on telephone interviews conducted for Simul Corp. / UtilityPULSE by Logit Group between September 24 - October 26, 2018, with 401 respondents who pay or look after the electricity bills from a list of residential and small and medium-sized business customers supplied by Oshawa Power. The 2017 telephone survey was conducted with 400 respondents between January 18 – February 11, 2017.

The sample of phone numbers chosen was drawn randomly to ensure each business or residential phone number on the list had an equal chance of being included in the poll.

The sample was stratified so that 85% of the interviews were conducted with residential customers and 15% with commercial customers.

In sampling theory, in 19 cases out of 20 (95% of polls in other words), the results based on a random sample of 401 residential and commercial customers will differ by no more than ±4.89 percentage points where opinion is evenly split.

The margin of error for the sub-samples is larger and should be used as directional information only. However, the directional information may have more meaning if historical data or Ontario benchmark data shows similar results.

Online COS DSP survey:

In order to write a "book" on customer engagement for Oshawa Power, a comprehensive survey with seven (7) customized "chapters," was produced online. Each chapter in the survey had a different theme, and the survey offered the respondent an opportunity to have someone from Oshawa Power contact them, thereby adding an interactive element to the survey.

Customers were invited to participate in the online COS DSP surveys via advertising efforts, social media messaging, home page website profile, and IVR calls. In total, 1,240 customers respondent to online COS DSP survey containing COS DSP information.

UtilityPULSE

A Division of Simul Corporation

TAKING A.I.M.

(Applied Insights Methodology)

UtilityPULSE, through polls and surveys, provides executives and managers with customer and employee feedback that assists in making both strategic and operational decisions. We believe by specializing in the utility sector with our polls and surveys, LDCs get stronger analysis of data and answers to key questions that, in turn, help them formulate key strategies to assist their organization's leaders in creating a better place to work and a better place to do business with.

All comments and questions should be addressed to:

Sid Ridgley, Simul Corporation
UtilityPULSE division
Tel: 1-905-895-7900
email: sridgley@simulcorp.com

Appendix D: Regional Planning Documents

Appendix D(i):GTA East Regional Infrastructure Plan 2019-2024

GTA East

2019-2024 REGIONAL INFRASTRUCTURE PLAN
FEBRUARY 29, 2020

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Prepared and supported by:

Company
Elexicon Energy Inc.
Oshawa PUC Networks Inc.
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator (IESO)
Hydro One Networks Inc. (Lead Transmitter)

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Disclaimer

This Regional Infrastructure Plan ("RIP") report is an electricity infrastructure plan to identify and address near and long-term based on information provided and/or collected by the Study Team.

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

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

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EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE WITH PARTICIPATION AND INPUT FROM THE RIP STUDY TEAM IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE PLANNED, DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE GTA EAST REGION.

The participants of the Regional Infrastructure Planning ("RIP") Study Team included members from the following organizations:

- Elexicon Energy Inc.
- Oshawa PUC Networks Inc.
- Independent Electricity System Operator (IESO)
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Lead Transmitter)

The last regional planning cycle for the GTA East Region was completed in January 2017 with the publication of the RIP report.

This RIP is the final phase of the 2nd regional planning cycle and follows the 2nd Cycle GTA East Region's Needs Assessment ("NA") in August 2019. Based on the findings of the NA, the Study Team recommended no further regional coordination is required at this time. Hence, RIP is based on the recommendations of NA report.

This RIP provides a consolidated summary of the outcome of the needs and recommended plans for the GTA East region as identified by the regional planning study team. The RIP also discusses needs identified in the previous regional planning cycle and the Needs Assessment report for this cycle; and the projects developed to address these needs. Implementation plans to address some of these needs are already completed or are underway. Since the previous regional planning cycle, following projects have been completed:

- Enfield TS: 75/100/125 MVA transformation capacity in Oshawa-Clarington sub-region (Completed in 2019)

The major infrastructure investments recommended by the Study Team over the near- and mid-term are provided in below Table 1, along with their planned in-service date and budgetary estimates for planning purpose.

Table 1: Recommended Plans in GTA East Region over the Next 10 Years

No.	Needs	Plans	Planned I/S Date	Budgetary Estimate ($M)
1	Increase Transformation Capacity in Pickering-Ajax-Whitby Sub-region	Build Seaton MTS	2021	43
2	Cherrywood TS – 230kV & 500kV Breaker Replacements (multi-phase projects)	Replace 230 kV and 500 kV Air Blast Circuit Breakers (ABCB) at Cherrywood TS	2027	184
3	Cherrywood TS – LV DESN Switchyard Refurbishment	Existing 44kV DESN switchyard replacement at Cherrywood TS	2025	12
4	Wilson TS – T1, T2 and Switchyard Refurbishment	Existing T1, T2 and 44 kV BY bus switchyard replacement	2022	36

The Study Team recommends:

- Continue with the investments listed in Table 1 while keeping the Study Team apprised of project status.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE GTA EAST REGION BETWEEN 2019 AND 2029.

The report was prepared by Hydro One Networks Inc. ("Hydro One") with input from Study Team members during the NA phase and documents the results of the Needs Assessments and recommended plan. RIP Study Team members included representative from Elexicon Energy Inc. ("Elexicon"), Oshawa PUC Networks Inc. ("OPUCN"), Hydro One Distribution, and the Independent Electricity System Operator ("IESO") in accordance with the Regional Planning process established by the Ontario Energy Board ("OEB") in 2013.

The GTA East Region comprises the municipalities of Pickering, Ajax, Whitby, Oshawa, Clarington, and Durham area. Electrical supply to the GTA East Region is provided through 500/230kV autotransformers at Cherrywood Transformer Station (TS) and Clarington TS and five 230 kV transmission lines connecting Cherrywood TS to Eastern Ontario. There are five Hydro One step-down transformer stations and three other direct transmission connected load customers. The distribution system is at two voltage levels, 44kV and 27.6kV. The boundaries of the GTA East Region are shown below in Figure 1-1.

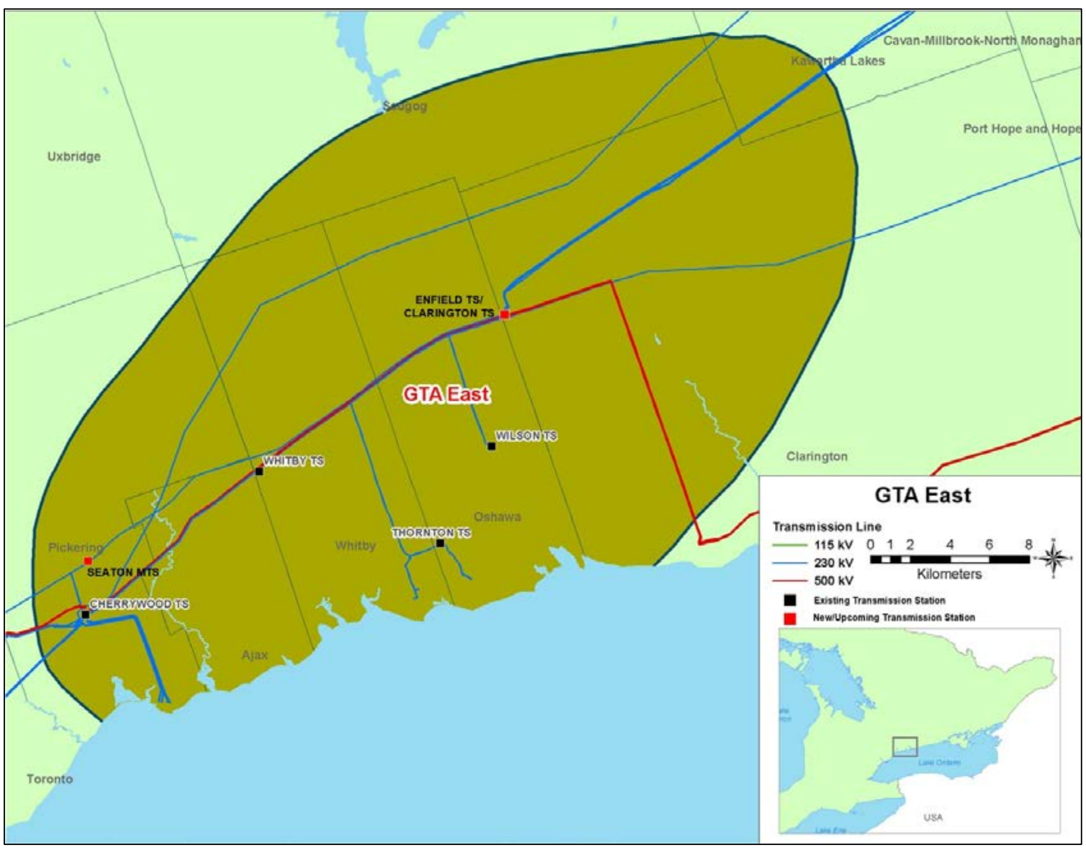


Figure 1-1: GTA East Region

1.1 Objective and Scope

The RIP report examines the needs in the GTA East Region. Its objectives are to:

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

The RIP reviewed factors such as the load forecast, major high voltage sustainment issues emerging over the near, mid and long-term, transmission and distribution system capability along with any updates with respect to local plans, conservation and demand management (“CDM”), renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- Discussion of any other major transmission infrastructure investment plans over the near, mid and long-term (0-20 years)
- Identification of any new needs and a wires plan to address these needs based on new and/or updated information, if any.

1.2 Structure

The rest of the report is organized as follows:

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

2. REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board ("OEB") in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment [1] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase, which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Study Team determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them.

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

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

[1] Also referred to as Needs Screening

The RIP phase is the fourth and final phase of the regional planning process and involves: discussion and reconfirmation of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive report of a wires plan for the region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter.

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

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

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

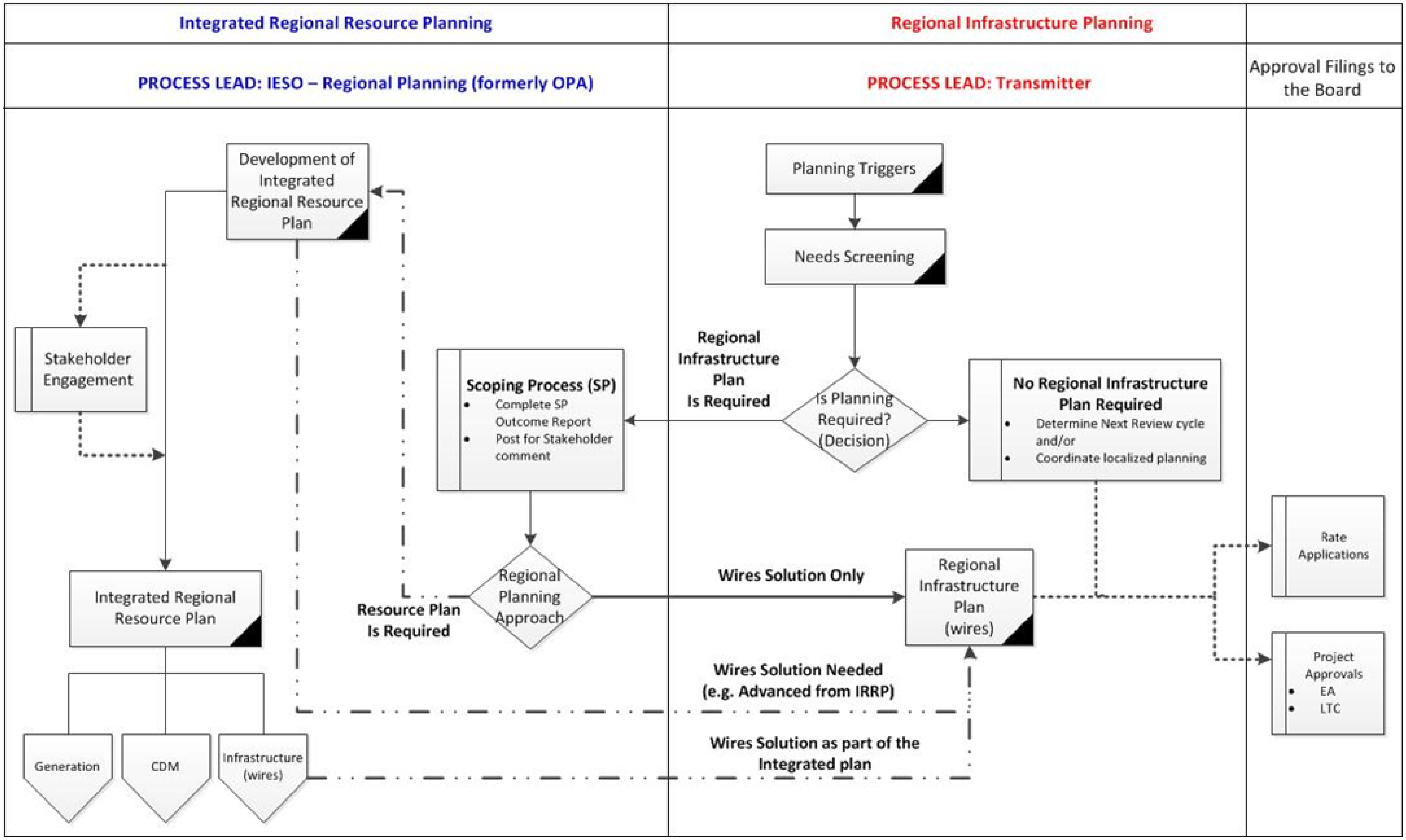


Figure 2-1: Regional Planning Process Flowchart

2.3 RIP Methodology

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

1. Data Gathering: The first step of the process is the review of planning assessment data collected in the previous phase of the regional planning process. Hydro One collects this information and reviews it with the Study Team to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Depending upon the changes to load forecast or other relevant information, regional technical assessment may or may not be required or be limited to specific issue only. Additional near and mid-term needs may be identified in this phase.
3. Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

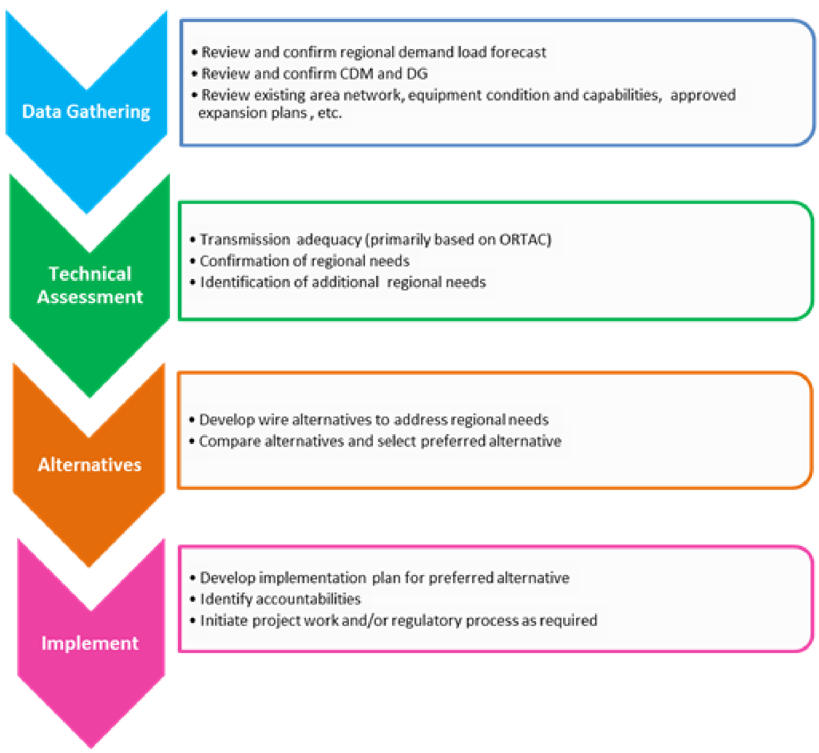


Figure 2-2: RIP Methodology

3. REGIONAL CHARACTERISTICS

THE GTA EAST REGION IS COMPRISED OF THE PICKERING-AJAX-WHITBY SUB-REGION AND THE OSHAWA-CLARINGTON SUB-REGION. ELECTRICAL SUPPLY TO THE REGION IS PROVIDED FROM FIVE 230KV STEP-DOWN TRANSFORMER STATIONS.

Bulk electrical supply to the GTA East Region is currently provided through Cherrywood TS and Clarington TS, two major 500/230kV autotransformer station in the region, and five 230kV circuits emanating east from Cherrywood TS. Five local area step-down transformer stations and three other direct transmission connected load customers are connected to the 230 kV system in the region. Major generation in the area includes the Pickering Nuclear Generating Station ("NGS") which consists of six generating units with a combined output of approximately 3000 MW and is connected to the 230kV system at Cherrywood TS.

The August 2019 GTA East Region NA report, prepared by Hydro One, considered the entire GTA East Region. For simplicity, this report divides GTA East Region into two sub-regions, Pickering-Ajax-Whitby Sub-region and Oshawa-Clarington Sub-region, as described below.

3.1 Pickering-Ajax-Whitby Sub-region

The Pickering-Ajax-Whitby Sub-region comprises primarily the City of Pickering, Town of Ajax, part of the Town of Whitby, and part of the Townships of Uxbridge and Scugog. It is supplied by Cherrywood TS, a 500/230kV autotransformer station, two 230kV transformer stations, namely Cherrywood TS DESN and Whitby TS (2 DESNs), that step down the voltage to 44kV and 27.6kV. The LDCs supplied in the Sub-region are Hydro One Distribution, and Elexicon.

The Pickering-Ajax-Whitby Sub-region transmission facilities are shown in Figure 3-1.

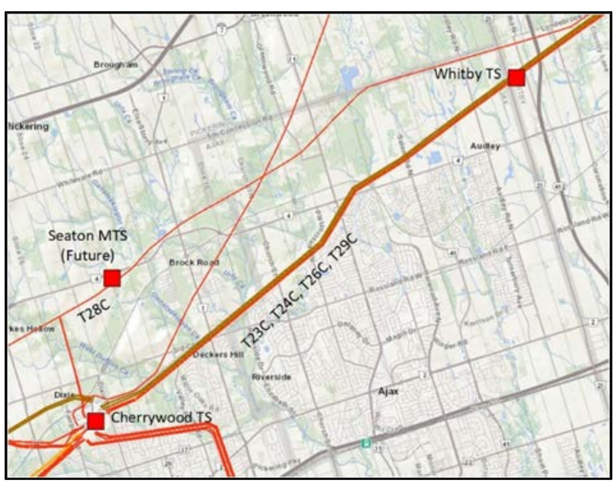


Figure 3-1: Pickering-Ajax-Whitby Sub-region

3.2 Oshawa-Clarington Sub-region

The Oshawa-Clarington sub-region comprises primarily the City of Oshawa, part of the Municipality of Clarington, part of Whitby, and part of the Township of Scugog. It is supplied by Cherrywood TS, a 500/230kV autotransformer station to the west, two 230kV transformer stations, namely Wilson TS (2 DESNs) and Thornton TS, that step down the voltage to 44kV at distribution level. The sub-region also includes three direct transmission connected load customers. Local generation in the area consists of the 60 MW Whitby Customer Generating Station ("CGS"), a gas-fired cogeneration facility that connects to 230kV circuit T26C. Thornton TS also supplies some load within the Pickering-Ajax-Whitby sub-region. The LDCs supplied in the sub-region are Elexicon, Hydro One Distribution, and OPUCN.

A new 500/230kV autotransformer station in the GTA East Region within the township of Clarington, Clarington TS, went into service in 2018. The new Clarington TS provided additional load meeting capability in the region and will eliminate the overloading of Cherrywood autotransformers that may result after the retirement of the Pickering NGS in the near future.

The new autotransformer station consists of two 750MVA, 500/230kV autotransformers and a 230kV switchyard. The autotransformers will be supplied from two 500kV circuits that pass next to the proposed site. The 230kV circuits supplying the east GTA will be terminated at Clarington TS. Clarington TS will become a major supply source for the GTA East Region load.

A new 230/44kV transformer station, Enfield TS, was in-serviced in March 2019. The transformer station provided relief to overloading at Wilson TS and supplies Hydro One Distribution and Oshawa PUC. The station is located inside the Clarington TS yard and is directly connected to the Clarington TS 230 kV bus.

The Oshawa-Clarington Sub-region transmission facilities are shown in Figure 3-2.

Figure 3-2: Oshawa-Clarington Sub-region

A single line diagram of the GTA East Region transmission system is shown in Figure 3-3.

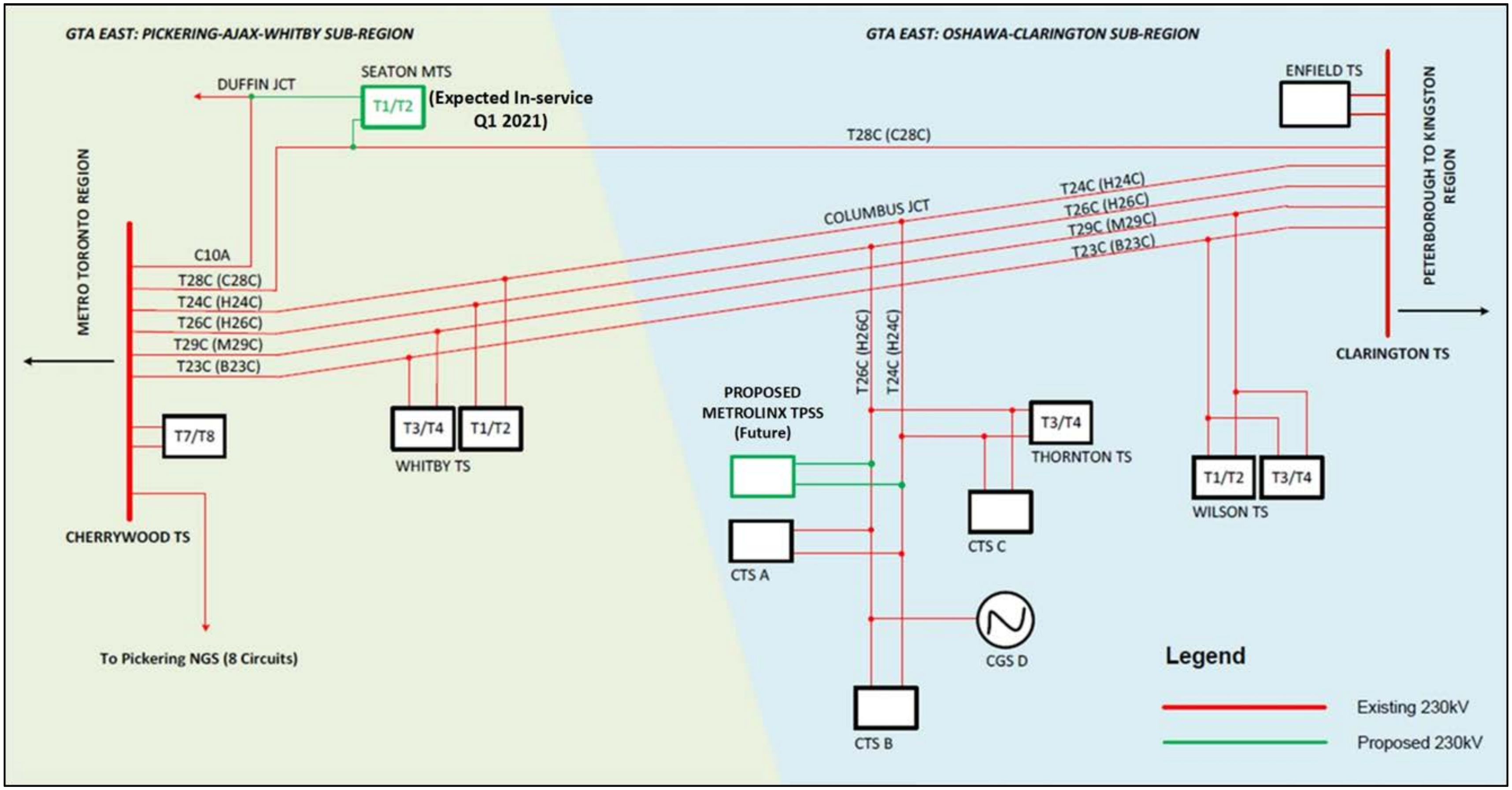


Figure 3-3: Single Line Diagram of GTA East Region

4. TRANSMISSION PROJECTS COMPLETED OVER LAST TEN YEARS

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND COMPLETED BY HYDRO ONE, IN CONSULTATION WITH THE LDCs AND/OR THE IESO, AIMED TO MAINTAIN OR IMPROVE THE RELIABILITY AND ADEQUACY OF SUPPLY IN THE GTA EAST REGION.

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

- Whitby TS T1/T2 (2009) – built a new step-down transformer station supplied from 230kV circuits T24C and T26C in municipality of Whitby to increase transformation capacity for Elexicon requirements.

- Wilson TS T1/T2 DESN1 (2015) – installed LV neutral grounding reactors to reduce line-to ground short circuit fault levels to facilitate DG connections.

- Thornton TS T3/T4 (2016) – replaced end-of-life transformers. Also installed LV neutral grounding reactors to reduce line-to-ground short circuit fault levels to facilitate DG connections.

- Clarington TS (2018) – built a new 500/230kV autotransformer station to increase transmission supply capacity to the GTA East Region, eliminate the overloading of Cherrywood TS autotransformers that may result after the retirement of Pickering NGS, and improve supply reliability to the Region.

- Enfield TS (2019) – built a new 230/44kV transformer station to provide relief for Wilson TS and for future load growth in Oshawa-Clarington sub-region.

5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

Figure 5-1 shows the GTA East Region's summer peak coincident and non-coincident load forecast. The non-coincident load forecast was used to determine the need for station capacity and the coincident load forecast was used to assess need for transmission line capacity in the region.

The load forecasts for the region were developed using the summer 2018 actual peak adjusted for extreme weather and applying the station net growth rates provided by the LDCs. The load in the GTA East Region is expected to increase at an annual rate of approximately 2.8% between 2019 and 2029. The gross and net non-coincident and coincident load forecast, adjusted for extreme weather, CDM, and DG, for each station in the region are provided in Appendix D and E.

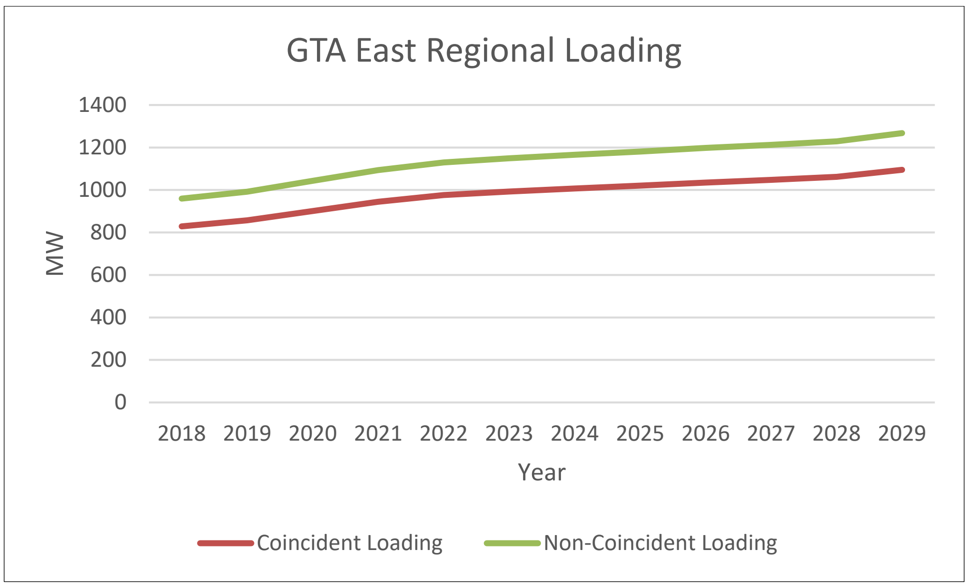


Figure 5-1 GTA East Region Net Load Forecast

5.2 Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2019-2029.
- All facilities listed in Section 4 are in-service.
- Where applicable, industrial loads have been assumed based on historical information.
- Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.
- Line capacity adequacy is assessed by using coincident peak loads.
- Normal planning supply capacity for transformer stations in this sub-region is determined by the Hydro One summer 10-Day Limited Time Rating (LTR).
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).
- Metrolinx plans to connect a Traction Power Substation (TPSS) to Hydro One's 230 kV circuits T24C and T26C in East Whitby. The Metrolinx TPSS loads have not been included in the forecast as the timing is uncertain and the loads do not impact the need or timing of new facilities.

6. ADEQUACY OF FACILITIES

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND DELIVERY STATION FACILITIES SUPPLYING THE GTA EAST REGION OVER THE 2019-2029 PERIOD.

Within the current regional planning cycle one regional assessment have been conducted for the GTA East Region. The study is shown below:

1) 2019 GTA East Needs Assessment (NA) Report

The NA report identified a number of needs to meet the forecast load demands and EOL asset issues. A review of the loading on the transmission lines and stations in the GTA East Region was also carried out as part of the RIP report using the latest regional load forecast as given in Appendix D. Sections 6.1 to 6.5 present the results of this review. Further description of assessments, alternatives and preferred plan along with status is provided in Section 7.

All the needs in the previous RIP have been addressed. Enfield TS is in-service and Seaton MTS is under contstruction.

6.1 230 kV Transmission Facilities

The GTA East Region is comprised of five 230kV circuits, T23C/T29C, T24C/T26C, and T28C, supplying both the Pickering-Ajax-Whitby Sub-region and the Oshawa-Clarington Sub-region. Refer to Figure 3-3 for the single line diagram of the transmission facilities in the Region.

1. Cherrywood TS to Clarington TS 230 kV circuits - T23C, T29C, T24C, T26C, and T28C

The Cherrywood TS to Clarington TS circuits, carry bulk transmission flows as well as serve local area station loads within the Region. These circuits are adequate over the study period. Pickering NGS is connected to the Cherrywood TS through 8 dedicated 230 kV circuits. Pickering NGS is expected to be retire in 2025.

6.2 500/230 kV Autotransformer Facilities

The 230 kV autotransformers facilities in the region consist of the following elements:

a. Cherrywood TS 500/230 kV autotransformers: T14, T15, T16, T17
b. Clarington TS 500/230 kV autotransformers: T2, T3

The autotransformers at Cherrywood TS and Clarington TS serve the 230 kV transmission network and local loads in GTA East. The Cherrywood TS autotransformer and Clarington TS autotransformer facilities are adequate over the study period.

6.3 Pickering-Ajax-Whitby Sub-region's Step-Down Transformer Station Facilities

There are two step-down transformer stations connected in the Pickering-Ajax-Whitby sub-region, summarized in Table 6-2. The station coincident and non-coincident forecasts are given in Appendix D.

Table 6-2: Transformation Capacities in the Pickering-Ajax-Whitby Sub-region

Facilities	Station MW Load			Station Limited Time Rating (LTR) MW	Need Date
	2030	2035	2040		
Cherrywood TS T7/T8 (44 kV)	160	160	160	160	2040+
Whitby TS T1/T2 (27.6 kV)	90	90	90	90	2040+
Whitby TS T1/T2 (44 kV)	70	74	83	90	2040+
Whitby TS T3/T4 (44 kV)	162	170	179	187	2040+
Seaton MTS (27.6kV)	75	79	83	153	2040+

Based on the submitted load forecasts, the stations in Pickering-Ajax-Whitby sub-region have adequate transformation capacity to supply the load in long term.

6.4 Oshawa-Clarington Sub-region's Step-Down Transformer Station Facilities

There are three step-down transformer stations in the Oshawa-Clarington Sub-region, summarized in Table 6-3.

Table 6-3: Transformation Capacities in the Oshawa-Clarington Sub-Region

Facilities	Station MW Load			Station Limited Time Rating (LTR) MW	Need Date
	2030	2035	2040		
Wilson TS T1/T2 (44 kV)	161	161	161	161	2040+
Wilson TS T3/T4 (44 kV)	134	134	134	134	2040+
Thornton TS T3/T4 (44 kV)	143	149	154	159	2040+
Enfield TS T1/T2 (44 kV)	144	171	202	157	2030-2035

The previous Regional Planning cycle recommended a new station, named Enfield TS, in the area mainly to relieve the Wilson TS from overloading as well as to meet the new load growth in the area. As per recommendation, Hydro One has installed a new 230kV / 44kV Enfield TS with six (6) 44kV feeder breaker positions with provision for two (2) additional 44kV future feeder breaker positions. The new Enfield TS is located on the the Clarington TS site and will supply OPUC through four (4) feeders and Hydro One Dx

through two (2) feeders. The station went in-service in March 2019 and currently feeder load transfer work is in progress to transfer some existing load from Wilson TS to Enfield TS.
Based on the submitted load forecasts, additional transformation capacity will be required in the long term.

6.5 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:

- Autotransformers
- Power transformers
- HV breakers
- Transmission line requiring refurbishment where an uprating is being considered for planning needs and require Leave to Construct (i.e., Section 92) application and approval
- HV underground cables where an uprating is being considered for planning needs and require EA and Leave to Construct (i.e., Section 92) application and approval

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

1. Replacing equipment with similar equipment and built to current standards (i.e., "like-for-like" replacement);
2. Replacing equipment with similar equipment of higher / lower ratings i.e. right sizing opportunity and built to current standards;
3. Replacing equipment with lower ratings and built to current standards by transferring some load to other existing facilities;
4. 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, major high voltage equipment has been identified as approaching its end of life over the next 10 years and assessed for right sizing opportunity in section 7.

6.6 System Reliability and Load Restoration

In case of contingencies on the transmission system, ORTAC provides the load restoration requirements relative to the amount of load affected. Planned system configuration must not exceed 600 MW of load curtailment/rejection. In all other cases, the following restoration times are provided for load to be restored for the outages caused by design contingencies.

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

The previous regional planning (RP) comprehensively assessed circuit pairs T29C/T23C and T24C/T26C as they are on the same tower line and the possibility of loss of either pair of circuits during peak load may result in load shortfall/outage exceeding the limits of 150MW and 250MW to be restored within 4 hours and 30 minutes, respectively. However, based on the analysis, historical performance and reliability data for these circuits in the region, the Study Team recommended that no action is required at this time. There is no change on the assumptions used in this report resulting in any significant system reliability or load restoration concerns in the region.

6.7 Longer Term Outlook (2030-2040)

While the RIP was focused on the 2019-2029 period, the Study Team has also looked at longer-term loading between 2030 and 2040.

No long term needs for the Pickering-Ajax-Whitby Sub-Region have been identified. Seaton MTS is expected to supply the Sub-Region's demand adequately over the next two decades.

The demand in Oshawa-Clarington Sub-Region is expected to grow over the long term period. The new Enfield TS will provide load relief to Wilson TS through distribution load transfer capability. As the demand grows in the northern Oshawa area in the long term, additional transformation capacity may have to be planned for in future. Further review and assessment will commence in next Regional Planning cycle to identify and develop alternatives to address new needs, if any.

Municipalities in region may develop their community energy plans with a primary focus to reduce their energy consumption by local initiatives over next 25 to 30 years. With respect to electricity, these communities may plan for an increased reliance on community energy sources such as distributed generation, generation behind the meters like rooftop solar systems and local energy battery storage systems to reduce cost and for improved reliability of electricity supply.

Some of the communities in Ontario are working towards self-sufficiency by improving efficiencies of existing local energy systems i.e. reducing energy consumption and losses by means of utilizing smarter buildings, houses, efficient heating, cooling, appliances, equipment, and processes for all community needs. Ultimately, the objective of these energy plans in the region is to be a net zero carbon community over the next 25 to 30 years.

Community energy plans may have potential to supplement and/or defer future transmission infrastructure development needs. The Study Team therefore recommends LDCs to review their respective regional community energy plans and provide updates to the working group of any potential projects that may affect future load forecasts in the next cycle of regional planning.

7. REGIONAL NEEDS & PLANS

THIS SECTION DISCUSSES ELECTRICAL INFRASTRUCTURE NEEDS IDENTIFIED IN THE PREVIOUS REGIONAL PLANNING CYCLE, THE NEEDS ASSESSMENT REPORT FOR THIS CYCLE; AND SUMMARIZES THE PLANS DEVELOPED TO ADDRESS THESE NEEDS.

This section outlines and discusses infrastructure needs and plans to address these needs for the near-term (up to 5 years) and the mid- term (5 to 10 years) and the expected planned in-service facilities to address these needs.

There are no new needs identified in the GTA East Region. Current development and sustainment plans are further discussed below.

7.1 Seaton MTS - Increase Transformation Capacity in Pickering-Ajax-Whitby Sub-Region

7.1.1 Description

The Pickering-Ajax-Whitby Sub-Region is supplied by Cherrywood TS at 44kV level and Whitby TS at 27.6kV and 44kV levels. Over the next 10 years, the load in this Sub-Region is forecasted to increase at approximately 2.9% annually.

With the proceeding of a new residential and mixed use commercial area in the Seaton are, significant increase in load demand is expected at 27.6kV level resulting in a shortage of transformation capacity at Whitby TS 27.6kV by 2021.

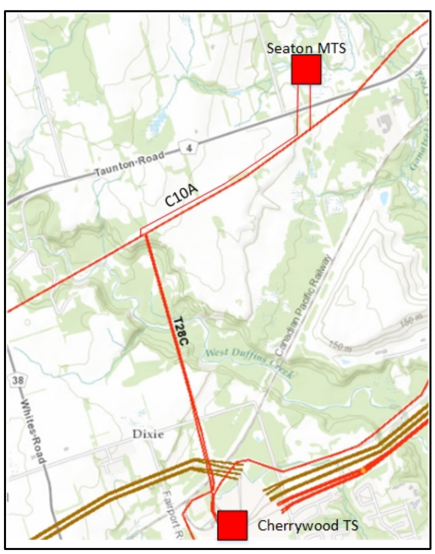


Figure 7-1: Location of Seaton MTS

The following alternatives were considered to address the Transformation Capacity in Pickering-Ajax-Whitby Sub-Region need:

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the expected thermal overloading at Whitby TS 27.6 kV due to the load growth in the Sub-Region.
2. **Alternative 2 – Build Seaton MTS:** Elexicon to proceed with the installation of a new Seaton MTS. To feed the new Seaton MTS, Hydro One will be converting an existing single circuit 230 kV transmission line (T28C) to a double circuit line from Duffin Jct to Seaton MTS to serve the station. Hydro One is working with Elexicon and planning for Q1 2020 in-service. This alternative would address the expected thermal overloading at Whitby TS 27.6kV due to the load growth in the Sub-Region.

7.2 Cherrywood TS – 230kV & 500kV Breaker Replacements (multi-phase project) Mid-Term End of Life Transformer Replacements

7.2.1 Description

Cherrywood TS is a major Bulk Electricity System (BES), Northeast Power Coordination Council (NPCC) station, located at east end of Greater Toronto Area (GTA). The station includes 500 kV and 230 kV switchyards, four autotransformers that transfer electricity from Darlington and Pickering Nuclear Generating Station into GTA, and a 44kV DESN tapped off the 230kV bus which delivers power to Elexicon. The existing 500kV and 230kV Air Blast Circuit Breaker (ABCBs), with an average age of 48 years are obsolete and at end of life. These are Bulk System elements and not in the scope of regional planning. Discussion is provided for information only.

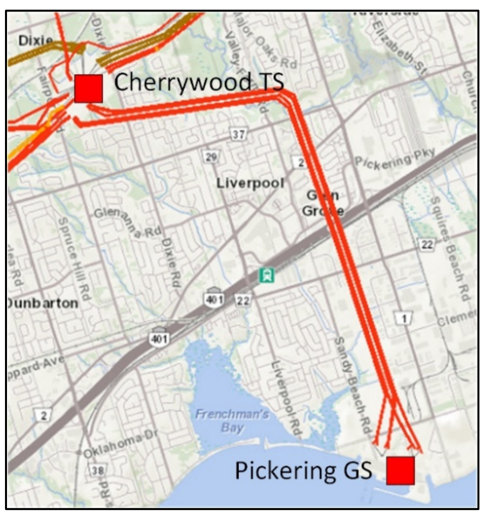


Figure 7-2: Cherrywood TS

The scope of this project is to replace the existing eight (8) 500kV and thirty (30) 230kV air-blast circuit breakers in a multi-phase project release. The targeted in-service for the final phase is in year 2027.

The following alternatives were considered to address Cherrywood TS HV Breakers end-of-life assets need:

3. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.
4. **Alternative 2 - Like-for-like replacement with similar equipment:** Proceed with these end of life asset replacement as per existing refurbishment plan for the HV breakers at Cherrywood TS. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.

7.3 Cherrywood TS – LV DESN Switchyard Refurbishment Mid-Term End of Life Breaker Replacement

7.3.1 Description

The LV switchyard for the 44 kV DESN T7/T8 at Cherrywood TS is at end of life due to age and condition. The scope of this project is to replace all 44 kV switchyard assets with the current standard equipment. The targeted in-service is in year 2025.

The following alternatives were considered to address Cherrywood TS DESN LV breaker end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.
2. **Alternative 2 - Like-for-like replacement with similar equipment:** Proceed with these end of life asset replacement as per the existing refurbishment plan for the LV breakers at Cherrywood TS DESN. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.

7.4 Wilson TS – T1, T2 and Switchyard Refurbishment

7.4.1 Description

Wilson TS is located in Oshawa and it contains 4 X 75/100/125 MVA, 230/44 kV, transformers that supplies city of Oshawa through OPUCN feeders and surrounding areas of Oshawa through Hydro One Dx owned feeders. The T1 and T2 transformers at Wilson TS and majority of assets within 44 kV BY switchyard have reached end of life. The associated spill containment structure do not meet current standard.

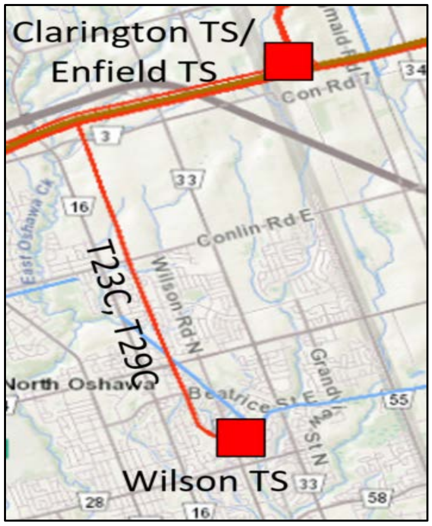


Figure 7-3: Wilson TS

The scope of this project is to replace T1/T2 step-down transformers, associated spill containment structure and majority of assets within 44 kV BY switchyard. The targeted in-service is in year 2022.

The Study Team has assessed downsizing and/or upsizing need for these transformers. The Working Group concluded that reducing the size of these transformers is not an option as the load in the area is increasing. Upsizing is also not an option because this is the highest rating of transformer. Accordingly, replacing these transformers with similar size is the only “right sizing” option.

The following alternatives were considered to address Wilson TS end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One’s obligation to provide reliable supply to the customers.
2. **Alternative 2 - Like-for-like replacement with similar equipment:** Proceed with these end of life asset replacement as per the existing refurbishment plan for the transformers at Wilson TS. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.

8. CONCLUSION AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN (RIP) REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE GTA EAST REGION.

The major infrastructure investments recommended by the Study Team in the near and mid-term planning horizon are provided in Table 8-1 below, along with their planned in-service date and budgetary estimates for planning purpose.

Table 8-1: Recommended Plans in GTA East Region over the Next 10 Years

No.	Needs	Plans	Planned I/S Date	Budgetary Estimate ($M)
1	Increase Transformation Capacity in Pickering-Ajax-Whitby Sub-region	Build Seaton MTS	2021	43
2	Cherrywood TS – 230kV & 500kV Breaker Replacements (multi-phase projects)	Replace 230 kV and 500 kV Air Blast Circuit Breakers (ABCB) at Cherrywood TS	2027	184
3	Cherrywood TS – LV DESN Switchyard Refurbishment	Existing 44kV DESN switchyard replacement at Cherrywood TS	2025	12
4	Wilson TS – T1, T2 and Switchyard Refurbishment	Existing T1, T2 and 44 kV BY bus switchyard replacement	2022	36

The Study Team recommends that:

- Hydro One and Elexicon continue with the infrastructure projects as listed above in Table 8-1 while keeping the Study Team apprised of project status.
- No additional transformation capacity is required in the Pickering-Ajax-Whitby sub-region in the long term.
- Additional transformation capacity may be required in the Oshawa-Clarington sub-region in the long term.

9. REFERENCES

[1]. Hydro One, "Needs Assessment Report, GTA East Region", 15 August 2019

[2]. Regional Infrastructure Planning Report 2017 – GTA East - January 2017

[3]. IRRP Report – Pickering-Ajax-Whitby Sub-Region – June 2016

[4]. Needs Assessment Report GTA East – August 2014

[5]. Planning Process Working Group Report to the Ontario Energy Board - May 2013

[6]. Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0 -August 2007

APPENDIX A: TRANSMISSION LINES IN THE GTA EAST REGION

Location	Circuit Designation	Voltage Level
Cherrywood TS to Clarington TS	T23C/T24C/T26C/T29C	230kV
Cherrywood TS to Clarington TS	T28C	230kV

APPENDIX B: STATIONS IN THE GTA EAST REGION

Station (DESN)	**Voltage Level**	**Supply Circuits**
Cherrywood TS T7/T8	230/44kV	Cherrywood TS, DK Bus
Whitby TS T1/T2 27.6 Whitby TS T1/T2 44	230/27.6kV 230/44kV	T24C/T26C
Whitby TS T3/T4	230/44kV	T23C/T29C
Wilson TS T1/T2	230/44kV	T23C/T29C
Wilson TS T3/T4	230/44kV	T23C/T29C
Thornton TS T3/T4	230/44kV	T24C/T26C
Enfield TS T1/T2	230/44kV	Clarington TS, PK Bus
Seaton MTS*	230/44kV	C10A/T28C

*Future – Expected In-service 2021

APPENDIX C: DISTRIBUTORS IN THE GTA EAST REGION

Distributor Name	Station Name	Connection Type
Elexicon Inc.	Whitby TS	Tx
	Thornton TS	Dx
	Cherrywood TS	Dx
	Wilson TS	Dx
	Seaton MTS	Tx
Oshawa PUC	Wilson TS	Tx
	Thornton TS	Tx
	Enfield TS	Tx
Hydro One Networks Inc.	Cherrywood TS	Tx
	Wilson TS	Tx
	Whitby TS	Tx
	Thornton TS	Tx
	Enfield TS	Tx

Appendix D: Area Stations Non Coincident Net Load

Area & Station	LTR (MW)	Near & Mid-Term Forecast (MW) 2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Long-Term Forecast (MW) 2030	2035	2040
Pickering-Ajax-Whitby																
Cherrywood TS T7/T8	175	161	164	163	163	162	162	161	161	161	160	160	160	160	160	160
Whitby TS T3/T4	187	142	124	132	137	143	148	150	152	154	156	158	160	162	170	179
Whitby TS T1/T2 (27.6kV)	90	56	59	74	90	90	90	90	90	90	90	90	90	90	90	90
Whitby TS T1/T2 (44kV)	90	44	57	58	60	61	62	63	64	66	67	68	69	70	74	83
Seaton MTS T1/T2	153	0	0	0	4	20	28	36	43	50	57	65	74	75	79	83
CTS A		25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
CTS B		95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
CTS C		21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
CGS D		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Area Total		545	545	568	594	617	631	642	651	661	671	682	694	698	714	736
Oshawa-Clarington																
Enfield TS T1/T2	157	0.0	19.0	83.5	108.9	111.4	115.0	118.5	121.9	126.4	129.9	134.4	139.0	144	171	202
Thornton TS T3/T4	160	138.3	137.9	130.7	132.9	135.2	136.2	137.2	138.2	139.2	140.3	141.3	142.4	143	149	154
Wilson TS T1/T2	161	153.6	152.0	152.5	151.2	153.2	155.4	156.7	158.8	160.2	161.4	161.9	161.0	161.0	161.0	161.0
Wilson TS T3/T3	134	141.7	141.7	115.3	116.0	124.1	125.5	127.0	128.5	130.0	131.4	132.9	134.0	134.0	134.0	134.0
Area Total		434	451	482	509	524	532	539	547	556	563	570	576	582	614	652
Regional Total		979	996	1050	1103	1141	1163	1181	1199	1217	1234	1252	1271	1280	1329	1387

Appendix E: Area Stations Coincident Net Load

Area & Station	LTR (MW)	Near & Mid-Term Forecast (MW)												Long-Term Forecast (MW)		
		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040
Pickering-Ajax-Whitby																
Cherrywood TS T7/T8	175	160	164	163	163	162	162	161	161	161	160	160	159	159	159	159
Whitby TS T3/T4	187	135	134	141	146	152	156	158	160	162	163	165	167	169	177	187
Whitby TS T1/T2 (27.6kV)	90	41	43	54	66	65	65	65	65	65	65	64	65	90	90	90
Whitby TS T1/T2 (44kV)	90	56	57	58	60	61	62	63	64	66	67	68	70	70	74	83
Seaton MTS T1/T2	153	0	0	0	4	20	28	36	43	50	57	65	74	75	79	83
CTS A		8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
CTS B		36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
CTS C		20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
CGS D		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Area Total		456	462	480	502	525	538	548	557	566	575	586	598	626	643	665
Oshawa-Clarington																
Enfield TS T1/T2	157	0.0	19.0	83.5	108.9	111.4	115.0	118.5	121.9	126.4	129.9	134.4	139.0	144	171	202
Thornton TS T3/T4	160	136.6	134.8	126.7	128.8	130.6	131.1	131.7	132.3	133.0	133.5	134.2	135.6	143	149	154
Wilson TS T1/T2	161	137.5	116.6	117.0	115.8	117.7	119.6	120.7	122.6	123.9	125.0	125.4	125.8	161.0	161.0	161.0
Wilson TS T3/T3	134	122.3	122.3	105.0	106.0	114.0	115.5	117.0	118.5	120.0	121.4	122.9	124.4	126.0	134.0	134.0
Area Total		396	393	432	459	474	481	488	495	503	510	517	525	574	614	652
Regional Total		853	855	912	961	998	1019	1036	1052	1070	1085	1103	1123	1201	1257	1317

APPENDIX F: LIST OF 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
DCF	Discounted Cash Flow
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GATR	Guelph Area Transmission Reinforcement
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme

Appendix D(ii): GTA East Needs Assessment Report

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

NEEDS ASSESSMENT REPORT

GTA East Region

Date: August 15, 2019

Prepared by: GTA East Region Study Team

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the GTA East Region and to recommend which need may require further assessment and/or regional coordination to develop a preferred plan. The results reported in this Needs Assessment are based on the input and information provided by the Study Team.

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 GTA East Region (the "Region")

LEAD Hydro One Networks Inc. ("HONI")

START DATE: JUNE 23, 2019 **END DATE:** August 15, 2019

1. INTRODUCTION

The first cycle of the Regional Planning process for the GTA East Region was completed in January 2017 with the publication of the Regional Infrastructure Plan ("RIP") which provided a description of needs and recommendations of preferred wires plans to address near-term needs.

This is the second cycle of regional planning starting from Needs Assessment ("NA"). The purpose of this NA is to identify any new needs and/or to reaffirm needs identified in the previous GTA East Regional Planning cycle.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the regional planning cycle should be triggered at least every five years. In light of these timelines, the 2nd Regional Planning cycle was triggered for GTA East Region.

3. SCOPE OF NEEDS ASSESSMENT

The assessment's primary objective is to identify the electrical infrastructure needs over the study period, develop options and recommend which needs require further regional coordination.

The scope of this NA includes:

- Review and reaffirm needs/plans identified in the previous RIP; and
- Identification and assessment of system capacity, reliability, operation, and aging infrastructure needs in the region.

The Study Team may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), IRRP and RIP, based on updated information available at that time.

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 the GTA East Region regarding capacity needs, reliability needs, operational issues, and major assets/facilities approaching end-of-life ("EOL"). In addition, community energy plans in the region have also been scanned and reviewed.

5. ASSESSMENT METHODOLOGY

The assessment methodology include 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 useful 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 useful life.

6. NEEDS

I. Previously identified need as part of the regional planning

The NA reaffirms previously identified needs –

a. Additional transformation capacity in Pickering-Ajax-Whitby sub-region:
   Seaton MTS is being built by Elexicon with an in-service date of Q1 2020. No further action is required.
b. Additional transformation capacity in Oshawa-Clarington sub-region:
   Enfield TS went in-service in March 2019. No further action is required.

II. Newly identified needs in the region

a. Line / Station Capacity

No new supply capacity needs have been identified by Study Team.

b. System Reliability & Operation

No new System Reliability and Operation needs have been identified by Study Team.

c. Aging Infrastructure Transformer replacements

i. Cherrywood TS – 230kV & 500kV Breaker Replacements (multi-phase) (2027)
ii. Cherrywood TS – MV Switchyard Refurbishment (2025)
iii. Wilson TS – T1/T2 & Switchyard Refurbishment (2025)

7. RECOMMENDATIONS

The Study Team's recommends that following end of life high voltage equipment should be replaced with similar equipment and it does not require further regional coordination (see further details in Section 7.1).

a. Cherrywood TS – 230kV & 500kV Breaker Replacement (multi-phase)
b. Cherrywood TS – MV switchyard Refurbishment
c. Wilson TS – T1/T2 & Switchyard Refurbishment

The implementation and execution plan for these needs will be coordinated by Hydro One with affected LDCs.

TABLE OF CONTENTS

List of Tables and Figures

1 INTRODUCTION

The first cycle of the Regional Planning process for the GTA East Region was completed in January 2017 with the publication of the Regional Infrastructure Plan (“RIP”). The RIP provided a description of needs and recommendations of preferred wires plans to address near- and medium-term needs.

The purpose of this Needs Assessment (“NA”) is to identify new needs and to reconfirm needs identified in the previous GTA East regional planning cycle. Since the previous regional planning cycle, some new needs in the region have been identified.

This report was prepared by the GTA East 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: GTA East Region Study Team Participants

Company
Elexicon Energy Inc.
Oshawa PUC Networks Inc.
Hydro One Networks Inc. (Lead Transmitter)
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator (“IESO”)

2 REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. In light of Regional Planning cycle timelines and new needs in the GTA East region, the 2nd Regional Planning cycle was triggered for the GTA East region.

3 SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the GTA East region and includes:

- Review the status of needs/plans identified in the previous RIP; 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"), IRRP, and/or RIP.

4 REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The GTA East Region comprises the municipalities of Pickering, Ajax, Whitby, Oshawa and parts of Clarington, and other parts of the Durham area. The boundaries of the GTA East Region are shown below in Figure 1.

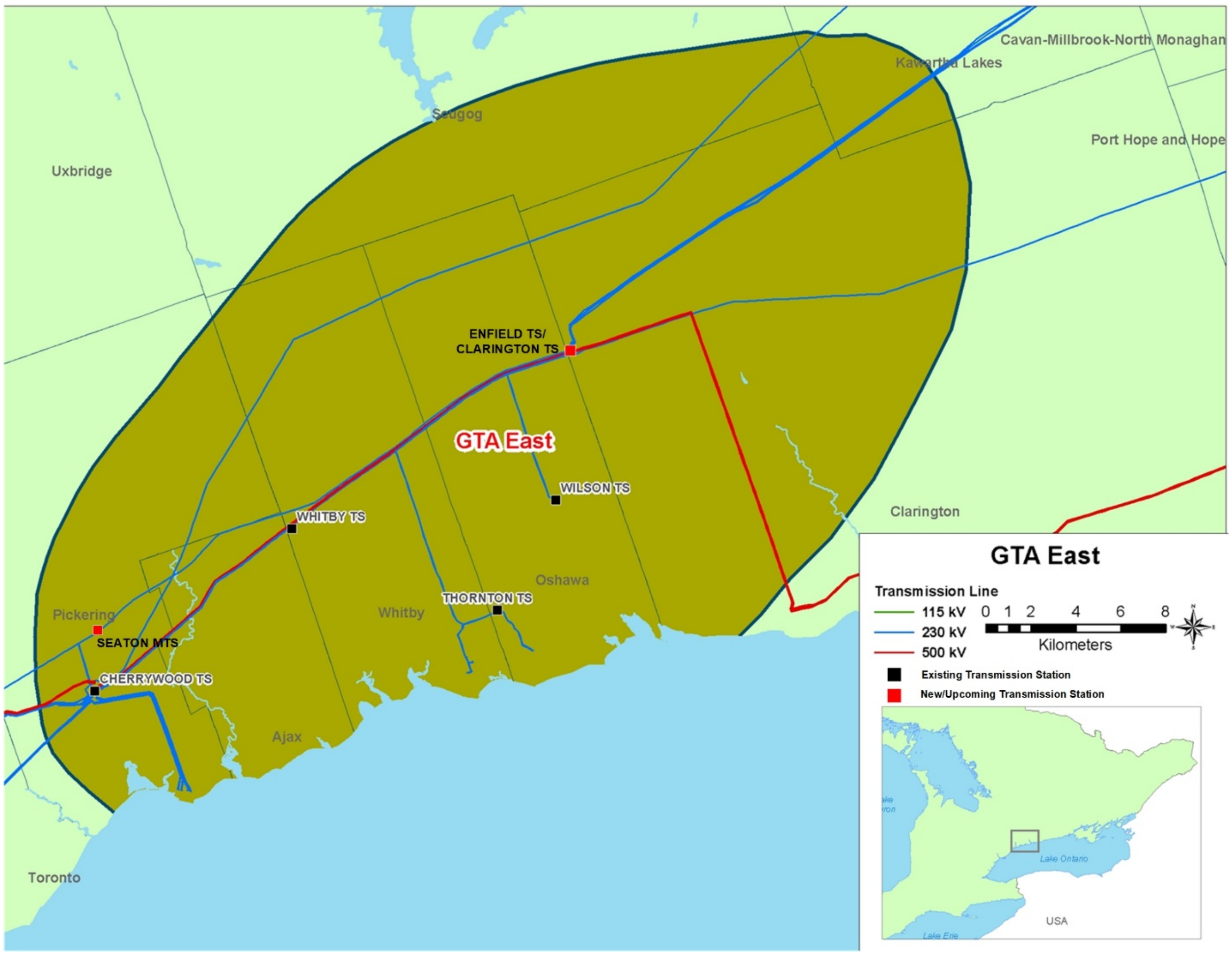


Figure 1: Geographical Area of GTA East Region with Electrical Layout

Electrical supply to the GTA East Region is provided through 500/230kV autotransformers at Cherrywood Transformer Station (TS) and five 230 kV transmission lines connecting Cherrywood to Eastern Ontario. There are four Hydro One step-down transformer stations and three other direct transmission connected load customers. The distribution system is at two voltage levels, 44kV and 27.6kV.

The existing facilities in the Region are summarized below and depicted in the single line diagram shown in Figure 2. The 500kV system is part of the bulk power system and is not studied as part of this Needs Screening:

- Cherrywood TS is the major transmission station that connects the 500kV network to the 230kV system via four 500/230kV autotransformers.
- Five step-down transformer stations supply the GTA East load: Cherrywood TS, Whitby TS, Wilson TS, Thornton TS and Enfield TS.
- Three customer transformer stations (CTS) are supplied in the region.
- Five 230kV circuits (T23C, T29C, T24C, T26C, T28C) emanating east from Cherrywood TS provide local supply to the GTA East Region. They extend from Cherrywood in the City of Pickering to Clarington TS.
- The Pickering Nuclear Generating Station (NGS) consists of 6 generating units with a combined output of approximately 3000 MW. It is connected to the 230kV system at Cherrywood.
- CGS D is a 60 MW gas-fired cogeneration facility that connects to circuit T26C.

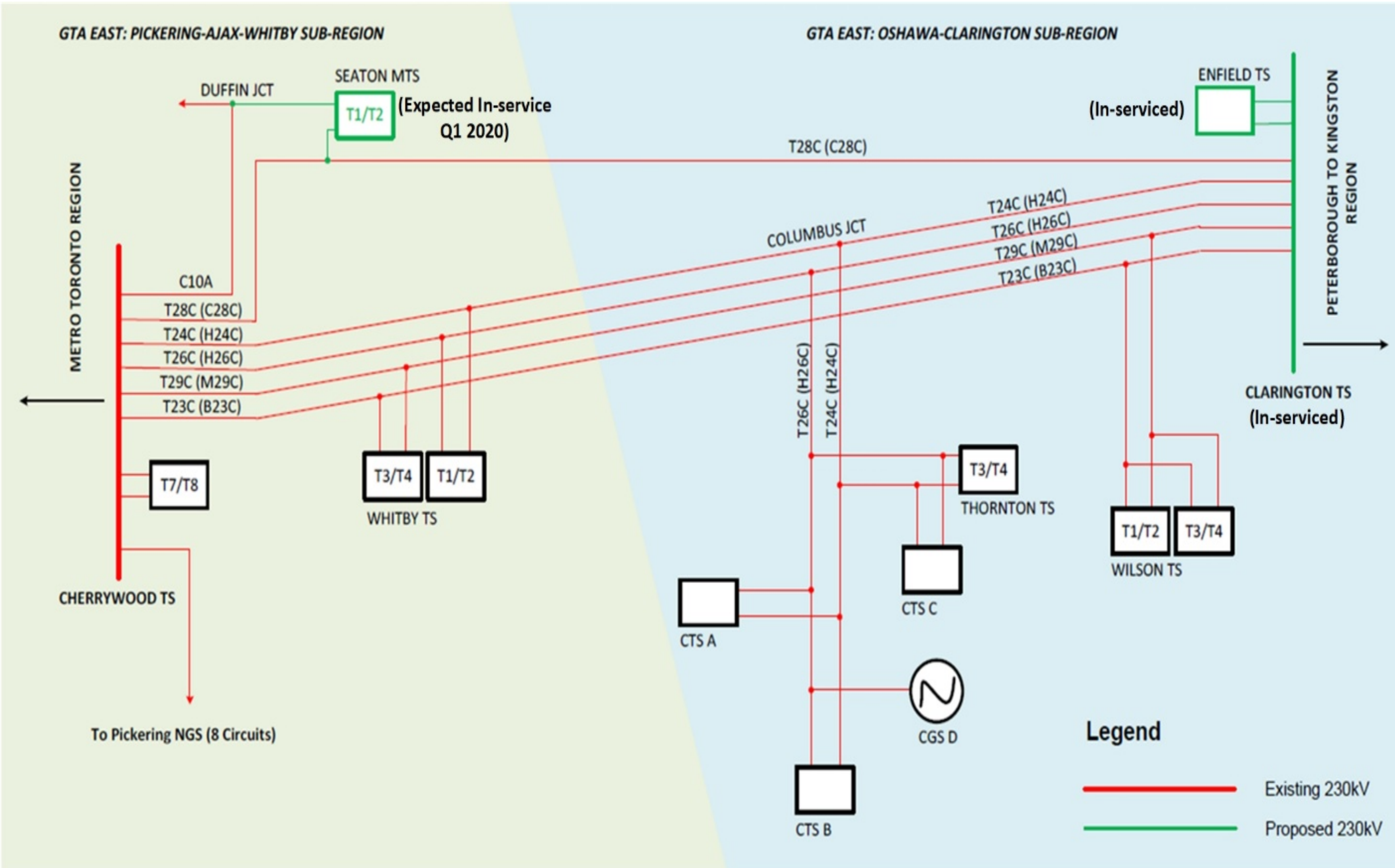


Figure 2: Single Line Diagram of GTA East Region

5 INPUTS AND DATA

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

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

6 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 GTA East region for the 10 year study period. The IESO provided a Conservation and Demand Management ("CDM") and Distributed Generation ("DG") forecast for the GTA East 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 2018 summer peak extreme weather corrected loads. The extreme summer weather correction factors were provided by Hydro One. The net extreme weather summer load forecasts were produced by reducing the gross load forecasts for each station by the % age CDM and then by the amount of effective DG capacity provided by the IESO for that station. These extreme weather summer load forecast for the individual stations in the GTA East region is given in Appendix A;

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

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

A technical assessment of needs was undertaken based on:

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

In addition, Hydro One has reviewed the Community Energy Plans in the region. There are currently no active Community Energy Plans in the region which can have any direct impact on the needs identified by the Study Team.

7 NEEDS

This section describes emerging needs identified in the GTA East Region, and also reaffirms the near, mid, and long-term needs already identified in the previous regional planning cycle. The recent load forecast prepared for this report is higher than that of the previous cycle of regional planning. This is attributed to the load growth at Enfield TS and Seaton MTS. A contingency analysis was performed for the region and no new system needs were identified.

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

Table 2: Needs Identified in the Previous Regional Planning Cycle

Type of Needs identified in the previous RP cycle	Needs Details	Current Status
Additional transformation capacity for Whitby TS T1/T2 27.6kV in Pickering-Ajax-Whitby Sub-Region	Whitby T1/T2 27.6 kV was expected to be loaded to capacity by 2020 and additional transformation capacity was required for the expected load growth in the area.	Seaton MTS is in construction with an expected in-service date of Q1 2020
Additional transformation capacity for Wilson TS T1/T2 & T3/T4 in Oshawa-Clarington Sub-Region	Wilson TS T1/T2 & T3/T4 was loaded pass its LTR rating and that immediate action was needed to address the overloading issue and expected load growth in the area	Enfield TS is currently in-service.

7.1 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:

- Autotransformers
- Power transformers
- HV breakers
- Transmission line requiring refurbishment where an uprating is being considered for planning needs and require Leave to Construct (i.e., Section 92) application and approval
- HV underground cables where an uprating is being considered for planning needs and require EA and Leave to Construct (i.e., Section 92) application and approval

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

1. Replacing equipment with similar equipment and built to current standards (i.e., "like-for-like" replacement);
2. Replacing equipment with similar equipment of higher / lower ratings i.e. right sizing opportunity and built to current standards;
3. Replacing equipment with lower ratings and built to current standards by transferring some load to other existing facilities;
4. 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 useful life over the next 10 years and assessed for right sizing opportunity.

a. Cherrywood TS – 230kV & 500kV Breaker Replacements (multi-phase project)

Cherrywood TS is a major Bulk Electricity System (BES), Northeast Power Coordination Council (NPCC) station, located at east end of Greater Toronto Area (GTA). The station includes 500 kV and 230 kV switchyards, four autotransformers that transfer electricity from Darlington and Pickering Nuclear Generating Station into GTA, and a 44kV DESN tapped off the 230kV bus which delivers power to Elexicon. The existing 500kV and 230kV Air Blast Circuit Breaker (ABCBs), with an average age of 48 years are obsolete and at end of life. The age, condition and lack of parts present significant difficulties in maintaining these breakers and the associated high pressure air system.

The scope of this project is to replace the existing eight (8) 500kV and thirty (30) 230kV air-blast circuit breakers in a multi-phase project release. The targeted in-service for the final phase is in year 2022. The Study Team recommended continuation of these end of life asset replacement as per the plan.

b. Cherrywood TS – LV DESN Switchyard Refurbishment

The MV DESN switchyard, with the exception of step-down transformers T7 and T8, at Cherrywood TS is at end of life due to age and condition. The scope of this project is to replace all 44 kV switchyard assets with the current standard equipment. The targeted in-service is in year 2025.

The Study Team recommended continuation of these end of life asset replacement as per the plan.

c. Wilson TS – T1, T2 and Switchyard Refurbishment

Wilson TS is located in Oshawa and it contains 4 X 75/100/125 MVA, 230/44 kV, transformers that supplies city of Oshawa through Oshawa Power feeders and surrounding areas of Oshawa through Hydro One Dx owned feeders. The T1 and T2 transformers at Wilson TS and majority of assets within 44 kV BY switchyard have reached end of life. The associated spill containment structure do not meet current standard.

The scope of this project is to replace T1/T2 step-down transformers, associated spill containment structure and majority of assets within 44 kV BY switchyard. The targeted in-service is in year 2025.

The Study Team has assessed downsizing and/or upsizing a need for these transformers. The Working Group concluded that reducing the size of these transformers is not an option as the load in the area is increasing. Upsizing is also not an option because this is the highest rating of transformer. Accordingly, replacing these transformers with similar size is the best “right sizing”. The Study Team recommends continuation of these end of life asset replacement as per the plan.

No other lines or HV station equipment in the GTA East region have been identified for major replacement/ refurbishment at this time. If and when new and/or additional information is available, it will be provided during the next planning phase.

7.2 Station and Transmission Capacity Needs in the GTA East Region

The following Station and Transmission supply capacities needs have been identified in the GTA East region during the study period of 2019 to 2028.

7.2.1 New Seaton MTS

The Pickering-Ajax-Whitby sub-region is being supplied by two step-down transformer stations, Cherrywood TS at 44 kV and Whitby TS at 27.6 kV and 44 kV. A new residential and mixed use commercial developing area, called Seaton, will result into significant 27.6 kV demand in the sub-region. The previous Regional Planning cycle as well as current submitted load forecast identified need for additional 27.6 kV capacity in the area.

Figure 3: Location of Seaton MTS

As recommended in the previous regional planning cycle, Elexicon has initiated installation of a new step down transformer station, called Seaton MTS. The station will be built and owned by Elexicon. To feed the new Seaton MTS, Hydro One will be converting an existing single circuit 230 kV transmission line (T28C) to a double circuit line from Duffin Jct to Seaton MTS to serve the station. Hydro One is working with Elexicon and planning for Q1 2020 in-service. No further action is required.

7.2.2 Enfield TS

Wilson TS is located within the city of Oshawa and has four 230kV / 44kV (T1/T2 & T3/T4) step down transformers that supplies OPUC and Hydro One Dx customers. Wilson TS normal supply capacities were exceeded due to significant growth over the time. The previous Regional Planning cycle recommended a new TS, now named Enfield TS, in the area mainly to relieve the Wilson TS from overloading as well as to meet the new load growth in the area. As per recommendation, Hydro One has installed a new 230kV / 44kV Enfield TS with six (6) 44kV feeder breaker positions with provision for two (2) additional 44kV future feeder breaker positions. The new Enfield TS is located adjacent to Clarington TS and will supply OPUC through four (4) feeders and Hydro One Dx through two (2) feeders. The station went in-service March 2019 and currently feeder load transfer work is in progress to transfer some existing load from Wilson TS to Enfield TS. No further action is required.

Figure 4: Location of Clarington TS and Enfield TS

7.3 Other Planning Considerations in the GTA East Region

As all the needs in the previous planning cycle are already addressed OR being addressed, and no new needs have arisen in the latest load forecast, no other consideration is needed.

8 CONCLUSION AND RECOMMENDATIONS

In conclusion, the capacity needs identified in the previous planning cycle are being addressed with projects under execution. All the new loads are expected to be accommodated by Enfield TS and Seaton MTS. It is recommended that Hydro One and the LDCs continue to monitor the loading of the existing facilities and new facilities over the next five (5) years to ensure adequate capacity is available for the new load in the region.

The Study Team recommendations are as follows:

A. Replacement of end of life component with similar equipment does not require further regional coordination. The Study Team considered these end of life asset replacement for right sizing opportunity and recommended continuation of replacing these assets with similar equipment. The implementation and execution plan for these needs will be coordinated by Hydro One with affected LDCs:

   a. Cherrywood TS – 230kV & 500kV Breaker Replacement (multi-phase)
   b. Cherrywood TS – MV DESN Switchyard Refurbishment
   c. Wilson TS – T1/T2 Replacement / Refurbishment

9 REFERENCES

[1] Regional Infrastructure Planning Report 2017 – GTA East - January 2017

[2] IRRP Report – Pickering-Ajax-Whitby Sub-Region – June 2016

[3] Needs Assessment Report GTA East – August 2014

[4] Planning Process Working Group Report to the Ontario Energy Board - May 2013

[5] Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0 -August 2007

Appendix A: GTA East Region Non-Coincident Summer Load Forecast

Transformer Station		Summer 10 Day LTR (MW)	Type	Actual	Forecasted										
Name	DESN ID			2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Cherrywood TS	T7/T8	175	Gross	N/A	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0
			DG	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			CDM	N/A	1.8	3.0	3.2	3.6	4.2	4.6	5.1	5.4	6.0	6.3	6.6
			Net	161.1	164.2	163.0	162.8	162.4	161.8	161.4	160.9	160.6	160.0	159.7	159.4
Seaton MTS	T1/T2	153	Gross	0.0	0.0	1.0	4.0	20.0	28.0	36.0	43.0	50.0	57.0	65.0	74.1
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			CDM	0.0	0.0	0.0	0.1	0.4	0.7	1.0	1.3	1.6	2.0	2.5	3.0
			Net	0.0	0.0	1.0	3.9	19.6	27.3	35.0	41.7	48.4	55.0	62.5	71.2
Thornton TS	T3/T4	160	Gross	N/A	138.5	131.3	133.5	135.8	136.8	137.8	138.8	139.8	140.9	141.9	143.0
			DG	N/A	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.0
			CDM	N/A	1.5	2.4	2.6	3.0	3.5	3.8	4.3	4.6	5.1	5.4	5.7
			Net	138.3	136.4	128.3	130.4	132.2	132.7	133.4	133.9	134.6	135.2	135.9	137.2
Whitby TS	T3/T4	187	Gross	142.4	143.3	151.0	155.8	161.7	166.7	168.7	170.7	172.8	175.0	177.1	179.2
			DG	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	0.0
			CDM	0.0	1.5	2.7	3.0	3.6	4.2	4.7	5.2	5.6	6.3	6.7	7.2
			Net	123.4	122.8	129.3	133.8	139.1	143.5	145.0	146.5	148.2	149.7	151.4	172.1
Whitby TS	T1/T2 (27.6kV)	90	Gross	56.0	59.0	74.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
			DG	0.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.0
			CDM	0.0	0.6	1.3	1.7	2.0	2.3	2.5	2.8	2.9	3.2	3.4	3.6
			Net	56.0	57.9	72.2	87.8	87.5	87.2	87.0	86.7	86.6	86.3	86.1	86.4
Whitby TS	T1/T2 (44kV)	90	Gross	43.7	57.7	59.5	61.2	63.1	64.3	65.6	66.9	68.3	69.6	71.0	72.4
			DG	0.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.0

			CDM	0.0	0.6	1.1	1.2	1.4	1.6	1.8	2.1	2.2	2.5	2.7	2.9
			Net	43.7	56.6	57.9	59.5	61.2	62.2	63.3	64.3	65.6	66.6	67.8	69.5
Wilson TS	T1/T2	161	Gross	153.6	153.6	155.3	154.1	156.7	159.4	161.2	163.8	165.6	167.4	168.3	169.1
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			CDM	0.0	1.6	2.8	3.0	3.4	4.0	4.5	5.0	5.4	6.0	6.4	6.8
			Net	153.6	152.0	152.5	151.2	153.2	155.4	156.7	158.8	160.2	161.4	161.9	162.4
Wilson TS	T3/T4	134	Gross	N/A	169.2	143.3	144.2	152.8	154.7	156.5	158.4	160.2	162.1	163.9	165.7
			DG	N/A	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0
			CDM	N/A	1.5	2.1	2.2	2.7	3.2	3.5	3.9	4.2	4.7	5.1	5.4
			Net	141.7	141.7	115.3	116.0	124.1	125.5	127.0	128.5	130.0	131.4	132.9	134.4
Enfield TS	T1/T2	157	Gross	0.0	19.0	83.5	108.9	111.4	115.0	118.5	121.9	126.4	129.9	134.4	139.0
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			CDM	0.0	0.2	1.5	2.1	2.4	2.9	3.3	3.7	4.1	4.7	5.1	5.6
			Net	0.0	18.8	82.0	106.8	109.0	112.1	115.2	118.2	122.3	125.2	129.3	133.5
CTS A			Net	25	25	25	25	25	25	25	25	25	25	25	25
CTS B			Net	95	95	95	95	95	95	95	95	95	95	95	95
CTS C			Net	21	21	21	21	21	21	21	21	21	21	21	21
CGS D			Net	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7

Appendix B: Lists of Step-Down Transformer Stations

Sr. No.	Transformer Stations	Voltage Level	Supply Circuits
1.	Cherrywood TS T7/T8	230/44kV	Cherrywood TS, DK Bus
2.	Whitby TS T1/T2 27.6 Whitby TS T1/T2 44	230/27.6kV 230/44kV	T24C/T26C
3.	Whitby TS T3/T4	230/44kV	T23C/T29C
4.	Wilson TS T1/T2	230/44kV	T23C/T29C
5.	Wilson TS T3/T4	230/44kV	T23C/T29C
6.	Thornton TS T3/T4	230/44kV	T24C/T26C
7.	Enfield TS T1/T2	230/44kV	Clarington TS, PK Bus
8.	Seaton MTS	230/44kV	C10A/T28C

Appendix C: Lists of Transmission Circuits

Sr. No.	Circuit ID	From Station	To Station	Voltage (kV)
1.	C10A	Cherrywood TS	Seaton MTS	230
2.	T23C	Cherrywood TS	Clarington TS	230
3.	T24C	Cherrywood TS	Clarington TS	230
4.	T26C	Cherrywood TS	Clarington TS	230
5.	T28C	Cherrywood TS	Clarington TS	230
6.	T29C	Cherrywood TS	Clarington TS	230

Appendix D: Lists of LDCs in the GTA East Region

Sr. No.	Company	Connection Type (TX/DX)
1.	Oshawa PUC	TX
2.	Elexicon Energy Inc.	TX / DX
3.	Hydro One Distribution	TX

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
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TS	Transformer Station

Appendix D(iii): Regional Planning - OPUCN Load Forecast

Load Forecast Template

Region Name: GTA East

Notes:

1	Enter data for the transformer stations supplying your LDC.
2	For LDCs directly connected to the transmission facilities (TX connected), load forecasts should factor in the load forecasts of any embedded distributor. Include a list of all embedded distributors
3	For LDCs that are embedded in another distributor's system (DX connected), DO NOT include your embedded load in forecasts submitted to the transmitter; instead, submit the embedded load forecasts to the host distributor for inclusion in their submission to the transmitter.
4	Provide coincident load forecast aggregated for all your feeders at the DESN level.
5	For Historical Data, LDCs are to provide the Net Load, i.e. Gross Peak Load minus any EXISTING Conservation & Demand Management (CDM) and Distributed Generation (DG), available during the time of peak demand.
6	For Forecasted Data, LDCs are to only provide the Gross Peak Load (which is the Forecasted Load from their Historical Net Load). IESO will provide Forecasted DG and CDM.
7	Provide load forecast in MWs under median/ normal weather condition and include power factor assumptions, if any. Note: The historical peak loads will be adjusted for extreme weather conditions by Hydro One
8	Provide load data in the appropriate table i.e. Summer peak vs. Winter peak
9	DO NOT double count load transfers
10	List all relevant assumptions made in preparing this load forecast
11	Weather normalized data has been used
12	An additional 10MW - 15MW of forecasted load is also expected to be transferred from Wilson TS/Thornton TS to Enfield TS.

									Summer Peak Load													
									Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)					
LDC	Circuit	Transformer Station Name	Connection Tx / Dx	Host Distributor	DESN ID	Bus ID	Feeder(s)	Type	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Power Factor
					(e.g. T1/T2)	(e.g. BY)																
Elexicon Energy	N/A	Cherrywood TS	TX	N/A	T7/T8	BY	M1-M8	Load														
								DG														
								CDM														
Elexicon Energy	C10A/T28C	Seaton MTS	TX	N/A	T1/T2	N/A	N/A	Load														
								DG														
								CDM														
Elexicon Energy	T24C/T26C	Thornton TS	TX	N/A	T3/T4	BY	M1,M6,M7,M8	Load														
								DG														
								CDM														
Elexicon Energy	T23C/T29C	Whitby TS	TX	N/A	T3/T4	JQ	M21-M28	Load														
								DG														
								CDM														
Elexicon Energy	T24C/T26C	Whitby TS	TX	N/A	T1/T2	BY	M43-M48	Load														
								DG														
								CDM														
Elexicon Energy	T24C/T26C	Whitby TS	TX	N/A	T1/T2	EZ	M5-M8	Load														
								DG														
								CDM														
Oshawa PUC	T24C/T26C	Thornton TS	Tx	NA	T3/T4	BY	M2-M5	Load	87	82	88	93	78	79	80	80	80	80	80	80	80	
								DG														
								CDM														
Oshawa PUC	T23C/T29C	Wilson TS	Tx	NA	T1/T2	BY	M1-M7	Load	135	118	129	132	133	131	133	135	136	138	139	140	140	
								DG														
								CDM														
Oshawa PUC	T23C/T29C	Wilson TS	Tx	NA	T3/T4	JQ	M18	Load	31	28	29	29	26	25	25	25	25	25	25	25	25	
								DG														
								CDM														
Oshawa PUC	C10A/T28C	Enfield TS	Tx	NA	T5/T6	BY	M5-M8	Load	0	0	0	19	40	48	50	53	56	59	63	66	70	
								DG														
								CDM														
Hydro One Dist.	C10A/T28C	Enfield TS	Tx	NA	T5/T6	BY	M3/M4	Load														
								DG														
								CDM														
Hydro One Dist.	T23C/T29C	Wilson TS	Tx	NA	T1/T2	BY	M8	Load														
								DG														
								CDM														
Hydro One Dist.	T23C/T29C	Wilson TS	Tx	NA	T3/T4	JQ	M11-M17	Load														
								DG														
								CDM														

Load Forecast Template

Region Name: GTA East

Notes:

1	Enter data for the transformer stations supplying your LDC.
2	For LDCs directly connected to the transmission facilities (TX connected), load forecasts should factor in the load forecasts of any embedded distributor. Include a list of all embedded distributors
3	For LDCs that are embedded in another distributor's system (DX connected), **DO NOT** include your embedded load in forecasts submitted to the transmitter; instead, submit the embedded load forecasts to the host distributor for inclusion in their submission to the transmitter.
4	Provide coincident load forecast aggregated for all your feeders at the DESN level.
5	For Historical Data, LDCs are to provide the Net Load, i.e. Gross Peak Load minus any EXISTING Conservation & Demand Management (CDM) and Distributed Generation (DG), available during the time of peak demand.
6	For Forecasted Data, LDCs are to only provide the Gross Peak Load (which is the Forecasted Load from their Historical Net Load). IESO will provide Forecasted DG and CDM.
7	Provide load forecast in MWs under median/ normal weather condition and include power factor assumptions, if any. Note: The historical peak loads will be adjusted for extreme weather conditions by Hydro One
8	Provide load data in the appropriate table i.e. Summer peak vs. Winter peak
9	**DO NOT** double count load transfers
10	List all relevant assumptions made in preparing this load forecast
11	Weather normalized data has been used
12	An additional 10MW - 15MW of forecasted load is also expected to be transferred from Wilson TS/Thornton TS to Enfield TS.

Winter Peak Load

									Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)					
LDC	Circuit	Transformer Station Name	Connection Tx / Dx	Host Distributor	DESN ID (e.g. T1/T2)	Bus ID (e.g. BY)	Feeder(s)	Type	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Power Factor
Elexicon Energy	N/A	Cherrywood TS	TX	N/A	T7/T8	BY	M1-M8	Load														
								DG														
								CDM														
Elexicon Energy	C10A/T28C	Seaton MTS	TX	N/A	T1/T2	N/A	N/A	Load														
								DG														
								CDM														
Elexicon Energy	T24C/T26C	Thornton TS	TX	N/A	T3/T4	BY	M1,M6,M7,M8	Load														
								DG														
								CDM														
Elexicon Energy	T23C/T29C	Whitby TS	TX	N/A	T3/T4	JQ	M21-M28	Load														
								DG														
								CDM														
Elexicon Energy	T24C/T26C	Whitby TS	TX	N/A	T1/T2	BY	M43-M48	Load														
								DG														
								CDM														
Elexicon Energy	T24C/T26C	Whitby TS	TX	N/A	T1/T2	EZ	M5-M8	Load														
								DG														
								CDM														
Oshawa PUC	T24C/T26C	Thornton TS	Tx	NA	T3/T4	BY	M2-M5	Load	83	79	82	82	80	81	80	80	80	80	80	80	80	
								DG														
								CDM														
Oshawa PUC	T23C/T29C	Wilson TS	Tx	NA	T1/T2	BY	M1-M7	Load	135	133	101	110	141	138	140	140	140	140	140	140	140	
								DG														
								CDM														
Oshawa PUC	T23C/T29C	Wilson TS	Tx	NA	T3/T4	JQ	M18	Load	22	23	22	19	29	28	25	25	25	25	25	25	25	
								DG														
								CDM														
Oshawa PUC	C10A/T28C	Enfield TS	Tx	NA	T5/T6	BY	M5-M8	Load	0	0	0	0	41	49	57	61	66	72	75	80	84	
								DG														
								CDM														
Hydro One Dist.	C10A/T28C	Enfield TS	Tx	NA	T5/T6	BY	M3/M4	Load														
								DG														
								CDM														
Hydro One Dist.	T23C/T29C	Wilson TS	Tx	NA	T1/T2	BY	M8	Load														
								DG														
								CDM														
Hydro One Dist.	T23C/T29C	Wilson TS	Tx	NA	T3/T4	JQ	M11-M17	Load														
								DG														
								CDM														

Appendix E: Planning Status Letter

Hydro One Networks Inc.
483 Bay Street
13th Floor, North Tower
Toronto, ON M5G 2P5
www.HydroOne.com

Tel: (416) 345-5420
Fax: (416) 345-4141
Ajay.Garg@HydroOne.com

March 15, 2020

Mr. Eric Andres
Senior Distribution Engineer
Oshawa PUC Networks Inc.
100 Simcoe St S
Oshawa, ON L1H 7M7

Dear Mr. Andres:

Subject: Regional Planning Status

As per your request, this Planning Status letter is provided to meet one of the requirements of your upcoming Rate Application to the Ontario Energy Board (OEB).

As you are aware, the province of Ontario is divided into 21 Regions for the purpose of Regional Planning (RP), a map of Ontario showing the 21 Regions and the list of LDCs in each of the Region are attached as Appendix A and B respectively.

Oshawa PUC Networks Inc. (OPUCN) is an LDC within the GTA East region and Hydro One Networks Inc. (Hydro One) is the lead transmitter.

This letter confirms that the second cycle of Regional Planning for the GTA East region is completed in February 2020. The findings and the recommendations stemming out of the 2nd cycle RP are provided in details in the GTA East Regional Infrastructure Planning (RIP) report (attached as Appendix C). The report can be accessed from Hydro One's Regional Planning website for GTA East region.

The current regional planning status for the GTA East region impacting OPUCN is summarized below:

GTA East Region:

The following transmission projects were undertaken by Hydro One to address near-term supply needs that were recommended in the first Regional Planning cycle.

- New Enfield TS, in-serviced May 2019, is a 230/44 kV DESN transformer station to increase supply capacity in the Oshawa-Clarington Sub-region and to provide load relief to Wilson TS.
- New Seaton MTS, expected in-service date of 2021, is a 230/27.6/27.6 transformer station to increase supply capacity in the Pickering-Ajax-Whitby region and to provide load relief to Whitby TS 27.6 kV following the development of new community of Seaton.

OPUCN was required to make the capital contribution for Enfield TS in accordance with Transmission System

Code. There are no direct cost implications of new Seaton MTS on OPUCN.

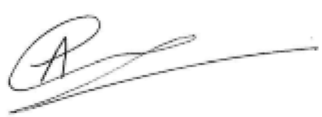
The recommendations in the second cycle of RP for GTA East region are only to replace some of the major high voltage end of life equipment as listed below:

- Cherrywood TS 230kV & 500kV breaker replacement (multi-phase)
- Cherrywood TS MV DESN Switchyard Refurbishment
- Wilson TS T1/T2 Replacement/ Refurbishment

As mentioned above, the second cycle Regional Infrastructure Planning report was completed and published in February 2020. The report didn't identify any need requiring further regional co-ordination during OPUCN's planning cycle at this time. There are no cost implications for OPUCN for projects developed by Hydro One in the 2nd cycle of Regional Planning.

OPUCN is an active participating member on the regional Study Teams and Hydro One is looking forward to continue working with OPUCN in executing the regional planning process. Please feel free to contact me if you have any questions.

Sincerely,



Ajay Garg, Manager – Regional Planning Coordination
Hydro One Networks Inc.

Appendix A. Map of Ontario's Planning Regions

Northern Ontario

Southern Ontario

Greater Toronto Area (GTA)

Burlington to Nanticoke	East Lake Superior	Chatham/Lambton/Sarnia
Greater Ottawa	London area	Greater Bruce/Huron
GTA East	Peterborough to Kingston	Niagara
GTA North	South Georgian Bay/Muskoka	North of Moosonee*
GTA West	Sudbury/Algoma	North/East of Sudbury
Kitchener- Waterloo- Cambridge-Guelph ("KWCG")	Northwest Ontario	Renfrew
Toronto	Windsor-Essex	St. Lawrence

*This region is not within Hydro One's territory.

Appendix B. List of LDCs for Each Region

(Hydro One as Upstream Transmitter)

Region	LDCs
1. Burlington to Nanticoke	• Energy+ Inc. • Brantford Power Inc. • Burlington Hydro Inc. • Haldimand County Hydro Inc.** • Alectra Utilities Corporation • Hydro One Networks Inc. • Norfolk Power Distribution Inc.** • Oakville Hydro Electricity Distribution Inc.
2. Greater Ottawa	• Hydro 2000 Inc. • Hydro Hawkesbury Inc. • Hydro One Networks Inc. • Hydro Ottawa Limited • Ottawa River Power Corporation • Renfrew Hydro Inc.
3. GTA North	• Alectra Utilities Corporation • Hydro One Networks Inc. • Newmarket-Tay Power Distribution Ltd. • Toronto Hydro Electric System Limited • Elexicon Energy Inc.
4. GTA West	• Burlington Hydro Inc. • Alectra Utilities Corporation • Halton Hills Hydro Inc. • Hydro One Networks Inc. • Milton Hydro Distribution Inc. • Oakville Hydro Electricity Distribution Inc.
5. Kitchener- Waterloo-Cambridge-Guelph ("KWCG")	• Energy+ Inc. • Centre Wellington Hydro Ltd. • Alectra Utilities Corporation • Halton Hills Hydro Inc. • Hydro One Networks Inc. • Kitchener-Wilmot Hydro Inc. • Milton Hydro Distribution Inc. • Waterloo North Hydro Inc. • Wellington North Power Inc.

6. Toronto	• Alectra Utilities Corporation • Hydro One Networks Inc. • Toronto Hydro Electric System Limited • Elexicon Energy Inc.
7. Northwest Ontario	• Atikokan Hydro Inc. • Chapleau Public Utilities Corporation • Fort Frances Power Corporation • Hydro One Networks Inc. • Kenora Hydro Electric Corporation Ltd. • Sioux Lookout Hydro Inc. • Thunder Bay Hydro Electricity • Distribution Inc.
8. Windsor-Essex	• E.L.K. Energy Inc. • Entegrus Power Lines lnc. [Chatham- Kent] • EnWin Utilities Ltd. • Essex Powerlines Corporation • Hydro One Networks Inc.
9. East Lake Superior* *Hydro One Sault Ste. Marie L.P. is the Lead Transmitter for the region.	• Algoma Power Inc. • Chapleau PUC • Sault Ste. Marie PUC • Hydro One Networks Inc.
10. GTA East	• Hydro One Networks Inc. • Oshawa PUC Networks Inc. (OPUCN) • Elexicon Energy Inc.
11. London Area	• Entegrus Power Lines lnc. [Middlesex] • Erie Thames Power Lines Corporation • Hydro One Networks Inc. • London Hydro Inc. • Norfolk Power Distribution Inc.** • St. Thomas Energy Inc. • Tillsonburg Hydro Inc. • Woodstock Hydro Services Inc.**
12. Peterborough to Kingston	• Eastern Ontario Power Inc. • Hydro One Networks Inc. • Kingston Hydro Corporation • Lakefront Utilities Inc. • Peterborough Distribution Inc. • Elexicon Energy Inc.

13. South Georgian Bay/Muskoka	• EPCOR • Hydro One Networks Inc. • InnPower Corporation • Lakeland Power Distribution Ltd. • Midland Power Utility Corporation • Orangeville Hydro Limited • Orillia Power Distribution Corporation • Alectra Utilities Corporation • Elexicon Energy Inc. • Elexicon Energy Inc. • Wasaga Distribution Inc.
14. Sudbury/Algoma	• Espanola Regional Hydro Distribution Corp. • Greater Sudbury Hydro Inc. • Hydro One Networks Inc.
15. Chatham/Lambton/Sarnia	• Bluewater Power Distribution Corporation • Entegrus Power Lines lnc. [Chatham- Kent] • Hydro One Networks Inc.
16. Greater Bruce/Huron	• Entegrus Power Lines lnc. [Middlesex] • Erie Thames Power Lines Corporation • Festival Hydro Inc. • Hydro One Networks Inc. • Wellington North Power Inc. • West Coast Huron Energy Inc. • Westario Power Inc.
17. Niagara	• Canadian Niagara Power Inc. [Port Colborne] • Grimsby Power Inc. • Haldimand County Hydro Inc.** • Alectra Utilities Corporation • Hydro One Networks Inc. • Niagara Peninsula Energy Inc. • Niagara-On-The-Lake Hydro Inc. • Welland Hydro-Electric System Corp. • Niagara West Transformation Corporation* * Changes to the May 17, 2013 OEB Planning Process Working Group Report

19. North/East of Sudbury	• Greater Sudbury Hydro Inc. • Hearst Power Distribution Company Limited • Hydro One Networks Inc. • North Bay Hydro Distribution Ltd. • Northern Ontario Wires Inc.
20. Renfrew	• Hydro One Networks Inc. • Ottawa River Power Corporation • Renfrew Hydro Inc.
21. St. Lawrence	• Cooperative Hydro Embrun Inc. • Hydro One Networks Inc. • Rideau St. Lawrence Distribution Inc.

**This Local Distribution Company (LDC) has been acquired by Hydro One Networks Inc.

Appendix C

2nd cycle Regional Infrastructure Planning (RIP) Report – February 2020

GTA East

2019-2024 REGIONAL INFRASTRUCTURE PLAN
FEBRUARY 29, 2020

hydro one

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Prepared and supported by:

Company
Elexicon Energy Inc.
Oshawa PUC Networks Inc.
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator (IESO)
Hydro One Networks Inc. (Lead Transmitter)

ieso
Power to Ontario.
On Demand.

Oshawa PUC Networks Inc.

hydro one

elexicon ENERGY

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Disclaimer

This Regional Infrastructure Plan ("RIP") report is an electricity infrastructure plan to identify and address near and long-term based on information provided and/or collected by the Study Team.

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

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EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE WITH PARTICIPATION AND INPUT FROM THE RIP STUDY TEAM IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE PLANNED, DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE GTA EAST REGION.

The participants of the Regional Infrastructure Planning ("RIP") Study Team included members from the following organizations:

- Elexicon Energy Inc.
- Oshawa PUC Networks Inc.
- Independent Electricity System Operator (IESO)
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Lead Transmitter)

The last regional planning cycle for the GTA East Region was completed in January 2017 with the publication of the RIP report.

This RIP is the final phase of the 2nd regional planning cycle and follows the 2nd Cycle GTA East Region's Needs Assessment ("NA") in August 2019. Based on the findings of the NA, the Study Team recommended no further regional coordination is required at this time. Hence, RIP is based on the recommendations of NA report.

This RIP provides a consolidated summary of the outcome of the needs and recommended plans for the GTA East region as identified by the regional planning study team. The RIP also discusses needs identified in the previous regional planning cycle and the Needs Assessment report for this cycle; and the projects developed to address these needs. Implementation plans to address some of these needs are already completed or are underway. Since the previous regional planning cycle, following projects have been completed:

- Enfield TS: 75/100/125 MVA transformation capacity in Oshawa-Clarington sub-region (Completed in 2019)

The major infrastructure investments recommended by the Study Team over the near- and mid-term are provided in below Table 1, along with their planned in-service date and budgetary estimates for planning purpose.

Table 1: Recommended Plans in GTA East Region over the Next 10 Years

No.	Needs	Plans	Planned I/S Date	Budgetary Estimate ($M)
1	Increase Transformation Capacity in Pickering-Ajax-Whitby Sub-region	Build Seaton MTS	2021	43
2	Cherrywood TS – 230kV & 500kV Breaker Replacements (multi-phase projects)	Replace 230 kV and 500 kV Air Blast Circuit Breakers (ABCB) at Cherrywood TS	2027	184
3	Cherrywood TS – LV DESN Switchyard Refurbishment	Existing 44kV DESN switchyard replacement at Cherrywood TS	2025	12
4	Wilson TS – T1, T2 and Switchyard Refurbishment	Existing T1, T2 and 44 kV BY bus switchyard replacement	2022	36

The Study Team recommends:

- Continue with the investments listed in Table 1 while keeping the Study Team apprised of project status.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE GTA EAST REGION BETWEEN 2019 AND 2029.

The report was prepared by Hydro One Networks Inc. ("Hydro One") with input from Study Team members during the NA phase and documents the results of the Needs Assessments and recommended plan. RIP Study Team members included representative from Elexicon Energy Inc. ("Elexicon"), Oshawa PUC Networks Inc. ("OPUCN"), Hydro One Distribution, and the Independent Electricity System Operator ("IESO") in accordance with the Regional Planning process established by the Ontario Energy Board ("OEB") in 2013.

The GTA East Region comprises the municipalities of Pickering, Ajax, Whitby, Oshawa, Clarington, and Durham area. Electrical supply to the GTA East Region is provided through 500/230kV autotransformers at Cherrywood Transformer Station (TS) and Clarington TS and five 230 kV transmission lines connecting Cherrywood TS to Eastern Ontario. There are five Hydro One step-down transformer stations and three other direct transmission connected load customers. The distribution system is at two voltage levels, 44kV and 27.6kV. The boundaries of the GTA East Region are shown below in Figure 1-1.

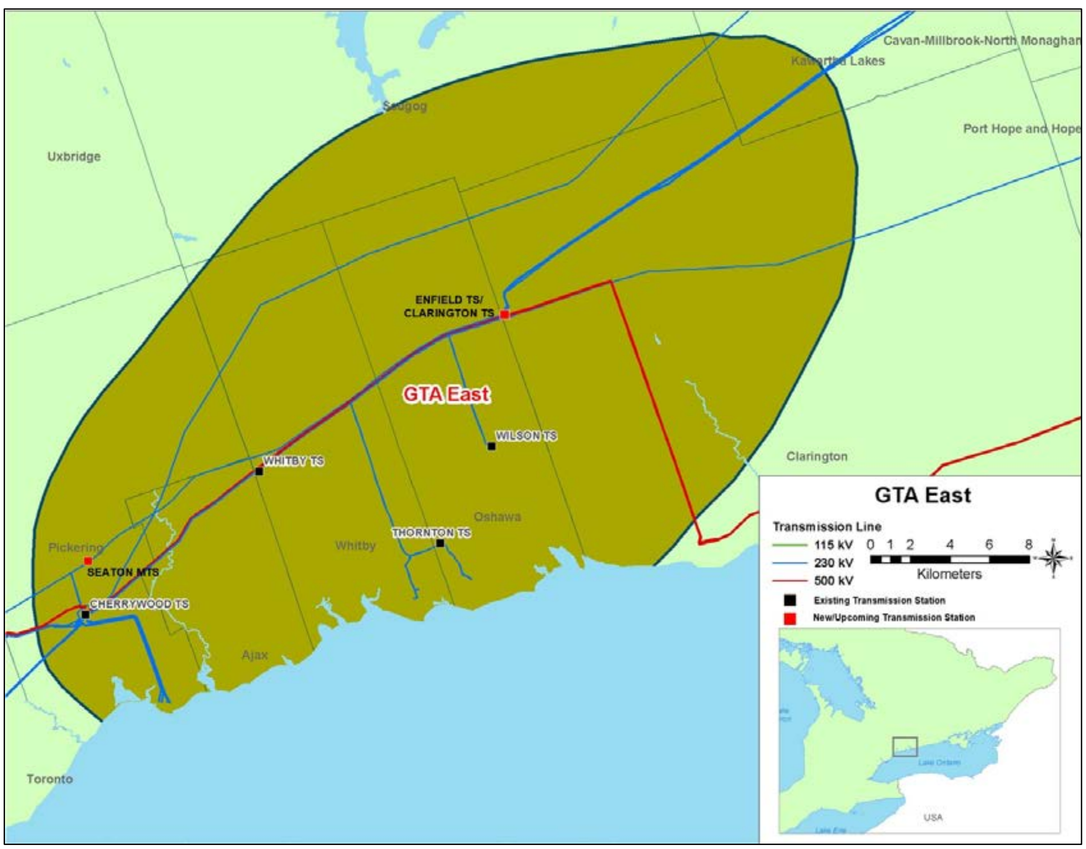


Figure 1-1: GTA East Region

1.1 Objective and Scope

The RIP report examines the needs in the GTA East Region. Its objectives are to:

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

The RIP reviewed factors such as the load forecast, major high voltage sustainment issues emerging over the near, mid and long-term, transmission and distribution system capability along with any updates with respect to local plans, conservation and demand management (“CDM”), renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- Discussion of any other major transmission infrastructure investment plans over the near, mid and long-term (0-20 years)
- Identification of any new needs and a wires plan to address these needs based on new and/or updated information, if any.

1.2 Structure

The rest of the report is organized as follows:

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

2. REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board ("OEB") in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment [1] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase, which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Study Team determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them.

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

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

[1] Also referred to as Needs Screening

The RIP phase is the fourth and final phase of the regional planning process and involves: discussion and reconfirmation of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive report of a wires plan for the region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter.

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

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

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

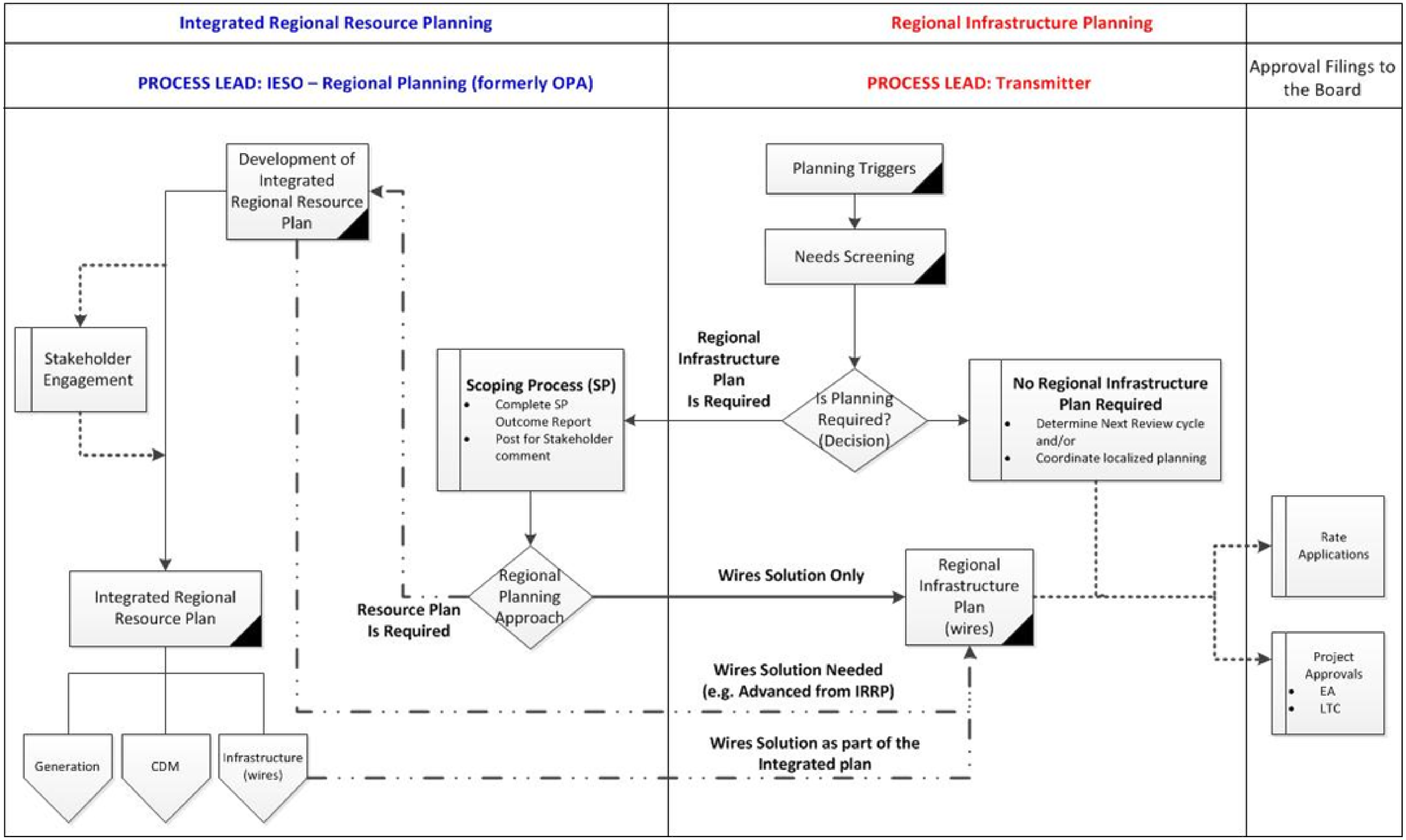


Figure 2-1: Regional Planning Process Flowchart

2.3 RIP Methodology

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

1. Data Gathering: The first step of the process is the review of planning assessment data collected in the previous phase of the regional planning process. Hydro One collects this information and reviews it with the Study Team to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Depending upon the changes to load forecast or other relevant information, regional technical assessment may or may not be required or be limited to specific issue only. Additional near and mid-term needs may be identified in this phase.
3. Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

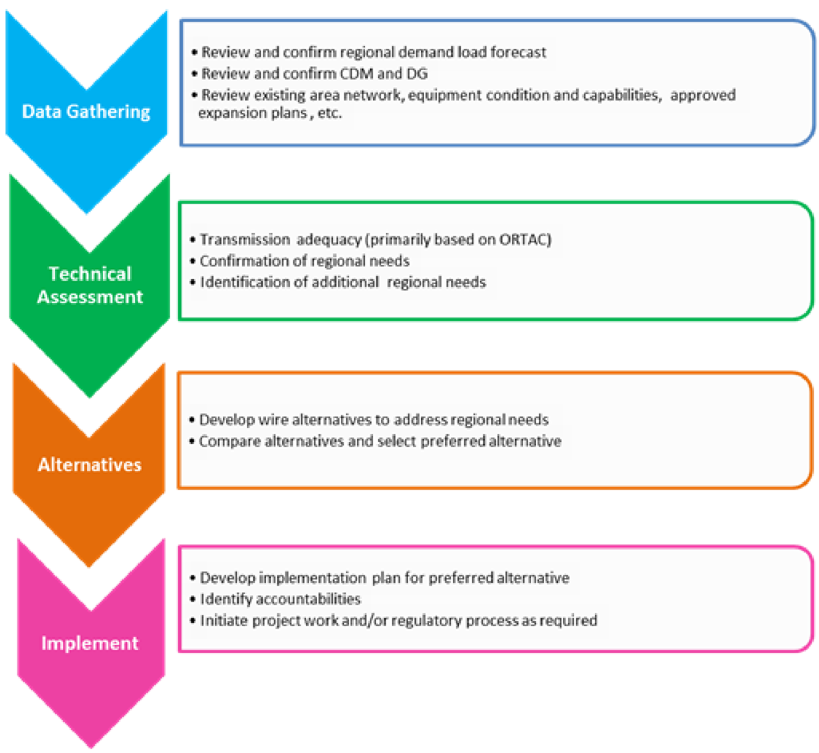


Figure 2-2: RIP Methodology

3. REGIONAL CHARACTERISTICS

THE GTA EAST REGION IS COMPRISED OF THE PICKERING-AJAX-WHITBY SUB-REGION AND THE OSHAWA-CLARINGTON SUB-REGION. ELECTRICAL SUPPLY TO THE REGION IS PROVIDED FROM FIVE 230KV STEP-DOWN TRANSFORMER STATIONS.

Bulk electrical supply to the GTA East Region is currently provided through Cherrywood TS and Clarington TS, two major 500/230kV autotransformer station in the region, and five 230kV circuits emanating east from Cherrywood TS. Five local area step-down transformer stations and three other direct transmission connected load customers are connected to the 230 kV system in the region. Major generation in the area includes the Pickering Nuclear Generating Station ("NGS") which consists of six generating units with a combined output of approximately 3000 MW and is connected to the 230kV system at Cherrywood TS.

The August 2019 GTA East Region NA report, prepared by Hydro One, considered the entire GTA East Region. For simplicity, this report divides GTA East Region into two sub-regions, Pickering-Ajax-Whitby Sub-region and Oshawa-Clarington Sub-region, as described below.

3.1 Pickering-Ajax-Whitby Sub-region

The Pickering-Ajax-Whitby Sub-region comprises primarily the City of Pickering, Town of Ajax, part of the Town of Whitby, and part of the Townships of Uxbridge and Scugog. It is supplied by Cherrywood TS, a 500/230kV autotransformer station, two 230kV transformer stations, namely Cherrywood TS DESN and Whitby TS (2 DESNs), that step down the voltage to 44kV and 27.6kV. The LDCs supplied in the Sub-region are Hydro One Distribution, and Elexicon.

The Pickering-Ajax-Whitby Sub-region transmission facilities are shown in Figure 3-1.

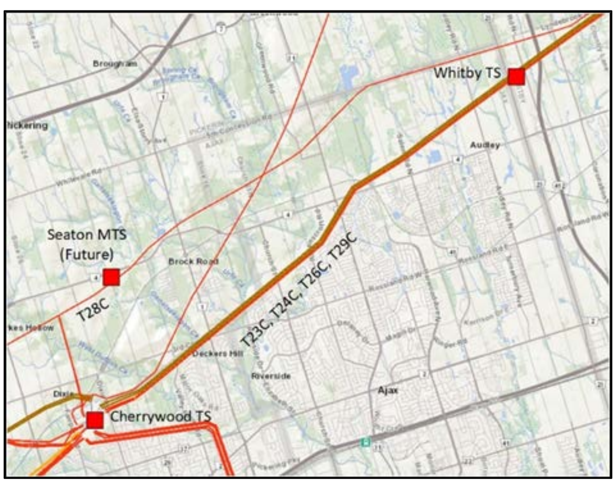


Figure 3-1: Pickering-Ajax-Whitby Sub-region

3.2 Oshawa-Clarington Sub-region

The Oshawa-Clarington sub-region comprises primarily the City of Oshawa, part of the Municipality of Clarington, part of Whitby, and part of the Township of Scugog. It is supplied by Cherrywood TS, a 500/230kV autotransformer station to the west, two 230kV transformer stations, namely Wilson TS (2 DESNs) and Thornton TS, that step down the voltage to 44kV at distribution level. The sub-region also includes three direct transmission connected load customers. Local generation in the area consists of the 60 MW Whitby Customer Generating Station ("CGS"), a gas-fired cogeneration facility that connects to 230kV circuit T26C. Thornton TS also supplies some load within the Pickering-Ajax-Whitby sub-region. The LDCs supplied in the sub-region are Elexicon, Hydro One Distribution, and OPUCN.

A new 500/230kV autotransformer station in the GTA East Region within the township of Clarington, Clarington TS, went into service in 2018. The new Clarington TS provided additional load meeting capability in the region and will eliminate the overloading of Cherrywood autotransformers that may result after the retirement of the Pickering NGS in the near future.

The new autotransformer station consists of two 750MVA, 500/230kV autotransformers and a 230kV switchyard. The autotransformers will be supplied from two 500kV circuits that pass next to the proposed site. The 230kV circuits supplying the east GTA will be terminated at Clarington TS. Clarington TS will become a major supply source for the GTA East Region load.

A new 230/44kV transformer station, Enfield TS, was in-serviced in March 2019. The transformer station provided relief to overloading at Wilson TS and supplies Hydro One Distribution and Oshawa PUC. The station is located inside the Clarington TS yard and is directly connected to the Clarington TS 230 kV bus.

The Oshawa-Clarington Sub-region transmission facilities are shown in Figure 3-2.

Figure 3-2: Oshawa-Clarington Sub-region

A single line diagram of the GTA East Region transmission system is shown in Figure 3-3.

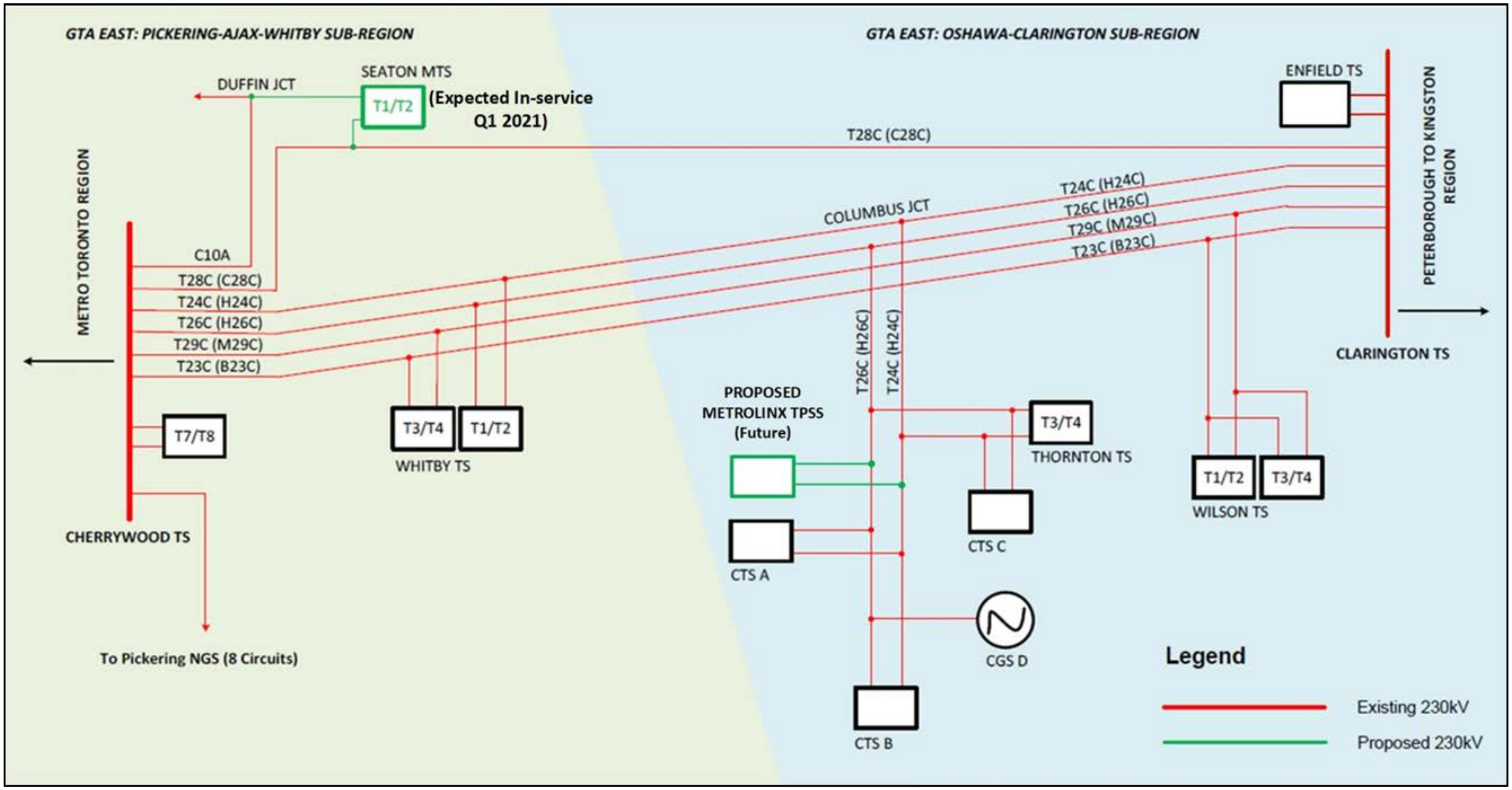


Figure 3-3: Single Line Diagram of GTA East Region

4. TRANSMISSION PROJECTS COMPLETED OVER LAST TEN YEARS

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND COMPLETED BY HYDRO ONE, IN CONSULTATION WITH THE LDCs AND/OR THE IESO, AIMED TO MAINTAIN OR IMPROVE THE RELIABILITY AND ADEQUACY OF SUPPLY IN THE GTA EAST REGION.

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

- Whitby TS T1/T2 (2009) – built a new step-down transformer station supplied from 230kV circuits T24C and T26C in municipality of Whitby to increase transformation capacity for Elexicon requirements.

- Wilson TS T1/T2 DESN1 (2015) – installed LV neutral grounding reactors to reduce line-to ground short circuit fault levels to facilitate DG connections.

- Thornton TS T3/T4 (2016) – replaced end-of-life transformers. Also installed LV neutral grounding reactors to reduce line-to-ground short circuit fault levels to facilitate DG connections.

- Clarington TS (2018) – built a new 500/230kV autotransformer station to increase transmission supply capacity to the GTA East Region, eliminate the overloading of Cherrywood TS autotransformers that may result after the retirement of Pickering NGS, and improve supply reliability to the Region.

- Enfield TS (2019) – built a new 230/44kV transformer station to provide relief for Wilson TS and for future load growth in Oshawa-Clarington sub-region.

5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

Figure 5-1 shows the GTA East Region's summer peak coincident and non-coincident load forecast. The non-coincident load forecast was used to determine the need for station capacity and the coincident load forecast was used to assess need for transmission line capacity in the region.

The load forecasts for the region were developed using the summer 2018 actual peak adjusted for extreme weather and applying the station net growth rates provided by the LDCs. The load in the GTA East Region is expected to increase at an annual rate of approximately 2.8% between 2019 and 2029. The gross and net non-coincident and coincident load forecast, adjusted for extreme weather, CDM, and DG, for each station in the region are provided in Appendix D and E.

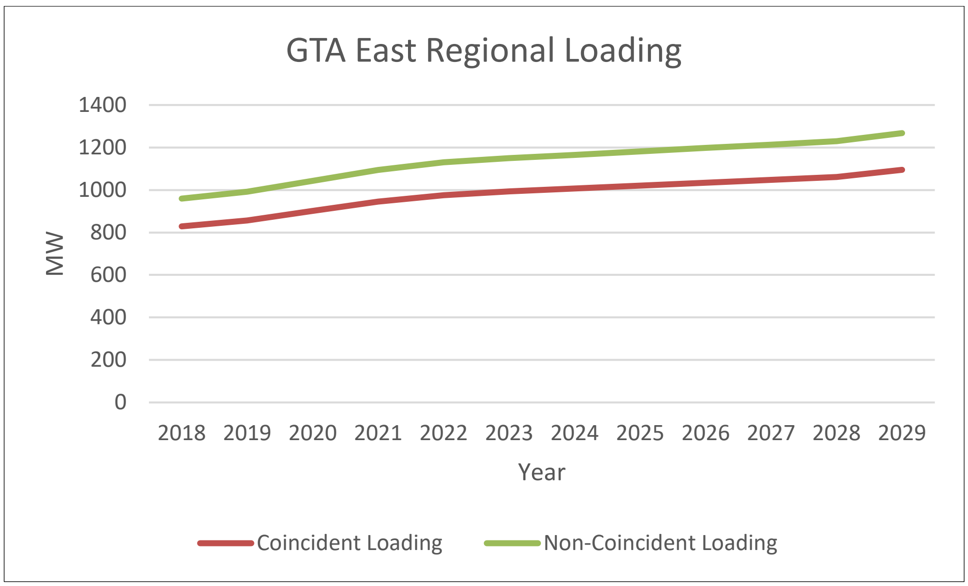


Figure 5-1 GTA East Region Net Load Forecast

5.2 Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2019-2029.
- All facilities listed in Section 4 are in-service.
- Where applicable, industrial loads have been assumed based on historical information.
- Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.
- Line capacity adequacy is assessed by using coincident peak loads.
- Normal planning supply capacity for transformer stations in this sub-region is determined by the Hydro One summer 10-Day Limited Time Rating (LTR).
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).
- Metrolinx plans to connect a Traction Power Substation (TPSS) to Hydro One's 230 kV circuits T24C and T26C in East Whitby. The Metrolinx TPSS loads have not been included in the forecast as the timing is uncertain and the loads do not impact the need or timing of new facilities.

6. ADEQUACY OF FACILITIES

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND DELIVERY STATION FACILITIES SUPPLYING THE GTA EAST REGION OVER THE 2019-2029 PERIOD.

Within the current regional planning cycle one regional assessment have been conducted for the GTA East Region. The study is shown below:

1) 2019 GTA East Needs Assessment (NA) Report

The NA report identified a number of needs to meet the forecast load demands and EOL asset issues. A review of the loading on the transmission lines and stations in the GTA East Region was also carried out as part of the RIP report using the latest regional load forecast as given in Appendix D. Sections 6.1 to 6.5 present the results of this review. Further description of assessments, alternatives and preferred plan along with status is provided in Section 7.

All the needs in the previous RIP have been addressed. Enfield TS is in-service and Seaton MTS is under contstruction.

6.1 230 kV Transmission Facilities

The GTA East Region is comprised of five 230kV circuits, T23C/T29C, T24C/T26C, and T28C, supplying both the Pickering-Ajax-Whitby Sub-region and the Oshawa-Clarington Sub-region. Refer to Figure 3-3 for the single line diagram of the transmission facilities in the Region.

1. Cherrywood TS to Clarington TS 230 kV circuits - T23C, T29C, T24C, T26C, and T28C

The Cherrywood TS to Clarington TS circuits, carry bulk transmission flows as well as serve local area station loads within the Region. These circuits are adequate over the study period. Pickering NGS is connected to the Cherrywood TS through 8 dedicated 230 kV circuits. Pickering NGS is expected to be retire in 2025.

6.2 500/230 kV Autotransformer Facilities

The 230 kV autotransformers facilities in the region consist of the following elements:

a. Cherrywood TS 500/230 kV autotransformers: T14, T15, T16, T17
b. Clarington TS 500/230 kV autotransformers: T2, T3

The autotransformers at Cherrywood TS and Clarington TS serve the 230 kV transmission network and local loads in GTA East. The Cherrywood TS autotransformer and Clarington TS autotransformer facilities are adequate over the study period.

6.3 Pickering-Ajax-Whitby Sub-region's Step-Down Transformer Station Facilities

There are two step-down transformer stations connected in the Pickering-Ajax-Whitby sub-region, summarized in Table 6-2. The station coincident and non-coincident forecasts are given in Appendix D.

Table 6-2: Transformation Capacities in the Pickering-Ajax-Whitby Sub-region

Facilities	Station MW Load			Station Limited Time Rating (LTR) MW	Need Date
	2030	2035	2040		
Cherrywood TS T7/T8 (44 kV)	160	160	160	160	2040+
Whitby TS T1/T2 (27.6 kV)	90	90	90	90	2040+
Whitby TS T1/T2 (44 kV)	70	74	83	90	2040+
Whitby TS T3/T4 (44 kV)	162	170	179	187	2040+
Seaton MTS (27.6kV)	75	79	83	153	2040+

Based on the submitted load forecasts, the stations in Pickering-Ajax-Whitby sub-region have adequate transformation capacity to supply the load in long term.

6.4 Oshawa-Clarington Sub-region's Step-Down Transformer Station Facilities

There are three step-down transformer stations in the Oshawa-Clarington Sub-region, summarized in Table 6-3.

Table 6-3: Transformation Capacities in the Oshawa-Clarington Sub-Region

Facilities	Station MW Load			Station Limited Time Rating (LTR) MW	Need Date
	2030	2035	2040		
Wilson TS T1/T2 (44 kV)	161	161	161	161	2040+
Wilson TS T3/T4 (44 kV)	134	134	134	134	2040+
Thornton TS T3/T4 (44 kV)	143	149	154	159	2040+
Enfield TS T1/T2 (44 kV)	144	171	202	157	2030-2035

The previous Regional Planning cycle recommended a new station, named Enfield TS, in the area mainly to relieve the Wilson TS from overloading as well as to meet the new load growth in the area. As per recommendation, Hydro One has installed a new 230kV / 44kV Enfield TS with six (6) 44kV feeder breaker positions with provision for two (2) additional 44kV future feeder breaker positions. The new Enfield TS is located on the the Clarington TS site and will supply OPUC through four (4) feeders and Hydro One Dx

through two (2) feeders. The station went in-service in March 2019 and currently feeder load transfer work is in progress to transfer some existing load from Wilson TS to Enfield TS.
Based on the submitted load forecasts, additional transformation capacity will be required in the long term.

6.5 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:

- Autotransformers
- Power transformers
- HV breakers
- Transmission line requiring refurbishment where an uprating is being considered for planning needs and require Leave to Construct (i.e., Section 92) application and approval
- HV underground cables where an uprating is being considered for planning needs and require EA and Leave to Construct (i.e., Section 92) application and approval

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

1. Replacing equipment with similar equipment and built to current standards (i.e., "like-for-like" replacement);
2. Replacing equipment with similar equipment of higher / lower ratings i.e. right sizing opportunity and built to current standards;
3. Replacing equipment with lower ratings and built to current standards by transferring some load to other existing facilities;
4. 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, major high voltage equipment has been identified as approaching its end of life over the next 10 years and assessed for right sizing opportunity in section 7.

6.6 System Reliability and Load Restoration

In case of contingencies on the transmission system, ORTAC provides the load restoration requirements relative to the amount of load affected. Planned system configuration must not exceed 600 MW of load curtailment/rejection. In all other cases, the following restoration times are provided for load to be restored for the outages caused by design contingencies.

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

The previous regional planning (RP) comprehensively assessed circuit pairs T29C/T23C and T24C/T26C as they are on the same tower line and the possibility of loss of either pair of circuits during peak load may result in load shortfall/outage exceeding the limits of 150MW and 250MW to be restored within 4 hours and 30 minutes, respectively. However, based on the analysis, historical performance and reliability data for these circuits in the region, the Study Team recommended that no action is required at this time. There is no change on the assumptions used in this report resulting in any significant system reliability or load restoration concerns in the region.

6.7 Longer Term Outlook (2030-2040)

While the RIP was focused on the 2019-2029 period, the Study Team has also looked at longer-term loading between 2030 and 2040.

No long term needs for the Pickering-Ajax-Whitby Sub-Region have been identified. Seaton MTS is expected to supply the Sub-Region's demand adequately over the next two decades.

The demand in Oshawa-Clarington Sub-Region is expected to grow over the long term period. The new Enfield TS will provide load relief to Wilson TS through distribution load transfer capability. As the demand grows in the northern Oshawa area in the long term, additional transformation capacity may have to be planned for in future. Further review and assessment will commence in next Regional Planning cycle to identify and develop alternatives to address new needs, if any.

Municipalities in region may develop their community energy plans with a primary focus to reduce their energy consumption by local initiatives over next 25 to 30 years. With respect to electricity, these communities may plan for an increased reliance on community energy sources such as distributed generation, generation behind the meters like rooftop solar systems and local energy battery storage systems to reduce cost and for improved reliability of electricity supply.

Some of the communities in Ontario are working towards self-sufficiency by improving efficiencies of existing local energy systems i.e. reducing energy consumption and losses by means of utilizing smarter buildings, houses, efficient heating, cooling, appliances, equipment, and processes for all community needs. Ultimately, the objective of these energy plans in the region is to be a net zero carbon community over the next 25 to 30 years.

Community energy plans may have potential to supplement and/or defer future transmission infrastructure development needs. The Study Team therefore recommends LDCs to review their respective regional community energy plans and provide updates to the working group of any potential projects that may affect future load forecasts in the next cycle of regional planning.

7. REGIONAL NEEDS & PLANS

THIS SECTION DISCUSSES ELECTRICAL INFRASTRUCTURE NEEDS IDENTIFIED IN THE PREVIOUS REGIONAL PLANNING CYCLE, THE NEEDS ASSESSMENT REPORT FOR THIS CYCLE; AND SUMMARIZES THE PLANS DEVELOPED TO ADDRESS THESE NEEDS.

This section outlines and discusses infrastructure needs and plans to address these needs for the near-term (up to 5 years) and the mid- term (5 to 10 years) and the expected planned in-service facilities to address these needs.

There are no new needs identified in the GTA East Region. Current development and sustainment plans are further discussed below.

7.1 Seaton MTS - Increase Transformation Capacity in Pickering-Ajax-Whitby Sub-Region

7.1.1 Description

The Pickering-Ajax-Whitby Sub-Region is supplied by Cherrywood TS at 44kV level and Whitby TS at 27.6kV and 44kV levels. Over the next 10 years, the load in this Sub-Region is forecasted to increase at approximately 2.9% annually.

With the proceeding of a new residential and mixed use commercial area in the Seaton are, significant increase in load demand is expected at 27.6kV level resulting in a shortage of transformation capacity at Whitby TS 27.6kV by 2021.

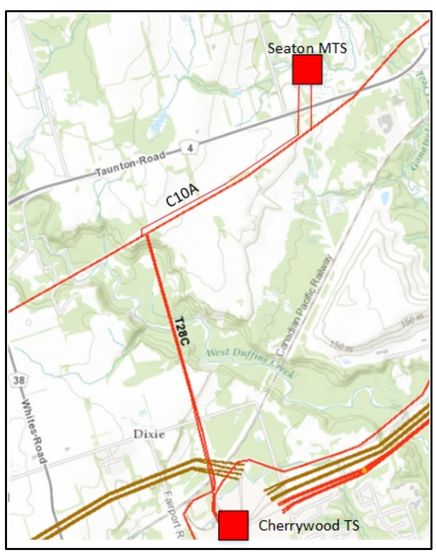


Figure 7-1: Location of Seaton MTS

The following alternatives were considered to address the Transformation Capacity in Pickering-Ajax-Whitby Sub-Region need:

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the expected thermal overloading at Whitby TS 27.6 kV due to the load growth in the Sub-Region.
2. **Alternative 2 – Build Seaton MTS:** Elexicon to proceed with the installation of a new Seaton MTS. To feed the new Seaton MTS, Hydro One will be converting an existing single circuit 230 kV transmission line (T28C) to a double circuit line from Duffin Jct to Seaton MTS to serve the station. Hydro One is working with Elexicon and planning for Q1 2020 in-service. This alternative would address the expected thermal overloading at Whitby TS 27.6kV due to the load growth in the Sub-Region.

7.2 Cherrywood TS – 230kV & 500kV Breaker Replacements (multi-phase project) Mid-Term End of Life Transformer Replacements

7.2.1 Description

Cherrywood TS is a major Bulk Electricity System (BES), Northeast Power Coordination Council (NPCC) station, located at east end of Greater Toronto Area (GTA). The station includes 500 kV and 230 kV switchyards, four autotransformers that transfer electricity from Darlington and Pickering Nuclear Generating Station into GTA, and a 44kV DESN tapped off the 230kV bus which delivers power to Elexicon. The existing 500kV and 230kV Air Blast Circuit Breaker (ABCBs), with an average age of 48 years are obsolete and at end of life. These are Bulk System elements and not in the scope of regional planning. Discussion is provided for information only.

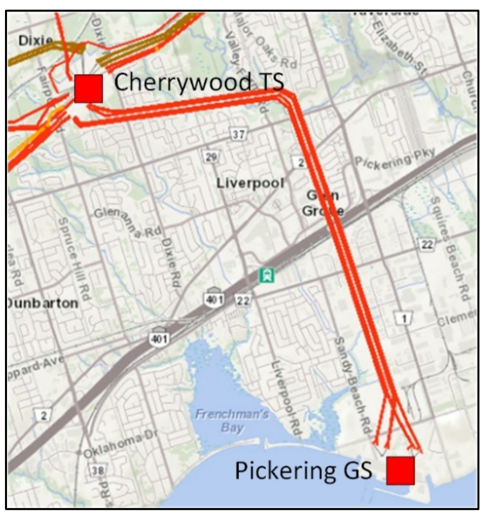


Figure 7-2: Cherrywood TS

The scope of this project is to replace the existing eight (8) 500kV and thirty (30) 230kV air-blast circuit breakers in a multi-phase project release. The targeted in-service for the final phase is in year 2027.

The following alternatives were considered to address Cherrywood TS HV Breakers end-of-life assets need:

3. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.
4. **Alternative 2 - Like-for-like replacement with similar equipment:** Proceed with these end of life asset replacement as per existing refurbishment plan for the HV breakers at Cherrywood TS. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.

7.3 Cherrywood TS – LV DESN Switchyard Refurbishment Mid-Term End of Life Breaker Replacement

7.3.1 Description

The LV switchyard for the 44 kV DESN T7/T8 at Cherrywood TS is at end of life due to age and condition. The scope of this project is to replace all 44 kV switchyard assets with the current standard equipment. The targeted in-service is in year 2025.

The following alternatives were considered to address Cherrywood TS DESN LV breaker end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.
2. **Alternative 2 - Like-for-like replacement with similar equipment:** Proceed with these end of life asset replacement as per the existing refurbishment plan for the LV breakers at Cherrywood TS DESN. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.

7.4 Wilson TS – T1, T2 and Switchyard Refurbishment

7.4.1 Description

Wilson TS is located in Oshawa and it contains 4 X 75/100/125 MVA, 230/44 kV, transformers that supplies city of Oshawa through OPUCN feeders and surrounding areas of Oshawa through Hydro One Dx owned feeders. The T1 and T2 transformers at Wilson TS and majority of assets within 44 kV BY switchyard have reached end of life. The associated spill containment structure do not meet current standard.

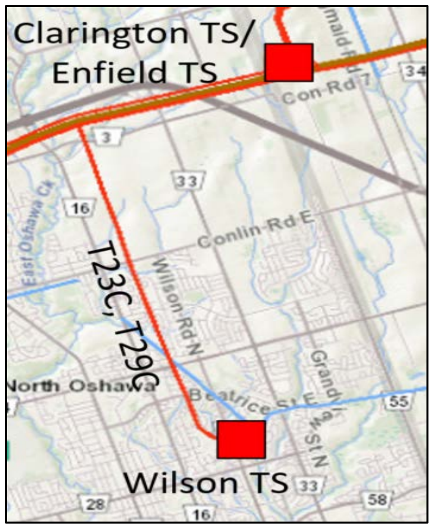


Figure 7-3: Wilson TS

The scope of this project is to replace T1/T2 step-down transformers, associated spill containment structure and majority of assets within 44 kV BY switchyard. The targeted in-service is in year 2022.

The Study Team has assessed downsizing and/or upsizing need for these transformers. The Working Group concluded that reducing the size of these transformers is not an option as the load in the area is increasing. Upsizing is also not an option because this is the highest rating of transformer. Accordingly, replacing these transformers with similar size is the only "right sizing" option.

The following alternatives were considered to address Wilson TS end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.
2. **Alternative 2 - Like-for-like replacement with similar equipment:** Proceed with these end of life asset replacement as per the existing refurbishment plan for the transformers at Wilson TS. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.

8. CONCLUSION AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN (RIP) REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE GTA EAST REGION.

The major infrastructure investments recommended by the Study Team in the near and mid-term planning horizon are provided in Table 8-1 below, along with their planned in-service date and budgetary estimates for planning purpose.

Table 8-1: Recommended Plans in GTA East Region over the Next 10 Years

No.	Needs	Plans	Planned I/S Date	Budgetary Estimate ($M)
1	Increase Transformation Capacity in Pickering-Ajax-Whitby Sub-region	Build Seaton MTS	2021	43
2	Cherrywood TS – 230kV & 500kV Breaker Replacements (multi-phase projects)	Replace 230 kV and 500 kV Air Blast Circuit Breakers (ABCB) at Cherrywood TS	2027	184
3	Cherrywood TS – LV DESN Switchyard Refurbishment	Existing 44kV DESN switchyard replacement at Cherrywood TS	2025	12
4	Wilson TS – T1, T2 and Switchyard Refurbishment	Existing T1, T2 and 44 kV BY bus switchyard replacement	2022	36

The Study Team recommends that:

- Hydro One and Elexicon continue with the infrastructure projects as listed above in Table 8-1 while keeping the Study Team apprised of project status.
- No additional transformation capacity is required in the Pickering-Ajax-Whitby sub-region in the long term.
- Additional transformation capacity may be required in the Oshawa-Clarington sub-region in the long term.

9. REFERENCES

[1]. Hydro One, “Needs Assessment Report, GTA East Region”, 15 August 2019

[2]. Regional Infrastructure Planning Report 2017 – GTA East - January 2017

[3]. IRRP Report – Pickering-Ajax-Whitby Sub-Region – June 2016

[4]. Needs Assessment Report GTA East – August 2014

[5]. Planning Process Working Group Report to the Ontario Energy Board - May 2013

[6]. Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0 -August 2007

APPENDIX A: TRANSMISSION LINES IN THE GTA EAST REGION

Location	Circuit Designation	Voltage Level
Cherrywood TS to Clarington TS	T23C/T24C/T26C/T29C	230kV
Cherrywood TS to Clarington TS	T28C	230kV

APPENDIX B: STATIONS IN THE GTA EAST REGION

Station (DESN)	**Voltage Level**	**Supply Circuits**
Cherrywood TS T7/T8	230/44kV	Cherrywood TS, DK Bus
Whitby TS T1/T2 27.6 Whitby TS T1/T2 44	230/27.6kV 230/44kV	T24C/T26C
Whitby TS T3/T4	230/44kV	T23C/T29C
Wilson TS T1/T2	230/44kV	T23C/T29C
Wilson TS T3/T4	230/44kV	T23C/T29C
Thornton TS T3/T4	230/44kV	T24C/T26C
Enfield TS T1/T2	230/44kV	Clarington TS, PK Bus
Seaton MTS*	230/44kV	C10A/T28C

*Future – Expected In-service 2021

APPENDIX C: DISTRIBUTORS IN THE GTA EAST REGION

Distributor Name	Station Name	Connection Type
Elexicon Inc.	Whitby TS	Tx
	Thornton TS	Dx
	Cherrywood TS	Dx
	Wilson TS	Dx
	Seaton MTS	Tx
Oshawa PUC	Wilson TS	Tx
	Thornton TS	Tx
	Enfield TS	Tx
Hydro One Networks Inc.	Cherrywood TS	Tx
	Wilson TS	Tx
	Whitby TS	Tx
	Thornton TS	Tx
	Enfield TS	Tx

Appendix D: Area Stations Non Coincident Net Load

Area & Station	LTR (MW)	Near & Mid-Term Forecast (MW) 2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Long-Term Forecast (MW) 2030	2035	2040
Pickering-Ajax-Whitby																
Cherrywood TS T7/T8	175	161	164	163	163	162	162	161	161	161	160	160	160	160	160	160
Whitby TS T3/T4	187	142	124	132	137	143	148	150	152	154	156	158	160	162	170	179
Whitby TS T1/T2 (27.6kV)	90	56	59	74	90	90	90	90	90	90	90	90	90	90	90	90
Whitby TS T1/T2 (44kV)	90	44	57	58	60	61	62	63	64	66	67	68	69	70	74	83
Seaton MTS T1/T2	153	0	0	0	4	20	28	36	43	50	57	65	74	75	79	83
CTS A		25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
CTS B		95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
CTS C		21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
CGS D		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Area Total		545	545	568	594	617	631	642	651	661	671	682	694	698	714	736
Oshawa-Clarington																
Enfield TS T1/T2	157	0.0	19.0	83.5	108.9	111.4	115.0	118.5	121.9	126.4	129.9	134.4	139.0	144	171	202
Thornton TS T3/T4	160	138.3	137.9	130.7	132.9	135.2	136.2	137.2	138.2	139.2	140.3	141.3	142.4	143	149	154
Wilson TS T1/T2	161	153.6	152.0	152.5	151.2	153.2	155.4	156.7	158.8	160.2	161.4	161.9	161.0	161.0	161.0	161.0
Wilson TS T3/T3	134	141.7	141.7	115.3	116.0	124.1	125.5	127.0	128.5	130.0	131.4	132.9	134.0	134.0	134.0	134.0
Area Total		434	451	482	509	524	532	539	547	556	563	570	576	582	614	652
Regional Total		979	996	1050	1103	1141	1163	1181	1199	1217	1234	1252	1271	1280	1329	1387

Appendix E: Area Stations Coincident Net Load

Area & Station	LTR (MW)	Near & Mid-Term Forecast (MW) 2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Long-Term Forecast (MW) 2030	2035	2040
Pickering-Ajax-Whitby																
Cherrywood TS T7/T8	175	160	164	163	163	162	162	161	161	161	160	160	159	159	159	159
Whitby TS T3/T4	187	135	134	141	146	152	156	158	160	162	163	165	167	169	177	187
Whitby TS T1/T2 (27.6kV)	90	41	43	54	66	65	65	65	65	65	65	64	65	90	90	90
Whitby TS T1/T2 (44kV)	90	56	57	58	60	61	62	63	64	66	67	68	70	70	74	83
Seaton MTS T1/T2	153	0	0	0	4	20	28	36	43	50	57	65	74	75	79	83
CTS A		8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
CTS B		36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
CTS C		20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
CGS D		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Area Total		456	462	480	502	525	538	548	557	566	575	586	598	626	643	665
Oshawa-Clarington																
Enfield TS T1/T2	157	0.0	19.0	83.5	108.9	111.4	115.0	118.5	121.9	126.4	129.9	134.4	139.0	144	171	202
Thornton TS T3/T4	160	136.6	134.8	126.7	128.8	130.6	131.1	131.7	132.3	133.0	133.5	134.2	135.6	143	149	154
Wilson TS T1/T2	161	137.5	116.6	117.0	115.8	117.7	119.6	120.7	122.6	123.9	125.0	125.4	125.8	161.0	161.0	161.0
Wilson TS T3/T3	134	122.3	122.3	105.0	106.0	114.0	115.5	117.0	118.5	120.0	121.4	122.9	124.4	126.0	134.0	134.0
Area Total		396	393	432	459	474	481	488	495	503	510	517	525	574	614	652
Regional Total		853	855	912	961	998	1019	1036	1052	1070	1085	1103	1123	1201	1257	1317

APPENDIX F: LIST OF 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
DCF	Discounted Cash Flow
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GATR	Guelph Area Transmission Reinforcement
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme

Appendix F: OMSCC Meeting Agenda (Typical)

1st Quarter OMSCC Agenda

March 27, 2019

Item No.1 – Overview of Oshawa's 2019/2020 Capital Design and Construction Program (Infrastructure Services)

Item No.2 - City Developments (Planning Services)

Update/overview of ongoing/future commercial developments and subdivisions within the City of Oshawa.

Item No.3 – Utility Schedule Update

Provide update to ongoing projects as well as scheduled work for 2019.

- Durham Region Schedule
- Oshawa PUC – Hydro/Fibre
- Enbridge Gas
- Rogers
- Bell
- TelMAX

Item No.4 – Other Business

Provide update to the recent Pavement Degradation Fee as well as discuss City priorities with regards to its growing fibre network.

Item No.5 – Municipal Consent Requirements Manual

Discuss *draft* Municipal Consent Requirements Manual. Utility providers to table any comments or concerns prior to OMSCC meeting. MCR attached to meeting request.

Appendix G: Metrolinx – Notice of Public Meeting #1

METROLINX

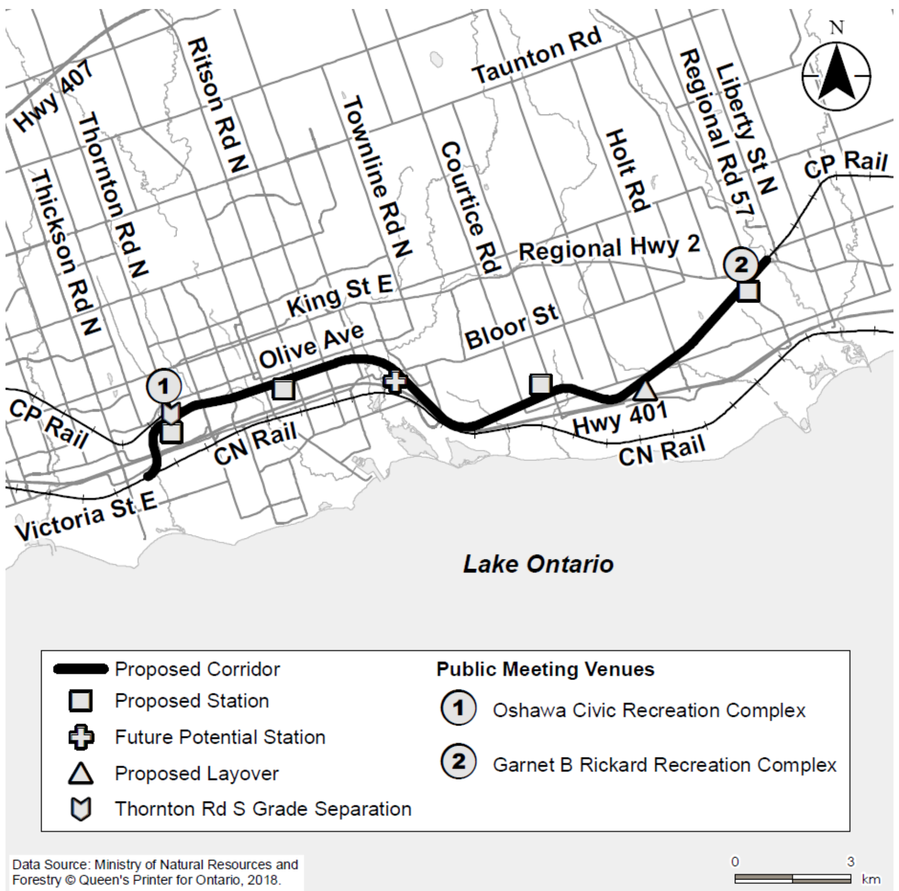
Notice of Public Meeting #1

Bowmanville Rail Expansion Project

Metrolinx currently operates all-day GO Transit rail service on the Lakeshore East Corridor between Union Station and the Oshawa GO Station. In 2011, Metrolinx examined expansion of this rail service as part of the *Oshawa to Bowmanville Rail Service Expansion and Rail Maintenance Facility* Environmental Project Report (EPR). The EPR was completed in accordance with the Transit Project Assessment Process (TPAP) under Ontario Regulation 231/08.

Since completion of the 2011 EPR, Metrolinx has advanced the design of the rail expansion project, and changes to the project are being assessed. The proposed changes include a new track alignment within the identified corridor, new or adjusted crossings, and refinements to facility design. An addendum to the 2011 EPR will be prepared to assess the effects of these changes.

Please refer to the Location Plan for a general overview of what we are assessing.



The Addendum Process

The Addendum to the 2011 EPR will be prepared in accordance with Section 15 of Ontario Regulation 231/08 and will document: the proposed changes to the transit project; updates to existing environmental conditions since completion of the 2011 EPR, the potential effects associated with the proposed changes and measures to mitigate the potential effects to the environment.

Find Out More

Planning for changes to this project includes consultation with property owners, members of the public, Indigenous communities, and review agencies, to share information and consider interests and concerns early in the process. Public meetings are being planned for you to learn about the project changes and to provide your input.

You are invited to attend Public Meeting #1 to review project information and the next steps in the process. Two Public Meeting #1 events are being held as follows:

Date: Tuesday, April 24, 2018
Time: 6:30pm to 8:30pm
Presentation: 7:00pm
Location: Garnet B Rickard Recreation Complex
Hall #2
2440 Highway 2
Bowmanville, ON L1C 3K2

Date: Wednesday April 25, 2018
Time: 6:30pm to 8:30pm
Presentation: 7:00pm
Location: Oshawa Civic Recreation Complex
Bobby Orr Room
99 Thornton Road South
Oshawa, ON L1J 5Y1

Please refer to the Location Plan for the approximate location of Public Meeting #1 events. Please note that all Public Meeting locations are accessible.

Your participation is an important part of the EPR Addendum process and the project team will be available to answer questions and receive your comments. The same information will be provided at both Public Meeting #1 events.

Stay Connected

Your feedback and community perspective are important. You are encouraged to find out more and ask questions at any time. For more information or to be added to the project mailing list, please contact:

Bowmanville Rail Expansion Project

c/o Stacey Kenny
Senior Advisor, Communications & Stakeholder Relations
20 Bay Street, Suite 600, Toronto, ON M5J 2W3
tel: 416-202-5059
email: bowmanvilleexpansion@metrolinx.com
website: http://www.metrolinx.com/en/regionalplanning/rer/bowmanvilleexpansion.aspx

All personal information included in a submission – such as name, address, telephone number and property location – is collected, maintained and disclosed by the Ministry of the Environment and Climate Change for the purpose of transparency and consultation.

The information is collected under the authority of the *Environmental Assessment Act* or is collected and maintained for the purpose of creating a record that is available to the general public as described in s. 37 of the *Freedom of Information and Protection of Privacy Act*. Personal information you submit will become part of a public record that is available to the general public unless you request that your personal information remain confidential. For more information, please contact Stacey Kenny (contact information provided) or the Ministry of the Environment and Climate Change Freedom of Information and Privacy Coordinator at 416-327-1434.

Pour plus de renseignements, veuillez composer le 1-888-GET-ON-GO (438-6646).

Metrolinx is working to provide residents and businesses in the GTHA with a transportation system that is modern, efficient and integrated. Find out more about Metrolinx's Regional Transportation Plan for the GTHA as well as GO Transit, PRESTO, and Union Pearson Express, divisions of Metrolinx, at **www.metrolinx.com**

This notice was first published on April 12, 2018

Appendix H: Renewable Energy Generation Investment Plan

Oshawa PUC Networks Inc.

Renewable Energy Generation Investment Plan

February 6, 2020

Executive Summary

Oshawa PUC Networks Inc. (OPUCN) is a licensed electricity distributor serving approximately 60,000 customers in the City of Oshawa. OPUCN is filing a Cost of Service Rate Application (EB-2020-0048) for rates to be in effect January 1st, 2021. In accordance with the Ontario Energy Board's (Board) Filing Requirements for Electricity Transmission and Distribution Applications; Chapter 5 – Consolidated Distribution System Plan Filing Requirements – 5.2.2 (d), OPUCN has prepared the Renewable Energy Generation (REG) Investment Plan for its service territory for the five (5) year period 2021-2025.

The REG Investment Plan outlines the readiness of OPUCN's distribution system to connect distributed energy resources (DER), including any expansion or reinforcement necessary to accommodate the connection of DERs over the period 2021-2025.

Presently connected onto OPUCN's distribution system are renewable energy installations with capacity totaling 3942.5 kW under the FIT, microFIT and net-metering program as follows:

- 334 micro-FIT solar photovoltaic (PV) installations with micro-FIT generation capacity of 2644.39kW;
- 6 FIT solar photovoltaic (PV) installation with FIT generation capacity of 940.0 kW;
- 38 net-metering solar photovoltaic (PV) installation with net-metering generation capacity of 358.1kW;

Additionally, the following generation projects are connected onto OPUCN's distribution system with capacity totaling to 4550 kW:

- 1 Combined Heat and Power (CHP) system with generation capacity of 1600kW
- 1 microgrid system consisting of 2400kW CHP, 500kW battery energy storage system and 50kW solar photovoltaic (PV) installation – 2950kW total generation capacity

Based on current generation applications received by OPUCN, there are potentially 3 small generation installations with proposed generation of 1539.6kW and 1 micro-embedded generation installation with proposed generation of 7.7kW that is being proposed to be connected to the distribution system.

Table 1 and Table 2 summarizes the total generation capacity and number of DERs connected and awaiting connection onto the OPUCN distribution system, respectively.

	Micro Generation	Small Generation	Mid-Sized Generation	Large Generation	Comments
Connected to OPUCN (kW)	2835.7	1106.8	4550	0	No constraints
Pending Connections (kW)	7.7	1539.6	0	0	No constraints

Table 1 – Total Generation Capacity Connected and Pending Connection on OPUCN Distribution System

	Micro Generation	Small Generation	Mid-Sized Generation	Large Generation	Comments
Connected to OPUCN	369	9	2	0	No constraints
Pending Connections	1	3	0	0	No constraints

Table 2 – Total Number of DERs Connected and Pending Connection on OPUCN Distribution System

As part of the Regional Planning process, OPUCN participated in the planning group meetings in identifying potential needs within the GTA east region including investments required to accommodate DER connections. A Needs Assessment report was created and published on the Hydro One Regional Planning web page on August 15th, 2019 and concluded that there are no additional investments required within the Oshawa area. A Planning Status Letter has been requested from the Regional Planning coordinator (Hydro One) to further support this.

With respect to future potential investments related to DER connections, OPUCN presently does not anticipate any need for immediate investments, however, depending on the size of future distributed generation applications and Connection Impact Assessments (CIA), there may be other constraints that warrant the need for additional investments either on the distribution and/or transmission system. As these costs are unknown at this time, OPUCN proposes that any future qualifying expenditure would be recorded in the Board approved Deferral Accounts and recovered at a more opportune time, through the provincial cost recovery mechanism set out in Section 79.1 of the OEB Act.

Table of Contents

Introduction

Oshawa PUC Networks Inc. (OPUCN) is a licensed electricity distributor serving approximately 60,000 customers in the City of Oshawa. OPUCN is filing a Cost of Service Rate Application under the Fourth Generation Incentive Rate (Price Cap IR) as set out in the Report of the Board: Renewed Regulatory Framework for Electricity (RRFE), for rates to be in effect January 1st, 2021. In accordance with the Ontario Energy Board's (Board) Filing Requirements for Electricity Transmission and Distribution Applications; Chapter 5 – Consolidated Distribution System Plan Filing Requirements, OPUCN has prepared the Renewable Energy Generation (REG) Investment Plan for its service territory for the five year period 2021-2025.

The REG Investment Plan outlines the readiness of OPUCN's distribution system to connect distributed energy resources (DER), including any expansion or reinforcement necessary to accommodate the connection of DERs over the period 2021-2025.

Assessment of OPUCN's Existing Distribution System

OPUCN is a local distribution company that is responsible for the distribution of electricity to the City of Oshawa. This territory is currently serviced from 3 Hydro One transmission stations (TS) including Wilson TS, Thornton TS, and Enfield TS and 9 distribution substations (DS).

OPUCN distribution system includes a total of 14 – 44kV primary distribution feeders, 8 from Wilson TS, 4 from Thornton TS, and 2 from Enfield TS along with up to 54 – 13.8kV primary distribution feeders to service customers either at primary voltages or at step down secondary voltages (347/600V, 120/208V or 120/240V). Each 44 kV feeder is rated at 23MVA and each 13.8kV feeder is rated at 7MVA under normal loading conditions.

Hydro One Transmission Stations

Hydro One's transmission stations have no short circuit capacity or thermal capacity constraints that exist. The information in the table was provided by Hydro One in the published "Hydro One List of Station Capacity" updated on December 19th, 2019 and indicates approximate amount of generation that can be added at each Hydro One owned station.

Station Name	Voltage (kV)	Available Short Circuit Capacity (MVA)	Available Thermal Capacity (MW)
Thornton TS	44	346.0	98.2
Wilson TS DESN1	44	278.0	112.1
Wilson TS DESN2	44	260.8	106.3
Enfield TS	44	254.6	91.9

Table 3 – Hydro One TS Capacity (Refer to Appendix A: Sections of Hydro One list of Station Capacity, Dec 19, 2019)

OPUCN Distribution Stations

Table 4 illustrates the remaining short circuit and thermal capacity at each of the 9 OPUCN DS based on connections and pending connections on the 13.8kV voltage level:

Distribution Substation Transformer		Voltage (kV)	Available Short Circuit Capacity (MVA)	Available Thermal Capacity (MW)
MS2	**T1**	13.8	101.9	25.7
	T2	13.8	101.7	26.3
MS5	**T1**	13.8	103.4	26.2
	T2	13.8	108.2	20.8
MS7	**T1**	13.8	97.3	21.4
	T2	13.8	97.2	21.3
MS9	**T1**	13.8	119.8	25.0
	T2	13.8	128.9	25.0
MS10	**T1**	13.8	82.5	25.5
	T2	13.8	118.5	20.8
MS11	**T1**	13.8	100.1	25.7
	T2	13.8	102.5	25.8
MS13	**T1**	13.8	112.5	26.2
	T2	13.8	108.8	26.0
MS14	**T1**	13.8	97.4	21.1
	T2	13.8	104.4	20.8
MS15	**T1**	13.8	101.5	25.7
	T2	13.8	98.4	26.2

Note: The acceptable thermal capacity limit at a TS or DS is established by adding together 60% of maximum MVA rating of the single transformer and the minimum station load.

Table 4 – OPUCN Distribution Substation Capacity

In summary, it is vital to ensure that the addition of any proposed distributed generation will not negatively impact distribution equipment or create safety concerns due to short circuit conditions. The assessment presents that there are no constraints and that there is sufficient capacity on the distribution system to connect future DERs subject to specific Connection Impact Assessments (CIA). OPUCN does not anticipate any requirement for immediate investments as a result of this.

Existing Distribution Energy Resources Connections

OPUCN has connected approximately 380 DERs totaling to almost 8.5MW of potential generation capacity to the distribution system which are summarized in Tables 5 and 6.

Project Type	# of Connected DERs	Generation Capacity (kW)
MicroFIT	334	2644.4
FIT	6	940.0
Net-Metering	38	358.1
CHP	1	1600.0
Microgrid	1	2950.0
Total	380	8492.5

Table 5 – Summary of Existing DERs Connected to the OPUCN Distribution System

Currently, there are 334 micro-FIT, 6 FIT and 38 net-metering distributed generation facilities that are connected to the distribution system totaling to about 3.9MW of renewable energy.

Also, 1 CHP and 1 microgrid are in-service and connected within OPUCN distribution system with a total installed capacity of 4.6MW. Both of these systems are being used for load displacement to offset customer's load consumption.

The following table provides the total number of existing DERs that are in-service with its respective total generation capacity by classification as per the Distribution System Code (DSC). Please refer to Appendix B: Generator Classification for details on generation classifications.

Project Type	# of Connected Projects	Generation Capacity (kW)
Micro Generation	369	2835.7
Small Generation	9	1106.8
Mid-Sized Generation	2	4550.0
Large Generation	0	0
Total	380	8492.5

Table 6 – Existing DERs by Classification

Regional Planning and Consultations

In keeping with the Chapter 5 – Consolidated Distribution System Plan Filing Requirements, and the Regional Planning process, OPUCN has participated in planning meetings and submitted an updated load forecast to the lead transmitter (Hydro One) in identifying any needs within the GTA East region including investments required to accommodate future DERs.

Upon reviewing all responses and updated information, Hydro One has created the Needs Assessment report and published on the Hydro One Regional Planning web page on August 15th, 2019. It was concluded that there are no additional investments required within the Oshawa area on a regional planning level. A Planning Status Letter has been requested from the Regional Planning coordinator (Hydro One) to further support this.

Investments to Facilitate Distributed Energy Resources

It should be noted that the feed-in tariff programs have ceased to exist as of December 31st, 2017 and transitioned to net-metering, load displacement, CHP or microgrid projects pursuant to the directive issued by the Ministry of Energy to the IESO. The last microFIT project within Oshawa service territory was connected on December 19th, 2018.

Based on historical trends, OPUCN connects approximately 38 DER projects annually, however, a significant decline in the number of connections was observed with the conclusion of the feed-in tariff programs having only 3 in-service connections with total generation capacity of 25kW in 2019. It is expected that generation connection capacity would improve with the anticipated connection of small generation facilities including a 439.6kW REG, 500kW REG, 600kW CHP and 2 proposed micro-embedded generation facilities (approximately 14.59kW) in the next couple of years.

No constraints were identified on the OPUCN distribution system to accommodate the potential connection of these DERs, and therefore, OPUCN is not proposing any immediate planned capital expansions or enhancements investments related to these connections for the 2021-2025 planning period. This will be further monitored as future proposed DERs are identified.

OPUCN will include the required expansion or enhancements as part of the capital program investment in the year of the confirmed installation date. As these costs are unknown at this time, OPUCN proposes that any future qualifying expenditure would be recorded in the Board approved Deferral Accounts and recovered at a more opportune time, through the provincial cost recovery mechanism set out in Section 79.1 of the OEB Act.

Appendix A: Sections of Hydro One List of Station Capacity, Dec 19, 2019

Hydro One List of Station Capacity

This document lists the estimated thermal and short circuit capacities for generation connections to distribution system supplied by Hydro One stations in the province of Ontario. Capacity on those stations constrained by limits on the transmission system is shown as Transmission Constraints (TC). For more information, please refer to the glossary of terms at the end.

The Thermal Capacity represents the estimated total name plate amount of generation that can be connected to the distribution system supplied by the subject bus or station. The Short Circuit capacity represents the estimated total acceptable short circuit contribution by generation connected to the distribution system supplied by the subject bus or station. Estimated short circuit capacity is not applicable to all Hydro One stations and buses depending on their type and configuration. Estimated short circuit capacity for those stations is shown as "N/A".

The listed capacity values in this document are estimates only and are based on the maximum permissible thermal and short circuit levels at Hydro One stations. This list does not reflect the capacity on Hydro One transmission network or indicate the condition of any Hydro One equipment. These estimated thermal and short circuit capacities are calculated without considering any existing or allocated generation capacity listed in Hydro One's List of Applications.

Please refer to the online station capacity calculator to determine preliminary connection availability. Note that capacity allocation will be determined when the generator applies for a Connection Impact Assessment (CIA) excluding microFIT applicants.

This document will be updated regularly. For any questions, please contact the Business Customer Centre at dxgenerationconnections@hydroone.com or 1-877-447-4412 (Option #2). An accompanying document titled "List of Applications" provides information regarding applications to connect at Hydro One-owned transformer stations. This document can be found on Hydro One's website www.HydroOne.com under the Distribution-Connected Generators section. The potential capacity of a feeder is described in that section as well.

The list was updated on December 19, 2019

Notes:

Coniston TS was removed as it is being decommissioned

Hydro One Distribution Generation List of Station Capacity December 19, 2019 HONI_LSC.pdf

Station Name	Bus Name	Feeder Name	Voltage (kV)	Minimum Load (MW)	Short Circuit Capacity (MVA)	Thermal Capacity (MW)	Upstream TS	Upstream TS feeder
ELGIN TS DESN1	JQ	M22,M23,M24,M25,M26,M27,M28,M30,M31,M32,M33,M34	13.8	10.87	32.0	10.9		
ELGIN TS DESN1	Total	M22,M23,M24,M25,M26,M27,M28,M30,M31,M32,M33,M34,M41,M42,M43,M44,M45,M46,M47,M48	13.8	17.71	N/A	Sum of Buses		
ELGIN TS DESN2	EZ	M51, M52, M53, M61, M62, M63	13.8	14.10	1.3	30.1		
ELGINBURG DS	Total	F1,F2,F3	8.32	1.17	N/A	3.6	KINGSTON GARDINER TS DESN1	M3
ELK LAKE DS	Total	F1	4.16	0.17	N/A	1.1	KIRKLAND LAKE TS	G3K
ELLESMERE TS	J	M21,M23,M25,M27,M29,M31	27.6	19.54	50.5	44.5		
ELLESMERE TS	Q	M22,M24,M26,M28,M30,M32	27.6	16.38	48.3	41.4		
ELLESMERE TS	Total	M21,M23,M25,M27,M29,M31,M22,M24,M26,M28,M30,M32	27.6	35.92	N/A	Sum of Buses		
ELLIOT LAKE DS	Total	F1,F2	12.5	0.89	N/A	3.3	ELLIOT LAKE TS	M3
ELLIOT LAKE MISS DS	T1	F1,F3	12.47	0.34	N/A	2.7	ELLIOT LAKE TS	M3
ELLIOT LAKE MISS DS	T2	F4,F5	12.47	0.69	N/A	3.6	ELLIOT LAKE TS	M3
ELLIOT LAKE MISS DS	Total	F1,F3,F4,F5	12.47	1.03	N/A	3.4	ELLIOT LAKE TS	M3
ELLIOT LAKE TS	B1B3	M1, M3	44	5.04	399.2	25.0		
ELMHURST DS	T1	F1,F2,F3	8.32	0.48	N/A	2.9	BROWN HILL TS	M2
ELMHURST DS	T2	F4,F5	27.6	1.60	N/A	5.0	BROWN HILL TS	M2
ELMIRA TS	BY	M1, M2, M3	27.6	10.99	76.7	31.0		
ELMVALE DS	Total	F1,F2	8.32	0.81	N/A	2.2	MIDHURST TS - DESN1	M10
ELORA UNION DS	Total	F1,F2,F4	8.32	0.64	N/A	3.0	FERGUS TS	M7
ELSINORE DS	Total	F1,F2,F3	8.32	1.11	N/A	3.5	OWEN SOUND TS	M25
EMBRUN DS	Total	F2,F3,F4,	8.32	0.91	N/A	TC	CHESTERVILLE TS	M1
EMO DS	Total	F1,F2	12.47	0.66	N/A	2.1	BARWICK TS	M1
EMSDALE DS	Total	F1,F2,F3	12.47	1.75	N/A	4.6	MUSKOKA TS	M10
ENFIELD TS DESN1	BY	M3,M4,M5,M6,M7,M8	44	31.90	254.6	91.9		
ENGLEHART NORTH DS	Total	F1,F2,F3	12.47	0.68	N/A	3.6	KIRKLAND LAKE TS	M62
ENNISMORE DS	Total	F1,F2,F3	8.32	0.88	N/A	3.3	DOBBIN TS	M2

Station Name	Bus Name	Feeder Name	Voltage (kV)	Minimum Load (MW)	Short Circuit Capacity (MVA)	Thermal Capacity (MW)	Upstream TS	Upstream TS feeder
SUNDRIDGE NORTH DS	Total	F2,F3	12.47	1.18	N/A	4.1	MUSKOKA TS	M2
SUNNIDALE CORNERS DS	Total	F1,F2,F3	8.32	1.00	N/A	3.4	STAYNER TS	M5
SUTTON BASE LN DS #1	T1	F2,F3	8.32	0.16	N/A	2.6	BROWN HILL TS	M12
SUTTON BASE LN DS #1	T2	F1	8.32	0.51	N/A	2.9	BROWN HILL TS	M12
SUTTON BASE LN DS #1	Total	Field Check	8.32	0.66	N/A	3.1	BROWN HILL TS	M12
SUTTON DS #2	Total	F1,F2,F3	8.32	0.86	N/A	3.3	BROWN HILL TS	M12
SWANSON DS	Total	F1,F2,F3	12.47	0.23	N/A	3.1	KIRKLAND LAKE TS	G3K
TALBOT TS DESN1	BY	M11,M12,M13,M14,M21,M22,M23,M25	27.6	21.32	0.0	61.3		
TALBOT TS DESN2	J1J2	M41, M42, M43, M46, M47, M48	27.6	17.69	131.3	33.7		
TALBOT TS DESN2	Q1Q2	M51, M52, M53, M54, M55, M56	27.6	17.51	129.2	33.5		
TALBOT TS DESN2	Total	M41, M42, M43, M46, M47, M48,M51, M52, M53, M54, M55, M56	27.6	36.29	N/A	Sum of Buses		
TAMWORTH DS	Total	F1,F2,F3	12.47	0.82	N/A	3.7	NAPANEE TS	M2
TARA DS #2	Total	F1,F2,F3	8.32	0.92	N/A	2.4	OWEN SOUND TS	M25
TAUNTON DS	Total	F1,F2	29.3	3.03	N/A	5.0	WILSON TS DESN2	M11
TAYLOR DS	Total	F1,F2,F3	12.47	1.70	N/A	4.6	MUSKOKA TS	M3
TAYLOR KIDD DS	T1	F1,F2,F3	8.32	0.98	N/A	3.4	KINGSTON GARDINER TS DESN1	M13
TAYLOR KIDD DS	T2	F4,F5,F6	8.32	1.32	N/A	3.7	KINGSTON GARDINER TS DESN1	M13
TAYLOR KIDD DS	Total	F1,F2,F3,F4,F5,F6	8.32	2.29	N/A	4.7	KINGSTON GARDINER TS DESN1	M13
TEMAGAMI DS	Total	F1, F2	12.5	0.44	32.4	3.3		
TERAULEY TS DESN1	A1A2	For any information or inquiries please contact Toronto Hydro	13.8	18.37	59.3	18.4		
TERAULEY TS DESN1	A9A10	For any information or inquiries please contact Toronto Hydro	13.8	14.25	57.3	14.2		
TERAULEY TS DESN1	Total	For any information or inquiries please contact Toronto Hydro	13.8	32.71	N/A	Sum of Buses		
TERAULEY TS DESN2	A3A4	For any information or inquiries please contact Toronto Hydro	13.8	13.70	97.6	13.7		
TERAULEY TS DESN2	A5A6	For any information or inquiries please contact Toronto Hydro	13.8	19.09	97.6	19.1		
TERAULEY TS DESN2	Total	For any information or inquiries please contact Toronto Hydro	13.8	34.45	N/A	Sum of Buses		
TESSIER DS	Total	F1,F2	12.47	0.29	N/A	1.7	LONGUEUIL TS	M24
THAMESVILLE NORTH DS	Total	F1,F2,F3	8.32	0.74	N/A	3.1	KENT TS DESN2	M24
THEDFORD DS	Total	F1,F2,F3	8	0.89	N/A	1.9	FOREST JURA DS	F1
THESSALON PEACHY DS	Total	F1,F2,F3	2.4	0.22	N/A	1.7	WHARNCLIFFE DS	F2
THORAH DS	Total	F1,F2,F3	8.32	1.05	N/A	3.4	BEAVERTON TS	M24
THORNDALE DS	Total	F1,F2,F3	8	0.75	N/A	3.2	HIGHBURY TS	M11
THORNTON DS	Total	F1,F2,F3	8.32	0.86	N/A	3.3	ALLISTON TS	M4
THORNTON TS	BY	M1,M2,M3,M4,M5,M6,M7,M8	44	30.97	346.0	98.2		
THOROLD ALLANPORT DS	Total	F1,F2	4.16	0.37	N/A	3.0	ALLANBURG TS	M8
THOROLD CLEVELAND DS	Total	F1,F2	4.16	0.33	N/A	2.7	THOROLD TS	M1

Station Name	Bus Name	Feeder Name	Voltage (kV)	Minimum Load (MW)	Short Circuit Capacity (MVA)	Thermal Capacity (MW)	Upstream TS	Upstream TS feeder
WARKWORTH DS	Total	F1,F2	8.32	0.96	N/A	2.4	SIDNEY TS	R8S
WARREN DS	T1	F1, F2	12.5	0.55	134.0	4.6		
WARREN DS	T2	F3, F4	12.5	1.12	134.4	5.2		
WARREN DS	Total	F1,F2,F3,F4	12.5	1.64	N/A	5.7		
WARTBURG DS	Total	F1,F2,F3	8.32	0.96	N/A	2.7	STRATFORD TS	M6
WARWICK DS	Total	F1,F2,F3	8.32	1.11	N/A	3.5	WANSTEAD TS	M1
WASHAGO DS	Total	F1,F2,F3	8.32	1.32	N/A	3.7	ORILLIA TS	M2
WASHBURN ISLAND DS	Total	F1,F2,F3	8.32	1.14	N/A	3.5	LINDSAY TS	M8
WATERFORD JAMES DS	Total	F1,F2,F3	8.32	0.90	N/A	3.3	NORFOLK TS	M6
WAUBAMIK DS	Total	F1	12.47	1.30	N/A	4.2	PARRY SOUND TS	M1
WAUBAUSHENE NORTH DS	Total	F1,F2,F3	8.32	1.08	N/A	3.5	WAUBAUSHENE TS	M1
WAUBAUSHENE TS	JQ	M1,M2,M3,M4,M5,M6,M7	44	35.87	532.0	75.9		
WAUPOOS DS	Total	F1,F2,F3	8.32	1.40	N/A	3.8	PICTON TS	M5
WELCOME DS	Total	F1,F2,F3	8.32	0.79	N/A	3.2	PORT HOPE TS DESN1	M18
WELLAND EFFINGHAM DS	Total	F1,F2,F3	8.32	0.96	N/A	3.4	CROWLAND TS	M13
WELLINGTON DS	Total	F1,F2,F3	8.32	0.77	N/A	3.2	PICTON TS	M5
WELLINGTON WHARF DS	Total	F1,F2	8.32	0.60	N/A	3.0	PICTON TS	M6
WENDOVER DS	T1	F1	27.6	1.89	237.7	13.9		
WENDOVER DS	T2	F3	27.6	1.57	437.6	15.0		
WENDOVER DS	Total	F1,F3	27.6	3.46	N/A	15.5		
WESLEY DS	T1	F1,F2	27.6	0.45	N/A	5.0	ARMITAGE TS DESN1	M12
WESLEY DS	T2	F3,F4	8.32	0.37	N/A	2.8	ARMITAGE TS DESN1	M12
WEST BAY DS # 2	Total	F1,F2,F3	12.47	0.00	N/A	4.8	MANITOULIN TS	M25
WEST FLAMBORO DS	Total	F1,F2	8.32	0.57	N/A	2.3	DUNDAS TS	M8
WEST LAKE DS	Total	F1,F2,F3	8.32	0.86	N/A	3.3	PICTON TS	M5
WEST LORNE DS	Total	F1,F2,F3	8.32	0.75	N/A	3.1	DUART TS DESN1	M6
WESTBROOK DS	Total	F1,F2,F3	8.32	0.92	N/A	3.3	KINGSTON GARDINER TS DESN1	M14
WESTON LAKE DS	Total	F1, F2	24.9	0.75	443.7	6.7		
WESTWOOD DS	Total	F1,F2,F3	8.32	1.34	N/A	3.7	OTONABEE TS DESN2	M28
WHARNCLIFFE DS	Total	F1, F2	24.9	1.28	37.2	3.7		
WHEATLEY DS #2	Total	F1,F2,F3	8.8	1.69	N/A	4.1	LEAMINGTON TS DESN1	M22
WHITBY TS DESN1	BY	M43, M44, M45, M46, M47, M48	27.6	0.41	5.7	25.4		
WHITBY TS DESN1	EZ	M5, M6, M7, M8	44	10.92	527.9	35.9		
WHITBY TS DESN2	JQ	M21,M22,M23,M24,M25,M26,M27,M28	44	50.02	274.6	110.0		
WHITE RIVER DS	Total	F1, F2, F3	24.9	10.00	106.4	13.6		
WHITEDOG DS	Total	F1	12.47	0.49	N/A	1.5	WHITEDOG FALLS GS	FP3
WHITEFISH DS	Total	F1, F2, F3	12.5	1.60	18.4	4.8		
WHITNEY DS	Total	F1,F2	12.48	0.54	N/A	TC	WALLACE TS	M6
WIARTON CLAUDE DS	Total	F1,F2,F3,F4,F5,F6	4.16	0.69	N/A	3.1	OWEN SOUND TS	M23
WILHAVEN DS	T1	F1, F2, F3	27.6	4.07	374.5	20.4		
WILHAVEN DS	T2	F4, F5	27.6	4.53	373.7	20.8		
WILHAVEN DS	Total	F1,F2,F3,F4,F5	27.6	8.60	N/A	20.0		
WILLIAMSTOWN DS	Total	F1,F2,F3	8.32	0.95	N/A	3.4	ST LAWRENCE TS	M25
WILLOW BEACH DS	Total	F1,F2,F3	8.32	0.69	N/A	3.1	BROWN HILL TS	M11
WILSON TS DESN1	BY	M1,M2,M3,M4,M5,M6,M7,M8	44	52.13	278.0	112.1		
WILSON TS DESN2	JQ	M11,M12,M13,M14,M15,M16,M17,M18	44	46.30	260.8	106.3		
WILSONVILLE DS	Total	F1,F2,F3	8.32	1.09	N/A	2.8	NORFOLK TS	M6

Reference: Hydro One List of Station Capacity
https://www.hydroone.com/businessservices_/generators_/Documents/honi_lsc.pdf

Appendix B: Generator Classification

Generator Classification	Rating
Micro	≤ 10 kW
Small	(a) ≤ 500 kW connected on distribution system voltage < 15 kV (b) ≤ 1 MW connected on distribution system voltage ≥ 15 kV
Mid-Sized	(a) ≤10 MW but > 500 kW connected on distribution system voltage < 15 kV (b) > 1 MW but ≤ 10 MW connected on distribution system voltage ≥ 15 kV
Large	> 10 MW

Reference: DSC Appendix F: Process and Technical Requirements for Connecting Embedded Generation Facilities
https://www.oeb.ca/documents/cases/EB-2005-0447/appendixf_201206.pdf

Appendix I: IESO Response to REG Investment Plan

Eric Andres

From: Miriam Heinz <Miriam.Heinz@ieso.ca>
Sent: February 24, 2020 6:18 PM
To: Eric Andres
Cc: Matthew Strecker
Subject: RE: IESO Contact for Letter of Comment on REG Investment Plan

Follow Up Flag: Follow up
Flag Status: Flagged

Hi Eric. The IESO has reviewed Oshawa PUC Networks Inc.'s (OPUCN) Renewable Energy Generation (REG) Investment Plan, and notes that OPUCN is not proposing any investments specific to connecting renewable energy generation (distributed energy resources) in the near term – that is for the plan period 2021 - 2025. This is consistent with the regional planning work in the GTA East Region where OPUCN participated in the Needs Assessment in which no immediate needs were identified to warrant a REG & DER investment.

Please note that in the case where a distributor has no REG investments during the 5-year Distribution System Plan (DSP) period no letter from the IESO is required, as the requirement is for when there *are* investments.

To illustrate this, provided below is an excerpt from the Ontario Energy Board's **Filing Requirements For Electricity Distribution Rate Applications** - Chapter 5, section 5.2.2 Coordinated planning with third parties:

d) For REG investments a distributor is expected to provide the comment letter provided by the IESO in relation to REG investments included in the distributor's DSP, along with any written response to the letter from the distributor, if applicable. The OEB expects that the IESO comment letter will include:

- *Whether the distributor has consulted with the IESO, or participated in planning meetings with the IESO;*
- *The potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the REG investments; and*
- *Whether the REG investments proposed in the DSP are consistent with any Regional Infrastructure Plan.*

The IESO appreciates having had the opportunity to review OPUCN's REG Investment Plan.

Please feel free to contact us if you have any questions.

Thanks,
Miriam

Miriam Heinz | Advisor, Regulatory Affairs
Independent Electricity System Operator (IESO) | T: (416) 969-6045 | C: (416) 917-3617
1600-120 Adelaide Street West, Suite 1600, Toronto, ON, M5H 1T1
E: miriam.heinz@ieso.ca
Web: www.ieso.ca | Twitter: IESO Tweets | LinkedIn: IESO

From: Eric Andres <eandres@opuc.on.ca>
Sent: February 6, 2020 5:04 PM
To: Miriam Heinz <Miriam.Heinz@ieso.ca>
Cc: Matthew Strecker <mstrecker@opuc.on.ca>
Subject: RE: IESO Contact for Letter of Comment on REG Investment Plan

CAUTION: This email originated from outside of the organization. Exercise caution when clicking on links or opening attachments even if you recognize the sender.

Hi Miriam,

Further to our discussion regarding OPUCN REG Investment Plan and issuance of IESO Letter of Comment, please refer to the attached documentation for your reference and review regarding our investment plan. OPUCN did not identify any investments as a result of DER connections.

Please do not hesitate to contact me if you require further information and clarification regarding this planning document.

Thanks and Regards,
Eric

Eric Andres, P.Eng.
Senior Distribution Engineer | Oshawa Power
905-723-4626 x 5198 | Cell (905) 242-9021
eandres@opuc.on.ca | www.opuc.on.ca

From: Eric Andres
Sent: January-22-20 11:46 AM
To: 'Miriam Heinz' <Miriam.Heinz@ieso.ca>
Subject: RE: IESO Contact for Letter of Comment on REG Investment Plan

Hi Miriam,

We are trying to get all DSP supporting documentations by end of February so the timelines works for us. Also, our preliminary assessment suggests that we will not require any investments.

Thanks again for this insight.

Eric

From: Miriam Heinz [mailto:Miriam.Heinz@ieso.ca]
Sent: January-22-20 11:42 AM
To: Eric Andres <eandres@opuc.on.ca>
Subject: RE: IESO Contact for Letter of Comment on REG Investment Plan

Hi Eric. We try to respond as soon as possible. Generally it can take a couple of weeks depending on resources but we have a strict timeline to reply within 30 days. If there are no investments in the plan we verify consistency with our planning documents and reply within days.

Did you have a time in mind by when you require a response?

Miriam

From: Eric Andres <eandres@opuc.on.ca>
Sent: January 22, 2020 11:34 AM
To: Miriam Heinz <Miriam.Heinz@ieso.ca>
Subject: RE: IESO Contact for Letter of Comment on REG Investment Plan

Thanks Miriam.

We are aiming to submit this in the next week. Would you also be able to please advise the typical turn-around time for the letter of comment?

Regards,
Eric

From: Miriam Heinz [mailto:Miriam.Heinz@ieso.ca]
Sent: January-22-20 11:29 AM
To: Eric Andres <eandres@opuc.on.ca>
Subject: RE: IESO Contact for Letter of Comment on REG Investment Plan

Hi Eric. I look forward to receiving your Plan and working to provide a letter of comment on any investments that may be a part of it.

Best regards,
Miriam

Miriam Heinz | Advisor, Regulatory Affairs
Independent Electricity System Operator (IESO) | T: (416) 969-6045 | C: (416) 917-3617
1600-120 Adelaide Street West, Suite 1600, Toronto, ON, M5H 1T1
E: miriam.heinz@ieso.ca
Web: www.ieso.ca | Twitter: IESO Tweets | LinkedIn: IESO

From: Eric Andres <eandres@opuc.on.ca>
Sent: January 22, 2020 11:20 AM

To: Steven Norrie <Steven.Norrie@ieso.ca>
Cc: Miriam Heinz <Miriam.Heinz@ieso.ca>
Subject: RE: IESO Contact for Letter of Comment on REG Investment Plan

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Thanks Steve for the prompt response.

Regards,
Eric

From: Steven Norrie [mailto:Steven.Norrie@ieso.ca]
Sent: January-22-20 11:17 AM
To: Eric Andres <eandres@opuc.on.ca>
Cc: Miriam Heinz <Miriam.Heinz@ieso.ca>
Subject: RE: IESO Contact for Letter of Comment on REG Investment Plan

Hi Eric, thank you everything is going well. I hope the same for you.

For your Renewable Energy Plan, please work through Miriam Heinz in Regulatory Affairs to coordinate our response.

Thank you and best regards, Steve

From: Eric Andres <eandres@opuc.on.ca>
Sent: January 22, 2020 11:00 AM
To: Steven Norrie <Steven.Norrie@ieso.ca>
Subject: IESO Contact for Letter of Comment on REG Investment Plan

CAUTION: This email originated from outside of the organization. Exercise caution when clicking on links or opening attachments even if you recognize the sender.

Hi Steven,

Hope everything is going well.

Oshawa Power is currently in the process of finalizing the **Renewable Energy Generation Investment Plan** in accordance with Section 5.2.2 (d) of the OEB Chapter 5 Filing Requirements and wanted to inquire the IESO contact to submit this documentation. Would you be able to please advise or direct me to the correct IESO contact?

Thank you for your assistance and if you require further information and clarification, please do not hesitate to contact me.

Best Regards,
Eric

Eric Andres, P.Eng.
Senior Distribution Engineer | Oshawa Power
905-723-4626 x 5198 | Cell (905) 242-9021
eandres@opuc.on.ca | www.opuc.on.ca

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Appendix J: 2018 Scorecard

Scorecard - Oshawa PUC Networks Inc.

9/29/2019

Performance Outcomes	Performance Categories	Measures		2014	2015	2016	2017	2018	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	**Service Quality**	New Residential/Small Business Services Connected on Time		95.60%	95.40%	92.60%	99.47%	99.78%	↑	90.00%	
		Scheduled Appointments Met On Time		100.00%	99.60%	100.00%	98.53%	100.00%	↓	90.00%	
		Telephone Calls Answered On Time		72.00%	70.20%	73.70%	90.52%	90.10%	↑	65.00%	
	Customer Satisfaction	First Contact Resolution		4 calls	149	521	277	103			
		Billing Accuracy		99.88%	99.93%	99.94%	99.94%	99.93%	↑	98.00%	
		Customer Satisfaction Survey Results		93% satisfied	93% satisfied	92%satisfied	92% satisfied	95% satisfied			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	**Safety**	Level of Public Awareness			85.00%	85.00%	85.00%	85.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C	→		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	0	→		0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000	→		0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		1.34	1.21	2.61	0.73	1.34	↑		1.18
		Average Number of Times that Power to a Customer is Interrupted [2]		1.19	1.27	2.06	0.98	1.29	↑		1.06
	Asset Management	Distribution System Plan Implementation Progress		Submitted	99%	97%	101.3%	70.2%			
	Cost Control	Efficiency Assessment		2	2	2	2	2			
		Total Cost per Customer [3]		$519	$545	$546	$532	$569			
		Total Cost per Km of Line [3]		$29,881	$31,719	$31,962	$31,280	$33,915			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	**Conservation & Demand Management**	Net Cumulative Energy Savings [4]			6.91%	24.21%	71.65%	83.00%			73.01 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time			100.00%		0.00%	100.00%			
		New Micro-embedded Generation Facilities Connected On Time		100.00%	100.00%	100.00%	100.00%	100.00%	→	90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	**Financial Ratios**	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.84	1.16	1.16	0.99	1.07			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		0.78	1.12	1.04	0.96	1.21			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.42%	9.30%	9.30%	9.19%	9.00%			
			Achieved	6.41%	7.59%	9.97%	7.62%	7.93%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the 2015-2020 Conservation First Framework. 2018 results are based on the IESO's unverified savings values contained in the March 2019 Participation and Cost Report.

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

2018 Scorecard Management Discussion and Analysis ("2018 Scorecard MD&A")

The link below provides a document titled "Scorecard - Performance Measure Descriptions" that has the technical definition, plain language description and how the measure may be compared for each of the Scorecard's measures in the 2018 Scorecard MD&A:
http://www.ontarioenergyboard.ca/OEB/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf

Scorecard MD&A - General Overview

- **General Overview:**
  In 2018, Oshawa PUC Networks Inc. (Oshawa Power) successfully exceeded all mandatory industry targets. We are pleased to provide the following detailed report with commentary for each specific target.

  In 2018, Oshawa Power excelled in the areas of Service Quality and Customer Satisfaction which saw results above target, and consistent with our exceptional performance in the prior year. In Safety we continue to see no electrical incidents, as we reached the next milestone for the Infrastructure Health and Safety Association's (IHSA) *Recognition of Performance Achievement Milestone*, in 2019, with over 500,000 no lost time hours. Our conservation results are well ahead of the curve with over 83% of our savings target achieved by the end of year 4 of the six-year program. We are focusing our efforts on operations and reliability to better improve response time for frequency and duration of outages. Oshawa Power is proud to share it has connected all renewable generation requests on time for the last five consecutive years. Lastly, our financial results show good liquidity and leverage as we earn within the allowable range of our return on equity.

  Oshawa Power will continue to focus its efforts in 2019 on achieving operating efficiencies and demonstrating continuous improvement in its performance measures. Key objectives in 2019 include: (i) customer engagement initiatives to solicit feedback from our customers on our long-term business and investment plans; (ii) improvements in the area of asset management, including the development of a new long-term Distribution System Capital Plan; and (iii) helping customer's access grants and assistance from provincially run conservation and low-income programs.

Service Quality

- **New Residential/Small Business Services Connected on Time**
  In 2018, Oshawa Power connected 99.78% of the 1,378 eligible low-voltage residential and small business customers (those utilizing connections under 750 volts) to its system within the five-day timeline prescribed by the OEB. Oshawa Power considers this service quality requirement an important customer engagement initiative as it is the utility's first opportunity to meet and/or exceed its customer's expectations. Oshawa Power's five-year history shows it has been consistently above the OEB mandated threshold, which is reflected in the level of customer satisfaction within Oshawa Power's territory. Oshawa Power continues to connect service on time in 2019, with

99.7% connected on time as at June 2019.

- **Scheduled Appointments Met On Time**
  Oshawa Power scheduled over 960 appointments to complete work requested by its customers in 2018, which included underground locates, direct requests from customers, and key account and conservation requests. Oshawa Power met 100% of these appointments on time, which is the maximum achievable.

- **Telephone Calls Answered On Time**
  In 2018, Oshawa Power customer contact center agents received over 58,000 qualifying calls from its customers – over 220 calls per working day. Agents answered calls within 30 seconds 90.10% of the time. This result exceeds the OEB-mandated 65% target for timely response. Oshawa Power offers customers 24/7 service through various online forms and interactive voice response tools. This allows us to address the most common customer inquiries and service needs cost-effectively without compromising quality or service excellence. Emergency and outage notification calls are addressed using a live answering service after hours to ensure high-quality responsiveness from operating crews. Oshawa Power continues to improve its quick response time in 2019, as at June 2019, 95% of calls have been answered within 30 seconds.

Customer Satisfaction

- **First Contact Resolution**
  In 2018, Oshawa Power tracked calls where customers' questions were not resolved during their initial call and required a follow-up phone call, or were escalated to a Team Leader, Supervisor or Manager. As noted above, Oshawa Power received over 58,000 qualifying calls during the year, of which 0.2% were not resolved on first contact.

- **Billing Accuracy**
  For the period from January 1, 2018 to December 31, 2018, Oshawa Power issued over 700,000 bills and achieved a bill accuracy measure of 99.93%. This compares favorably to the prescribed OEB target of 98%.

- **Customer Satisfaction Survey Results**
  In 2018, Oshawa Power engaged UtilityPULSE to conduct a customer satisfaction survey. The findings from the annual survey results are utilized to make enhancements in processes, services and communications strategies throughout the organization. 95% of Oshawa Power's customers rated their experience with Oshawa Power as fairly satisfied to very satisfied. Satisfaction levels for Oshawa Power were 6% higher than the Ontario utility satisfaction result of 89%. Some examples of changes that have been made as a result of customer feedback in prior years include improvements in the telephone interactive voice response (IVR) system, increase in online presence through social media, and the implementation of an outage management system (OMS) that communicates to customers experiencing an outage.

Safety

- **Public Safety**

In May 2015, the OEB requested the implementation of a public safety measure for all Local Distribution Companies (LDCs). The OEB stated that the public safety metric will have the following components and will be included on the LDCs' annual scorecards:

a) Component A - Public Awareness of Electrical Safety
b) Component B - Compliance with Ontario Regulation 22/04
c) Component C - Serious Electrical Incident Index

Component A – Public Awareness of Electrical Safety

Component A, Public Awareness of Electrical Safety, measures the level of awareness of key electrical safety precautions among the public within the electricity distributor's service territory, and the degree of effectiveness for distributors' activities on preventing electrical accidents. The OEB requested that all LDCs carry out a survey using the Electrical Safety Authority's (ESA) approved methodology and pre-formed set of questions, so that a final LDC Awareness Score (bound between 0-100%) can be calculated.

Oshawa Power, and 33 other utilities, engaged UtilityPULSE to administer the survey as well as calculate the final score. The survey ran in January 2018, and Oshawa Power's final public awareness index score was 85%. Based upon the survey results of the participants, Oshawa Power customer awareness index was higher than the average score of 82% for the utilities who engaged in the survey. The survey will run again in early 2020.

Component B – Compliance with Ontario Regulation 22/04

Ontario Regulation 22/04 - *Electrical Distribution Safety,* establishes objective based electrical safety requirements for the design, construction, and maintenance of electrical distribution systems owned by licensed distributors. Specifically, the regulation requires the approval of equipment, plans, specifications and inspection of construction before they are put into service.

The definitions of a C, NI and NC score, as categorized by the ESA, are provided below:

Score	Definition
C	Compliant - Fully or substantially meeting the requirements of Regulation 22/04.
NI	Needs Improvement - Continuing failure to comply with a previously identified Needs Improvement item - Non-pervasive failure to comply with adequate, established procedures for complying with Regulation 22/04.
NC	Non-Compliance - A failure to comply with a substantial part of Regulation 22/04; or - Continuing failure to comply with a previously identified Needs Improvement item.

Oshawa Power was fully compliant with Ontario Regulation 22/04 for the year 2018, achieving a score of C. Oshawa Power's continued achievement of compliance is due to our strong commitment to safety, and adherence to standards and company procedures & policies.

Component C – Serious Electrical Incident Index

Oshawa Power reported no fatalities or other serious incidents due to contact with its infrastructure in 2018, thereby achieving a score of 0.000 for the Serious Electrical Incident Index per 100 km of line. In July of 2018, Oshawa Power reported one serious electrical incident to the ESA, which was a result of a contractor failing to follow safety precautions. No one was injured as the contractor's equipment came in contact with a power line.

Oshawa Power takes public safety in the vicinity of its distribution equipment very seriously, and regularly carries out activities to take prompt corrective action where potential public safety issues are identified. Oshawa Power achieved the Infrastructure Health & Safety Association's Certificate of Recognition™ (COR) and has done so for three consecutive years. The utility scored a near-perfect 94% in an audit conducted under the highest safety standard in the province. Oshawa Power is also a member in good standing with the Canada Safety Council. Oshawa Power promotes public safety messages through bill inserts, our website and social media so our customers stay informed.

System Reliability

- **Average Number of Hours that Power to a Customer is Interrupted**

  Oshawa Power's reported Average Number of Hours that Power to a Customer is Interrupted (i.e., duration excluding loss of supply) of 1.34 exceeds its target of 1.18 (based on a fixed five-year average performance from 2010 to 2014), and was higher than the previous year's result of 0.73. The year over year increase from 2017 and 2018, is principally due to aging distribution infrastructure and animal contacts with equipment. Oshawa Power continues to invest in the utility's distribution system by renewing aged and faulty equipment to help mitigate the duration of outages in the future.

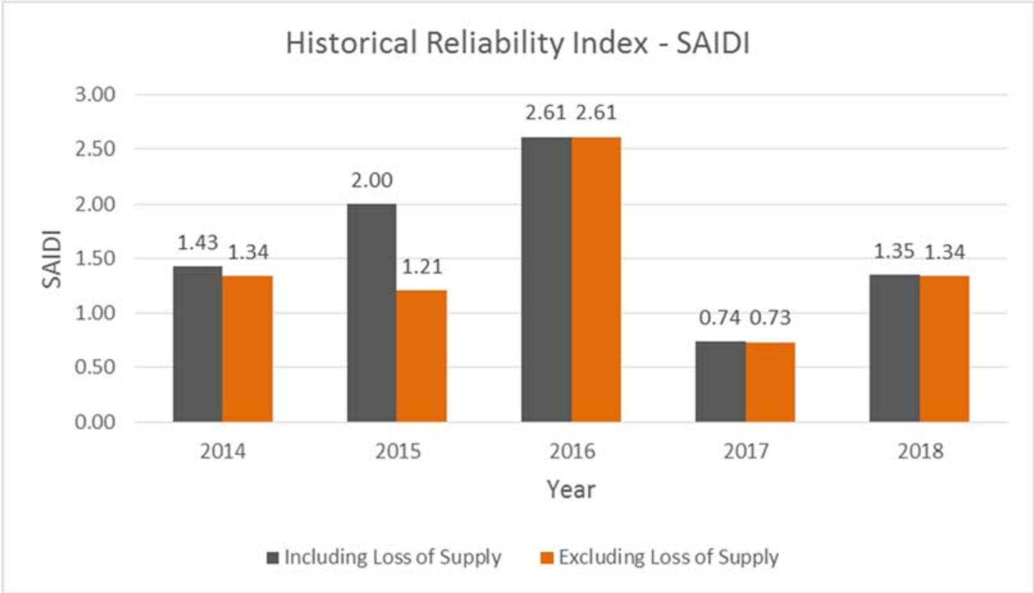
  In 2019, Oshawa Power continues to rebuild faulty and aged distribution infrastructure, and optimize OMS and smart grid technologies. The OMS continues to provide us with better visibility on the occurrence of system or customer outages, and improves communication to customers experiencing an outage. It automatically provides information regarding the outage area, number of customers affected and the anticipated outage response and restoration time.

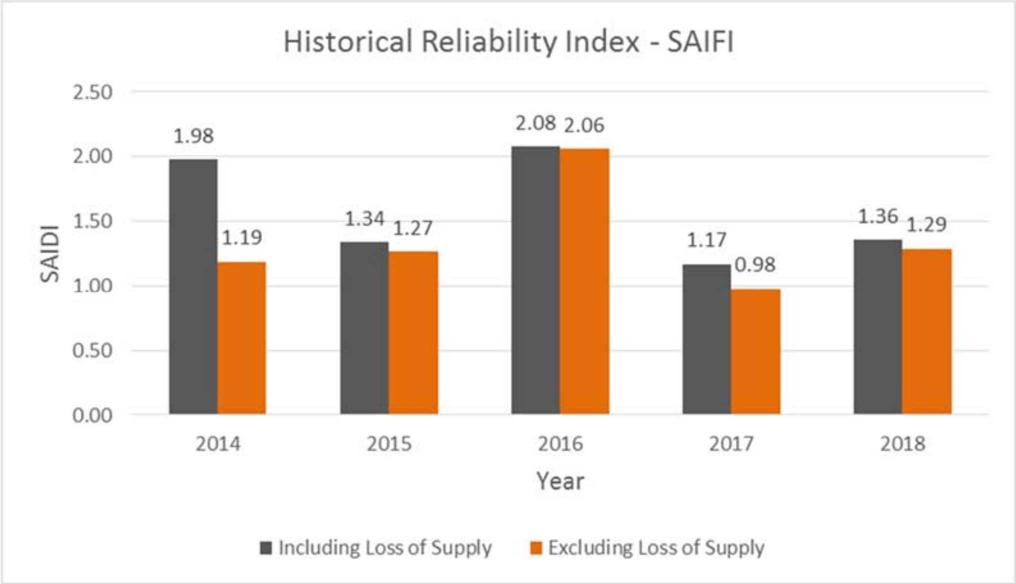
- **Average Number of Times that Power to a Customer is Interrupted**

  Oshawa Power's reported Average Number of Times that Power to a Customer is Interrupted (i.e., frequency excluding loss of supply) for 2018 was 1.29 which is higher compared to its target of 1.06, and higher than previous year's performance of 0.98. The year over year increase from 2017 to 2018 is principally due to animal contacts with equipment. Oshawa Power has been proactive in the installation of line covers to mitigate the occurrence of this type of outage in the future.

  Oshawa Power's renewal of aged distribution assets is in progress, and will help to further improve the reliability of the system. Oshawa Power also coordinates with Hydro One to ensure their programs are directed at the most critical assets impacting service in Oshawa, and to mitigate outages caused by loss of supply. Oshawa Power has also included in the planned capital investments the installation of additional equipment that will provide rapid isolation of faults to reduce the number of customers affected during an outage.

The graphs below summarize Oshawa Power last 5 years of reported SAIDI and SAIFI:





Asset Management

- **Distribution System Plan Implementation Progress**

  In 2014, Oshawa Power filed an application with the OEB for a full review of its rates effective January 1, 2015. Oshawa Power submitted its Distribution System Plan (DSP) to the OEB as part of the application. The metric that Oshawa Power chose to most effectively reflect our performance in Distribution System Plan Implementation Progress, is the ratio of actual total capital expenditures made in a calendar year, over the total amount of planned capital expenditures for that calendar year. For the twelve months ended December 31, 2018, Oshawa Power spent 70.2% of its OEB approved capital budget for the year. We came in under budget for the year primarily due to the deferral and reallocation of projects to subsequent years.

  In 2018, Oshawa Power completed construction of the Municipal Station 9 with customer connections scheduled in the summer of 2019. This state-of-the-art facility will also improve our outage response capacity by providing a backup control should our Simcoe Street facility become unavailable. Construction continued on Hydro One's Enfield Transformer Station which will provide an important third point of supply for our distribution network when it is commissioned in June 2019. Oshawa Power's capital spending tackles the importance and complexity associated with the significant population growth in Oshawa. In 2019, we continue to overcome these challenges while delivering on our capital program.

Cost Control

- **Efficiency Assessment**

  The total costs for Ontario local electricity distribution companies are evaluated by the Pacific Economics Group Research, LLC (PEG) on behalf of the OEB to produce a single efficiency ranking for each distributor. The performance rankings for 2018 are included in PEG's *Empirical Research in Support of Incentive Rate-Setting: 2018 Benchmarking Update Report* to the OEB issued on August 15, 2018.

  The electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual and predicted costs. Utilities whose actual costs are lower than predicted are characterized as efficient and are assigned to Group 1 (25% or more below predicted cost) or Group 2 (between 10% and 25%). Utilities that are considered average performers will be assigned to Group 3 (actual costs are within +/-10% of predicted costs). Utilities whose actual costs are higher than predicted will be assigned to Group 4 (between 10% and 25% above predicted cost) or Group 5 (in excess of 25% above predicted cost).

  Oshawa Power continues to be ranked in Group 2, where a Group 2 distributor is defined as having actual costs between 10% and 25% lower than predicted costs. Oshawa Power's goal is to sustain current efficiencies, and remain a cost-effective utility.

- **Total Cost per Customer**

  Total Cost per Customer is evaluated by PEG on behalf of the OEB, and is calculated as the sum of Oshawa Power's capital and operating costs, divided by the total number of customers served. Oshawa Power's 2018 cost performance is $569 per customer, resulting in a 7% increase over the prior year.

  Over the reporting period 2014 through 2018, Oshawa Power's Total Cost per Customer has increased by an average annual rate of just 2.5%. In addition to inflationary pressure, the renewal and growth of the distribution system, Province wide programs and costs required to address higher than normal customer growth in Oshawa have all contributed to the increase in capital expenditures and operating costs. The increase is in line with the increase in predicted costs as per the PEG Report, thereby continuing to position Oshawa Power in Cohort 2.

  In accordance with the OEB's decision on our Custom IR (incentive regulation) Cost of Service rate application, Oshawa Power will continue to replace distribution assets proactively along a carefully managed timeframe in a manner that balances system risks and customer value and add new infrastructure to address capacity constraints resulting from growth. Oshawa Power will also continue to implement productivity and improvement initiatives to help offset some of the costs associated with future system improvement, enhancements and growth.

- **Total Cost per Km of Line**

  This measure uses the same total cost that is used in the Cost per Customer calculation above. The total cost is divided by the kilometers of line that Oshawa Power operates to serve its customers. Oshawa Power's 2018 rate is $33,915 per Km of Line which represents an increase of 8.4% over the prior year. The average annual increase over the reporting period is 4.7%. The increase is in line with the increase in predicted costs as per the PEG Report, thereby continuing to position Oshawa Power in Cohort 2.

  Oshawa Power has been investing in infrastructure renewal at higher than normal rate over the last several years in response to its aging distribution system. As capital investments for replacement and rehabilitation of existing lines grows at a faster rate than additions of lines within Oshawa Power's service area,

  As reported in its Distribution System Plan (Custom IR Cost of Rate Application), Oshawa Power anticipates that renewal expenditures will normalize over the next five years.

Conservation & Demand Management

Oshawa Power has continued to successfully deliver the Save On Energy programs, under the province's Conservation Frist Framework (CFF). Efforts in 2018 focused on ramping-up for the 2019 and 2020 seasons, which would have been the final years of the CFF. Efforts also included helping customers navigate the cancellation of incentive programs, such as the Green Ontario Fund. As of March 21, 2019, Ontario Bill 87 came into effect which discontinued conservation program delivery by local utilities. The directive, given by the Minister of Energy, will see a new framework for provincially delivered energy-efficiency programs begin April 1, 2019.

Under the 2015 to 2020 CFF, Oshawa Power was assigned an energy savings target of 73 GWh. The achievement of this energy efficiency target is governed via an Energy Conservation Agreement (ECA). The IESO periodically issues updates to the ECA and Oshawa Power regularly commits to the updated terms. As of March 21, 2019, the ECA between Oshawa Power and the IESO has been terminated as per ministerial directive noted earlier.

The following section describes the net cumulative energy savings that were achieved in each of 2015 (the preparatory year for the CFF), 2016, 2017 and 2018. Please note that the savings for 2018 are "Gross Unverified" savings as the IESO no longer provides "Net Cumulative Energy Savings" reports to LDCs, following the cancellation of CFF through Ontario Bill 87 in early 2019, cited above.

- **Cumulative Energy Savings**
  - ✓ 15,583 MWh in 2015 (net, verified);
  - ✓ 13,731 MWh in 2016 (net, verified);
  - ✓ 23,040 MWh in 2017 (net, verified);
  - ✓ 8,244 MWh in 2018 (gross, unverified).

Oshawa Power's cumulative total energy savings for the CFF as of December 31, 2018 is therefore 60,598 MWh, or 83% of the multi-year target. Prior to the cancellation of the CFF, Oshawa Power was projected to exceed our 2020 conservation targets.

Connection of Renewable Generation

- **Renewable Generation Connection Impact Assessments Completed on Time**

  Electricity distributors are required to conduct Connection Impact Assessments (CIAs) for renewable generation facilities >10kW within 60 days of receiving a complete application from the Generator. In 2018, Oshawa Power had three CIA connection request for renewable generation facilities >10kW. All three were connected on time as per OEB guidelines.

- **New Micro-embedded Generation Facilities Connected On Time**
  In 2018, Oshawa Power successfully connected 56 new micro-embedded generation facilities (microFIT and net-meter projects of less than 10 kW), all of which were connected within the prescribed time frame of five business days, in accordance with the Distribution System Code provisions. The minimum acceptable performance level for this measure is 90% of the time, and Oshawa Power has significantly exceeded the target. Our workflow to connect these projects is simplified and transparent with our customers. Oshawa Power works closely with its customers and their contractors to tackle any connection issues to ensure the project is connected on time.

Financial Ratios

- **Liquidity: Current Ratio (Current Assets/Current Liabilities)**
  The current ratio is an indicator of a company's ability to repay its short term debts and financial obligations. Companies with a ratio of greater than 1 are often referred to as being "liquid". Generally, the higher the number, the more "liquid" and the larger the margin of safety to cover the company's short-term debts and financial obligations. Oshawa Power's current ratio for 2018 is 1.07. Oshawa Power monitors and manages its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements.

- **Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio**
  The OEB uses a deemed capital structure of 60% debt, 40% equity for electricity distributors when establishing rates. This deemed capital mix is equal to a debt to equity ratio of 1.5 (60/40). A debt to equity ratio of more than 1.5 indicates that a distributor is more highly levered than the deemed capital structure. A high debt to equity ratio may indicate that an electricity distributor may have difficulty generating sufficient cash flows to make its debt payments. A debt to equity ratio of less than 1.5 indicates that the distributor is less levered than the deemed capital structure. Oshawa Power's debt to equity ratio for 2018 was 1.21 compared with 0.96 in 2017. Oshawa Power continues to be below the OEB's deemed capital structure, as the trend from 2014 to 2018 illustrates a debt to equity ratio of less than 1.5.

- **Profitability: Regulatory Return on Equity – Deemed (included in rates)**
  Oshawa Power's current distribution rates were approved by the OEB and include an expected regulatory return on equity (ROE) of 9.00%, which is based on the OEB's deemed capital structure of 60% debt and 40% equity as noted earlier. The OEB allows a distributor to earn within +/- 3% of the expected return on equity. When a distributor performs outside of this range, the actual performance may trigger a regulatory review of the distributor's revenues and costs structure by the OEB. The regulated return for the year 2019 decreases to 8.98%.

- **Profitability: Regulatory Return on Equity – Achieved**
  Oshawa Power's ROE for 2018 was 7.93%, compared with a regulatory ROE of 9.00% for the same period. For 2018, Oshawa Power earned a lower return than the approved rate, however; results are within the expected ROE range set out by the OEB.

Note to Readers of 2018 Scorecard MD&A

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management's best judgement on the reporting date of the performance scorecard, and could be markedly different in the future.

Appendix K: Grid Modernization Plan

OSHAWA PUC

Oshawa PUC Networks Inc.

GRID MODERNIZATION PLAN

Prepared by

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METSCO
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P-18-174

March 2020

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Version History

Version	Date	Description
1.0	March 26, 2020	Report Issue

Technical and System Acronyms

In most cases throughout this report, system terms are described in long form and committees are described with their proper names. In some tables short form acronyms are used to save space. The following list of acronyms are sometimes used in this document.

- ACA – Asset Condition Assessment
- ADMS -- Advanced Distribution Management System
- AM – Asset Management
- AMI – Advanced Meter Infrastructure
- CIS -- Customer Information Systems
- CVR -- Conservation Voltage Reduction
- DA -- Distribution Automation
- DMS – Distribution Management Systems
- EV – Electric Vehicles
- FLISR -- Fault Location, Isolation and System Restoration
- GIS -- Geographic Information Systems
- IT/OT – Information Technology/Operational Technology
- IVR – Intelligent/Integrated Voice Recognition
- OEB – Ontario Energy Board
- OMS – Outage Management Systems
- ODS – Operational Data Store
- SCADA – Supervisory Control and Data Acquisition
- TS/MS – Transformer Station Municipal Station

Table of Contents

1. Oshawa Power Background

Oshawa Power Background

Oshawa Power and Utilities Corporation (Oshawa Power) and its subsidiaries conduct regulated electricity distribution and other non-regulated operations in the service area of Oshawa, Ontario. The Company provides regulated electricity distribution services to approximately 73,000 businesses and residences, through its principal subsidiary Oshawa PUC Networks Inc. ("Networks").

Oshawa Power constructed a new state-of-the-art facility (Municipal Station 9) which will meet the demand for power and also improve outage response capacity by providing a backup control room and a space for managers and service representatives to work should the Simcoe Street facility become unavailable.

Oshawa Power drives innovation with projects including: a complex data analytic solution based on the Pi System to add advanced features to our network, E-Mission, a comprehensive electric vehicle(EV) strategy aimed at increasing electrification of transportation. and a Peak Performance pilot program that examined how pricing plans could help them consumption to *off-peak* periods.

Developing a Grid Modernization Plan

Oshawa Power believes in planning for future innovative and technological applications of the electrical distribution system, and in keeping with the intents of the Province's Long-Term Energy Plan, Oshawa Power has commissioned METSCO Energy Solutions to develop a Strategic plan to reflect the modernization of the grid (The Plan).

This intent of The Plan is to provide strategic direction and priorities to inform the next level planning and business case development. In most (but not all) cases, the technology required to modernize the grid is available, however at this time not very many utilities have developed a fully modernized approach. The report is intended to give long term guidance in the development of future oriented decisions and provide a basis for shorter term project prioritization.

	This Plan				
White Papers and R&D	Strategic Plans Long Term Plan, System Level Plan	Feasibility Plan Short Term, Gap Analysis	Business Case Per Project Plan	Project Planning Conceptual and Basic Plans	Constriction Plans Specifications and Details

Project Methodology

In 2014, Oshawa Power commissioned an initial grid modernization study which was used as the basis for the 5-year plan leading up to this point. That study identified a number of key investment strategies to be implemented in the short term and made best predictions about how the following five years would evolve.

Since that time, there have been a number of changes in the utility environment and a number of technical advances that have altered the landscape. As a result, while Oshawa Power planners have completed a number of the projects envisioned in the previous report, in a number of other cases it made more sense to defer projects.

This project was designed to:

- Review the previous plans and the work completed to this time.
- Examine the Long-Term Energy Plan, other umbrella drivers.
- Look at the unique opportunities and challenges facing Oshawa Power
- Propose modernization technologies that integrate with Oshawa Power systems
- Propose objectives, strategies and plans specific to Oshawa Power
- Assess existing systems, customer preferences and trends
- Include behind the meter and before the meter solutions.

2. Oshawa Power Smart Grid Vision

Oshawa Power is proud of its history in the application of innovative technologies and applications. Over the past years, Oshawa Power has taken on a number of projects that have helped increase reliability, increase data management, advanced the cause of "Electrification of Transportation" and contributed to the goals of The City of Oshawa and The Region of Durham.

Oshawa Power has been involved is several "Flag Ship" activities which are indicative of both Oshawa Power's commitment to innovative advancement and success at managing technology integration. Some of the highlights are presented below.

Peak Performance

Oshawa Power was selected by the Ontario Energy Board (OEB) to conduct a $5.5 million study to examine whether pricing options and digital engagement could be used to measurably shift load to off-peak rate period. Some customers demonstrating a nearly 10 per cent conservation effect during peak times. The final report on the initiative will be posted on the Ontario Energy Board's website.

Solar Energy Management Study

A study called the Solar Energy Management Study, examined the results of installing rooftop solar panels, battery storage and energy management systems on the homes of 30 Oshawa Power customers. In a virtual power plant concept, the systems were linked to form a microgrid and demonstrated value for distributed generators looking to supply to Ontario's grid.

OSI Pi System

New Pi System by OSI, is a digital warehouse that collects all of the company's operational data. The utility then began using the data to create high-level analytical programs that will drive Oshawa Power to the next level of operational excellence

E-Mission

E-Mission is a survey and study to examine the effects that wholesale migration to Electric Vehicle technology could have on the utility's infrastructure. The data collected is helping Oshawa Power to plan for the future of electric transportation.

Durham Community Energy Plan

Oshawa Power is proud to sponsor and be the leading utility contributor to the Durham Community Energy Plan and promoting Durham Region's low-carbon future. The study found that the low-carbon option would provide thousands of local job opportunities, result in significant greenhouse gas reductions and allow for numerous lifestyle benefits. The utility will incorporate elements of the document into its future business planning for strategic growth.

Combined Heat and Power

Oshawa Power is developing proposals to own and operate systems that will supply electricity and thermal energy to the Delpark Homes Centre, South Oshawa Community Centre and Oshawa Civic Recreation Centre. Having year-round thermal loads (heating swimming pools) made these facilities ideal candidates for this technology. As well, Durham College's Whitby Campus is exploring the prospect of hosting an Oshawa Power owned and operated the facility on their campus similar to Oshawa Power's 2.4 MW The system at Ontario Tech University, Durham College that will help the college achieve its energy security goals

Electric bus

Oshawa Power is developing a business case for electrification of a local bus fleet. The plan would see Oshawa Power install, own and operate electric vehicle (EV) charging infrastructure at transit depots and on routes. Solar power generated at the depots may be used for charging.

Website and Customer Access

Oshawa Power did an overhaul of the company's website giving customers more access to data, the ability to request services, access to technical information and access to conservation and safety communications.

Cyber Security

In compliance with the OEB Ontario Cyber Security Framework, Oshawa Power acted to harden the IT networks against unwanted intrusions that include hacking, malware and viruses including: migrating to a next-generation firewall that uses artificial intelligence capabilities to automatically detect and remediate nefarious activity, and moving to disk-based storage for additional backup capabilities. Continued effort is required to maintain a secure infrastructure.

MS9 and Backup Control Room

To meet the new growth in the service area, Oshawa Power built a state-of-the-art Municipal Station 9 (MS9) for the summer of 2019. The new station is equipped with the latest sensor and control technology to enhance the reliability and security of the Oshawa Power system.

The site also includes a new backup control room. In the event of a disruption at the utility's main control room become unavailable for any reason, Oshawa Power can operate the critical elements of the utility's business from a dedicated area in the new facility. In addition to the control room, the facility provides a space where customer service representatives can maintain contact with customers and managers can direct efforts to restore the system to full functionality.

3. Evolving Smart Grid to ADMS

The Advanced Distribution Management System (ADMS), can be thought of as the ultimate in Electrical Distribution Operations, providing electric utilities with leading critical grid management capabilities to improve outage response, optimize evolving grid operation and manage technical impacts such a reliability, distributed energy resource (DER) integration and network visibility.

The ADMS is a highly integrated version of many other systems, that are built up from basic needs and applications. The ADMS is often thought of as the integration of Outage Management Systems (OMS) and Distribution Management Systems (DMS). Underneath the OMS and DMS systems are Customer Information Systems (CIS), Geographic Information Systems (GIS), Distribution Automation (DA), Fault Location, Isolation and System Restoration (FLISR) and many other advanced applications including Conservation Voltage Reduction (CVR) and Conservation and Demand Management (CDM).

It is not generally practical to start off with the implementation of a full ADMS. At this time very few utilities have succeeded in a complete installation. It is more beneficial to focus activities on those areas which have immediate benefit and invest in those applications with an understanding that an overall ADMS is the end objective. However, it is important to plan the infrastructure backbone such as communications protocols, cyber security, back-up centers and data management with the understanding of the ultimate applications.

Systems Typically Integrated to become ADMS

System	Utilization	Purpose
Customer Information System (CIS)	OMS	*Link customer reported outages to system map*
Geographic Information System (GIS)	DMS/OMS	*Link system map to geography*
SCADA	DMS/OMS	*Monitor and control system*
Vehicle Tracking and Dispatch	OMS	*Identify crew locations and optimize dispatch*
Interactive Voice Recognition and other communications options	OMS	*Provide two-way communications with customers.*
Advanced Metering Infrastructure	OMS	*Automate communication of device status at each service point*
Protection, FLISR and D/A	ADMS	*Automate outage detection and restoration.*
Demand Response	ADMS	*Manage DERs and optimize power/energy delivery.*
External Factors (Weather Monitoring)	ADMS	*Predict loads, and weather-related outage events. Plan for dispatch, predict duration of high-risk situations*

The Components of a Modern Grid

There are many subsystems within the operating systems of a distribution utility. These may include:

Integrated ADMS

- Real Time Cyme Analysis -- State Estimator
- Advanced Apps
- Weather prediction/crew standby
- Performance Center
- Vehicle Locating

Interoperable Systems

Customer Choice **CIS**	**Load Management** **DMS**	**Outage Management** **OMS –**	**Asset Management** **AMS**
• Green Button • CDM • Home energy Management • Outage Maps • Outage Notices • Transactional • Net Metering, RPP • Remote Start Stop • Electrification of Transportation	• CVR (Volt Var) • Storage DER • EVs • 1547 Management • ramp rates voltage frequency • New EV stations • MDMR	• FLISR/DA • AMI Next level • Mobile Dispatch • SCADA-Distribution • SCADA-Stations • Storm Center	GIS ACA – Investment Planning • New TS's • Neutral Grounding • Inspection and Maintenance • Remote Connect Disconnect • Remote relay settings • Procurement • Work Dispatch

Infrastructure, Digital Backbone (IT/OT)

- Cyber Security -- layer 3 security, Segment IP (IT/OT)
- ODS functionality
- backup power to data center, Active-Active-Failover
- Fiber/cell network.
- backhaul upgrades, enhanced wireless coverage,

4. External Drivers

The use of the distribution system is undergoing unprecedented change. A number of advances can be expected to require investment in the coming five to ten years. In particular the application of distributed energy resources (DERs) and electric vehicles (EVs) are reliant on intelligence and communications at the extreme ends of the system. The traditional system is being converted to a collector and aggregator of users and suppliers with many small connections.

Customer and regulatory bodies are demanding that the operations of the distribution network change to accommodate new activities. The most immediate and impactful of these changes include:

- increasing demand by customers for choices of billing structures,
- increasing demand by customers for access to billing data,
- increasing penetrations of electric vehicles (EVs), distributed energy resources (DERs) and small-scale energy storage,
- increasing demand to take the lead on emission reductions,
- increasing demand to build resilience to climate change issues, and
- increasing pressure from regulatory bodies and government to support innovation.

For the first time, the Province's Long Term Energy Plan directly addresses the distribution system. The plan speaks to making the distribution system a "smarter grid" and focuses on:

- EV's, DER's, and home energy storage,
- increasing customer choice, business models, pricing plans,
- modernizing regulation and rate designs,
- modernizing the grid with SCADA, automation and
- increasing in reliability and energy efficiency on the distribution system,
- the electrification of the transportation sector,
- creating and monitoring value and performance for consumers,
- elimination of regulatory barriers, and
- a reaffirmed and enhanced commitment to "Conservation First" programs and the value of conservation.

In its role as the regulator of rates, the Ontario Energy Board (OEB) has the mandate to execute government policy and has specifically focussed on:

- distribution rates based on condition-based asset renewal,
- operational efficiencies,
- improvements in reliability,
- initiatives on Cyber Security, and
- evolving regulation, such as "Net Metering", "Regulated Price Plan".

The Independent Electricity System Operator (IESO) has an impact on the Oshawa Power distribution system and is charged with management of:

- evolutions in meter data handing and changes to billing systems,
- management of energy conservation programs, and
- Cyber security.

The Ontario Government has targeted electricity system as a primary concern. The latest policy announcements continue to point to increased access to customer data to provide choice and promote conservation.

At the local level, conventional loading of the distribution system is increasing due Municipal growth initiatives, and province-wide electrification of the transportation system. Major projects impact the distribution system from a loading standpoint but also create opportunities to develop a “Smarter Grid” that is capable of load management, integrated communications and conservation initiatives. Major projects targets in the Oshawa area include:

- Durham Region’s “Durham Community Energy Plan” which “seeks to accelerate the transition to a clean energy economy”,
- Durham Region Transit’s plans for electrifying their fleet of nearly 200 buses, starting with an eight-bus pilot in Oshawa in 2020,
- MetroLinx - Electrification of Transportation, light rail (LRTs) and/or EV Busses along Main St.,
- Residential EVs that necessitate charging stations in the downtown core, and
- Large new developments such as a new “Mega Hospital” with expected higher penetration of DERs and opportunities to install new technology at the stations and along the feeders.

5. Smart Grid Planning Report 2014 and resulting activities

In the 2014 report, the currently (at the time) available Smart Grid technologies were examined for applicability and benefit for implementation and a projection of the priorities for development was created. Over the subsequent period, these priorities were adjusted to suit the needs of the system as it actually developed.

That report was divided opportunities into 4 sections, Metering, Customer Service, Distribution Operations and Distributed Resources. The sections and tables below reflect the projects recommended in that report of that assessment with a column added for 2018 status.

2014 Plan -- Metering

Program	Description	Investigated	Suitable for Oshawa	Proposed New Program	Already in Progress	2018 Status
AMI Process Redesign	Enhancing system to create more efficient meter-to-bill process	X	X	X		Partial
AMI Extension	Extending AMI reach to include all customers, including high use customers	X	X	X		Completed.
Prepaid Metering	Enabling prepaid metering to support customer control of accounts	X	X	X		Deferred
Remote Connect/Disconnect	Equipping meters with connect/disconnect collars to reduce labor costs	X	X		X	Completed.

AMI (Advanced Metering Infrastructure)

Oshawa Power has extended AMI to all customers and implemented it in as much depth as the current technology allows. In particular the AMI system is communicating with the outage restoration system (OMS), and with the Customer Service systems over the Oshawa Power data network.

There are a number of limitations that will be resolved with the next generation of meters the primary focus of which is the "last gasp" reporting which will significantly improve fault locating in the OMS system but will also include better filtering of momentary outages which are currently being reported as and distorting the outage picture. New meter technology will also communicate in the more reliable 5.4GHz band.

On an Industry scale, meters are being sampled and tested to determine if they are at end of life, or if they can be extended 3 to 5 more years. Upgrades to meter technology will occur when meters replacements are mandated thru the meter verification process.

Pre-paid metering/Remote Disconnections

A program to install pre-paid metering complete with remote connect/disconnection capability was put in place and approximately 400 units were installed. Subsequently, the Province of Ontario introduced legislation which changed the treatment of disconnections and the program was cancelled.

2014 Plan -- Customer Service

Program	Description	Investigated	Suitable for Oshawa	Proposed New Program	Already in Progress	2018 Status
Billing System Redesign	Integrating systems to reduce cost of back office operations	X	X	X		Partial
Enhanced IVR	Extending the capabilities of Oshawa's IVR system to provide better customer service	X	X		X	On-going
Planned Outage Notification	Provide automated system that would notify customers in advance of a planned outage	X				Deferred
Payment Reminder System	Build a system that would provide billing reminders via text, e-mail, or automated phone call	X	X			Partial
Web Start/Stop Service	Deploy automated system that would allow customers to self-provision service requests	X	X			Partial

Billing System

The Billing System was upgraded to "Billing View" by 2016 the current system implementation. There are further opportunities to examine as the Utility Billing model evolves. Provincial Initiatives such as the Regulated Pricing Plan (RPP) and Green Button Initiatives are examples of external drivers that impact the Billing System.

Enhanced IVR (Intelligent/Integrated Voice Recognition)

Elements of Enhanced IVR have been put in place. Information is automatically collected from customers from phone calls and is in use for payment reminders, however handling of that information is manual in the cases of outage reporting and further enhancements are expected.

Planned outage notification

There is limited functionality to identify customers affected by planned outages, however there are no tools in place for notifications to be sent out. Customers are manually notified of planned outages

Payment Reminder System and Web Start Stop

The payment reminder system is operational in the context of the current implementation. As customer access to information and service evolve through the use of technologies such as smart-phone aps and web interfaces, these services are expected to be expanded.

2014 Plan -- Distribution Operations

Program	Description	Investigated	Suitable for Oshawa	Proposed New Program	Already in Progress	2018 Status
SCADA Upgrade	Provide additional automation for Supervisory Control and Data Acquisition system	X	X	X		On-going
Voltage Monitoring	Monitoring voltage and end of feeders to improve quality of service	X	X	X		Partial
Outage Management	Developing a dynamic system to support outage notification and restoration efforts	X	X		X	Completed.
Automated Switching	Installing automated switches in underground vaults to improve worker safety	X	X		X	Completed.
Substation Monitoring	Deploying sensing equipment and video surveillance at substations to monitor equipment condition and theft/vandalism	X			X	Completed.
Feeder Automation	Deploying IEDs and automated controllers, switch gears, RTUs, and capacitors to provide additional control over the network	X			X	On-Going
Enhanced Communications Networks	Extending reach of field communications with fiber, wireless, and power line communications	X			X	On-Going
Feeder Gateway Temperature Monitoring	Monitoring feeder gateway temperature to avoid outages and reduce need for system upgrades	X				N/A
Phase and Load Balancing	Installing devices to balance the load across feeders and phases to improve grid efficiency	X				N/A
Synchrophasors	Deploy phasor measurement units to provide a real-time measurement of electrical quantities across the power system	X				N/A

Scada Upgrades

SCADA system upgrades project is an on-going project that was not specifically defined in 2014. Significant activity has taken place in the development of Survalent's "World View" product which is currently operating in an isolated system. The next significant development of the SCADA implementation is expected to be a move to Survalent's "Smart View".

Voltage Monitoring

Voltage monitoring is a tool that is generally built on other technologies such as AMI, Feeder Automation and Substation Monitoring. Voltage Monitoring is implemented to the extent practical with the current systems in place.

Outage Management

The development of the Outage Management System (OMS) represents one of the most significant efforts of the previous period. The existing OMS is modelled from the higher-level Geographic Information System (GIS - Hexagon/Intergraph), and is automatically dispatching crews via text message to the predicted locations of outages based on information derived from the SCADA system from the AMI and Customer calls. The system populates a Live Outage Map, which is accessible in the field on tablets and field crews can close outages as they are restored.

The OMS is operated as an operational secure system and a "ghost system" is accessible by the rest of the organization for analysis and tracking purposes. Currently, the integration of the OMS and CIS systems is successful as far as it has been implements but the system lacks IVR ability, so customer calls are manually logged into the system by the Call Center processes. The OMS is also unable to manage abnormal system conditions (feeder switching etc.). The integration of lower level maps is ongoing. The OMS is also limited by the ability of the AMI to deliver last gasp and filtered momentary information resulting in less efficient fault location.

It was expected that the development of the OMS would directly impact SAIDI and SAIFI statistics, however the result has been a more rigorous reporting of outages that were previously missed which is masking the operational improvement.

Automated Switching

Oshawa Power has implemented automated switching as planned in the downtown 13.8kV system and created a self-healing network. The switching technology is located on primary side of the distribution system and includes sensing which supports improved fault locating.

Substation Monitoring

Oshawa Power has deployed substation monitoring on an opportunistic basis, capitalizing on the developments of metering and relaying technology as available. A data historian (OSI PI), captures loading, meter data, and SCADA information. Future plans are to pass this information to engineering systems to dynamically calculate losses and analyze waveforms to predict equipment outages. There is an ongoing objective at the provincial level to update the Meter Data

Management and Repository System (MDM/R) and the substation monitoring opportunities are expected to evolve in the coming period.

Feeder Automation

Oshawa Power has implemented a “Self-Healing Feeder System” with 5 teams of 3 switches (5 auto-transfer schemes) based on S&C IntelliTeam technology and executed basic integration to the SCADA and OMS systems. The IntelliTeam system is a closed application that take system inputs and then acts within its own network and reports results which limits the ability to interact with other systems. Oshawa Power has also placed a number of smart fault indicators which report back to SCADA and OMS to enhance system status information at the time of a fault.

Enhanced communication network

Communication infrastructure is becoming an increasingly critical asset. Oshawa Power communicates with a blended system of secure network technology including ICCP (metering data), proprietary systems such as S&C’s SpeedNet radios (feeder automation), cellular (AMI), isolated dark fibre owned by the non-regulated entity, and the public internet and switched telephone network (primarily customer access, and administrative).

There is a need to integrate and rationalize network technology (rebuild and secure) and improve field communications as well as stay current with the “OEB Cyber Security Framework” (currently self-assessed as “Medium Risk. The existing IP addressing structure needs to be rebuilt as it was developed piece-meal and the entire network needs to be upgraded to ‘Layer 3’ security.

2014 Plan -- Distributed Resources

Program	Description	Investigated	Suitable for Oshawa	Proposed New Program	Already in Progress	2018 Status
Transmission Management	Deploying system intelligence to enable more efficient management of wholesale power purchases	X	X	X		On-going
Demand Management	Developing an energy demand management plan that combines demand response, energy storage, and distributed generation	X	X		X	On-Going
Load Control	Installing load control devices to reduce system peak	X	X		X	On-going
Bulk Storage	Using energy storage to reduce system peak and generation requirements	X				N/A

Transmission Management

Oshawa Power is participating in updates to the Wholesale metering system as required by the regulations which may involve further updates to the Meter Data Management and Repository System (MDM/R)

Demand Management and Load Control

Oshawa Power in cooperation with the New Energy and Industrial Technology Development Organization (NEDO) of Japan, has created a small deployment of DERs which were studied for the ability to manage demand response. Oshawa Power continues to explore technologies to manage the inevitable changing demands to be put on the distribution system. DER's will have the most significant impact on the shape of system peak of all technologies being considered.

Bulk Storage

System scale storage systems are continuing to evolve. Storage is expected to be useful to manage system peak and to stabilize variability created by DER penetration and to overcome limitations expressed in IEEE 1547. Oshawa Power has not planned a system level storage project at this time. IEEE 1547 and the Canadian CSA C22.3 No 9 have been revised over time to allow for more discretion on the part of the utilities to connect DERs.

6. Anticipated Drivers – Oshawa Power

There are a number of changes in the use of electricity that can be projected to impact Oshawa Power in coming five-year planning window. These changes may be:

- externally driven to facilitate DERs, EVs and Mass transit Electrification; or
- internally driven to improve reliability or manage growth, or
- driven by regulation such as Cyber Security, data access or conservation.

Upgrades are likely to include application of distribution automation, communications systems enhancements, software and hardware, and web interfaces.

Distributed Energy Resources (DERs)

Distributed Energy Resources (DERs) usually describe the combination of Distributed Generation (DG) such as small-scale Wind and Solar Power, and local level Energy Storage such as user-based battery systems. The impact of DERs can vary widely with governmental policy and incentives. At the current time the business case for solar and wind is marginal, but incentives can easily create an immediate demand for new connections. Public opinion tends to be in support of DERs and technology is improving making accelerated application more probably.

While utilities have limited visibility "behind the meter", there remains a need to maintain system stability. Recent changes to IEEE 1547 and the counterpart CSA C22.3 No.9 have created an opportunity to increase penetrations of DERs if the utility can manage impacts.

The most probable outcomes are an increased need for SCADA controls and communications systems to dispatch load and generation sites. This may include the opportunity for users to communicate with each other outside of the utility system.

Electrification of Transport

Electrification of Transport will have two most probable impacts on the Distribution System. Personal use electric vehicles (EV's) are very close to being economically advantageous, and with the application of reasonable incentives could become the purchase of choice and mass transit such as electric LRT and Busses are increasingly expected.

Oshawa Power needs to plan for EVs by considering how to manage data to and from charging sites (homes and commercial centers). This need may arise quickly on a neighbourhood basis or evenly throughout the system. Oshawa Power has begun to monitor residential EV uptake through a branded strategy called E-mission, and is actively participating in the Canadian Urban Transit Research & Innovation Consortium to ensure needs are met for major transit providers such as Durham Region Transit and MetroLinx.

Conservation and Energy Optimization

Conservation and energy optimization opportunities continue to be a focus of the long-term energy planning models, in particular the market renewal activities underway at the Independent Electricity System Operator (IESO) in Ontario. A push to greener energy sources puts an emphasis on DER options and community-based energy initiatives, such as the Durham Community Energy Plan, will create a need for Oshawa Power to adapt to new situations.

Customer Choice

The Ontario Government continues to support giving customers choices and information as a way for users to control their energy usage and costs. Initiative are underway to expand customer access to data, to examine the impact and signals provided by rate design, and to permit customer integration of smart appliances and small generation and storage.

Distribution Systems

Distribution Engineers have long been concerned with the provision of reliable power at reasonable rates. Distribution automation (DA), fault location, isolation and service restoration (FLISR), and Supervisory Control and Data Acquisition (SCADA) systems have emerged as viable opportunities to reduce the frequency and impact of outages, to manage power quality, and to manage maintenance costs.

Conservation Voltage Regulation (CVR) systems have the ability to manage system peak, reduce losses and optimize voltage profile across a feeder. CVR has proven to be a cost-effective application in many situations.

Informational Technology and Operational Technology (IT/OT)

Although usually an after-thought, IT/OT systems are impacted with each change to the changes in the rest of the system. Network systems that were adequate for smaller applications can quickly become over-taxed as new systems can be several orders of magnitude more data intensive than previous applications. As Oshawa Power makes more data available to customers, and more choices available at the user end, the communications systems become overloaded and require reconfiguration. Also, an increased focus on backup security, and protection of customers private data has resulting in significant changes to Cyber-Security practices that require a significant investment in infrastructure.

7. System Level Benefit Assessment

Each of the core systems deliver a piece of the functionality needed at the modern utility. The following section is a brief description of the system level benefits that can be achieved.

IT/OT -- Cyber Security, Operational Data Store and Network Infrastructure

Compliance with the “OEB Ontario Cyber Security Framework” (network design and data layers) is considered to be a mandatory requirement.

The information technology (IT) “backbone” including wireless and fiber infrastructure as well as management of communications protocols and network design, is required to enable any of the other investments and maintain system security.

The Operational Data Store (ODS) is an integrate database that consolidates data from field and measuring sources such as SCADA, AMI, GIS, ACA and OMS, and integrates with the CIS, to give visibility to the operations, planning and customer users on system status and consumption information. The ODS must be up to date with current security and patches to ensure that private information is not accessed across the network and must be of sufficient scale to handle incoming data, queries and backup demands.

Longer term core system projects such as a server “fail-over” function, back up supply to the control room, emergency power and physical redundancy are expected to have future impact as reliance on the operational systems starts to have a bigger impact on system operations.

Customer Information Systems (CIS)

Compliance with Province of Ontario initiatives which includes giving the customers the right to demand their billing data, adapting to changing Regulated Price Plan (RPP) and providing other in-home data access, (web client and mobile applications) is considered to be high priority. Program compliance is considered mandatory with a small allowance for timing of implementation. Drivers include Provincial Government initiatives, directives in the Long-Term Energy Plan and compliance with OEB regulation.

In addition, there is increasing pressure to provide automated outage information using online and mobile apps as well as telephone technology, and there is a need for outage information to come from customers to inform outage management activities. Opportunities also exist for customers to initiate service requests autonomously over phone and web.

Asset Management Systems (AMS)

The OEB has a requirement that the LDCs demonstrate Condition Based Planning, and moving to risk-based investment planning for System Renewal projects. Upgrades that support enhanced Asset Management (AM) are considered high priority. Affected systems include Geographic

Information Systems and Mapping (GIS), Asset Condition Assessment (ACA), and Work Management Systems.

Advanced Metering Infrastructure (AMI)

Regulations that apply to metering infrastructure ensure that meters are certified, re-certified and replaced on a regular basis. The current meters are in validation stages with the expectation of a 3-year certification extension however system upgrades will be planned over a 10-year cycle to avoid a mass conversion of meters. New meters will greatly reduce nuisance outage reporting and improve communications and outage management.

Outage Management Systems (OMS) – Reliability.

An OMS is generally built up of an Advanced Metering Infrastructure (AMI) system and a Distribution Automation(DA) or SCADA system. In the case of Oshawa Power, the next step in this project will need better information from the AMI system. This improvement is expected in the next generation of AMI meters.

In the short-term OMS improvements will be planned with improvements SCADA and DA integration. Improvements to the “Incoming Voice Recognition:” system will greatly help reduce outage costs and timing.

In general, Oshawa Power reliability results do not support system-wide investment however, local/feeder level reliability concerns exist which may be best managed by the application of “smart switches” that can dramatically reduce the cost (and duration) of outages. New subdivisions and line re-builds should incorporate “smart switches”, during construction, incremental costs are minor compared to benefits.

Model based Fault Location, Isolation and Service Restoration (FLISR) dispatch is expected to provide benefits however successful application will be built on the DA systems and significant enhancements to distribution system modelling.

Distribution Management Systems (DMS)

A DMS is useful where penetrations of DERs, EVs and energy storage are starting to change the operational characteristics of the Distribution System. Since DERs and EVs are not constrained at this time, and there is limited opportunity to use DERs to reduce outage durations or costs.

In the near future, Oshawa Power could experience a medium level of EV or Solar/Wind penetrations which could create the opportunity to start the processes of Distribution Load Management. EV densities are the most likely candidate to cause constraints which will first appear at the distribution transformer and may create a need for communications to the home. The MetroLinx electrification project (3 stations) is an ideal opportunity to establish standards and reference installations

Advanced Distribution Management System (ADMS)

The evolution of Smart Grid to ADMS is discussed in detail in Section 3 of this report. Significant investment in ADMS is most likely to be driven by a need to dispatch DERs and is unlikely in 5-year window. Prudent investment in integrated systems is the main focus at this time.

Future Applications -- Long Term Energy Plan

In 2017, the Ministry of Energy released Ontario's Long-Term Energy Plan. This plan is one of the most prominent recognitions of electrical distribution systems as enablers of technology integration. Included in that document are some future oriented concepts that are not yet ready for deployment and which are listed here as future applications including Interoperability and Transactional Energy.

Interoperability in general means that customer appliances can communicate seamlessly all the way through the distribution and transmission systems to the generating facilities. In the short term the application of this concept is limited to ensuring that distribution smart devices and some customer equipment are set up with common protocols, communications and security systems. In the future it may mean that load requirements at one site can autonomously trigger generation requirements at another. However, beyond the projects already listed in this study is not a candidate for investment.

Transactional Energy is a concept of balancing demand and supply using economic signals. It may allow users to designate preferred sources of supply such as low-carbon producers, or it may allow discretionary consumption to be linked to times of excess or flexible supply, such as charging EVs from Solar availability. The distribution system plays a minor role in Transactional Energy which will be mostly a communications function. Transactional Energy is not likely to be an investment driver in the near future, and if it is, it will be a regulated activity.

Future Applications -- Utility Systems Improvements

There are a number of opportunities to reduce Utility O&M costs by modernizing operations. In those cases where a positive business case exists, investment usually advances quickly. In other applications the business case may not work out until either precursor investments are in place or until technology is advanced. Some of those projects are listed here for completeness, but these are not expected to receive investment dollars in the coming planning window, including:

- vehicle tracking and dispatch
- Conservation Voltage Regulation (CVR).
- utility scale energy storage (bulk storage), and/or
- procurement and materials automation.

8. Prioritization of Modernization Opportunities

In order to prioritize project planning, modernization opportunities are examined relative to the system benefits and drivers. Project are considered to be the greatest potential benefit if they:

- support need for customer choice, either driven by customers or driven externally,
- enable by DERs EVs and storage,
- improve reliability,
- comply with regulation, or
- reduce costs.

Modernization opportunities are then assessed for their ability to achieve the desired benefits and/or impact the system drivers. For instance, the application of a DMS is meant to allow for more control over DERs, DERs are not currently constrained by control issues and penetration levels will increase slowly. Therefore, DMS does little to enable DERs in the near term.

The most impactive and applicable of the grid modernization activities for the near-term planning window are briefly discussed below. Scoring in each column is subjective but show an overall investment strategy over the expected 5-year impact of the system.

Systems and Applications	**Effective Impact**					**5yr Score**
	Choice	**DER Enabling**	**Reliability**	**Regulatory**	**Cost**	
IT/OT *1 *2				*		Mandatory
CIS *1	10			10*		20*
OMS incl DA/FLISR			5	8	6	19
AMI *1				10*	8	18*
AMS (ACA-GIS)			3		6	9
DMS	2	2	1			5
ADMS	1	1	1		1	4
Future Apps						
Vehicle Tracking					2	2
CVR		1	1			2
Interoperability	0	0	0			0
Transact Energy	0					0
Bulk Storage					0	0

*1 Note 1: Cyber Security, CIS and AMI improvements are driven by regulatory initiatives.

*2 IT/OT includes Cyber Security, Data Network, ODS

9. Project Cost and Impact Scores

The following list of projects and costs are planned for the 2020-2025 planning period. For project specifics, please see Section 10.

Disclaimer: The following table is presented as a planning document and is a snapshot as of the report writing (March 2020).

Proj ID	Project	2020	2021	2022	2023	2024	2025	Priority Scoring
SS-05	MS Network Upgrade	100,000	-	-	150,000	150,000	150,000	N/D
SS-07	GIS Version Update	57,500	142,500	110,000	5,000	55,000	155,000	N/D
SA-05	AMI System Upgrades	605,000	386,600	411,800	437,000	462,200	487,400	N/D
SS-08	OMS Version Update	150,000	25,000	-	100,000	-	50,000	N/D
SS-10	SCADA Version Update	-	-	-	60,000	-	-	N/D
SS-11	Repair, Improvements and Upgrades of OT and Smart Grid Infrastructure	25,000	41,000	39,000	43,000	31,000	40,000	N/D
GP-10	Customer Self-Serve Online Portal	140,000	-	-	-	-	-	200
SS-09	ODS System	100,000	100,000	100,000	100,000	100,000	100,000	148
SS-04	SCADA Integration and Deployment of Automation Controllers and Network Connected Devices	50,000	250,000	100,000	100,000	100,000	-	136
SS-01	MS Transformer Monitoring & Telemetry	150,000	150,000	150,000	150,000	150,000	150,000	81
SS-02	13.8kV Automated Switching	50,000	200,000	200,000	200,000	200,000	200,000	69
SS-06	MS Battery and Battery Charger Upgrades	60,000	-	-	-	-	50,000	48
SS-03	SCADA Operated 44kV OH switches	125,000	100,000	100,000	100,000	100,000	100,000	47
	Annual Totals	**1,612,500**	**1,395,100**	**1,210,800**	**1,445,000**	**1,348,200**	**1,482,400**	

* N/D = Non-discretionary

10. Project Descriptions and Benefits

Disclaimer: The following project descriptions are presented for planning purposes and represent a snapshot of activity as of the report writing (March 2020).

The following section lists the proposed projects for the five-year planning window. Each project is presented with a short description of the project, is connected with the major system that it is in support of, and indicates the primary benefits. A five-year cost projection is also provided.

Projects are then given a representative project priority scoring. The scoring is developed by reviewing the system impact derived in Section 9, factored by the impact of the proposed project on the affected system. The project impact is assessed at a general level by considering the benefits of the system in terms from High to Low. Projects that are required to meet regulatory requirements are scored as “Non-Discretionary (N/D)”

The final project scoring can be represented by:

$$\sum_{1}^{n} System\ Impact\ x\ Project\ Impact$$

SA-05 AMI System Upgrades

Description: The AMI System Update consists of replacing all failed smart meters that are currently in-service with the next generation of meters. The replacement program includes upgrading the AMI data collector units to wireless routers and connecting these to the fiber network. Various system upgrades will be included as necessary to maintain the communications and meet regulatory requirements.

Major Systems: Advanced Metering Infrastructure (AMI)

Benefit: There is a regulatory requirement to recertify and replace all meters on a regular cycle. Existing meters will be managed, and certifications extended as much as possible.

The new meters will enable DER functionality once the conversion is completed and reduce nuisance outage reporting. Communications and Cybersecurity infrastructure will be improved through the process.

Budget Costs (5yr):

Proj ID	Project	2020	2021	2022	2023	2024	2025
SA-05	AMI System Upgrades	605,000	386,600	411,800	437,000	462,200	487,400

Project Priority: The project has a high impact on Regulatory compliance, as all meters must be replaced on regular cycles. The project has a secondary benefit of cost reduction by planning replacement cycles efficiently. Additionally, the project will be part of Oshawa Power's compliance with Cyber security requirements and will help reduce costs by reducing nuisance outage reporting.

Impact	Choice	DER	Reliability	Regulatory	Cost
AMI				10*	8
Project				10	8
IT/OT				*	
Project				*	
			Project Score		Non-Discretionary

Project Descriptions - System Service

SS-01 Municipal Substation Transformer Monitoring and Telemetry

Description: Oshawa Power is planning to retrofit 12 power transformers and install monitoring system to establish more data points for condition monitoring.

Major Systems: Asset Management Systems (AMS)

Benefit: The Asset Condition Assessment (ACA) process has identified the need for more continuous monitoring to ensure an effective and reliable operation.

Budget Costs (5yr):

Proj ID	Project	2020	2021	2022	2023	2024	2025
SS-01	MS Transformer Monitoring & Telemetry	150,000	150,000	150,000	150,000	150,000	150,000

Project Priority: Project has a high impact on Costs by monitoring high value assets to avoid outages and costly repairs. Project has a secondary benefit on Reliability as most station transformer outages do not create long outages unless another event also occurs.

Impact	Choice	DER	Reliability	Regulatory	Cost
AMS			3		6
Project			7		10
			Project Score		81

SS-02 Expansion of 13.8kV Overhead Automated Switching

Description: Approximately 15 smart switches will be installed at strategic locations of the distribution system to enhance the utility's ability to perform automated switching operations during normal and emergency conditions.

Major Systems: Outage Management Systems (OMS) – Distribution Automation/FLISR

Benefit: This project is a part of Oshawa Power's efforts towards improving service reliability and reducing outage time. Sensor information will also inform control room operations.

Budget Costs (5yr):

Proj ID	Project	2020	2021	2022	2023	2024	2025
SS-02	13.8kV Automated Switching	50,000	200,000	200,000	200,000	200,000	200,000

Project Priority: Project has a high impact on Reliability as smart switches are applied to feeders with significant load and customer counts. The contribution to SAIFI and SAIDI statistics is dramatically reduced if power can be restored within a minute. Project has a secondary benefit on Costs by reducing truck rolls to operate switching devices.

Impact	Choice	DER	Reliability	Regulatory	Cost
OMS			5	8	6
Project			9		4
			Project Score		69

SS-03 SCADA Operated 44kV OH switches and remote switching- 44kV

Description: Approximately 5 SCADA operated 44kV switches that will be installed at key locations on our 44kV distribution system to enhance the utility's ability to perform switching operations during normal and emergency conditions.

Major Systems: Outage Management Systems (OMS) – Distribution Automation/FLISR

Benefit: This project is a part of Oshawa Power's efforts towards improving service reliability and modernizing the existing grid into a smart grid system.

Budget Costs (5yr):

Proj ID	Project	2020	2021	2022	2023	2024	2025
SS-03	SCADA Operated 44kV OH switches	125,000	100,000	100,000	100,000	100,000	100,000

Project Priority: This project has a high impact on Reliability as SCADA switches are applied to feeders with significant load and customer counts. The contribution to SAIFI and SAIDI statistics is dramatically reduced if power can be restored quickly, however due to lack of automation is expected to be longer than a minute. Project has a secondary benefit on Costs by reducing truck rolls to operate switching devices.

Impact	Choice	DER	Reliability	Regulatory	Cost
OMS			5	8	6
Project			7		2
			Project Score		47

SS-04 SCADA Integration and Deployment of Automation Controllers and Network Connected Devices

Description: Oshawa Power will install a centralized automation controller for the distribution system self-healing, smart lateral reclosers and smart power quality monitors. The devices may also include but not limited to intelligent electronic devices (IEDs) such as smart fault indicators, intelligent line sensors and required communication hardware and components.

Major Systems: Outage Management Systems (OMS) – Distribution Automation/FLISR

Benefit: Service reliability is the main driver for this project. The project will improve service reliability by use of monitoring, automation and communication technologies to aid outage management. Improving operational efficiencies is the secondary driver for this project. The data transmitted from IEDs to the existing SCADA and OMS will provide better visibility of grid operation and access to useful data for engineering analysis and system planning.

Budget Costs (5yr):

Proj ID	Project	2020	2021	2022	2023	2024	2025
SS-04	SCADA Integration and Deployment of Automation Controllers and Network Connected Devices	50,000	250,000	100,000	100,000	100,000	-

Project Priority: The project has a high impact on Reliability by reducing restoration times across the system. The project also impacts regulatory requirements by collecting system information for OEB reporting requirements. The project has a secondary benefit of Costs reductions by monitoring Power Quality and allowing management of losses.

Impact	Choice	DER	Reliability	Regulatory	Cost
OMS			6	8	6
Project			9	8	3
			Project Score		136

SS-05 Municipal Substation Network Upgrade

Description: Oshawa Power will be modernizing its substation Local Area Network (LAN) communication from Layer 2 to Layer 3 communication switches and installing a communication backbone wide area network (WAN) to increase cyber security, data bandwidth, reduce communication latencies for Operational Technologies (OT) and smart grid device communications. Cyber security software tools will be installed to track, manage and handle day-to-day system cyber security threats. Data concentrators will also be installed to optimize traffic between substation and control room communication.

Major Systems: Cyber Security and IT/OT Systems

Benefit: This project is a part of two components, “OEB Cyber Security Framework” compliance and Oshawa Power’s efforts towards improving service reliability and modernizing the existing grid into a smart grid system.

Budget Costs (5yr):

Proj ID	Project	2020	2021	2022	2023	2024	2025
SS-05	MS Network Upgrade	100,000	-	-	150,000	150,000	150,000

Project Priority: The project has a high impact on Oshawa Power’s efforts to comply with OEB mandated Cybersecurity requirements.

Project is effectively non-discretionary.

Impact	Choice	DER	Reliability	Regulatory	Cost
IT/OT				*	
Project				*	
			Project Score		Non-Discretionary

SS-06 Municipal Substation Battery and Battery Charger Upgrades

Description: Oshawa Power will add online condition monitoring modules to the battery and battery charger systems at six of the nine municipal substations. The new systems will bring real time asset-health related information to SCADA and to the asset heath database system. Upgrades will take place for the battery systems that are expected to reach the end of their useful service life by 2025.

Major Systems: Asset Management Systems (AMS) and Asset Renewal Investment

Benefit: The project will provide opportunity to improve continuous monitoring of health condition of critical asset by installing battery condition monitoring system which will communicate with SCADA to provide measured values of battery temperature, float voltage and internal resistance (per NERC and IEEE standard recommendations for battery monitoring). The system will improve asset management practices and operational efficiencies through collection of key information related to operation and performance of the battery.

Budget Costs (5yr):

Proj ID	Project	2020	2021	2022	2023	2024	2025
SS-06	MS Battery and Battery Charger Upgrades	60,000	-	-	-	-	50,000

Project Priority: The project has a high impact on Cost reductions relative to project cost, as replacement of battery systems is necessary due to degradation of existing assets while the increment to add monitoring is small and the benefits are significant. The project has a small secondary benefit in Reliability improvements, as most battery system issues do not create outages

Impact	Choice	DER	Reliability	Regulatory	Cost
AMS			3		6
Project			1		9
			Project Score		48

SS-07 GIS Version Update

Description: The core GIS system software will undergo a version update to bring it to the current package and align with the GIS vendor and Microsoft upgrades and maintain security of the systems and will facilitate field capture of real-time data.

An upgrade is required to allow for field deployment to better capture real-time data to assist in the transition from condition-based asset management to risk-based asset management. This upgrade will also allow for greater flexibility in the data model as well as interoperability with existing and future systems.

Major Systems: IT/OT Cybersecurity, Asset Management System (AMS) – ACA

Benefits: It is necessary to conduct a routine version update to maintain version align with the latest GIS and Microsoft systems and ensure system functionality and cybersecurity. The benefits will include field collection of condition data to help ensure that the correct assets are being maintained or replaced to minimize the risk for outages on the system and potential safety risks. The updated GIS system will also become part of the basis for the Outage Management System (OMS) and future Advanced Distribution Management System (ADMS).

Budget Costs (5yr):

Proj ID	Project	2020	2021	2022	2023	2024	2025
SS-07	Routine GIS Infrastructure Upgrades and Enhancements for Operational Needs	57,500	142,500	110,000	5,000	55,000	155,000

Project Priority: The project has a high impact on Oshawa Power's efforts to comply with OEB mandated Cybersecurity requirements. The project has a secondary impact on the AMS in costs reductions as it will lower the costs of collecting field condition data and reliability as it will improve asset management. The project is effectively non-discretionary.

Impact	Choice	DER	Reliability	Regulatory	Cost
IT/OT				*	
Project				*	
AMS-ACA			3		6
Project			3		8
			Project Score		Non-Discretionary

Project Descriptions - System Access

SS-08 OMS Version Update

Description: The core OMS system software will undergo a version update to bring it to the current package and align Microsoft upgrades and maintain security of the systems.Upgrade enhancements include Advanced Restoration time algorithms, better trouble analysis processes, improved switching simulators, and user security enhancements.

Major Systems: IT/OT Cybersecurity, Outage Management Systems (OMS)

Benefit: It is necessary to conduct a routine version update to maintain version align with the latest Survalent and Microsoft systems and ensure system functionality and cybersecurity. The Outage Management System (OMS) upgrade project is to provide better stability, prediction, customer integration, and customer information.

Budget Costs (5yr):

Proj ID	Project	2020	2021	2022	2023	2024	2025
SS-08	OMS Version Update	150,000	25,000	-	100,000	-	50,000

Project Priority: Project has a high impact on Oshawa Power's efforts to comply with OEB mandated Cybersecurity requirements. Project has a secondary impact on the OMS in costs reductions as it will lower the costs integrating the OMS with customer information systems. Project is effectively non-discretionary.

Impact	Choice	DER	Reliability	Regulatory	Cost
IT/OT				*	
Project				*	
OMS			5	8	6
Project					8
			Project Score		Non-Discretionary

SS-09 ODS System

Description: Implementation and continued development of Operational Data Store (ODS) and Business Intelligence (BI) Analysis system to assist corporate and management in making informed business decisions based on objective data gathered through a variety of data sources. These sources will be comprised of SCADA, AMI, GIS and field information.

Major Systems: IT/OT – ODS (touches all systems), CIS, AMS

Benefit: The system for recording operational data is ad hoc and spread across many systems. Some critical reporting features such as customer visibility of system conditions and operational visibility of system conditions are not possible due to lack of integration of data. The ODS system will support automation of cross platform applications such as, automated delivery of planned outage notices, customer usage notifications, transformer loading, system faults & meter infrastructure events.

ODS system will also support increased operational efficiencies such as power flow analysis, forecasting asset failure, predicting and correcting billing issues, asset condition assessment, and better customer visibility to utility operations through web presentment.

Budget Costs (5yr):

Proj ID	Project	2020	2021	2022	2023	2024	2025
SS-09	Upgrades and Enhancements to ODS Systems	100,000	100,000	100,000	100,000	100,000	100,000

Project Priority: Project has a high impact on the Regulatory reporting requirements of the CIS and AMS systems as without the ODS the operational data is kept in discreet systems and not available cross platforms. The ODS system will be developed compliant with OEB cybersecurity needs, but does not address a specific existing gap and does not have a Cybersecurity impact.

Impact	Choice	DER	Reliability	Regulatory	Cost
IT/OT				*	
Project					
CIS	10			10*	
Project	3			10	
AMS			3	6	
Project			2	7	

	Project Score	148

SS-10 SCADA Version Update

Description: The core SCADA system software will undergo a version update to bring it to the current package and align with Survalent and Microsoft upgrades and maintain security of the systems. The new version will align with possible future updates to Advanced Distribution Management Systems (automation).

Major Systems: IT/OT Cybersecurity, OMS – SCADA

Benefit: It is necessary to conduct a routine version update to maintain version align with the latest Survalent and Microsoft systems and ensure system functionality and cybersecurity. The upgraded the system will also expand the functionality for field viewing of the SCADA data as well as allowing for greater flexibility and graphical presentation of SCADA connectivity. The upgrade will overcome limits on the number of values (amps/volts/watts/var) that can be linked to the ODS .The upgrade will also serve as the basis for the ADMS system which will be required to meet the changing nature of the grid such as distributed energy generation, EV charges and energy storage.

Budget Costs (5yr):

Proj ID	Project	2020	2021	2022	2023	2024	2025
SS-10	SCADA Version Update	-	-	-	60,000	-	-

Project Priority: The project has a high impact on Oshawa Power's efforts to comply with OEB mandated Cybersecurity requirements. The project has a secondary impact on the SCADA in costs reductions as it will lower the costs of presenting system conditions to field operators. The project is effectively non-discretionary.

Impact	Choice	DER	Reliability	Regulatory	Cost
IT/OT				*	

Project				*	
OMS			5	8	6
Project					8
			Project Score		Non-discretionary

SS-11 Repair, Improvements and Upgrades of OT and Smart Grid Infrastructure

Description: This project will include replacing damaged equipment, upgrading firmware, improving communication and functionality of existing devices. This project will include existing automated overhead switches, radio communication systems, vault communication system, underground switches, smart fault indicators data concentrators and other existing smart grid devices.

This project will include repairing and replacing batteries of approximately 90 existing enclosures, communication modules and data concentrators. Typical lifespan of these batteries is expected to be three to five years.

Major Systems: OT and Smart Grid (OMS) Infrastructure

Benefit: This project is a renewal program which provides for the repair, improvement and upgrade of existing OT and Smart Grid Infrastructure in support of Oshawa Power's Smart Grid(OMS) and OT systems.

Budget Costs (5yr):

Proj ID	Project	2020	2021	2022	2023	2024	2025
SS-11	Repair, Improvements and Upgrades of OT and Smart Grid Infrastructure	25,000	41,000	39,000	43,000	31,000	40,000

Project Priority: The project is a reactive project to renewal degraded assets on an as-needed basis. The project is non-discretionary.

Impact	Choice	DER	Reliability	Regulatory	Cost

	Project Score	Non-discretionary

Project Descriptions – General Plant

GP-10 Customer Self-Serve Online Portal

Description: Oshawa Power will implement an enhanced self-service tool that will allow customers the ability to log into a secure portal to view balances, due dates, bills as well as smart meter activity and predicted bill statistics. The software has the ability to provide current alerts based on customer settings including bill/usage thresholds, high usage and other configurable options.

Major Systems: Customer Information Systems (CIS)

Benefit: The new system will allow customers to sign up for payment and past due reminders as well as a quick pay feature which links to several financial institutions. It has the ability to show net metering charts and provide weather chart overlays as well as holiday and rate management tools. The software has an OMS real time secure web service which allow customers to sign up for outage notifications by email, text or IVR. In a 2018 Customer Satisfaction survey is was noted that providing several communication channels to meet customer need was key to improving the customer experience. It was also noted that rising customer expectation meant 24/7 availability to various communication avenues such as an online self-serve option for managing their account.

Budget Costs (5yr):

Proj ID	Project	2020	2021	2022	2023	2024	2025
GP-10	Customer Self-Serve Online Portal	140,000	-	-	-	-	-

Project Priority: Project has a high impact on the provision of customer Choice as mandated by regulatory processes.

Impact	Choice	DER	Reliability	Regulatory	Cost
CIS	10			10*	
Project	10			10	
			Project Score		200*