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Overview of Rate Base

Ex.2/Tab 1/Sch.1 - Rate Base Overview

InnPower Corporation’s Rate Base for the 2017 – 2021 Test Years is determined by taking the average of the balances at the beginning and the end of the Test Year, plus a working capital allowance which is 7.5% 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 for Electricity Distribution Rate Applications – 2015 Edition for 2016 Rate Applications.

InnPower Corporation converted to International Financial Reporting Standards (“MIFRS”) on January 1, 2015 and has prepared this application under MIFRS. Historical data has been provided under CGAAP for 2013 and InnPower Corporation has presented 2014 data under both CGAAP and MIFRS.

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

The presented rate base calculations have been utilized to determine the proposed revenue requirement presented in Exhibit 6. The following tables present InnPower Corporation’s Rate Base calculations for the test years of 2017 – 2021.

Table 2.1 Rate Base Calculation Summary

	Last Board Approved 2013	2014	2015	2016 Bridge	2017 Test	2018 Test	2019 Test	2020 Test	2021 Test
Net Capital Assets in Service									
Opening Balance	$ 28,199,498	$ 30,850,492	$ 34,019,681	$ 49,145,019	$ 52,526,867	$ 56,747,200	$ 61,253,586	$ 64,900,451	$ 68,007,206
Ending Balance	$ 30,850,492	$ 34,019,681	$ 49,145,019	$ 52,526,867	$ 56,747,200	$ 61,253,586	$ 64,900,451	$ 68,007,206	$ 71,031,201
Average Balance	$ 29,524,995	$ 32,435,086	$ 41,582,350	$ 50,835,943	$ 54,637,033	$ 59,000,393	$ 63,077,019	$ 66,453,829	$ 69,519,204
Working Capital Allowance	$ 3,666,053	$ 3,961,443	$ 4,239,822	$ 4,587,055	$ 2,941,124	$ 3,074,834	$ 3,246,020	$ 3,381,234	$ 3,567,730
Total Rate Base	$ 33,191,048	$ 36,396,529	$ 45,822,172	$ 55,422,998	$ 57,578,157	$ 62,075,227	$ 66,323,039	$ 69,835,062	$ 73,086,933

Table 2.1A Rate Base Calculation Breakdown

Expenses for Working Capital	Last Board Approved 2013	2014	2015	2016 Bridge	2017 Test	2018 Test	2019 Test	2020 Test	2021 Test
Eligible Distribution Expenses									
3500 Distribution - Operations	$ 1,323,999	$ 1,342,978	$ 1,377,569	$ 1,568,480	$ 1,843,870	$ 2,030,600	$ 2,083,700	$ 2,138,100	$ 2,194,100
3550 Distribution - Maintenance	$ 463,151	$ 471,477	$ 427,525	$ 530,250	$ 681,745	$ 699,600	$ 717,900	$ 736,700	$ 755,900
3650 Billing & Collecting	$ 1,054,939	$ 1,169,535	$ 1,096,116	$ 1,203,967	$ 1,184,825	$ 1,295,900	$ 1,329,700	$ 1,364,400	$ 1,400,100
3700 Community Relations	$ 5,419	$ 5,663	$ 8,066	$ 10,250	$ 12,000	$ 12,300	$ 12,600	$ 12,900	$ 13,300
3800 Admin & General	$ 2,147,739	$ 2,234,998	$ 2,648,314	$ 2,704,335	$ 3,142,082	$ 3,323,000	$ 3,490,000	$ 3,581,200	$ 3,674,800
6105 Taxes other than Income tax	$ 24,132	$ 13,463	$ 117,714	$ 88,900	$ 122,500	$ 125,700	$ 129,000	$ 132,400	$ 135,900
Total Eligible Distribution Expense	$ 5,019,379	$ 5,238,114	$ 5,675,305	$ 6,106,182	$ 6,987,022	$ 7,487,100	$ 7,762,900	$ 7,965,700	$ 8,174,100
3350 Power Supply Expenses	$ 25,531,064	$ 27,773,907	$ 29,656,547	$ 32,119,278	$ 32,227,960	$ 33,510,688	$ 35,517,366	$ 37,117,414	$ 39,395,629
Total Expenses for Working Capital	$ 30,550,443	$ 33,012,021	$ 35,331,852	$ 38,225,460	$ 39,214,982	$ 40,997,788	$ 43,280,266	$ 45,083,114	$ 47,569,729
Working Capital Factor	12%	12%	12%	12%	7.50%	7.50%	7.50%	7.50%	7.50%
Total Working Capital Allowance	$ 3,666,053	$ 3,961,443	$ 4,239,822	$ 4,587,055	$ 2,941,124	$ 3,074,834	$ 3,246,020	$ 3,381,234	$ 3,567,730

Ex.2/Tab 1/Sch.2 - Rate Base Trend

Based on the information presented in Table 2.1 Rate Base Summary, InnPower Corporation provides the following variance analysis.

The Rate Base for the 2017 Test Year has increased by $2,155,159 over the Bridge Year and $24,387,109 over the last Board Approved Rate Base. The reason for the increase in the 2017 Test Year is mainly attributed to:

- The inclusion of InnPower Corporation’s new Corporate Headquarter and Administration building in 2015.
- Significant capital additions from 2014 – 2016 to support infrastructure for growth, 3 year average increase of 19%. 2014 – 10%, 2015 – 26% and 2016 – 21%.
- Annual changes in cost of power and increases in OM&A expenses. Cost of Power has increased an average of 8% for 2014 – 2016. Eligible expenses have increased an average of 7% for 2014 – 2016.
- The Working Capital allowance for the Bridge Year was 12%. The Test Year has a Working Capital Allowance of 7.5% which resulted in a decrease of $1,645,932 from the 2016 Bridge Year. The use of a 7.5% rate is consistent with the Board’s letter of June 3. 2015.

Ex.2/Tab 1/Sch.3 - Rate Base Variance Analysis

The following paragraphs and Tables 2.2 to Table 2.5 provide a narrative on the changes that have driven the increase in rate base since InnPower Corporation's 2010 Board Approved Cost of Service Application.

Table 2.2 2017 Test Year to 2016 Bridge Year Variances

	2017 Test	2016 Bridge	Variance	%
Net Capital Assets in Service				
Opening Balance	$ 52,526,867	$ 49,145,019	$ 3,381,848	7%
Ending Balance	$ 56,747,200	$ 52,526,867	$ 4,220,334	8%
Average Balance	$ 54,637,033	$ 50,835,943	$ 3,801,091	7%
Working Capital Allowance	$ 2,941,124	$ 4,587,055	-$ 1,645,932	-36%
Total Rate Base	$ 57,578,157	$ 55,422,998	$ 2,155,159	4%

The total projected average balance in 2017 of $54,637,033 is $3,801,091, or 7%, greater than 2016. The main reason for the variance is:

- In 2016, the utility's investment in its distribution system is required to support growth within our service territory and maintain the system running in a safe and reliable manner. The working capital allowance reflects a decrease due to the reduction in rate from 12% to 7.5% which is consistent with the Board's letter of June 3, 2015.

Table 2.3 2016 Bridge Year to 2015 Variances

	2016 Bridge	2015	Variance	%
Net Capital Assets in Service				
Opening Balance	$ 49,145,019	$ 34,019,681	$ 15,125,338	44%
Ending Balance	$ 52,526,867	$ 49,145,019	$ 3,381,848	7%
Average Balance	$ 50,835,943	$ 41,582,350	$ 9,253,593	22%
Working Capital Allowance	$ 4,587,055	$ 4,239,822	$ 347,233	8%
Total Rate Base	$ 55,422,998	$ 45,822,172	$ 9,600,826	21%

The total projected average balance in 2016 of $50,835,943 is $9,253,593, or 22%, greater than 2015. The main reason for this variance is:

- The inclusion of InnPower Corporation's new Administration and Corporate Headquarters in July 2015 to rate base.
- Continuation of line work to provide capacity for Friday Harbour.
- Increase in customer connections impacting Base capital costs.

Table 2.4 2015 to 2014 Variances

	2015	2014	Variance	%
Net Capital Assets in Service				
Opening Balance	$ 34,019,681	$ 30,850,492	$ 3,169,189	10%
Ending Balance	$ 49,145,019	$ 34,019,681	$ 15,125,338	44%
Average Balance	$ 41,582,350	$ 32,435,086	$ 9,147,264	28%
Working Capital Allowance	$ 4,239,822	$ 3,961,443	$ 278,380	7%
Total Rate Base	$ 45,822,172	$ 36,396,529	$ 9,425,643	26%

The total projected average balance in 2015 of $41,582,350 is $9,147,264, or 28%, greater than 2014. The main reason for this variance is:

- Belle Ewart DS station replacement.
- Brian Wilson transformer failure and replacement.
- Continuation of line work to provide capacity for Friday Harbour.

Table 2.5 2014 to 2013 Variances

	2014	Last Board Approved 2013	Variance	%
Net Capital Assets in Service				
Opening Balance	$ 30,850,492	$ 28,199,498	$ 2,650,994	9%
Ending Balance	$ 34,019,681	$ 30,850,492	$ 3,169,189	10%
Average Balance	$ 32,435,086	$ 29,524,995	$ 2,910,091	10%
Working Capital Allowance	$ 3,961,443	$ 3,666,053	$ 295,389	8%
Total Rate Base	$ 36,396,529	$ 33,191,048	$ 3,205,481	10%

The total projected average balance in 2014 of $32,435,086 is $2,910,091, or 10%, greater than 2014. The main reason for this variance is:

- Commencement of line work for Friday Harbour.

Ex.2/Tab 1/Sch.4 – Fixed Asset Continuity Schedule

The following continuity schedules present InnPower Corporation's investment in capital assets, the associated accumulated amortization and the net book value for each Capital USoA account for the 2013 Historic Year, 2014 Historic Year, 2015 Historic Year, 2016 Bridge Year and 2017 - 2021Test Years.

InnPower Corporation attests that the continuity statements reconcile with the calculated depreciation expenses under Exhibit 4 – Operating Costs, and are presented by asset account.

The following Tables are Board Appendix 2-BA for the 2013, 2014 and 2015 Actuals, 2016 Bridge Year, and 2017, 2018, 2019, 2020 and 2021 Test Years.

Table 2.6 Appendix 2-BA 2013 CGAAP Fixed Asset Continuity Schedule

Fixed Asset Continuity Schedule (Distribution & Operations)
As at December 31, 2013

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
	1612	Land Rights	982,510	0	0	982,510	(572,921)	(15,126)	0	(588,047)	394,463
	1805	Land - Substations	792,971	179,066	0	972,037	0	0	0	0	972,037
47	1808	Buildings - Substations				0				0	0
13	1810	Leasehold Improvements	86,252	0	0	86,252	(86,252)	0	0	(86,252)	0
47	1820	Substation equipment	4,311,364	164,418	0	4,475,782	(2,413,615)	(85,927)	0	(2,499,542)	1,976,240
47	1821	Substation transformers				0				0	0
47	1822	Substation switchgear and other elements				0				0	0
47	1823	Substation breakers and reclosures				0				0	0
47	1830	Poles, Towers & Fixtures	10,110,986	1,112,472	(92,325)	11,131,132	(4,379,464)	(196,350)	70,398	(4,505,416)	6,625,717
47	1831	Poles, towers and fixtures - concrete				0				0	0
47	1832	Poles, towers and fixtures - wood				0				0	0
47	1835	OH Conductors & Devices	14,057,886	1,403,523	(50,073)	15,411,336	(7,537,250)	(188,425)	38,214	(7,687,462)	7,723,874
47	1836	Overhead conductors and devices - secondary service				0				0	0
47	1837	Overhead conductors and devices - switches				0				0	0
47	1838	Overhead conductors and devices - capacitor banks				0				0	0
47	1839	Overhead conductors and devices - primary				0				0	0
47	1840	UG Conduit	2,440,333	20,539	0	2,460,872	(549,273)	(66,668)	0	(615,940)	1,844,932
47	1843	Underground conduit chambers and other elements				0				0	0
47	1844	Underground conductors and devises primary PILC				0				0	0
47	1845	UG Conductors & Devices	12,037,279	51,562	(18,175)	12,070,666	(4,579,031)	(243,722)	8,258	(4,814,495)	7,256,170
47	1846	Underground conductors and devices primary XLPE				0				0	0
47	1847	Underground conductors and devices secondary and service in duct				0				0	0
47	1848	Underground conductors and devices secondary and service direct buried				0				0	0
47	1849	Underground conductors and devices secondary and service in duct				0				0	0
47	1850	Line Transformers	4,090,747	132,221	29,579	4,252,548	(2,611,639)	(76,385)	39,602	(2,648,423)	1,604,124
47	1851	Padmount transformers	4,984,935	208,807	(54,098)	5,139,643	(3,068,984)	(59,929)	25,231	(3,103,682)	2,035,962
47	1852	Line transformers - Underground				0				0	0
47	1855	Services (OH & UG)	4,238,781	228,276	0	4,467,057	(1,824,389)	(72,191)	0	(1,896,580)	2,570,477
47	1856	Services				0				0	0
47	1860	Meters	2,446,555	126,986	(18,762)	2,554,780	(570,645)	(182,148)	16,358	(736,436)	1,818,344
47	1861	Smart Meters				0				0	0
47	1862	Smart Meters - Residential				0				0	0
47	1863	Smart Meters - Commercial				0				0	0
N/A	1905	Land	863,611	1,015,496	(662,562)	1,216,545	0	0	0	0	1,216,545
	1906	Land Rights				0				0	0
47	1908	Buildings & Fixtures	744,089	4,304	0	748,392	(285,190)	(11,324)	0	(296,515)	451,878
13	1910	Leasehold Improvements				0				0	0
8	1915	Office Furniture & Equipment	314,603	12,060	0	326,663	(247,407)	(14,563)	0	(261,971)	64,692
10	1920	Computer - Hardware	570,318	61,164	(33,392)	598,089	(387,789)	(66,218)	33,174	(420,833)	177,257
45	1921	Computer - Hardware post Mar 22/04				0				0	0
12	1611	Computer - Software	463,502	177,250	0	640,751	(342,235)	(95,944)	0	(438,180)	202,571
10	1930	Transportation Equipment	1,167,493	65,100	0	1,232,593	(598,070)	(144,358)	0	(742,429)	490,165
8	1935	Stores Equipment	36,285	0	0	36,285	(20,437)	(2,445)	0	(22,883)	13,402
8	1940	Tools, Shop & Garage Equipment	500,835	8,337	0	509,172	(225,010)	(37,618)	0	(262,629)	246,543
8	1945	Measurement & Testing Equipment	40,375	5,794	0	46,169	(17,082)	(3,486)	0	(20,568)	25,601
8	1950	Power operated Equipment				0				0	0
8	1955	Communications Equipment				0				0	0
47	1970	Load Management controls				0				0	0
47	1980	System Supervisory Equipment	1,692,883	202,625	0	1,895,508	(887,494)	(112,506)	0	(1,000,000)	895,508
47	1981	System Supervisory Protection and Control				0				0	0
47	1982	System Supervisory Protection and Control				0				0	0
47	1975	Solar PV - panels and racking				0				0	0
47	1976	Solar PV - invertors				0				0	0
47	1995	Contributions & Grants	(9,364,012)	(428,863)	0	(9,792,874)	1,793,096	243,768	0	2,036,863	(7,756,011)
	2005	Property under Capital Lease				0				0	0
		Total before Work in Process	**57,610,582**	**4,751,136**	**(899,808)**	**61,461,909**	**(29,411,084)**	**(1,431,568)**	**231,234**	**(30,611,417)**	**30,850,492**
PIA		Provision for impairment of assets									
WIP		Work in Process	327,879	3,389,303	0	3,717,182	0	0	0	0	3,717,182
		Total	**57,938,461**	**8,140,439**	**(899,808)**	**65,179,091**	**(29,411,084)**	**(1,431,568)**	**231,234**	**(30,611,417)**	**34,567,674**
							Less: Fully Allocated Depreciation				
							Transportation	(144,358)			
							PPE	(110,038)			
						Net Depreciation per TB		(1,177,172)		30,611,414	34,567,672

Table 2.7 Appendix 2-BA 2014 CGAAP Fixed Asset Continuity Schedule

Fixed Asset Continuity Schedule (Distribution & Operations)												
As at December 31, 2014												
CGAAP			Cost					Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance		Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
	1612	Land Rights	982,510	0	0	982,510		(588,047)	(15,126)	0	(603,173)	379,337
	1805	Land - Substations	972,037	0	0	972,037		0	0	0	0	972,037
47	1808	Buildings - Substations	0	0	0	0		0	0	0	0	0
13	1810	Leasehold Improvements	86,252	0	0	86,252		(86,252)	0	0	(86,252)	0
47	1820	Substation equipment	4,475,782	2,895,486	(391,901)	6,979,368		(2,499,542)	(133,797)	229,098	(2,404,240)	4,575,128
47	1821	Substation transformers	0	0	0	0		0	0	0	0	0
47	1822	Substation switchgear and other elements	0	0	0	0		0	0	0	0	0
47	1823	Substation breakers and reclosures	0	0	0	0		0	0	0	0	0
47	1830	Poles, Towers & Fixtures	11,131,132	576,011	(28,625)	11,678,519		(4,505,416)	(214,179)	17,612	(4,701,983)	6,976,536
47	1831	Poles, towers and fixtures - concrete	0	0	0	0		0	0	0	0	0
47	1832	Poles, towers and fixtures - wood	0	0	0	0		0	0	0	0	0
47	1835	OH Conductors & Devices	15,411,336	724,698	(37,174)	16,098,859		(7,687,462)	(206,931)	28,199	(7,866,194)	8,232,665
47	1836	Overhead conductors and devices - secondary serv	0	0	0	0		0	0	0	0	0
47	1837	Overhead conductors and devices - switches	0	0	0	0		0	0	0	0	0
47	1838	Overhead conductors and devices - capacitor banks	0	0	0	0		0	0	0	0	0
47	1839	Overhead conductors and devices - primary	0	0	0	0		0	0	0	0	0
47	1840	UG Conduit	2,460,872	320,502	0	2,781,375		(615,940)	(70,931)	0	(686,871)	2,094,503
47	1843	Underground conduit chambers and other elements	0	0	0	0		0	0	0	0	0
47	1844	Underground conductors and devises primary PILC	0	0	0	0		0	0	0	0	0
47	1845	UG Conductors & Devices	12,070,666	279,956	(11,882)	12,338,740		(4,814,495)	(247,483)	5,208	(5,056,770)	7,281,970
47	1846	Underground conductors and devices primary XLPE	0	0	0	0		0	0	0	0	0
47	1847	Underground conductors and devices secondary ar	0	0	0	0		0	0	0	0	0
47	1848	Underground conductors and devices secondary ar	0	0	0	0		0	0	0	0	0
47	1849	Underground conductors and devices secondary ar	0	0	0	0		0	0	0	0	0
47	1850	Line Transformers	9,392,191	556,533	(116,969)	9,831,755		(5,752,105)	(146,576)	46,068	(5,852,612)	3,979,143
47	1851	Padmount transformers				0					0	0
47	1852	Line transformers - Underground	0	0	0	0		0	0	0	0	0
47	1855	Services (OH & UG)	4,467,057	519,764	(2,273)	4,984,548		(1,896,580)	(81,169)	181	(1,977,568)	3,006,980
47	1856	Services	0	0	0	0		0	0	0	0	0
47	1860	Meters	2,554,780	131,827	(61,196)	2,625,410		(736,436)	(176,032)	14,831	(897,636)	1,727,774
47	1861	Smart Meters	0	0	0	0		0	0	0	0	0
47	1862	Smart Meters - Residential	0	0	0	0		0	0	0	0	0
47	1863	Smart Meters - Commercial	0	0	0	0		0	0	0	0	0
N/A	1905	Land	1,216,545	0	0	1,216,545		0	0	0	0	1,216,545
	1906	Land Rights	0	0	0	0		0	0	0	0	0
47	1908	Buildings & Fixtures	748,392	0	0	748,392		(296,515)	(11,367)	0	(307,882)	440,510
13	1910	Leasehold Improvements	0	0	0	0		0	0	0	0	0
8	1915	Office Furniture & Equipment	326,663	9,292	0	335,955		(261,971)	(14,034)	0	(276,005)	59,950
10	1920	Computer - Hardware	598,089	80,063	(130,613)	547,540		(420,833)	(70,671)	130,613	(360,891)	186,649
45	1921	Computer - Hardware post Mar 22/04	0	0	0	0		0	0	0	0	0
12	1611	Computer - Software	640,751	198,585	(10,519)	828,817		(438,180)	(133,981)	10,519	(561,642)	267,175
10	1930	Transportation Equipment	1,232,593	3,268	0	1,235,861		(742,429)	(139,931)	0	(882,360)	353,501
8	1935	Stores Equipment	36,285	4,788	0	41,073		(22,883)	(2,589)	0	(25,471)	15,601
8	1940	Tools, Shop & Garage Equipment	509,172	17,553	0	526,725		(262,629)	(38,486)	0	(301,115)	225,610
8	1945	Measurement & Testing Equipment	46,169	4,067	0	50,236		(20,568)	(3,979)	0	(24,548)	25,688
8	1950	Power operated Equipment	0	0	0	0		0	0	0	0	0
8	1955	Communications Equipment	0	0	0	0		0	0	0	0	0
47	1970	Load Management controls	0	0	0	0		0	0	0	0	0
47	1980	System Supervisory Equipment	1,895,508	125,462	0	2,020,970		(1,000,000)	(118,906)	0	(1,118,907)	902,064
47	1981	System Supervisory Protection and Control	0	0	0	0		0	0	0	0	0
47	1982	System Supervisory Protection and Control	0	0	0	0		0	0	0	0	0
47	1975	Solar PV - panels and racking	0	0	0	0		0	0	0	0	0
47	1976	Solar PV - invertors	0	0	0	0		0	0	0	0	0
47	1995	Contributions & Grants	(9,792,874)	(1,416,471)	3,875	(11,205,471)		2,036,863	268,852	(6)	2,305,708	(8,899,763)
	2005	Property under Capital Lease	0			0		0			0	0
		Total before Work in Process	**61,461,909**	**5,031,383**	**(787,279)**	**65,706,013**		**(30,611,417)**	**(1,557,316)**	**482,323**	**(31,686,410)**	**34,019,603**
PIA		Provision for impairment of assets										
WIP		Work in Process	3,717,182	8,664,669	0	12,381,851		0	0	0	0	12,381,851
		Total after Work in Process	**65,179,091**	**13,696,052**	**(787,279)**	**78,087,864**		**(30,611,417)**	**(1,557,316)**	**482,323**	**(31,686,410)**	**46,401,454**
							Less: Fully Allocated Depreciation					
							Transportation		(139,931)			
							PPE refund		(165,196)			
							Net Depreciation per TB		(1,252,189)			46,401,607

Table 2.8 Appendix 2-BA 2014 (MIFRS) Fixed Asset Continuity Schedule

Fixed Asset Continuity Schedule (Distribution & Operations)
As at December 31, 2014
MIFRS

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
	1612	Land Rights	394,463	0	0	394,463	0	(15,126)	0	(15,126)	379,337
	1805	Land - Substations	972,037	0	0	972,037	0	0	0	0	972,037
47	1808	Buildings - Substations	0	0	0	0	0	0	0	0	0
13	1810	Leasehold Improvements				0	0			0	0
47	1820	Substation equipment	1,976,240	2,895,486	(162,802)	4,708,924	0	(133,797)	0	(133,797)	4,575,128
47	1821	Substation transformers	0	0	0	0	0	0	0	0	0
47	1822	Substation switchgear and other elements	0	0	0	0	0	0	0	0	0
47	1823	Substation breakers and reclosures	0	0	0	0	0	0	0	0	0
47	1830	Poles, Towers & Fixtures	6,625,717	576,011	(11,013)	7,190,714	0	(214,179)	0	(214,179)	6,976,536
47	1831	Poles, towers and fixtures - concrete	0	0	0	0	0	0	0	0	0
47	1832	Poles, towers and fixtures - wood	0	0	0	0	0	0	0	0	0
47	1835	OH Conductors & Devices	7,723,874	724,698	(8,976)	8,439,596	0	(206,931)	0	(206,931)	8,232,665
47	1836	Overhead conductors and devices - secondary service	0	0	0	0	0	0	0	0	0
47	1837	Overhead conductors and devices - switches	0	0	0	0	0	0	0	0	0
47	1838	Overhead conductors and devices - capacitor banks	0	0	0	0	0	0	0	0	0
47	1839	Overhead conductors and devices - primary	0	0	0	0	0	0	0	0	0
47	1840	UG Conduit	1,844,932	320,502	0	2,165,434	0	(70,931)	0	(70,931)	2,094,503
47	1843	Underground conduit chambers and other elements	0	0	0	0	0	0	0	0	0
47	1844	Underground conductors and devises primary PILC	0	0	0	0	0	0	0	0	0
47	1845	UG Conductors & Devices	7,256,170	279,956	(6,674)	7,529,453	0	(247,483)	0	(247,483)	7,281,970
47	1846	Underground conductors and devices primary XLPE	0	0	0	0	0	0	0	0	0
47	1847	Underground conductors and devices secondary and service in duct	0	0	0	0	0	0	0	0	0
47	1848	Underground conductors and devices secondary and service direct buried	0	0	0	0	0	0	0	0	0
47	1849	Underground conductors and devices secondary and service in duct	0	0	0	0	0	0	0	0	0
47	1850	Line Transformers	3,640,086	556,533	(70,901)	4,125,719	0	(146,576)	0	(146,576)	3,979,143
47	1851	Padmount transformers				0	0			0	0
47	1852	Line transformers - Underground	0	0	0	0	0	0	0	0	0
47	1855	Services (OH & UG)	2,570,477	519,764	(2,092)	3,088,149	0	(81,169)	0	(81,169)	3,006,980
47	1856	Services	0	0	0	0	0	0	0	0	0
47	1860	Meters	1,818,344	131,827	(46,365)	1,903,806	0	(176,032)	0	(176,032)	1,727,774
47	1861	Smart Meters	0	0	0	0	0	0	0	0	0
47	1862	Smart Meters - Residential	0	0	0	0	0	0	0	0	0
47	1863	Smart Meters - Commercial	0	0	0	0	0	0	0	0	0
N/A	1905	Land	1,216,545	0	0	1,216,545	0	0	0	0	1,216,545
	1906	Land Rights	0	0	0	0	0	0	0	0	0
47	1908	Buildings & Fixtures	451,878	0	0	451,878	0	(11,367)	0	(11,367)	440,510
13	1910	Leasehold Improvements	0	0	0	0	0	0	0	0	0
8	1915	Office Furniture & Equipment	64,692	9,292	0	73,984	0	(14,034)	0	(14,034)	59,950
10	1920	Computer - Hardware	177,257	80,063	0	257,320	0	(70,671)	0	(70,671)	186,649
45	1921	Computer - Hardware post Mar 22/04	0	0	0	0	0	0	0	0	0
12	1611	Computer - Software	202,571	198,585	0	401,156	0	(133,981)	0	(133,981)	267,175
10	1930	Transportation Equipment	490,165	3,268	0	493,433	0	(139,931)	0	(139,931)	353,501
8	1935	Stores Equipment	13,402	4,788	0	18,190	0	(2,589)	0	(2,589)	15,601
8	1940	Tools, Shop & Garage Equipment	246,543	17,553	0	264,096	0	(38,486)	0	(38,486)	225,610
8	1945	Measurement & Testing Equipment	25,601	4,067	0	29,667	0	(3,979)	0	(3,979)	25,688
8	1950	Power operated Equipment	0	0	0	0	0	0	0	0	0
8	1955	Communications Equipment	0	0	0	0	0	0	0	0	0
47	1970	Load Management controls	0	0	0	0	0	0	0	0	0
47	1980	System Supervisory Equipment	895,508	125,462	0	1,020,970	0	(118,906)	0	(118,906)	902,064
47	1981	System Supervisory Protection and Control	0	0	0	0	0	0	0	0	0
47	1982	System Supervisory Protection and Control	0	0	0	0	0	0	0	0	0
47	1975	Solar PV - panels and racking	0	0	0	0	0	0	0	0	0
47	1976	Solar PV - invertors	0	0	0	0	0	0	0	0	0
47	1995	Contributions & Grants	(7,756,011)	(1,416,471)	3,869	(9,168,614)	0	268,929	0	268,929	(8,899,685)
	2005	Property under Capital Lease	0			0	0			0	0
		Total before Work in Process	**30,850,492**	**5,031,383**	**(304,955)**	**35,576,920**	**0**	**(1,557,239)**	**0**	**(1,557,239)**	**34,019,681**
PIA		Provision for impairment of assets									
WIP		Work in Process	3,717,182	8,664,669	0	12,381,851	0	0	0	0	12,381,851
		Total after Work in Process	**34,567,674**	**13,696,052**	**(304,955)**	**47,958,771**	**0**	**(1,557,239)**	**0**	**(1,557,239)**	**46,401,532**

Less: Fully Allocated Depreciation	
Transportation	(139,931)
Deferred Revenue	268,929
Net Depreciation	(1,686,236)

Table 2.9 Appendix 2-BA 2015 Fixed Asset Continuity Schedule

Fixed Asset Continuity Schedule (Distribution & Operations)
As at December 31, 2015

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
	1612	Land Rights	394,463		(17)	394,446	(15,126)	(12,699)	17	(27,808)	366,638
	1805	Land - Substations	972,037	77,556	0	1,049,593	0	0	0	0	1,049,593
47	1808	Buildings - Substations	0			0	0			0	0
13	1810	Leasehold Improvements	0			0	0			0	0
47	1820	Substation equipment	4,708,924	779,993	(3,109)	5,485,808	(133,797)	(191,509)	3,109	(322,197)	5,163,612
47	1821	Substation transformers	0			0	0			0	0
47	1822	Substation switchgear and other elements	0			0	0			0	0
47	1823	Substation breakers and reclosures	0			0	0			0	0
47	1830	Poles, Towers & Fixtures	7,190,714	1,533,272	(12,553)	8,711,433	(214,179)	(237,728)	1,204	(450,703)	8,260,731
47	1831	Poles, towers and fixtures - concrete	0			0	0			0	0
47	1832	Poles, towers and fixtures - wood	0			0	0			0	0
47	1835	OH Conductors & Devices	8,439,596	1,390,592	(9,487)	9,820,701	(206,931)	(225,949)	1,291	(431,589)	9,389,112
47	1836	Overhead conductors and devices - secondary service	0			0	0			0	0
47	1837	Overhead conductors and devices - switches	0			0	0			0	0
47	1838	Overhead conductors and devices - capacitor banks	0			0	0			0	0
47	1839	Overhead conductors and devices - primary	0			0	0			0	0
47	1840	UG Conduit	2,165,434	546,399	(15,253)	2,696,580	(70,931)	(81,467)	192	(152,206)	2,544,374
47	1843	Underground conduit chambers and other elements	0			0	0			0	0
47	1844	Underground conductors and devises primary PILC	0			0	0			0	0
47	1845	UG Conductors & Devices	7,529,453	283,406	(7,492)	7,805,367	(247,483)	(254,303)	579	(501,207)	7,304,160
47	1846	Underground conductors and devices primary XLPE	0			0	0			0	0
47	1847	Underground conductors and devices secondary and service in duct	0			0	0			0	0
47	1848	Underground conductors and devices secondary and service direct buried	0			0	0			0	0
47	1849	Underground conductors and devices secondary and service in duct	0			0	0			0	0
47	1850	Line Transformers	4,125,719	999,677	(22,972)	5,102,424	(146,576)	(164,241)	3,807	(307,010)	4,795,414
47	1851	Padmount transformers	0			0	0			0	0
47	1852	Line transformers - Underground	0			0	0			0	0
47	1855	Services (OH & UG)	3,088,149	479,966	(9,769)	3,558,346	(81,169)	(93,028)	146	(174,051)	3,384,295
47	1856	Services	0			0	0			0	0
47	1860	Meters	1,903,806	113,146	(11,281)	2,005,671	(176,032)	(178,804)	3,192	(351,644)	1,654,027
47	1861	Smart Meters	0			0	0			0	0
47	1862	Smart Meters - Residential	0			0	0			0	0
47	1863	Smart Meters - Commercial	0			0	0			0	0
N/A	1905	Land	1,216,545		(201,049)	1,015,496	0			0	1,015,496
	1906	Land Rights	0			0	0			0	0
47	1908	Buildings & Fixtures	451,878	12,430,510	(451,878)	12,430,510	(11,367)	(145,132)	17,051	(139,448)	12,291,061
13	1910	Leasehold Improvements	0			0	0			0	0
8	1915	Office Furniture & Equipment	73,984	154,231	(4,713)	223,502	(14,034)	(19,569)	1,467	(32,136)	191,366
10	1920	Computer - Hardware	257,320	149,497	(5,283)	401,534	(70,671)	(82,659)	4,831	(148,499)	253,035
45	1921	Computer - Hardware post Mar 22/04	0			0	0			0	0
12	1611	Computer - Software	401,156	185,053	(15,673)	570,536	(133,981)	(169,499)	15,673	(287,807)	282,729
10	1930	Transportation Equipment	493,433	33,347	(9,505)	517,275	(139,931)	(120,051)	8,589	(251,393)	265,881
8	1935	Stores Equipment	18,190	117,204	(59)	135,335	(2,589)	(8,603)	59	(11,133)	124,202
8	1940	Tools, Shop & Garage Equipment	264,096	41,581	(109)	305,568	(38,486)	(41,285)	109	(79,662)	225,906
8	1945	Measurement & Testing Equipment	29,667			29,667	(3,979)	(4,161)		(8,140)	21,527
8	1950	Power operated Equipment	0			0	0			0	0
8	1955	Communications Equipment	0			0	0			0	0
47	1970	Load Management controls	0			0	0			0	0
47	1980	System Supervisory Equipment	1,020,970	569,196	(2,569)	1,587,597	(118,906)	(133,510)	2,569	(249,847)	1,337,750
47	1981	System Supervisory Protection and Control	0			0	0			0	0
47	1982	System Supervisory Protection and Control	0			0	0			0	0
47	1975	Solar PV - panels and racking	0			0	0			0	0
47	1976	Solar PV - invertors	0			0	0			0	0
47	1995	Contributions & Grants	(9,168,614)	(2,267,837)	77,513	(11,358,938)	268,929	313,336	783	583,048	(10,775,890)
	2005	Property under Capital Lease	0			0	0			0	0
		Total before Work in Process	**35,576,920**	**17,616,789**	**(705,258)**	**52,488,451**	**(1,557,239)**	**(1,850,861)**	**64,668**	**(3,343,432)**	**49,145,019**
PIA		Provision for impairment of assets	0			0	0	0	0	0	0
WIP		Work in Process	12,381,851	(11,584,124)		797,727	0	0	0	0	797,727
		Total after Work in Process	**47,958,771**	**6,032,665**	**(705,258)**	**53,286,178**	**(1,557,239)**	**(1,850,861)**	**64,668**	**(3,343,432)**	**49,942,746**
							Less: Fully Allocated Depreciation				
							Transportation	(120,051)			
							Deferred Revenue	313,336		583,048	
							PP&E refund	(164,995)			
							Net Depreciation	(1,879,151)		(3,926,480)	

Table 2.10 Appendix 2-BA 2016 Fixed Asset Continuity Schedule

Fixed Asset Continuity Schedule (Distribution & Operations)
As at December 31, 2016

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
	1612	Land Rights	394,446			394,446	(27,808)	(15,109)		(42,917)	351,529
	1805	Land - Substations	1,049,593			1,049,593	0			0	1,049,593
47	1808	Buildings - Substations	0			0	0			0	0
13	1810	Leasehold Improvements	0			0	0			0	0
47	1820	Substation equipment	5,485,808	2,008,854		7,494,662	(322,197)	(174,908)		(497,105)	6,997,558
47	1821	Substation transformers	0			0	0			0	0
47	1822	Substation switchgear and other elements	0			0	0			0	0
47	1823	Substation breakers and reclosures	0			0	0			0	0
47	1830	Poles, Towers & Fixtures	8,711,433	1,245,717	(12,000)	9,945,150	(450,703)	(258,961)	100	(709,564)	9,235,587
47	1831	Poles, towers and fixtures - concrete	0			0	0			0	0
47	1832	Poles, towers and fixtures - wood	0			0	0			0	0
47	1835	OH Conductors & Devices	9,820,701	1,111,002	(6,000)	10,925,703	(431,589)	(245,465)	50	(677,004)	10,248,699
47	1836	Overhead conductors and devices - secondary service	0			0	0			0	0
47	1837	Overhead conductors and devices - switches	0			0	0			0	0
47	1838	Overhead conductors and devices - capacitor banks	0			0	0			0	0
47	1839	Overhead conductors and devices - primary	0			0	0			0	0
47	1840	UG Conduit	2,696,580	1,282,396		3,978,976	(152,206)	(112,818)		(265,024)	3,713,952
47	1843	Underground conduit chambers and other elements	0			0	0			0	0
47	1844	Underground conductors and devises primary PILC	0			0	0			0	0
47	1845	UG Conductors & Devices	7,805,367	613,881	(2,800)	8,416,448	(501,207)	(268,239)	25	(769,421)	7,647,027
47	1846	Underground conductors and devices primary XLPE	0			0	0			0	0
47	1847	Underground conductors and devices secondary and service in duct	0			0	0			0	0
47	1848	Underground conductors and devices secondary and service direct buried	0			0	0			0	0
47	1849	Underground conductors and devices secondary and service in duct	0			0	0			0	0
47	1850	Line Transformers	5,102,424	1,818,685	(138,000)	6,783,109	(307,010)	(205,772)	600	(512,182)	6,270,927
47	1851	Padmount transformers	0			0				0	0
47	1852	Line transformers - Underground	0			0	0			0	0
47	1855	Services (OH & UG)	3,558,346	983,373		4,541,719	(174,051)	(112,944)		(286,995)	4,254,724
47	1856	Services	0			0	0			0	0
47	1860	Meters	2,005,671	168,055	(8,500)	2,165,226	(351,644)	(187,107)	75	(538,676)	1,626,550
47	1861	Smart Meters	0			0	0			0	0
47	1862	Smart Meters - Residential	0			0	0			0	0
47	1863	Smart Meters - Commercial	0			0	0			0	0
N/A	1905	Land	1,015,496			1,015,496	0			0	1,015,496
	1906	Land Rights	0			0	0			0	0
47	1908	Buildings & Fixtures	12,430,510	15,000		12,445,510	(139,448)	(245,450)		(384,898)	12,060,611
13	1910	Leasehold Improvements	0			0	0			0	0
8	1915	Office Furniture & Equipment	223,502	15,000		238,502	(32,136)	(30,031)		(62,167)	176,335
10	1920	Computer - Hardware	401,534	130,000		531,534	(148,499)	(119,439)		(267,938)	263,596
45	1921	Computer - Hardware post Mar 22/04	0			0	0			0	0
12	1611	Computer - Software	570,536	358,500		929,036	(287,807)	(221,953)	0	(509,760)	419,276
10	1930	Transportation Equipment	517,275			517,275	(251,393)	(139,642)		(391,035)	126,239
8	1935	Stores Equipment	135,335	5,000		140,335	(11,133)	(21,360)		(32,492)	107,843
8	1940	Tools, Shop & Garage Equipment	305,568	38,000		343,568	(79,662)	(45,350)		(125,011)	218,556
8	1945	Measurement & Testing Equipment	29,667	15,000		44,667	(8,140)	(4,729)		(12,870)	31,798
8	1950	Power operated Equipment	0			0	0			0	0
8	1955	Communications Equipment	0			0	0			0	0
47	1970	Load Management controls	0			0	0			0	0
47	1980	System Supervisory Equipment	1,587,597	84,002		1,671,599	(249,847)	(193,083)		(442,930)	1,228,669
47	1981	System Supervisory Protection and Control	0			0	0			0	0
47	1982	System Supervisory Protection and Control	0			0	0			0	0
47	1975	Solar PV - panels and racking	0			0	0			0	0
47	1976	Solar PV - invertors	0			0	0			0	0
47	1995	Contributions & Grants	(11,358,938)	(4,227,692)		(15,586,630)	583,048	485,884		1,068,932	(14,517,698)
	2005	Property under Capital Lease	0			0	0			0	0
		Total before Work in Process	**52,488,451**	**5,664,773**	**(167,300)**	**57,985,924**	**(3,343,432)**	**(2,116,475)**	**850**	**(5,459,057)**	**52,526,867**
PIA		Provision for impairment of assets	0			0	0			0	0
WIP		Work in Process	797,727			797,727	0			0	797,727
		Total after Work in Process	**53,286,178**	**5,664,773**	**(167,300)**	**58,783,651**	**(3,343,432)**	**(2,116,475)**	**850**	**(5,459,057)**	**53,324,594**

Less: Fully Allocated Depreciation	
Transportation	(139,642)
Deferred Revenue	485,884
Refund PPE	(165,124)
Net Depreciation	(2,297,593)

Table 2.11 Appendix 2-BA 2017 Fixed Asset Continuity Schedule

Fixed Asset Continuity Schedule (Distribution & Operations)
As at December 31, 2017

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
	1612	Land Rights	394,446			394,446	(42,917)	(15,109)		(58,026)	336,420
	1805	Land - Substations	1,049,593			1,049,593	0			0	1,049,593
47	1808	Buildings - Substations	0			0	0			0	0
13	1810	Leasehold Improvements	0			0	0			0	0
47	1820	Substation equipment	7,494,662	326,511	0	7,821,173	(497,105)	(204,291)	0	(701,396)	7,119,777
47	1821	Substation transformers	0			0	0			0	0
47	1822	Substation switchgear and other elements	0			0	0			0	0
47	1823	Substation breakers and reclosures	0			0	0			0	0
47	1830	Poles, Towers & Fixtures	9,945,150	2,234,344	(13,200)	12,166,294	(709,564)	(299,893)	110	(1,009,346)	11,156,948
47	1831	Poles, towers and fixtures - concrete	0			0	0			0	0
47	1832	Poles, towers and fixtures - wood	0			0	0			0	0
47	1835	OH Conductors & Devices	10,925,703	1,631,578	(6,600)	12,550,681	(677,004)	(269,764)	55	(946,713)	11,603,968
47	1836	Overhead conductors and devices - secondary service	0			0	0			0	0
47	1837	Overhead conductors and devices - switches	0			0	0			0	0
47	1838	Overhead conductors and devices - capacitor banks	0			0	0			0	0
47	1839	Overhead conductors and devices - primary	0			0	0			0	0
47	1840	UG Conduit	3,978,976	2,184,446	0	6,163,422	(265,024)	(156,151)	0	(421,175)	5,742,247
47	1843	Underground conduit chambers and other elements	0			0	0			0	0
47	1844	Underground conductors and devises primary PILC	0			0	0			0	0
47	1845	UG Conductors & Devices	8,416,448	989,999	(3,080)	9,403,367	(769,421)	(288,204)	28	(1,057,597)	8,345,770
47	1846	Underground conductors and devices primary XLPE	0			0	0			0	0
47	1847	Underground conductors and devices secondary and service in duct	0			0	0			0	0
47	1848	Underground conductors and devices secondary and service direct buried	0			0	0			0	0
47	1849	Underground conductors and devices secondary and service in duct	0			0	0			0	0
47	1850	Line Transformers	6,783,109	2,494,095	(151,800)	9,125,404	(512,182)	(260,016)	660	(771,538)	8,353,866
47	1851	Padmount transformers	0			0	0			0	0
47	1852	Line transformers - Underground	0			0	0			0	0
47	1855	Services (OH & UG)	4,541,719	1,521,969	0	6,063,688	(286,995)	(143,821)	0	(430,816)	5,632,872
47	1856	Services	0			0	0			0	0
47	1860	Meters	2,165,226	250,632	(9,350)	2,406,508	(538,676)	(201,093)	83	(739,686)	1,666,821
47	1861	Smart Meters	0			0	0			0	0
47	1862	Smart Meters - Residential	0			0	0			0	0
47	1863	Smart Meters - Commercial	0			0	0			0	0
N/A	1905	Land	1,015,496			1,015,496	0			0	1,015,496
	1906	Land Rights	0			0	0			0	0
47	1908	Buildings & Fixtures	12,445,510	15,000	0	12,460,510	(384,898)	(246,050)	0	(630,948)	11,829,561
13	1910	Leasehold Improvements	0			0	0			0	0
8	1915	Office Furniture & Equipment	238,502	15,000	0	253,502	(62,167)	(31,531)	0	(93,698)	159,804
10	1920	Computer - Hardware	531,534	165,000	0	696,534	(267,938)	(148,939)	0	(416,876)	279,658
45	1921	Computer - Hardware post Mar 22/04	0			0	0			0	0
12	1611	Computer - Software	929,036	339,325	0	1,268,361	(509,760)	(308,458)	0	(818,218)	450,143
10	1930	Transportation Equipment	517,275	818,500	0	1,335,775	(391,035)	(221,492)	0	(612,527)	723,247
8	1935	Stores Equipment	140,335	5,250	0	145,585	(32,492)	(21,872)	0	(54,364)	91,221
8	1940	Tools, Shop & Garage Equipment	343,568	39,900	0	383,468	(125,011)	(49,245)	0	(174,256)	209,212
8	1945	Measurement & Testing Equipment	44,667	69,760	0	114,427	(12,870)	(8,967)	0	(21,837)	92,590
8	1950	Power operated Equipment	0			0	0			0	0
8	1955	Communications Equipment	0			0	0			0	0
47	1970	Load Management controls	0			0	0			0	0
47	1980	System Supervisory Equipment	1,671,599	32,400	0	1,703,999	(442,930)	(196,963)	0	(639,893)	1,064,106
47	1981	System Supervisory Protection and Control	0			0	0			0	0
47	1982	System Supervisory Protection and Control	0			0	0			0	0
47	1975	Solar PV - panels and racking	0			0	0			0	0
47	1976	Solar PV - invertors	0			0	0			0	0
47	1995	Contributions & Grants	(15,586,630)	(6,326,270)	0	(21,912,900)	1,068,932	667,848	0	1,736,780	(20,176,120)
	2005	Property under Capital Lease	0			0	0			0	0
		Total before Work in Process	**57,985,924**	**6,807,439**	**(184,030)**	**64,609,333**	**(5,459,057)**	**(2,404,010)**	**935**	**(7,862,132)**	**56,747,200**
PIA		Provision for impairment of assets	0			0	0			0	0
WIP		Work in Process	797,727			797,727	0			0	797,727
		Total after Work in Process	**58,783,651**	**6,807,439**	**(184,030)**	**65,407,060**	**(5,459,057)**	**(2,404,010)**	**935**	**(7,862,132)**	**57,544,927**

Less: Fully Allocated Depreciation	
Transportation	(221,492)
Contributions & Gran	667,848
PP&E Amortization	
Net Depreciation	(2,850,366)

Table 2.12 Appendix 2-BA 2018 Fixed Asset Continuity Schedule

Fixed Asset Continuity Schedule (Distribution & Operations)
As at December 31, 2018

							Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
	1612	Land Rights	394,446			394,446	(58,026)	(15,109)		(73,135)	321,311
	1805	Land - Substations	1,049,593			1,049,593	0			0	1,049,593
47	1808	Buildings - Substations	0			0	0			0	0
13	1810	Leasehold Improvements	0			0	0			0	0
47	1820	Substation equipment	7,821,173	2,917,659	0	10,738,832	(701,396)	(244,844)	0	(946,240)	9,792,592
47	1821	Substation transformers	0			0	0			0	0
47	1822	Substation switchgear and other elements	0			0	0			0	0
47	1823	Substation breakers and reclosures	0			0	0			0	0
47	1830	Poles, Towers & Fixtures	12,166,294	2,481,964	(13,860)	14,634,398	(1,009,346)	(352,296)	116	(1,361,526)	13,272,872
47	1831	Poles, towers and fixtures - concrete	0			0	0			0	0
47	1832	Poles, towers and fixtures - wood	0			0	0			0	0
47	1835	OH Conductors & Devices	12,550,681	1,812,397	(6,930)	14,356,148	(946,713)	(298,464)	58	(1,245,119)	13,111,029
47	1836	Overhead conductors and devices - secondary service	0			0	0			0	0
47	1837	Overhead conductors and devices - switches	0			0	0			0	0
47	1838	Overhead conductors and devices - capacitor banks	0			0	0			0	0
47	1839	Overhead conductors and devices - primary	0			0	0			0	0
47	1840	UG Conduit	6,163,422	2,426,536	0	8,589,958	(421,175)	(213,789)	0	(634,964)	7,954,994
47	1843	Underground conduit chambers and other elements	0			0	0			0	0
47	1844	Underground conductors and devises primary PILC	0			0	0			0	0
47	1845	UG Conductors & Devices	9,403,367	1,099,715	(3,234)	10,499,848	(1,057,597)	(314,325)	29	(1,371,893)	9,127,955
47	1846	Underground conductors and devices primary XLPE	0			0	0			0	0
47	1847	Underground conductors and devices secondary and service in duct	0			0	0			0	0
47	1848	Underground conductors and devices secondary and service direct buried	0			0	0			0	0
47	1849	Underground conductors and devices secondary and service in duct	0			0	0			0	0
47	1850	Line Transformers	9,125,404	2,880,502	(159,390)	11,846,516	(771,538)	(327,199)	693	(1,098,044)	10,748,472
47	1851	Padmount transformers	0			0	0			0	0
47	1852	Line transformers - Underground	0			0	0			0	0
47	1855	Services (OH & UG)	6,063,688	1,690,640	0	7,754,328	(430,816)	(182,470)	0	(613,286)	7,141,042
47	1856	Services	0			0	0			0	0
47	1860	Meters	2,406,508	270,000	(9,818)	2,666,690	(739,686)	(218,447)	87	(958,046)	1,708,643
47	1861	Smart Meters	0			0	0			0	0
47	1862	Smart Meters - Residential	0			0	0			0	0
47	1863	Smart Meters - Commercial	0			0	0			0	0
N/A	1905	Land	1,015,496			1,015,496	0			0	1,015,496
	1906	Land Rights	0			0	0			0	0
47	1908	Buildings & Fixtures	12,460,510	15,000	0	12,475,510	(630,948)	(246,350)	0	(877,298)	11,598,211
13	1910	Leasehold Improvements	0			0	0			0	0
8	1915	Office Furniture & Equipment	253,502	15,000	0	268,502	(93,698)	(33,031)	0	(126,729)	141,773
10	1920	Computer - Hardware	696,534	150,000	0	846,534	(416,876)	(180,439)	0	(597,315)	249,219
45	1921	Computer - Hardware post Mar 22/04	0			0	0			0	0
12	1611	Computer - Software	1,268,361	290,516	0	1,558,877	(818,218)	(328,432)	0	(1,146,650)	412,227
10	1930	Transportation Equipment	1,335,775	627,025	0	1,962,800	(612,527)	(366,045)	0	(978,572)	984,227
8	1935	Stores Equipment	145,585	5,513	0	151,098	(54,364)	(22,410)	0	(76,774)	74,324
8	1940	Tools, Shop & Garage Equipment	383,468	241,895	0	625,363	(174,256)	(63,334)	0	(237,590)	387,773
8	1945	Measurement & Testing Equipment	114,427	30,800	0	145,227	(21,837)	(13,995)	0	(35,832)	109,395
8	1950	Power operated Equipment	0			0	0			0	0
8	1955	Communications Equipment	0			0	0			0	0
47	1970	Load Management controls	0			0	0			0	0
47	1980	System Supervisory Equipment	1,703,999	47,408	0	1,751,407	(639,893)	(199,623)	0	(839,516)	911,891
47	1981	System Supervisory Protection and Control	0			0	0			0	0
47	1982	System Supervisory Protection and Control	0			0	0			0	0
47	1975	Solar PV - panels and racking	0			0	0			0	0
47	1976	Solar PV - invertors	0			0	0			0	0
47	1995	Contributions & Grants	(21,912,900)	(9,626,226)	0	(31,539,126)	1,736,780	942,893	0	2,679,673	(28,859,453)
	2005	Property under Capital Lease	0			0	0			0	0
		Total before Work in Process	**64,609,333**	**7,376,344**	**(193,232)**	**71,792,445**	**(7,862,132)**	**(2,677,709)**	**983**	**(10,538,858)**	**61,253,586**
PIA		Provision for impairment of assets	0			0	0			0	0
WIP		Work in Process	797,727			797,727	0			0	797,727
		Total after Work in Process	**65,407,060**	**7,376,344**	**(193,232)**	**72,590,172**	**(7,862,132)**	**(2,677,709)**	**983**	**(10,538,858)**	**62,051,313**

Less: Fully Allocated Depreciation	
Transportation	(366,045)
Contributions & Gran	942,893
PP&E Amortization	
Net Depreciation	(3,254,557)

Table 2.13 Appendix 2-BA 2019 Fixed Asset Continuity Schedule

Fixed Asset Continuity Schedule (Distribution & Operations)
As at December 31, 2019

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
	1612	Land Rights	394,446			394,446	(73,135)	(15,109)		(88,244)	306,202
	1805	Land - Substations	1,049,593			1,049,593	0			0	1,049,593
47	1808	Buildings - Substations	0			0	0			0	0
13	1810	Leasehold Improvements	0			0	0			0	0
47	1820	Substation equipment	10,738,832	225,654	0	10,964,486	(946,240)	(284,135)	0	(1,230,375)	9,734,111
47	1821	Substation transformers	0			0	0			0	0
47	1822	Substation switchgear and other elements	0			0	0			0	0
47	1823	Substation breakers and reclosures	0			0	0			0	0
47	1830	Poles, Towers & Fixtures	14,634,398	2,958,312	(14,553)	17,578,157	(1,361,526)	(412,744)	121	(1,774,149)	15,804,008
47	1831	Poles, towers and fixtures - concrete	0			0	0			0	0
47	1832	Poles, towers and fixtures - wood	0			0	0			0	0
47	1835	OH Conductors & Devices	14,356,148	2,160,239	(7,277)	16,509,110	(1,245,119)	(331,569)	61	(1,576,627)	14,932,483
47	1836	Overhead conductors and devices - secondary service	0			0	0			0	0
47	1837	Overhead conductors and devices - switches	0			0	0			0	0
47	1838	Overhead conductors and devices - capacitor banks	0			0	0			0	0
47	1839	Overhead conductors and devices - primary	0			0	0			0	0
47	1840	UG Conduit	8,589,958	2,892,246	0	11,482,204	(634,964)	(280,273)	0	(915,237)	10,566,967
47	1843	Underground conduit chambers and other elements	0			0	0			0	0
47	1844	Underground conductors and devises primary PILC	0			0	0			0	0
47	1845	UG Conductors & Devices	10,499,848	1,475,776	(3,396)	11,972,228	(1,371,893)	(346,519)	31	(1,718,381)	10,253,847
47	1846	Underground conductors and devices primary XLPE	0			0	0			0	0
47	1847	Underground conductors and devices secondary and service in duct	0			0	0			0	0
47	1848	Underground conductors and devices secondary and service direct buried	0			0	0			0	0
47	1849	Underground conductors and devices secondary and service in duct	0			0	0			0	0
47	1850	Line Transformers	11,846,516	3,423,226	(167,360)	15,102,382	(1,098,044)	(405,996)	728	(1,503,312)	13,599,070
47	1851	Padmount transformers	0			0	0			0	0
47	1852	Line transformers - Underground	0			0	0			0	0
47	1855	Services (OH & UG)	7,754,328	2,015,114	0	9,769,442	(613,286)	(227,052)	0	(840,338)	8,929,104
47	1856	Services	0			0	0			0	0
47	1860	Meters	2,666,690	250,000	(10,308)	2,906,382	(958,046)	(235,781)	92	(1,193,735)	1,712,646
47	1861	Smart Meters	0			0	0			0	0
47	1862	Smart Meters - Residential	0			0	0			0	0
47	1863	Smart Meters - Commercial	0			0	0			0	0
N/A	1905	Land	1,015,496			1,015,496	0			0	1,015,496
	1906	Land Rights	0			0	0			0	0
47	1908	Buildings & Fixtures	12,475,510	15,000	0	12,490,510	(877,298)	(246,650)	0	(1,123,948)	11,366,561
13	1910	Leasehold Improvements	0			0	0			0	0
8	1915	Office Furniture & Equipment	268,502	15,000	0	283,502	(126,729)	(34,531)	0	(161,260)	122,242
10	1920	Computer - Hardware	846,534	150,000	0	996,534	(597,315)	(210,439)	0	(807,754)	188,780
45	1921	Computer - Hardware post Mar 22/04	0			0	0			0	0
12	1611	Computer - Software	1,558,877	274,000	0	1,832,877	(1,146,650)	(310,768)	0	(1,457,418)	375,459
10	1930	Transportation Equipment	1,962,800	95,918	0	2,058,718	(978,572)	(438,339)	0	(1,416,911)	641,806
8	1935	Stores Equipment	151,098	5,788	0	156,886	(76,774)	(22,975)	0	(99,749)	57,137
8	1940	Tools, Shop & Garage Equipment	625,363	43,990	0	669,353	(237,590)	(77,629)	0	(315,219)	354,134
8	1945	Measurement & Testing Equipment	145,227	247,340	0	392,567	(35,832)	(27,902)	0	(63,734)	328,833
8	1950	Power operated Equipment	0			0	0			0	0
8	1955	Communications Equipment	0			0	0			0	0
47	1970	Load Management controls	0			0	0			0	0
47	1980	System Supervisory Equipment	1,751,407	114,778	0	1,866,185	(839,516)	(205,029)	0	(1,044,545)	821,640
47	1981	System Supervisory Protection and Control	0			0	0			0	0
47	1982	System Supervisory Protection and Control	0			0	0			0	0
47	1975	Solar PV - panels and racking	0			0	0			0	0
47	1976	Solar PV - invertors	0			0	0			0	0
47	1995	Contributions & Grants	(31,539,126)	(9,675,905)	0	(41,215,031)	2,679,673	1,275,690	0	3,955,363	(37,259,668)
	2005	Property under Capital Lease	0			0	0			0	0
		Total before Work in Process	**71,792,445**	**6,686,476**	**(202,894)**	**78,276,027**	**(10,538,858)**	**(2,837,750)**	**1,033**	**(13,375,575)**	**64,900,451**
PIA		Provision for impairment of assets	0			0	0			0	0
WIP		Work in Process	797,727			797,727	0			0	797,727
		Total after Work in Process	**72,590,172**	**6,686,476**	**(202,894)**	**79,073,754**	**(10,538,858)**	**(2,837,750)**	**1,033**	**(13,375,575)**	**65,698,178**

Less: Fully Allocated Depreciation	
Transportation	(438,339)
Contributions & Gran	1,275,690
PP&E Amortization	
Net Depreciation	(3,675,101)

Table 2.14 Appendix 2-BA 2020 Fixed Asset Continuity Schedule

Fixed Asset Continuity Schedule (Distribution & Operations)
As at December 31, 2020

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
	1612	Land Rights	394,446			394,446	(88,244)	(15,109)		(103,353)	291,093
	1805	Land - Substations	1,049,593			1,049,593	0			0	1,049,593
47	1808	Buildings - Substations	0			0	0			0	0
13	1810	Leasehold Improvements	0			0	0			0	0
47	1820	Substation equipment	10,964,486	324,319	0	11,288,805	(1,230,375)	(291,010)	0	(1,521,385)	9,767,420
47	1821	Substation transformers	0			0	0			0	0
47	1822	Substation switchgear and other elements	0			0	0			0	0
47	1823	Substation breakers and reclosures	0			0	0			0	0
47	1830	Poles, Towers & Fixtures	17,578,157	2,954,188	(15,281)	20,517,064	(1,774,149)	(478,438)	127	(2,252,460)	18,264,604
47	1831	Poles, towers and fixtures - concrete	0			0	0			0	0
47	1832	Poles, towers and fixtures - wood	0			0	0			0	0
47	1835	OH Conductors & Devices	16,509,110	2,157,228	(7,640)	18,658,698	(1,576,627)	(367,548)	64	(1,944,111)	16,714,587
47	1836	Overhead conductors and devices - secondary service	0			0	0			0	0
47	1837	Overhead conductors and devices - switches	0			0	0			0	0
47	1838	Overhead conductors and devices - capacitor banks	0			0	0			0	0
47	1839	Overhead conductors and devices - primary	0			0	0			0	0
47	1840	UG Conduit	11,482,204	2,888,214	0	14,370,418	(915,237)	(352,529)	0	(1,267,766)	13,102,652
47	1843	Underground conduit chambers and other elements	0			0	0			0	0
47	1844	Underground conductors and devises primary PILC	0			0	0			0	0
47	1845	UG Conductors & Devices	11,972,228	1,482,199	(3,565)	13,450,862	(1,718,381)	(383,493)	33	(2,101,841)	11,349,021
47	1846	Underground conductors and devices primary XLPE	0			0	0			0	0
47	1847	Underground conductors and devices secondary and service in	0			0	0			0	0
47	1848	Underground conductors and devices secondary and service di	0			0	0			0	0
47	1849	Underground conductors and devices secondary and service in	0			0	0			0	0
47	1850	Line Transformers	15,102,382	3,430,723	(175,727)	18,357,378	(1,503,312)	(491,670)	764	(1,994,218)	16,363,160
47	1851	Padmount transformers	0			0	0			0	0
47	1852	Line transformers - Underground	0			0	0			0	0
47	1855	Services (OH & UG)	9,769,442	2,012,306	0	11,781,748	(840,338)	(275,503)	0	(1,115,841)	10,665,907
47	1856	Services	0			0	0			0	0
47	1860	Meters	2,906,382	250,000	(10,824)	3,145,558	(1,193,735)	(252,447)	96	(1,446,086)	1,699,471
47	1861	Smart Meters	0			0	0			0	0
47	1862	Smart Meters - Residential	0			0	0			0	0
47	1863	Smart Meters - Commercial	0			0	0			0	0
N/A	1905	Land	1,015,496			1,015,496	0			0	1,015,496
	1906	Land Rights	0			0	0			0	0
47	1908	Buildings & Fixtures	12,490,510	15,000	0	12,505,510	(1,123,948)	(246,950)	0	(1,370,898)	11,134,611
13	1910	Leasehold Improvements	0			0	0			0	0
8	1915	Office Furniture & Equipment	283,502	15,000	0	298,502	(161,260)	(36,031)	0	(197,291)	101,211
10	1920	Computer - Hardware	996,534	150,000	0	1,146,534	(807,754)	(240,439)	0	(1,048,193)	98,341
45	1921	Computer - Hardware post Mar 22/04	0			0	0			0	0
12	1611	Computer - Software	1,832,877	245,000	0	2,077,877	(1,457,418)	(280,964)	0	(1,738,382)	339,495
10	1930	Transportation Equipment	2,058,718	101,079	0	2,159,797	(1,416,911)	(458,038)	0	(1,874,949)	284,847
8	1935	Stores Equipment	156,886	6,077	0	162,963	(99,749)	(23,569)	0	(123,318)	39,645
8	1940	Tools, Shop & Garage Equipment	669,353	46,188	0	715,541	(315,219)	(82,137)	0	(397,356)	318,185
8	1945	Measurement & Testing Equipment	392,567	49,707	0	442,274	(63,734)	(42,755)	0	(106,489)	335,785
8	1950	Power operated Equipment	0			0	0			0	0
8	1955	Communications Equipment	0			0	0			0	0
47	1970	Load Management controls	0			0	0			0	0
47	1980	System Supervisory Equipment	1,866,185	117,266	0	1,983,451	(1,044,545)	(212,764)	0	(1,257,309)	726,142
47	1981	System Supervisory Protection and Control	0			0	0			0	0
47	1982	System Supervisory Protection and Control	0			0	0			0	0
47	1975	Solar PV - panels and racking	0			0	0			0	0
47	1976	Solar PV - invertors	0			0	0			0	0
47	1995	Contributions & Grants	(41,215,031)	(10,009,484)	0	(51,224,515)	3,955,363	1,615,092	0	5,570,455	(45,654,060)
	2005	Property under Capital Lease	0			0	0			0	0
		Total before Work in Process	**78,276,027**	**6,235,010**	**(213,037)**	**84,298,000**	**(13,375,575)**	**(2,916,302)**	**1,084**	**(16,290,793)**	**68,007,206**
PIA		Provision for impairment of assets	0			0	0			0	0
WIP		Work in Process	797,727			797,727	0			0	797,727
		Total after Work in Process	**79,073,754**	**6,235,010**	**(213,037)**	**85,095,727**	**(13,375,575)**	**(2,916,302)**	**1,084**	**(16,290,793)**	**68,804,933**

Less: Fully Allocated Depreciation	
Transportation	(458,038)
Contributions & Gran	1,615,092
PP&E Amortization	
Net Depreciation	(4,073,356)

Table 2.15 Appendix 2-BA 2021 Fixed Asset Continuity Schedule

Fixed Asset Continuity Schedule (Distribution & Operations)
As at December 31, 2021

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
	1612	Land Rights	394,446			394,446	(103,353)	(15,109)		(118,462)	275,984
	1805	Land - Substations	1,049,593			1,049,593	0			0	1,049,593
47	1808	Buildings - Substations	0			0	0			0	0
13	1810	Leasehold Improvements	0			0	0			0	0
47	1820	Substation equipment	11,288,805	170,378	0	11,459,183	(1,521,385)	(297,193)	0	(1,818,578)	9,640,605
47	1821	Substation transformers	0			0	0			0	0
47	1822	Substation switchgear and other elements	0			0	0			0	0
47	1823	Substation breakers and reclosures	0			0	0			0	0
47	1830	Poles, Towers & Fixtures	20,517,064	3,120,631	(16,045)	23,621,650	(2,252,460)	(545,936)	134	(2,798,262)	20,823,388
47	1831	Poles, towers and fixtures - concrete	0			0	0			0	0
47	1832	Poles, towers and fixtures - wood	0			0	0			0	0
47	1835	OH Conductors & Devices	18,658,698	2,278,768	(8,022)	20,929,444	(1,944,111)	(404,515)	67	(2,348,559)	18,580,885
47	1836	Overhead conductors and devices - secondary service	0			0	0			0	0
47	1837	Overhead conductors and devices - switches	0			0	0			0	0
47	1838	Overhead conductors and devices - capacitor banks	0			0	0			0	0
47	1839	Overhead conductors and devices - primary	0			0	0			0	0
47	1840	UG Conduit	14,370,418	3,050,940	0	17,421,358	(1,267,766)	(426,769)	0	(1,694,535)	15,726,823
47	1843	Underground conduit chambers and other elements	0			0	0			0	0
47	1844	Underground conductors and devises primary PILC	0			0	0			0	0
47	1845	UG Conductors & Devices	13,450,862	1,564,610	(3,744)	15,011,728	(2,101,841)	(421,578)	34	(2,523,385)	12,488,343
47	1846	Underground conductors and devices primary XLPE	0			0	0			0	0
47	1847	Underground conductors and devices secondary and service in duct	0			0	0			0	0
47	1848	Underground conductors and devices secondary and service direct buried	0			0	0			0	0
47	1849	Underground conductors and devices secondary and service in duct	0			0	0			0	0
47	1850	Line Transformers	18,357,378	3,629,826	(184,514)	21,802,690	(1,994,218)	(579,927)	802	(2,573,343)	19,229,347
47	1851	Padmount transformers	0			0	0			0	0
47	1852	Line transformers - Underground	0			0	0			0	0
47	1855	Services (OH & UG)	11,781,748	2,125,682	0	13,907,430	(1,115,841)	(325,284)	0	(1,441,125)	12,466,305
47	1856	Services	0			0	0			0	0
47	1860	Meters	3,145,558	250,000	(11,365)	3,384,193	(1,446,086)	(269,114)	101	(1,715,099)	1,669,093
47	1861	Smart Meters	0			0	0			0	0
47	1862	Smart Meters - Residential	0			0	0			0	0
47	1863	Smart Meters - Commercial	0			0	0			0	0
N/A	1905	Land	1,015,496			1,015,496	0			0	1,015,496
	1906	Land Rights	0			0	0			0	0
47	1908	Buildings & Fixtures	12,505,510	15,000	0	12,520,510	(1,370,898)	(247,250)	0	(1,618,148)	10,902,361
13	1910	Leasehold Improvements	0			0	0			0	0
8	1915	Office Furniture & Equipment	298,502	15,000	0	313,502	(197,291)	(37,531)	0	(234,822)	78,680
10	1920	Computer - Hardware	1,146,534	150,000	0	1,296,534	(1,048,193)	(270,439)	0	(1,318,632)	(22,098)
45	1921	Computer - Hardware post Mar 22/04	0			0	0			0	0
12	1611	Computer - Software	2,077,877	250,000	0	2,327,877	(1,738,382)	(258,490)	0	(1,996,872)	331,005
10	1930	Transportation Equipment	2,159,797	114,337	0	2,274,134	(1,874,949)	(479,580)	0	(2,354,529)	(80,396)
8	1935	Stores Equipment	162,963	6,381	0	169,344	(123,318)	(24,191)	0	(147,509)	21,835
8	1940	Tools, Shop & Garage Equipment	715,541	48,498	0	764,039	(397,356)	(86,872)	0	(484,228)	279,811
8	1945	Measurement & Testing Equipment	442,274	52,191	0	494,465	(106,489)	(47,850)	0	(154,339)	340,126
8	1950	Power operated Equipment	0			0	0			0	0
8	1955	Communications Equipment	0			0	0			0	0
47	1970	Load Management controls	0			0	0			0	0
47	1980	System Supervisory Equipment	1,983,451	54,880	0	2,038,331	(1,257,309)	(218,502)	0	(1,475,811)	562,520
47	1981	System Supervisory Protection and Control	0			0	0			0	0
47	1982	System Supervisory Protection and Control	0			0	0			0	0
47	1975	Solar PV - panels and racking	0			0	0			0	0
47	1976	Solar PV - invertors	0			0	0			0	0
47	1995	Contributions & Grants	(51,224,515)	(10,666,010)	0	(61,890,525)	5,570,455	1,971,565	0	7,542,020	(54,348,505)
	2005	Property under Capital Lease	0			0	0			0	0
		Total before Work in Process	**84,298,000**	**6,231,112**	**(223,690)**	**90,305,422**	**(16,290,793)**	**(2,984,565)**	**1,138**	**(19,274,220)**	**71,031,201**
PIA		Provision for impairment of assets	0			0	0			0	0
WIP		Work in Process	797,727			797,727	0			0	797,727
		Total after Work in Process	**85,095,727**	**6,231,112**	**(223,690)**	**91,103,149**	**(16,290,793)**	**(2,984,565)**	**1,138**	**(19,274,220)**	**71,828,928**
				16,897,122							
							Less: Fully Allocated Depreciation				
							Transportation	(479,580)			
							Contributions & Gran	1,971,565			
							PP&E Amortization				
							Net Depreciation	(4,476,550)			

Historical Capital Projects/Expenditures

Ex.2/Tab 2/Sch.1 – Summary of Historical Capital Projects

For the historical timeframe of 2013-2016 InnPower Corporation was not monitoring a Distribution System Plan ("DSP"). InnPower Corporation is submitting its first DSP plan with this application. Although InnPower Corporation was not monitoring a DSP for the historical years, InnPower Corporation elected to provide a cross reference of capital expenditures under the RRFE functions: System Access, System Renewal, System Services and General Plant for the timeframe of 2013, 2014 and 2015.

Future capital projects 2016-2021 have also been provided by means of presenting Appendix 2-AA following the historical analysis.

Table 2.16 2013 Capital Projects/Expenditures

Projects	Category	Investment Category	Actual Cost	Actual Contributions	Net Actual Cost
Distribution Plant					
DO-001 Station Reclosurer	Reliability	System Service	169,828		169,828
DO-002 44 kV Alduti Ruptor	Reliability	System Service	185,785		185,785
DO-003 27.6 kV Mechanized SCADA controlled load interpt	Reliability	System Service	13,384		13,384
DO-004 System Renewal & Betterments	Infrastructure Replacement	System Renewal	181,259		181,259
DO-005 U/G Padmounted TX Replacements & painting	Infrastructure Replacement	System Renewal	81,562		81,562
DO-006 Substandard Transformer Rehabs	Infrastructure Replacement	System Renewal	179,665		179,665
DO-007 Pole Replacements	Infrastructure Replacement	System Renewal	395,175		395,175
DO-008 27 kV Extension 20th SR, BBPT to 13th Line	Reliability	System Service	687,654		687,654
DO-009 Big Bay Point F3 for BBPT development	Customer Demand	System Access	2,979		2,979
DO-010 Utility relocates	Customer Demand	System Access	1,766		1,766
DO-012 BBPT line ext for BBPT dev & new 27.6 kV sub stn	Customer Demand	System Access	397,894		397,894
DO-014 3 ph 27.6kV conductoring 20th btwn 5th & 7th	Customer Demand	System Service	123,174		123,174
DO-015 3 ph 44kV Repoling/Reconductoring 20th btwn 6th & 7th	Infrastructure Replacement	System Renewal	149,284		149,284
DB-001- Retail meters	Meters	System Access	96,757		96,757
Base	Customer Demand	System Access	968,603	428,863	539,740
Sub-Total Distribution Plant			**3,634,769**	**428,863**	**3,205,906**
2013 General Plant	**Category**	**Investment Category**			
GO-001 New Building & Land	Facility	General Plant	1,015,496		1,015,496
GB-001,2&5 Building security & network	Facility	General Plant	4,304		4,304
GB-003 Furniture & Equipment	Furniture	General Plant	12,060		12,060
GB-001 Hardware General	Hardware & Software	General Plant	53,604		53,604
GB-001 Software General	Hardware & Software	General Plant	124,394		124,394
GF-001 GP Upgrade	Hardware & Software	General Plant	31,588		31,588
GO-010 Eng topobase & IFRS enhancement	Hardware & Software	General Plant	28,828		28,828
GO-003 Transport Equipment	Transport	General Plant	64,048		64,048
GO-005 Fleet tools	Tools	General Plant	8,337		8,337
GO-006 Measurement & Testing tools	Tools	General Plant	5,794		5,794
GO-007 System Supervisory	Reliability	System Service	45,457		45,457
GO-012 Scada program conversion	Reliability	System Service	151,319		151,319
Sub-Total General Plant			1,545,229	0	1,545,229
2013 Grand Total			**5,179,998**	**428,863**	**4,751,135**

Table 2.17 2014 Capital Projects/Expenditures

Projects	Category	Investment Category	Actual Cost	Actual Contributions	Net Actual Cost
Distribution Plant					
DO-001 Pole replacement	Infrastructure Replacement	System Renewal	401,651		401,651
DO-002 Substandard Transformer Rehabs	Infrastructure Replacement	System Renewal	131,794		131,794
DO-003 Transformer/Switchgear replacements & painting	Infrastructure Replacement	System Renewal	7,574		7,574
DO-004 System Renewal & betterments	Infrastructure Replacement	System Renewal	156,029		156,029
DO-005 Reclosurere automation & replacement 4 yr cycle	Reliability	System Service	214,679		214,679
DO-009 County relocates IBR & 20th SD	Customer Demand	System Access			-
DO-010 Lefroy Distribution Station	Substations	System Service	2,336,737		2,336,737
DB-001 Retail meters	Meters	System Access	120,569		120,569
GO-012 Scada program conversion	Reliability	System Service	-		-
Economic Evaluation	Customer Demand	System Access	893,568	764,009	129,559
Base	Customer Demand	System Access	1,665,195	652,462	1,012,733
Sub-Total Distribution Plant			**5,927,796**	**1,416,471**	**4,511,325**
2014 General Plant					
GO-001 New Building	Facility	General Plant			-
GB-003 Furniture & Equipment	Furniture	General Plant	9,292		9,292
GB-002A Hardware General	Hardware & Software	General Plant	80,063		80,063
GB-002B Software General	Hardware & Software	General Plant	88,347		88,347
GF-001 Budget Software	Hardware & Software	General Plant	48,849		48,849
GO-003 Transport Equipment	Transport	General Plant	-		-
GO-004 Stores Equipment	Tools	General Plant	4,788		4,788
GO-005 Fleet tools	Tools	General Plant	20,820		20,820
GO-006 Measurement & Testing tools	Tools	General Plant	539		539
GO-007 System Supervisory	Reliability	System Service	54,572		54,572
GO-012 Scada program conversion	Reliability	System Service	212,788		212,788
Sub-Total General Plant			520,058	0	520,058
2014 Grand Total			**6,447,854**	**1,416,471**	**5,031,383**

Table 2.18 2015 Capital Projects/Expenditures

2015 Capital Projects					
Projects	**Category**	**Investment Category**	**Actual Cost**	**Actual Contributions**	**Net Actual Cost**
Distribution Plant					
IPC2015BASE1 - C & CTC WORK ORDERS		System Access	$ 282,319	-$ 8,248	$ 274,071
IPC2015BASE2 - PO WORK ORDERS		System Access	$ 30,806	$ -	$ 30,806
IPC2015BASE3 - L, DG, RPO, RCTC WORK ORDERS		System Access	$ 901,869	-$ 949,337	-$ 47,469
IPC2015BASE4 - SD WORK ORDERS		System Access	$ 1,557,550	-$ 1,267,955	$ 289,595
IPC2015DB001 - RETAIL/WHOLESALE METERS		System Access	$ 95,343		$ 95,343
IPC2015DO013 - COUNTY RELOCATES IBR & 20TH SR		System Access	$ 253,796		$ 253,796
IPC2015DO008 - POLE REPLACEMENT 2015		System Renewal	$ 114,433		$ 114,433
IPC2015DO009 - INFRASTRUCTURE REPLACEMENTS & BETTERMENTS		System Renewal	$ 185,862		$ 185,862
IPC2015DO010 - TRANSFORMER/SWITCHGEAR REPLACEMENTS & PAINTING		System Renewal	$ 30,455		$ 30,455
IPC2015DO017 - DS TRANSFORMER OIL RE-INHIBIT PROGRAM		System Renewal	$ 18,591		$ 18,591
IPC2015GB003 - INFRASTRUCTURE REPLACEMENT		System Renewal	$ 16,883		$ 16,883
IPC2015DO005 - LINE RECLOSER REFURBISHMENT		System Renewal	$ 17,459		$ 17,459
IPC2015DO006 - SUBSTANDARD TRANSFORMER REHAB		System Renewal	$ 103,800		$ 103,800
IPC2015DO002 - LINE EXT MAPLEVIEW RD 20TH SR TO PR WILLIAM WAY		System Service	$ 325,911		$ 325,911
IPC2015DO003 - LINE EXT MAPLEVIEW DR YONGE ST TO MADELAINE		System Service	$ -		$ -
IPC2015DO004 - LINE REBUILD YONGE ST FROM LOCKHART TO MAPLEVIW		System Service	$ 433,436		$ 433,436
IPC2015DO007 - LINE EXT BBP RD & 25TH SR TO FRIDAY HARBOUR S ENTR		System Service	$ 599,917		$ 599,917
IPC2015DO020 - LOCKHART ROAD REBUILD PHASE 1		System Service	$ 260,002		$ 260,002
IPC2015DO011 - 27.6KV MECHANIZED SCADA CONTR LOAD INTERRUPT		System Service	$ 132		$ 132
IPC2015DO012 - 44KV ALDUTIRUPTOR SCADA CONTROLLED SWITCHES		System Service	$ 175,151		$ 175,151
IPC2015DO014 - DS ELECTRICAL CODE COMPLIANCE UPGRADE		System Service	$ 129,692		$ 129,692
IPC2015DO015 - DS BATTERY BACKUP SYSTEM		System Service	$ 545,994		$ 545,994
IPC2015DO018 - RADIO COMMUNICATION 2014 CARRYFORWARD		System Service	$ 136,938		$ 136,938
IPC2015DO019 - LEFROY DS UPGRADE		System Service	$ 152,900		$ 152,900
IPC2015GO011 - CAPACITOR INTERLINK TO SCADA		System Service	$ 141		$ 141
IPC2015GO014 - SCADA BATTERIES & CHARGERS & CABINET REPLCMNT		System Service	$ 183,883		$ 183,883
Sub-Total Distribution Plant			**$ 6,553,260**	**-$ 2,225,541**	**$ 4,327,719**
2015 General Plant					
IPC2015GB001A - HARDWARE GENERAL		General Plant	148,675		148,675
IPC2015GB001B - SOFTWARE GENERAL		General Plant	61,990		61,990
IPC2015GB002 - FURNITURE & EQUIPMENT		General Plant	29,067		29,067
IPC2015GF001 - FINANCE & REG IT HW & SW		General Plant	94,356		94,356
IPC2015GO001 - ENGINEERING IT PROJECT		General Plant	82,472		82,472
IPC2015GO004 - FLEET TOOLS		General Plant	12,630		12,630
IPC2015GO005 - STORES EQUIPMENT		General Plant	117,204		117,204
IPC2015GO006 - TOOLS, SHOP & GARAGE EQUIP		General Plant	17,865		17,865
IPC2015GO007 - MEASUREMENT & TESTING EQUIP		General Plant	11,086		11,086
IPC2015GO008 - RADIO REPEATED FAULT IND		General Plant	28,857		28,857
IPC2015GO009 - SYSTEM SUPERVISORY & CONTR RM		General Plant	67,317		67,317
IPC2015GO010 - RADIO COMMUNICATION IT INFRASTR		General Plant	822		822
IPC2015GO012 - FLEET VEHICLE REPLACEMENT		General Plant	33,347		33,347
IPC2015GO013 - NEW BUILDING		General Plant	12,475,713	- 40,537	12,435,176
IPC2015GO015 - POLE BUNK		General Plant	68,583		68,583
Sub-Total General Plant			13,249,984	-40,537	13,209,448
2014 Grand Total			19,803,244	- 2,266,077	17,537,166

Table 2.19 Summary of Historical Capital Projects

	2013 Board Approved	2013 Actual	2014	2015	2016
Actual Cost		$ 5,179,998	$ 6,447,854	$ 19,803,244	$ 25,016,571
Contributions		$ 428,863	$ 1,416,471	$ 2,266,077	$ 19,351,810
Net Actual Capital Spend	$ 5,400,000	$ 4,751,135	$ 5,031,383	$ 17,537,167	$ 5,664,761
Variance		-12.0%	-6.8%	224.8%	4.9%

2013 Actual to Board Approved

In 2013 InnPower Corporation did not achieve a capital spend of $5,400,000. The under-spending amounts to $648,865, or 12%.

2014 Actual to Board Approved

In 2014 InnPower Corporation did not achieve a capital spend of $5,400,000. The under-spending amounts to $368,617, or 6.8%.

2015 Actual to Board Approved

In 2015 the addition of InnPower Corporation's new Administration and Headquarters exceeded the approved spend by $12,435,176. If the Headquarters were removed, the actual capital spend would be $5,101,990, which is underspend $298,010 by or a variance of 5.5%.

2016 Actual to Board Approved

In 2016 InnPower Corporation's forecasted spend is $5,684,761, exceeding the Board Approved amount by 5%.

From 2013 – 2015 InnPower Corporation reduced the gap in achieving the total capital forecast spend from 12% in 2013 to 5.5% in 2015. 2016 is trending to come in at $5,664,761 which will be 4.9% over the forecast.

Throughout the historical timeframe for capital projects and expenditures, InnPower Corporation has focused on three key areas to improve our capital output to achieve the forecastt:

- Resources (internal and external);
- Tools and training, and
- Processes.

Resources:

Internal

- The Engineering Department has expanded its resource pool in the past few years. The Engineering Department now has three engineers with P.Eng. designations who are able to design and approve engineering drawings for sub-transmission, stations, distribution, SCADA, Engineering IT, and other related works.
- Internal engineering resource capability has been increased as a result of contracting out a non-engineering function (locating) that took up 20-40% of Eng-Tech time.

External

- In the past few years InnPower has worked towards developing external resource pools of engineers, designers, CAD operators, and field surveyors to support the higher workloads related to grid expansion and modernization.
- As a result it is far more capable today to process large amounts of work within a short time frame.
- External contractors have been hired, as noted above, to free up internal engineering resources.

Tools & Training:

Engineering Software

- In the past few years InnPower had invested in advanced Engineering software to improve its design capability.
  Tthis has also helped reduce the duration of the design of jobs.

Work Order Processing Application

- In the past few years InnPower introduced an Excel based work processing application for layouts and capital jobs to help reduce job order processing time and increase quality of work.

Personnel Training:

- Staff have been trained on a routine basis on newly introduced software and design standards (use of USF Standards) to ensure high level of competence, high throughput, and improved quality of workmanship.

Processes:

- InnPower has put more emphasis on collaboration, job planning, and overall information flow between stakeholders to improve job efficiency.
- InnPower has invested in process automation in the past few years to reduce job processing time.
- InnPower introduced an Excel based work processing application for layouts as noted above to help reduce job order processing time and increase quality of work.

Table 2.20 Appendix 2-AA 2016 – 2021 Capital Projects

Appendix 2-AA
Capital Projects Table

Totals are Net of Contibutions

Projects	2016 Bridge	2017 Test Year	2018	2019	2020	2021
Reporting Basis						
SYSTEM ACCESS						
BASE	$ 799,431	$ 1,251,376	$ 1,242,920	$ 1,257,772	$ 1,274,109	$ 1,292,080
DB001 Meters	$ 147,500					
IBR & 5 SR	$ 415,364					
Metering		$ 230,000	$ 270,000	$ 250,000	$ 250,000	$ 250,000
Intersection Widening IBR & Yonge St.		$ 272,430				
Road Widening IBR between Yonge St & 20 SR			$ 471,300			
Road Widening IBR between Yonge St & 10 SR				$ 86,985		
Road Widening IBR between Hwy 400 & 10 SR					$ 74,333	
Road Widening IBR between Hwy 27 & 5 SR						$ 471,300
Contributions System Access	$ 3,790,270	$ 5,561,525	$ 9,626,225	$ 9,675,905	$ 10,009,484	$ 10,666,010
Sub-Total System Access	**$ 1,362,295**	**$ 1,753,806**	**$ 1,984,220**	**$ 1,594,757**	**$ 1,598,442**	**$ 2,013,380**
SYSTEM RENEWAL						
BASE	$ 137,500	$ 116,885	$ 122,725	$ 128,861	$ 135,304	$ 148,834
Substandard Transformer Rehab	$ 109,505	$ 85,000	$ 30,000	$ 31,500	$ 33,075	
Pole Replacement Program	$ 200,914	$ 126,470	$ 148,500	$ 155,925	$ 163,721	$ 171,907
Infrastructure Replacements and Betterments	$ 143,098	$ 150,253	$ 157,766	$ 165,654	$ 173,936	$ 182,633
Line Reclosure Refurbishments - 4 Year Cycle	$ 15,186	$ 15,945	$ 16,742	$ 17,579	$ 18,458	$ 19,381
DS Oil Re-inhibit Treatment	$ 26,216	$ 27,527	$ 57,806	$ 60,696	$ 30,000	
Padmounted Transformer and Switchgear	$ 83,256	$ 43,710	$ 45,895	$ 48,190	$ 50,599	$ 53,129
Station rehab	$ 199,280	$ 104,300	$ 109,853	$ 115,346	$ 242,226	$ 115,680
Ewart Street Rebuild - Phased Approach	$ 101,790	$ 105,000	$ 50,000	$ 52,500	$ 56,700	$ 131,274
Transformers	$ 120,000	$ 100,000	$ 110,000	$ 121,000	$ 133,100	$ 146,410
Reliability Rebuild: Subtransmission - Lockhart		$ 170,650	$ 89,933	$ 294,429	$ 203,060	$ 213,214
Reliability Rebuild: Subtransmission - 5 SideRoad		$ 75,000		$ 550,000	$ 225,000	$ 225,000
Reliability Rebuild: Distribution - Cookstown		$ 50,000	$ 52,500	$ 55,125	$ 200,880	$ 156,000
Reliability Rebuild: Distribution - Lefroy		$ 22,500	$ 47,250	$ 49,613	$ 52,093	$ 54,697
Reliability Rebuild: Distribution - Alcona		$ 22,500	$ 47,250	$ 49,613	$ 52,093	$ 54,697
Everton Back Lot Conversion - Phased Approach				$ 155,000	$ 135,000	
Reliability Rebuild: Distribution - Phased			$ 22,500		$ 75,000	
Reliability Rebuild: Distribution - Strathallan			$ 31,500	$ 33,075	$ 34,728	$ 36,465
Sandy Cove: U/G Cable Replacement Phased				$ 700,000	$ 250,000	$ 250,000
Parkview Rear Lot: 1 Phase Relocate to Street				$ 135,000	$ 135,000	
Degrassi Cove: U/G Converstion						$ 150,000
Contributions System Renewal						
Sub-Total System Renewal	**$ 1,136,744**	**$ 1,215,740**	**$ 1,140,220**	**$ 2,919,106**	**$ 2,399,973**	**$ 2,109,321**
SYSTEM SERVICE						
Stroud DS Automation	$ 164,590					
Repoling: McKay Rd - 5 SR to 10 SR	$ 400,041	$ 273,427				
Cedar Point DS Transformer Upgrade	$ 1,578,016					
Repoling: 5 SR - McKay Road to Salem Rd	$ 362,573					
Distribution SCADA controlled load interrupting		$ 75,000	$ 78,750	$ 82,688	$ 86,821	$ 91,162
Repoling: BBP - Friday Harbour DS to FH		$ 362,570				
Repoling: Lockhart Road - Huronia to Stroud DS		$ 618,932				
Sandy Cove DS		$ 125,000				
Repoling: Mapleview Dr - Prince William Way to		$ 837,831				
DS Transformer Oil Containment		$ 45,000		$ 49,613	$ 52,093	$ 54,698
Subtransmission SCADA Controlled Switches				$ 148,500	$ 155,925	
SCADA PME Morotized Switch Gear				$ 165,000	$ 173,250	$ 181,913
Capacitor Intelilink to SCADA				$ 65,000	$ 65,000	
Friday Harbour DS			$ 2,750,000			
Repoling: 5 SR - 5th Line to IBR				$ 315,000	$ 330,750	$ 347,288
Repoling: 20 SR - 5th Line to 4th Line					$ 219,940	$ 230,937
400 Corridor Voltage Conversion & Servicing				$ 250,000	$ 262,500	$ 275,625
Alcona South Voltage Conversion				$ 200,000	$ 210,000	$ 220,500
Contributions System Service						
Sub-Total System Service	**$ 2,505,220**	**$ 2,337,760**	**$ 2,828,750**	**$ 1,275,801**	**$ 1,556,279**	**$ 1,402,123**

GENERAL PLANT						
IT Hardware	$ 130,000					
IT Software	$ 115,000					
Furniture and Equipment	$ 15,000					
Buildings and Fixtures	$ 15,000					
Finance IT	$ 122,000					
Engineering IT	$ 121,500					
Fleet Tools	$ 15,000					
Stores Equipment	$ 5,000					
Tools, Shop and Garage Equipment	$ 23,000					
Measurement and Testing Equipment	$ 15,000					
Distribution Fault Current Indicators	$ 41,002					
System Supervisory	$ 43,000					
IT Hardware		$ 165,000	$ 150,000	$ 150,000	$ 150,000	$ 150,000
IT Software		$ 95,000	$ 95,000	$ 95,000	$ 95,000	$ 95,000
Furniture and Equipment		$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000
Buildings and Fixtures		$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000
Finance IT		$ 77,000	$ 50,000	$ 60,000	$ 50,000	$ 50,000
Engineering IT		$ 167,325	$ 145,516	$ 119,000	$ 100,000	$ 105,000
Fleet Tools		$ 15,750	$ 16,538	$ 17,364	$ 18,232	$ 19,144
Stores Equipment		$ 5,250	$ 5,513	$ 5,788	$ 6,077	$ 6,381
Tools, Shop and Garage Equipment		$ 24,150	$ 25,358	$ 26,625	$ 27,956	$ 29,354
Measurement and Testing Equipment		$ 28,000	$ 30,800	$ 32,340	$ 33,957	$ 35,654
Distribution Fault Current Indicators		$ 18,760		$ 15,000	$ 15,750	$ 16,537
System Supervisory		$ 32,400	$ 47,408	$ 49,778	$ 52,266	$ 54,880
Measuring Tools & Equipment IT & Meter		$ 23,000				
Replacement Double Bucket Truck - 1993 Altec		$ 373,500				
Fleet Vehicle Replacement: 1-2006 Ford 1/2 Ton		$ 45,000				
Tech Vehicle - Ford Escape 2009 (#89)			$ 45,000			
Locator Vehicle Mini-Van (x2)		$ 63,000				
Tehnologist Vehicle - NEW		$ 43,500				
Inspector Vehicle - NEW		$ 43,500				
RBD - New Crew		$ 250,000				
Tech Vehicle - Ford Escape 2008 Replacement			$ 45,675			
Meter Tech Vehicle - NEW			$ 45,675			
Inspector Vehicle - NEW			$ 45,675			
Tech Vehicle - Ford Escape 2009 & 2010				$ 95,918		
Fleet Vehicle Replacement: 2005 1/2 Ton (#87)					$ 51,750	
Tech Vehicle - Ford Escape 2008 Replacement					$ 49,329	
Fleet Vehicle Replacement: 2011 -1/2 To (#96)						$ 54,337
Fleet Vehicle Replacement: 2011 - 1 Ton (#101)						$ 60,000
65' Double Bucket - New Crew			$ 400,000			
1 Ton Pickup Truck - New Crew			$ 45,000			
Clothing for 3 Men			$ 10,000			
Tools for 3 Men			$ 15,000			
Tooling for Bucket & RBD			$ 150,000			
100 Travellers			$ 5,000			
Additional Spider System			$ 20,000			
Tension Machines				$ 200,000		
Sub Total Contributions	$ 19,351,810	$ 20,018,968	$ 21,332,020	$ 9,675,905	$ 10,009,484	$ 10,666,010
Sub-Total General Plant	**$ 20,012,312**	**$ 21,519,103**	**$ 22,755,178**	**$ 10,572,718**	**$ 10,689,801**	**$ 11,372,297**
Sub-Total System Service	**$ 2,505,220**	**$ 2,337,760**	**$ 2,828,750**	**$ 1,275,801**	**$ 1,556,279**	**$ 1,402,123**
Sub-Total System Renewal	**$ 1,136,744**	**$ 1,215,740**	**$ 1,140,220**	**$ 2,919,106**	**$ 2,399,973**	**$ 2,109,321**
Sub-Total System Access	**$ 1,362,295**	**$ 1,753,806**	**$ 1,984,220**	**$ 1,594,757**	**$ 1,598,442**	**$ 2,013,380**
Miscellaneous						
Total	**$ 5,664,761**	**$ 6,807,441**	**$ 7,376,348**	**$ 6,686,477**	**$ 6,235,011**	**$ 6,231,111**
Less Renewable Generation Facility Assets						
Total	**$ 5,664,761**	**$ 6,807,441**	**$ 7,376,348**	**$ 6,686,477**	**$ 6,235,011**	**$ 6,231,111**

Notes:

1 Please provide a breakdown of the major components of each capital project undertaken in each year. Please
2 The applicant should group projects appropriately and avoid presentations that result in classification of significant

InnPower Corporation's Full details of the Distribution Plan is contained in Tab 5/SCH 2 of this Exhibit.

Ex.2/Tab 2/Sch.2 - Accumulated Depreciation

InnPower Corporation has adopted depreciation rates based on the Kinectrics Asset Depreciation Study in its previous Cost of Service Application (EB-2012-0139). The rates used are presented in Appendix 2 –BB of the Chapter 2 Appendices which is enclosed below:

Appendix 2BB – Service Life Comparison

Appendix 2-BB
Service Life Comparison
Table F-1 from Kinetrics Report[1]

Parent*	#	Asset Details: Category| Component | Type			Useful Life: MIN UL	TUL	MAX UL	USoA Account Number	USoA Account Description	Current: Years	Current: Rate	Proposed: Years	Proposed: Rate	Outside Range of Min, Max TUL?: Below Min TUL	Above Max TUL
OH	1	Fully Dressed Wood Poles	Overall		35	45	75	1830	Poles,Towers and Fixtures	25	4%	40	2.5%	No	No
			Cross Arm	Wood	20	40	55	1830	Poles,Towers and Fixtures	25	4%	40	2.5%	No	No
				Steel	30	70	95	1830	Poles,Towers and Fixtures	25	4%	40	2.5%	No	No
	2	Fully Dressed Concrete Poles	Overall		50	60	80	1830	Poles,Towers and Fixtures	25	4%	40	2.5%	Yes	No
			Cross Arm	Wood	20	40	55	1830	Poles,Towers and Fixtures	25	4%	40	2.5%	No	No
				Steel	30	70	95	1830	Poles,Towers and Fixtures	25	4%	40	2.5%	No	No
	3	Fully Dressed Steel Poles	Overall		60	60	80	N/A							
			Cross Arm	Wood	20	40	55	N/A							
				Steel	30	70	95	N/A							
	4	OH Line Switch			30	45	55	1835	Overhead Conductors & Devices	25	4%	40	3%	No	No
	5	OH Line Switch Motor			15	25	25	1835	Overhead Conductors & Devices	25	4%	20	5%	No	No
	6	OH Line Switch RTU			15	20	20	1835	Overhead Conductors & Devices	25	4%	20	5%	No	No
	7	OH Integral Switches			35	45	60	1835	Overhead Conductors & Devices	25	4%	40	3%	No	No
	8	OH Conductors			50	60	75	1835	Overhead Conductors & Devices	25	4%	60	2%	No	No
	9	OH Transformers & Voltage Regulators			30	40	60	1850	Line Transformers	25	4%	40	3%	No	No
	10	OH Shunt Capacitor Banks			25	30	40	N/A							
	11	Reclosers			25	40	55	N/A							
TS & MS	12	Power Transformers	Overall		30	45	60	1850	Line Transformers	25	4%	40	3%	No	No
			Bushing		10	20	30								
			Tap Changer		20	30	60								
	13	Station Service Transformer			30	45	55								
	14	Station Grounding Transformer			30	40	40								
	15	Station DC System	Overall		10	20	30								
			Battery Bank		10	15	15	1820	Distribution Station Equipment	30	3%	20	5%	No	Yes
			Charger		20	20	30	1820	Distribution Station Equipment	30	3%	20	5%	No	No
	16	Station Metal Clad Switchgear	Overall		30	40	60	1820	Distribution Station Equipment	25	4%	40	3%	No	No
			Removable Breaker		25	40	60								
	17	Station Independent Breakers			35	45	65								
	18	Station Switch			30	50	60								
	19	Electromechanical Relays			25	35	50								
	20	Solid State Relays			10	30	45	1820	Distribtion Station Equipment	25	4%	30	3%	No	No
	21	Digital & Numeric Relays			15	20	20								
	22	Rigid Busbars			30	55	60								
	23	Steel Structure			35	50	90								
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables			60	65	75	N/A							
	25	Primary Ethylene-Propylene Rubber (EPR) Cables			20	25	25	1845	Underground Conductors & Devices	25	4%	40	3%	No	Yes
	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried			20	25	30	1845	Underground Conductors & Devices	25	4%	40	3%	No	Yes
	27	Primary Non-TR XLPE Cables in Duct			20	25	30	1845	Underground Conductors & Devices	25	4%	40	3%	No	Yes
	30	Secondary PILC Cables			70	75	80	N/A							
	31	Secondary Cables Direct Buried			25	35	40	1855	Service	25	4%	40	3%	No	No
	32	Secondary Cables in Duct			35	40	60	1855	Service	25	4%				
	33	Network Tranformers	Overall		20	35	50	N/A							
			Protector		20	35	40	N/A							
	34	Pad-Mounted Transformers			25	40	45	1850	Line Transformers	25	4%	40	3%	No	No
	35	Submersible/Vault Transformers			25	35	45	1850	Line Transformers	25	4%	40	3%	No	No
	36	UG Foundation			35	55	70	1840	Underground Conduit	25	4%	60	2%	No	No
	37	UG Vaults	Overall		40	60	80	N/A							
			Roof		20	30	45	N/A							
	38	UG Vault Switches			20	35	50	1845	Underground Conductors & Devices	25	4%	30	3%	No	No
	39	Pad-Mounted Switchgear			20	30	45	1845	Underground Conductors & Devices	25	4%	30	3%	No	No
	40	Ducts			30	50	85	1840	Underground Conduit	25	4%	60	2%	No	No
	41	Concrete Encased Duct Banks			35	55	80	1840	Underground Conduit	25	4%	60	2%	No	No
	42	Cable Chambers			50	60	80	1840	Underground Conduit	25	4%	60	2%	No	No
S	43	Remote SCADA			15	20	30								

Table F-2 from Kinetrics Report[1]

#	Asset Details: Category| Component | Type		Useful Life Range		USoA Account Number	USoA Account Description	Current: Years	Current: Rate	Proposed: Years	Proposed: Rate	Outside Range of Min, Max TUL?: Below Min Range	Above Max Range
1	Office Equipment		5	15	1915	Office Furniture & Equipment	10	10%	10	10%	No	No
2	Vehicles	Trucks & Buckets	5	15	1930	Transportation Equipment	8	13%	15	7%	No	No
		Trailers	5	20	1930	Transportation Equipment	8	13%	20	5%	No	No
		Vans	5	10	1930	Transportation Equipment	5	20%	12	8%	No	Yes
3	Administrative Buildings		50	75	200/201	Building & Fixtures	May-50	0%	May-50	0%	No	Yes
4	Leasehold Improvements		Lease dependent		N/A		0		0			
5	Station Buildings	Station Buildings	50	75	1808	Building & Fixtures	50	2%	50	2%	No	No
		Parking	25	30	1808	Building & Fixtures	30	3%	30	3%	No	No
		Fence	25	60	1808	Building & Fixtures	25	4%	25	4%	No	No
		Roof	20	30	1808	Building & Fixtures	20	5%	20	5%	No	No
6	Computer Equipment	Hardware	3	5	1920	Computer Equipment - Hardware	5	20%	5	20%	No	No
		Software	2	5	1925	Computer Equipment - Software	5	20%	5	20%	No	No
7	Equipment	Power Operated	5	10	N/A							
		Stores	5	10	1935	Stores Equipment	10	10%	10	10%	No	No
		Tools, Shop, Garage Equipment	5	10	1940	Tools, Shops Garage Equipment	10	10%	10	10%	No	No
		Measurement & Testing Equipment	5	10	1945	Measurement and Testing Equipment	10	10%	10	10%	No	No
8	Communication	Towers	60	70	1955	Communication Equipment	10	10%	10	10%	Yes	No
		Wireless	2	10	1955	Communication Equipment	10	10%	10	10%	No	No
9	Residential Energy Meters		25	35	1860	Meters	25	4%	15	7%	Yes	No
10	Industrial/Commercial Energy Meters		25	35	1860	Meters			20	5%	Yes	No
11	Wholesale Energy Meters		15	30	N/A							
12	Current & Potential Transformer (CT & PT)		35	50	1860	Meters			45	2%	No	No
13	Smart Meters		5	15	1860	Meters	15	7%	15	7%	No	No
14	Repeaters - Smart Metering		10	15	1915	Office Furniture & Equipment	5	20%	5	20%	Yes	No
15	Data Collectors - Smart Metering		15	20	1915	Office Furniture & Equipment	5	20%	5	20%	Yes	No

*** TS & MS = Transformer and Municipal Stations UG = Underground Systems S = Monitoring and Control Systems**

Allowance for Working Capital

Ex.2/Tab 3/Sch.1 - Derivation of Working Capital

InnPower Corporation has used the 7.5% Allowance Approach for the purpose of calculating its Allowance for Working Capital. This was done in accordance with the letter issued by the Board on June 3, 2015. 7.5% of the sum of Cost of Power and controllable expenses (i.e., Operations, Maintenance, Billing and Collecting, Community Relations, Administration and General).

InnPower Corporation attests that the Cost of Power is determined by split between RPP and non-RPP customers based on actual data, use most current RPP price, use current UTR. The derivation of the Cost of Power can be found in the explanations below.

Expenses for Working Capital	Last Board Approved 2013	2014	2015	2016 Bridge	2017 Test	2018 Test	2019 Test	2020 Test	2021 Test
Eligible Distribution Expenses									
3500 Distribution - Operations	$ 1,323,999	$ 1,342,978	$ 1,377,569	$ 1,568,480	$ 1,843,870	$ 2,030,600	$ 2,083,700	$ 2,138,100	$ 2,194,100
3550 Distribution - Maintenance	$ 463,151	$ 471,477	$ 427,525	$ 530,250	$ 681,745	$ 699,600	$ 717,900	$ 736,700	$ 755,900
3650 Billing & Collecting	$ 1,054,939	$ 1,169,535	$ 1,096,116	$ 1,203,967	$ 1,184,825	$ 1,295,900	$ 1,329,700	$ 1,364,400	$ 1,400,100
3700 Community Relations	$ 5,419	$ 5,663	$ 8,066	$ 10,250	$ 12,000	$ 12,300	$ 12,600	$ 12,900	$ 13,300
3800 Admin & General	$ 2,147,739	$ 2,234,998	$ 2,648,314	$ 2,704,335	$ 3,142,082	$ 3,323,000	$ 3,490,000	$ 3,581,200	$ 3,674,800
6105 Taxes other than Income tax	$ 24,132	$ 13,463	$ 117,714	$ 88,900	$ 122,500	$ 125,700	$ 129,000	$ 132,400	$ 135,900
Total Eligible Distribution Expense	$ 5,019,379	$ 5,238,114	$ 5,675,305	$ 6,106,182	$ 6,987,022	$ 7,487,100	$ 7,762,900	$ 7,965,700	$ 8,174,100
3350 Power Supply Expenses	$ 25,531,064	$ 27,773,907	$ 29,656,547	$ 32,119,278	$ 32,227,960	$ 33,510,688	$ 35,517,366	$ 37,117,414	$ 39,395,629
Total Expenses for Working Capital	$ 30,550,443	$ 33,012,021	$ 35,331,852	$ 38,225,460	$ 39,214,982	$ 40,997,788	$ 43,280,266	$ 45,083,114	$ 47,569,729
Working Capital Factor	12%	12%	12%	12%	7.50%	7.50%	7.50%	7.50%	7.50%
Total Working Capital Allowance	$ 3,666,053	$ 3,961,443	$ 4,239,822	$ 4,587,055	$ 2,941,124	$ 3,074,834	$ 3,246,020	$ 3,381,234	$ 3,567,730

Cost of Power Calculations

Commodity Prices

In accordance with the Filing Requirements, the commodity price estimate used to calculate the COP was determined in a way that bases the split between RPP and Non-RPP customers based on 2015 actuals.

For 2017 the RPP and Non-RPP price was obtained from the RPP Report for the time period of November 1, 2015 through to October 31, 2016.

Table ES-1: Average RPP Supply Cost Summary (for the 12 months from November 1, 2015)

RPP Supply Cost Summary for the period from November 1, 2015 through October 31, 2016		Current
Forecast Wholesale Electricity Price		$18.82
Load-Weighted Price for RPP Consumers ($ / MWh)		$20.57
Impact of the Global Adjustment ($ / MWh)	+	$87.92
Adjustment to Address Bias Towards Unfavourable Variance ($ / MWh)	+	$1.00
Adjustment to Clear Existing Variance ($ / MWh)	+	($2.22)
Average Supply Cost for RPP Consumers ($ / MWh)	=	**$107.28**

Source: Navigant

For the Test Years 2018 – 2021, InnPower Corporation prepared trend analysis of actual RPP and Non-RPP costs. This analysis is presented in Appendix A of this Exhibit, RPP and Non-RPP forecast for 2017 – 2021 Test Years.

InnPower Corporation understands that the commodity charge will be updated to reflect any changes to commodity prices that may become available prior to the approval of this application.

Wholesale Market Service Charges

The Wholesale Market Service Charges, ("WMS, RRP and OESP"') for the 2017 Test Year were calculated based on the OEB Decision and Rate Order EB-2015-0294 issued November 19, 2015.

WMS – $/kWh 0.0036

RRP – $/kWh 0.0013

OESP -$/kWh 0.0011

With the exception of the OESP service charge, the Wholesale Market Service Costs have been very stable for a number of years. Thus InnPower Corporation has utilized the rates outlined in EB-2015-0294 without adjustment.

For the Test Years 2018 – 2021, InnPower has assumed the 2017 rates understanding that the rates will be updated on the annual update process.

Network and Connection Charges

InnPower Corporation pays Network and Connection charges from Hydro One Inc. as InnPower is a fully embedded utility.

InnPower Corporation has completed the RTSR Model with this application and has utilized the outcome in determination of the 2017 UTR rates.

InnPower understands that the transmission costs will be updated to reflect any new rates that may become available prior to the approval of the application.

For the Test Years 2018 – 2021, InnPower has assumed the 2017 rates understanding that the rates will be updated on the annual update process.

Low Voltage Charges

InnPower Corporation incurs low voltage charges from Hydro One Inc. due to being an embedded utility. In Exhibit 8 InnPower Corporation proposes Low Voltage Service Rates which have been utilized in this application for the Cost of Power calculation.

Smart Meter Entity Charges

The Smart Meter Entity costs are calculated based on the rate of $0.79 per month for each of the Residential and General Service < 50 kW customers. The forecasted 2017 number of customers was utilized to calculate the 2017 Test Year.

Table 2.16 Summary of Cost of Power Calculations

	2016 Bridge	2017 Test	2018 Test	2019 Test	2020 Test	2021 Test
Commodity RPP	$ 19,663,399	$ 19,545,437	$ 20,381,291	$ 21,655,576	$ 22,916,752	$ 24,024,014
Commodity Non-RPP	$ 7,781,186	$ 7,857,477	$ 8,232,308	$ 8,826,634	$ 9,484,942	$ 10,149,171
Transmission - Network	$ 1,430,161	$ 1,429,649	$ 1,449,342	$ 1,481,171	$ 1,087,153	$ 1,534,108
Transmission - Connection	$ 1,029,975	$ 1,029,363	$ 1,043,156	$ 1,065,600	$ 1,087,153	$ 1,102,773
Wholesale Market Service	$ 922,379	$ 920,994	$ 933,314	$ 953,107	$ 972,189	$ 986,095
Rural Rate Assitance	$ 333,081	$ 332,581	$ 337,030	$ 344,178	$ 351,068	$ 356,090
SME	$ 155,899	$ 160,989	$ 168,317	$ 179,466	$ 189,714	$ 199,241
OESP	$ 281,944	$ 281,528	$ 285,179	$ 291,227	$ 297,058	$ 301,307
LV	$ 521,254	$ 669,941	$ 680,751	$ 720,406	$ 731,385	$ 742,831
Total Cost of Power	**$ 32,119,278**	**$ 32,227,960**	**$ 33,510,688**	**$ 35,517,366**	**$ 37,117,414**	**$ 39,395,629**

Ex.2/Tab 3/Sch.2 - Lead Lag Study

InnPower Corporation is not proposing to use a lead lag study in order to determine its Working Capital Allowance and has chosen to follow the Board's June 3, 2015 letter providing two approaches for the calculation of the allowance for working capital:

(1) The 7.5% allowance approach; or
(2) The filing of a lead/lag study.

In addition, InnPower Corporation has not previously been directed by the Board to undertake a lead/lag study.

Smart Meter Deployment and Stranded Meters

Ex.2/Tab 4/Sch.1 - Disposition of Smart Meters and Treatment of Stranded Meters

Introduction:

In InnPower Corporation's last COS Application completed in 2013 InnPower Corporation received approval from the Board for the disposition and recovery of costs related to smart meters. No further dispositions or recoveries are requested in this Application.

Capital Expenditures

Ex.2/Tab 5/Sch.1 - Planning

Regional Planning

InnPower Corporation is a contributing member of the South Georgian Bay/Muskoka Region Regional Planning team. As an outcome of the Scoping Assessment, an Integrated Regional Resource Planning is currently underway and is expected to be completed in Q4 2016.

A copy of the Regional Planning Status letter is provided in Appendix B of this Exhibit.

Ex.2/Tab 5/Sch.2 – Distribution System Plan

The Distribution System Plan is located in Appendix C of this Exhibit.

Ex.2/Tab 5/Sch.3 - Capitalization Policy

Capitalization Policy under CGAAP:

InnPower Corporation applies direct attributable costs only to capital. These direct costs are described further below. The minimum threshold for capitalizing expenditures is $1000 for a capital project or expense.

Material Direct Cost:

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

Labour Direct Cost:

The labour direct cost is comprised of all the eligible salaries for staff as well of their supervisors that directly work on a capital project.

Capitalization Policy under IFRS:

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

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

The cost of an item of PP&E includes any costs that are directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating the manner intended by management. All costs shall be documented, recorded historically, including methods and sources used to establish any estimated costs.

Certain costs are explicitly prohibited from inclusion as costs of an item of PP&E:

a) Costs of opening a new facility;
b) Costs of introducing a new product or service (including advertising and promotion);
c) Costs of conducting business in a new location or with a new class of customer (including costs of staff training);
d) Administration and other general overhead costs; and
e) Day-to-day servicing costs.

IAS 16 does not indicate what constitutes an item of PP&E. Judgment is required when applying the core principle.

Directly Attributable:

The term "Directly Attributable" is not defined in IAS 16. The specific facts and circumstances surrounding the cost and the ability to demonstrate that the cost is directly attributable to an item of PP&E is critical to establishing whether the cost should be capitalized. The cost must be attributed to a specific item of PP&E at the time it is incurred. The incurrence of that cost should aid directly in the construction effort making the asset more capable of being used than if the cost had not been incurred.

General Policy for Capitalization and Depreciation:

InnPower Corporation capital assets, and their designated service life, should be categorized as follows in Appendix 2-BB from the Chapter 2 Appendices.

<u>Account 1830 to 1860 – Poles, OH Conductors, Transformers, UG Conduit, Meters, etc.</u>

The capitalized expenditures for these accounts include:

- Material and supplies direct costs.
- Labour direct cost.
- Labour burden.
- Vehicle and equipment burden.
- subcontractor

Material and Supplies Direct Costs:

The material and supplies direct cost is comprised of all the eligible material that is used on a capital project, including its freight to destination. No administrative charges are added.

Labour Direct Cost:

The labour direct cost consists of all the eligible salaries for staff as well as their supervisors on a capital project.

Labour Burden:

The Labour Burden is comprised of employee benefits including:

- Employment Insurance Premiums (Employer portion)
- Canada Pension Plan Premiums (Employer portion)
- Employer Health Tax Premiums
- OMERS (Employer portion)
- Medical and Health Benefits
- Life Insurance
- WSIB
- Clothing and Safety Footwear Allocation
- Vacations
- Statutory Holidays
- Bereavement
- On-call / stand-by costs

The Labour Burden rate is a percentage calculated every year and based on the actual employee rates and benefits costs divided by 2,080 hours (regular hours worked in a year). Then all employee rates are added together and divided by the number of employees to get the average overhead percentage hourly rate for the year. The Labour Burden rate is then allocated to capital based upon the Labour Direct Cost charged to capital.

In 2014, the labor burden percentage rate was established at 49.10%.

Vehicle and Equipment Burden:

A vehicle burden rate is calculated for each class of vehicle based on the budgeted costs of operating each vehicle and the budgeted hours of usage for each class. The hourly rate is based on the total expenses, divided by the number of hours used. This hourly rate is allocated to capital based on the time that the vehicle is used on the job site, thus establishing the fact that the use of the vehicle is directly attributable to an item of PP&E. The expenses below are included in the operating costs:

- Depreciation.
- Vehicle Maintenance.
- Fuel.
- Insurance.

Account 1905 - Land Acquisition

The recorded cost of land includes:

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

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

Account 1908 – Building

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

- Original contract price of asset;
- Expenses for remodeling, repairing or changing a purchased building to make it available for the purpose for which it was acquired;
- Interest charges until building acquisition, project renovation, improvement or alteration is complete;
- Architects and engineers fees for design as well as expenses for the preparation of plans, specifications, blueprints, etc.; and
- Cost of building permits.

Each building is divided into 4 major building components. The components are as follows:

1. Building Structure.
2. Building Outside / Fence.
3. Interior Construction.
4. Roof.

The total cost of the building or additional square footage is then allocated among the 4 major building components.

Building Renovations/Rehabilitation:
A building renovation is defined as enhancements made to a previously existing building component. The total expenditure capitalized is based on the invoice or contract price. No administrative charges are added.

Building Outside / Fence improvements:
Building Outside / Fence improvements include items such as landscaping, driveways, sidewalks, parking lots, fencing, outdoor lighting, and other non-building improvements. Please note that Land improvements can be further categorized as non-exhaustible under account 1905 – Land acquisitions. The total project cost must meet the set minimum threshold and shall be recorded as capital based on the invoice or contract price. No administrative charges are added.

Account 1915 to 1955 – Office Furniture, Computer, Vehicles, Tools and Other Equipment
For capitalization of expenditures with a service life of more than one year, the total invoice or contract price is used, including its freight to destination. No storage, stockroom expenses or administrative charges are added.

Changes to Capitalization Policy
InnPower Corporation has implemented the regulatory accounting changes to its capitalization policy effective January 1, 2013 as evidenced in the last COS Application (EB-2013-0139) for rates effective May 1, 2013. No further changes to the capitalization policy have been made since the last COS Application.

Ex.2/Tab 5/Sch.4 - Capitalization of Overhead

InnPower Corporation confirms that indirect overhead costs such as general and administration costs that are not directly attributable to an asset, are not, nor have they ever been capitalized.

Ex.2/Tab 5/Sch.5 - Costs of Eligible Investments for Distributors

InnPower Corporation attests that it has not included any costs or included any Investments to Connect Qualifying Generation Facilities in its capital costs or in its Distribution System Plan.

Ex.2/Tab 5/Sch.6 - New Policy Options for the Funding of Capital

InnPower Corporation is proposing a Custom IR approach for a 5 year period 2016 – 2021 with this application. As discussed in Exhibit 1 - Executive Summary the request for a custom IR is to provide InnPower Corporation with the ability to fund capital expenditures to support growth requirements. This request will also negate the requirement of InnPower Corporation rebasing on an annual basis and allow the transition for InnPower Corporation from a rural service territory to an urban territory.

Ex.2/Tab 5/Sch.7 - Addition of ICM Assets to Rate Base

In conjunction with InnPower Corporation's IRM application for 2015 Rates an Incremental Capital Module (ICM) was submitted seeking recovery of the cost of a new Administration and Operations Centre under EB=2014-0086.

Incremental Capital Summary

Using the pull-down menu below, please identify what year of the IRM cycle you are in.
3rd year of IRM cycle

Name or General Description of Project
Innisfil Hydro New Corporate Operations Centre

Details of Project
Building of a Operations Centre and Corporate Headquarters

Asset Component	Capital Cost	Depreciation Rate	CCA Class	CCA Rate
1 Building	7,909,626	2%	1	6%
2 Roof and HVAC	754,637	5%	1	6%
3 Parking lot and roads	781,945	4%	17	8%
4 Land	891,496	0%		0%
5				

	2015	2016	2017	2018	2019
Closing Net Fixed Asset	10,110,502	9,883,300	9,656,097	9,428,895	9,201,693
Amortization Expense	227,202	227,202	227,202	227,202	227,202
CCA	582,411	546,216	512,292	480,495	450,691

The Decision and Order approved a resulting revenue requirement of $845,836 to be collected through an ICM Rate Rider. The sunset of the ICM Rate Rider is December 31, 2016. As InnPower Corporation does not have audited financial statements for the 2016 time period a true up of the ICM Rider cannot be undertaken at this time.

InnPower Corporation is requesting that the true up occur with the 2018 annual true up of the Custom IR.

Incremental Capital Adjustment

Current Revenue Requirement

Current Revenue Requirement - Total			$ 7,607,411	A

Return on Rate Base

Incremental Capital CAPEX			$10,337,704	B
Depreciation Expense			$ 227,202	C
Incremental Capital CAPEX to be included in Rate Base			$10,110,502	D = B - C
Deemed ShortTerm Debt %	4.0%	E	$ 404,420	G = D * E
Deemed Long Term Debt %	56.0%	F	$ 5,661,881	H = D * F
Short Term Interest	2.07%	I	$ 8,371	K = G * I
Long Term Interest	4.36%	J	$ 247,094	L = H * J
Return on Rate Base - Interest			$ 255,465	M = K + L
Deemed Equity %	40.0%	N	$ 4,044,201	P = D * N
Return on Rate Base -Equity	8.98%	O	$ 363,169	Q = P * O
Return on Rate Base - Total			$ 618,634	R = M + Q

Amortization Expense

Amortization Expense - Incremental		C	$ 227,202	S

Grossed up PIL's

Regulatory Taxable Income		O	$ 363,169	T
Add Back Amortization Expense		S	$ 227,202	U
Deduct CCA			$ 582,411	V
Incremental Taxable Income			$ 7,960	W = T + U - V
Current Tax Rate (F1.1 Z-Factor Tax Changes)		X		
PIL's Before Gross Up			$ -	Y = W * X
Incremental Grossed Up PIL's			$ -	Z = Y / (1 - X)

Ontario Capital Tax

Incremental Capital CAPEX			$10,337,704	AA
Less : Available Capital Exemption (if any)			$ -	AB
Incremental Capital CAPEX subject to OCT			$10,337,704	AC = AA - AB
Ontario Capital Tax Rate (F1.1 Z-Factor Tax Changes)	0.000%	AD		
Incremental Ontario Capital Tax			$ -	AE = AC * AD

Incremental Revenue Requirement

Return on Rate Base - Total		Q	$ 618,634	AF
Amortization Expense - Total		S	$ 227,202	AG
Incremental Grossed Up PIL's		Z	$ -	AH
Incremental Ontario Capital Tax		AE	$ -	AI
Incremental Revenue Requirement			$ 845,836	AJ = AF + AG + AH + AI

Ex.2/Tab 5/Sch.8 - Service Quality and Reliability Performance

InnPower Corporation records and reports annually the following Service Reliability Indices:

- SAIDI = Total Customer-Hours of Interruptions/Total Customers Served
- SAIFI = Total Customer Interruptions/Total Customers Served
- CAIDI = Total Customer-Hours of Interruptions/Total Customer Interruptions

These indices provide InnPower Corporation with annual measures of its service performance that are used for internal benchmarking purposes when making comparisons with other distribution companies (e.g. to better understand the rankings that will support the OEB's Incentive Rate Making Mechanism and Performance Based Regulation). They are reported in accordance with Section 7.3.2 of the OEB's Electricity Distribution Rate Handbook.

Following is Appendix 2-G-SQI from the Chapter 2 Appendices.

Appendix 2-G Service Reliability Indictors

Appendix 2-G
Service Reliability Indicators
2012- 2015

Index	Including outages caused by loss of supply					Excluding outages caused by loss of supply				
	2012	2013	2014	2015	2016	2012	2013	2014	2015	2016
SAIDI	0.980	2.140	4.700	1.740		3.110	2.160	5.020	1.510	
SAIFI	1.110	1.100	3.140	0.990		1.690	1.100	3.930	1.080	

5 Year Historical Average

SAIDI		2.390		2.950
SAIFI		1.585		1.950

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

Indicator	OEB Minimum Standard	2012	2013	2014	2015	2016
Low Voltage Connections	90.0%	95.0%	97.0%	96.4%	97.9%	
High Voltage Connections	90.0%	n/a	n/a	n/a	n/a	
Telephone Accessibility	65.0%	73.0%	68.0%	70.6%	80.4%	
Appointments Met	90.0%	64.0%	88.0%	94.4%	91.8%	
Written Response to Enquires	80.0%	100.0%	100.0%	98.4%	97.5%	
Emergency Urban Response	80.0%	n/a	n/a	n/a	n/a	
Emergency Rural Response	80.0%	100.0%	100.0%	100.0%	100.0%	
Telephone Call Abandon Rate	10.0%	6.7%	9.1%	7.5%	9.5%	
Appointment Scheduling	90.0%	98.0%	97.0%	97.7%	97.7%	
Rescheduling a Missed Appointment	100.0%	n/a	n/a	n/a	n/a	
Reconnection Performance Standard	85.0%	97.0%	99.0%	98.9%	99.7%	

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Appendix A – RPP and Non-RPP Forecast 2017 - 2021

RPP and Non RPP forecast for 2018 - 2021 Test Years

Updated data	May-06	Nov-06	May-07	Nov-07	May-08	Nov-08	May-09	Nov-09	May-10	Nov-10	May-11	Nov-11	May-12	Nov-12	May-13	Nov-13	May-14	Nov-14	May-15	Nov-15	May-16	Nov-16	May-17	Nov-17	May-18	Nov-18	May-19
	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
Forecast Wholesale Electricity Price ($ / MWh)	$62.30	$58.74	$58.01	$54.10	$60.72	$50.16	$44.88	$35.68	$36.66	$39.23	$40.15	$31.83	$21.05	$20.65	$19.33	$19.67	$26.28	$20.64	$19.92	$18.82							
Load-Weighted Price for RPP Consumers ($ / MWh)	$67.65	$63.56	$62.83	$58.55	$65.57	$53.46	$48.00	$38.14	$39.51	$42.16	$43.41	$34.62	$22.99	$23.06	$21.05	$21.95	$28.70	$22.52	$21.68	$20.57							
Impact of the Global Adjusment ($ / MWh)	($4.79)	($1.70)	($0.52)	$2.18	($1.11)	$8.52	$14.26	$24.94	$27.72	$26.38	$28.22	$40.08	$57.72	$59.36	$66.12	$67.93	$64.68	$74.88	$65.94	$87.92							
Impact of the OPG Non-prescribed Asset Rebate ($ / MWh)	($6.45)	($5.45)	($5.41)	($4.20)	($7.44)	($1.02)																					
Adjusment to Address Bias Towards Unfavourable Variance ($ / MWh)	$1.11	$1.12	$1.10	$0.92	$1.00	$1.00	$0.94	$0.94	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00							
Adjusment to Recover Existing Variance ($ / MWh)	$5.04	$1.44	($0.96)	($3.16)	($3.52)	($1.66)	($2.47)	($1.86)	$1.14	($1.16)	$0.35	($0.06)	($1.02)	($4.10)	($4.21)	($1.50)	($1.87)	($3.45)	($2.52)	($2.22)							
Average Supply Cost for RPP Consumers ($ / MWh)	$62.56	$58.97	$57.04	$54.29	$54.50	$60.30	$60.73	$62.16	$69.37	$68.38	$72.98	$75.64	$80.69	$79.32	$83.96	$89.38	$92.51	$94.95	$86.10	$107.27	$98.96	$101.40	$103.80	$106.24	$108.64	$111.08	$113.48
Average Supply Cost for Non-RPP Consumers ($ / MWh)	Unable to reflect the impact of OPG Non-prescribed Asset						$59.14	$60.62	$64.38	$65.61	$68.37	$71.91	$78.77	$80.01	$85.45	$87.60	$90.96	$95.52	$85.86	$106.74	$96.76	$99.15	$101.49	$103.87	$106.22	$108.60	$110.95
% Non-RPP to RPP	Rebate for RPP on Non-RPP Price						97%	98%	93%	96%	94%	95%	98%	101%	102%	98%	98%	101%	100%	100%	98%						
													Average		98%												
													2016 per 11/15 Navigant report			**2016 used for calculating 2017-2021**		**Use for 2017**		**Use for 2018**		**Use for 2019**		**Use for 2020**		**Use for 2021**	
Average Supply Cost for RPP Consumers ($ / kWh)													**$0.10728**			**$0.09896**		**$0.10624**		**$0.11108**		**$0.00000**		**$0.00000**		**$0.00000**	
Average Supply Cost for Non-RPP Consumers ($ / kWh)													**$0.10670**			**$0.09676**		**$0.10387**		**$0.10860**		**$0.00000**		**$0.00000**		**$0.00000**	

% Make-up of Forecast Wholesale Electricity Price ($ / MWh)

Appendix B - Regional 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

hydro one

April 8th 2016

Brenda L. Pinke
Regulatory/CDM Manager
InnPower Corporation
7251 Yonge Street
Innisfil, Ontario, L9S 0J3

Dear Ms. Pinke:

Subject: Regional Planning Status

In reference to your request for a regional planning status letter, please note that InnPower belongs to the South Georgian Bay/Muskoka Region, which is in Group 2. A map showing details with respect to the 21 Regions/Groups and a list of Local Distribution Companies (LDCs) in each Region is attached in Appendix A and B respectively.

InnPower is an embedded LDC supplied via 44 kV lines from Alliston TS, Everett TS, and Barrie TS. The needs that may impact InnPower distribution system, as identified in the Needs Assessment, are summarized below:

- The 115 kV circuit E3B, supplying Barrie TS radially from Essa TS, and the Essa 230/115 kV autotransformers, are expected to exceed their limited time rating upon loss of the companion circuit or autotransformer;
- Barrie TS transformers are nearing their end-of-life and are expected to exceed their normal supply capacity;
- Load restoration criteria (4 hours) may not be met for loss of double 230 kV circuits E8V and E9V, supplying Alliston TS and Everett TS.

As the outcome of the Scoping Assessment, an Integrated Regional Resource Planning (IRRP) is currently underway and is expected to be completed in Q4 2016.

To address the capacity needs in a timely manner, Hydro One, in parallel to the ongoing IRRP, will be working with the LDCs in developing a wires plan to upgrade Barrie TS transformers and E3B/E4B circuits to 230 kV voltage level. This upgrade is expected to increase supply capacity to customers connected to Barrie TS. Further details will be discussed with the Working Group and communicated as they become available.

Hydro One looks forward to continue working with InnPower in executing the regional planning process. Please feel free to contact me if you have any questions.

Sincerely,

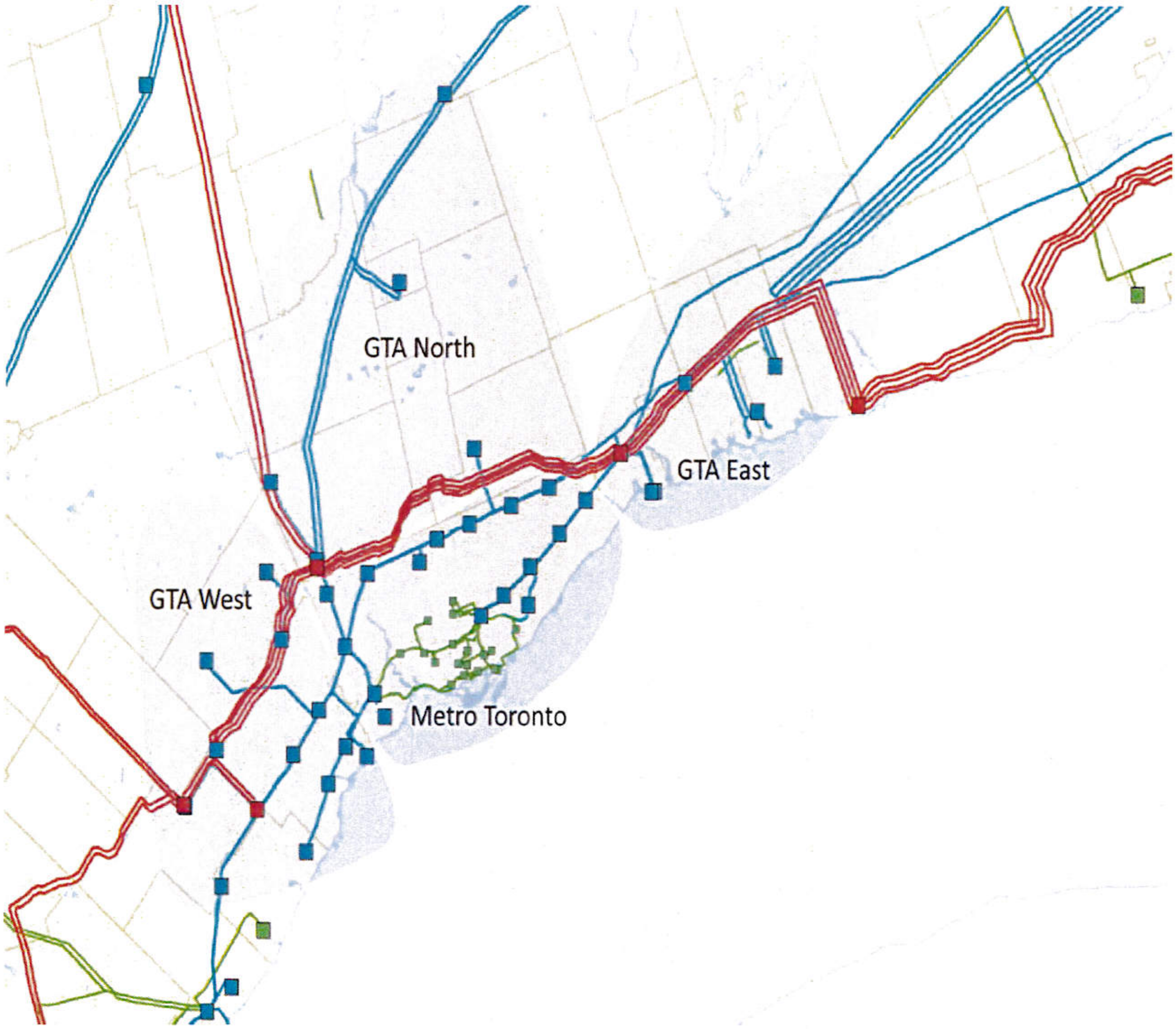
Ajay Garg, Manager – Regional Planning Coordination
Hydro One Networks Inc.

Appendix A: Map of Ontario's Planning Regions

Northern Ontario

Southern Ontario

Greater Toronto Area (GTA)



Group 1	Group 2	Group 3
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")		Renfrew
Metro Toronto		St. Lawrence
Northwest Ontario		
Windsor-Essex		

Appendix B: List of LDCs for Each Region

[Hydro One as Upstream Transmitter]

Region	LDCs
1. Burlington to Nanticoke	• Brant County Power Inc. • Brantford Power Inc. • Burlington Hydro Inc. • Haldimand County Hydro Inc. • Horizon 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	• Enersource Hydro Mississauga Inc. • Hydro One Brampton Networks Inc. • Hydro One Networks Inc. • Newmarket-Tay Power Distribution Ltd. • PowerStream Inc. • PowerStream Inc. [Barrie] • Toronto Hydro Electric System Limited • Veridian Connections Inc.
4. GTA West	• Burlington Hydro Inc. • Enersource Hydro Mississauga Inc. • Halton Hills Hydro Inc. • Hydro One Brampton Networks Inc. • Hydro One Networks Inc. • Milton Hydro Distribution Inc. • Oakville Hydro Electricity Distribution Inc.

5. Kitchener- Waterloo-Cambridge-Guelph ("KWCG")	• Cambridge and North Dumfries Hydro Inc. • Centre Wellington Hydro Ltd. • Guelph Hydro Electric System - Rockwood Division • Guelph Hydro Electric Systems Inc. • 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. Metro Toronto	• Enersource Hydro Mississauga Inc. • Hydro One Networks Inc. • PowerStream Inc. • Toronto Hydro Electric System Limited • Veridian Connections 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 Inc. [Chatham-Kent] • EnWin Utilities Ltd. • Essex Powerlines Corporation • Hydro One Networks Inc.
9. East Lake Superior	N/A → This region is not within Hydro One's territory

10. GTA East	• Hydro One Networks Inc. • Oshawa PUC Networks Inc. • Veridian Connections Inc. • Whitby Hydro Electric Corporation
11. London area	• Entegrus Power Lines Inc. [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. • Veridian Connections Inc.
13. South Georgian Bay/Muskoka	• Collingwood PowerStream Utility Services Corp. (COLLUS PowerStream Corp.) • Hydro One Networks Inc. • Innisfil Hydro Distribution Systems Limited • Lakeland Power Distribution Ltd. • Midland Power Utility Corporation • Orangeville Hydro Limited • Orillia Power Distribution Corporation • Parry Sound Power Corp. • Powerstream Inc. [Barrie] • Tay Power • Veridian Connections Inc. • Veridian-Gravenhurst Hydro Electric 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 Inc. [Chatham-Kent] • Hydro One Networks Inc.
16. Greater Bruce/Huron	• Entegrus Power Lines Inc. [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.* • Horizon 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
18. North of Moosonee	N/A → This region is not within Hydro One's territory

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.

Appendix C – Distribution System Plan

InnPower Corporation

Distribution System Plan

Filed with InnPower's 2017 Cost of Service Application

Historical Period: 2012 to 2016

Forecast Period: 2017 to 2021

2 June 2016

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1 Introduction

InnPower Corporation ("**InnPower**") has prepared this Distribution System Plan ("**DSP**") in accordance with the Ontario Energy Board's ("**OEB**'s") *Chapter 5 Consolidated Distribution System Plan Filing Requirements* dated 28 March 2013 (the "**Filing Requirements**") as part of its 2017 Cost of Service ("**COS**") Application.

This introductory section outlines the background and drivers for this DSP, presents a description of InnPower, provides the objectives and scope of work for the DSP, and summarizes the outline of the DSP.

1.1 Background & Drivers

InnPower's DSP has been prepared to support the four (4) key objectives from the OEB's *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* ("**RRFE**"):

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

InnPower's DSP was developed for the 2017 to 2021 period based on its existing asset management processes and capital expenditure planning. The DSP documents the practices, policies, and processes that are in place to ensure that investment decisions support InnPower's desired outcomes in a cost effective manner and provide value to the customer. The DSP integrates information which results in an optimal investment plan covering:

1. system expansion considerations;
2. system renewal considerations;
3. regional planning considerations;
4. renewable generation considerations;
5. smart grid considerations;
6. customer value considerations; and
7. alignment with public policy objectives.

InnPower's capital investments over the planning period have been aligned to the four (4) categories of system access, system renewal, system service, and general plant. Investments within these categories have been paced and prioritized to meet the objectives of the RRFE.

1.1.1 System Access

System access investments are modifications to InnPower's distribution system (including asset relocations) that InnPower is obligated to perform to provide customers with access to electricity services via the distribution system. Drivers for this investment category are customer service requests, other third party infrastructure development requests, and mandated service obligations (e.g. as per the Distribution System Code).

1.1.2 System Renewal

System renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of InnPower's distribution system to provide customers with electricity services. Assets and asset systems may be at the end of their service life due to failure, failure risk, substandard performance, high performance risk, or functional obsolescence.

1.1.3 System Service

System service investments are modifications to InnPower's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements. Drivers for this investment category include expected changes in load that will constrain the ability of the system to provide consistent service delivery and meeting system operational objectives in safety, reliability, power quality, and system efficiency.

1.1.4 General Plant

General plant investments are modifications, replacements or additions to InnPower'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. Drivers for this investment category include system capital investment support, system maintenance support, business operations efficiency, and non-system physical plant.

1.2 Description of the Utility Company

The Hydro Electric Commission of the Corporation of the Town of Innisfil was created in January 1991 as provided for in *Bill 177, 1990*. It continued to serve only the former Village of Cookstown until 1993 when the distribution assets in the remainder of the newly incorporated Town of Innisfil were purchased from Ontario Hydro. Innisfil Hydro Distribution Systems Limited ("**Innisfil Hydro**") was incorporated as a for-profit local distribution company ("**LDC**") in the year 2000 as required by the *Electricity Act, 1998*. In January 2015, Innisfil Hydro changed its name to InnPower Corporation.

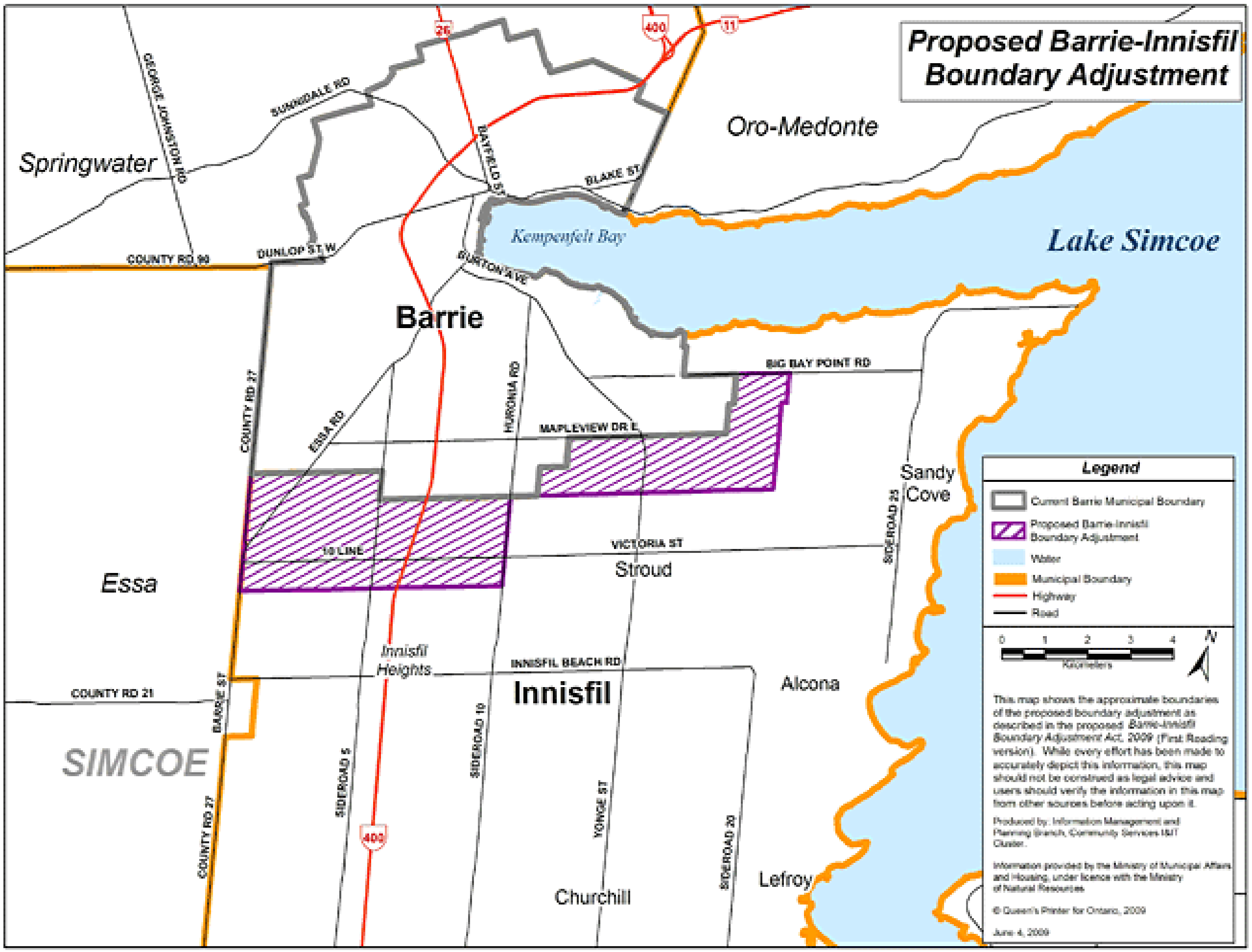
InnPower is a member of the Cornerstone Hydro Electric Concepts Association ("**CHEC**"), a cooperative that combines resources and competencies between its 15 LDC members. InnPower has access to a common set of design, construction, and material standards, as per its membership with Utilities Standards Forum ("**USF**"). InnPower is also an active member of the Electricity Distributors Association ("**EDA**").

1.2.1 Service Area

InnPower serves approximately 16,000 customers within a service area of 292 square kilometres

The *Barrie-Innisfil Boundary Adjustment Act, 2009* granted the City or Barrie approximately 2,300 hectares of land within the former boundaries of the Town of Innisfil for development (see Figure 1-1). This land falls within InnPower's service territory. Therefore, InnPower's service territory encompasses the lands of South Barrie and all of the Town of Innisfil, which includes the communities of Stroud, Alcona, Lefroy, Churchill, Cookstown, Gilford, Sandy Cove, and Big Bay Point.

Figure 1-1: Barrie-Innisfil boundary adjustment

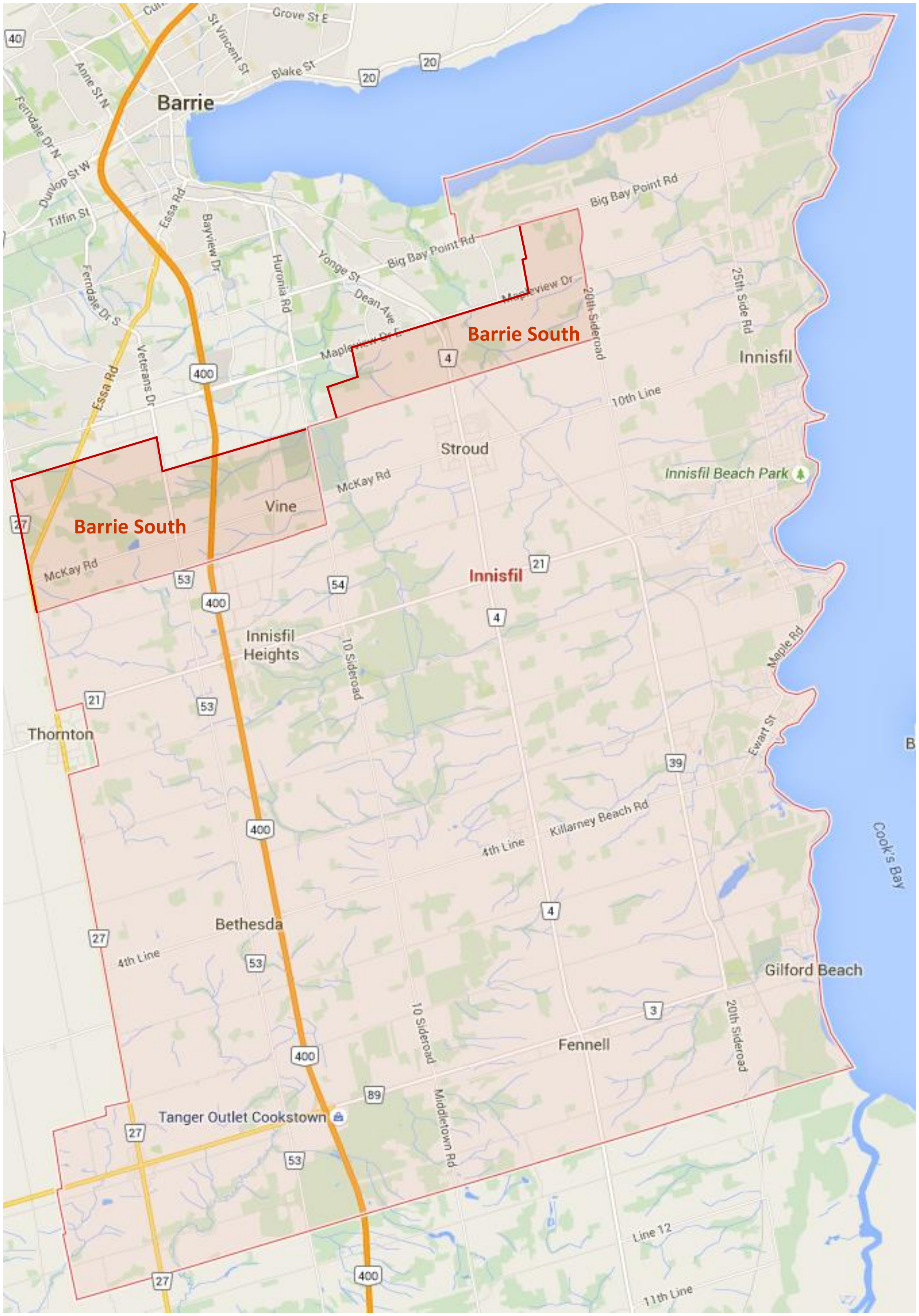


InnPower's service territory is depicted in Figure 1-2.

InnPower receives its power from 44 kV subtransmission feeders, which deliver power to the twelve (12) distribution substations ("**DS**") and large 44 kV customers. The 44 kV feeders are owned by InnPower within its service territory, except for the portions that feed Cookstown West DS and Thornton DS. The 44 kV feeders egress from three transformer stations ("**TS**") owned by Hydro One Networks Inc. ("**HONI**"). Alliston TS and Everett TS step power down from 230 kV to 44 kV, while Barrie TS steps power down from 115 kV to 44 kV and is fed from 230-115 kV autotransformers at Essa TS.

There are three (3) DS owned by InnPower that step power down from 44 kV to 27.6/16.0 kV: Bob Deugo DS, Brian Wilson DS (which has two transformers that can be tied together), and the newly constructed Belle Ewart DS. The other nine (9) DS within InnPower's service territory step power down from 44 kV to 8.32/4.81 kV. Of these, seven (7) are owned by InnPower and two (2), Cookstown West DS and Thornton DS, are owned by HONI.

Figure 1-2: InnPower's service territory



1.2.2 Load Growth

Load growth is the most prominent capital investment driver over the forecast period of this DSP. Following the *Oak Ridges Moraine Protection Act, 2001*, property developers have acquired parcels of land within the Town of Innisfil for the purpose of development. The projected population and employment growth within the Town of Innisfil vary between the official plans of the Town of Innisfil, the County of Simcoe, and the Province of Ontario; but all agree that the growth will be significant. A population increase of approximately 70% to 100% is expected from 2011 to 2031.

Table 1-1 presents the Town of Innisfil's population from the 2011 census and employment from 2006 estimates, as well as projected 2031 levels based on various growth plans. The Provincial Growth Plan is from the Intergovernmental Action Plan for Simcoe, Barrie & Orillia, but does not include two (2) developments approved by the Town of Innisfil known as Friday Harbour and Sleeping Lion.

Table 1-1: Town of Innisfil past and future population and employment from various sources

Source	Population	Employment
Innisfil 2011 census and 2006 employment estimate	33,080	5,700
Innisfil Official Plan, 2031	55,500	27,750
Simcoe Official Plan 2031	65,000	13,100
Provincial Growth Plan, 2031	56,000	13,100
Provincial Growth Plan, 2031; plus Friday Harbour and Sleeping Lion	65,240	13,100

1.2.2.1 *Residential Development*

The development plans which pertain to the time period of this DSP have been summarized below.

1. The City of Barrie's official plan estimates 40,788 residents with 68 MW of demand by 2031 in the South Barrie area that will be served by InnPower. Customer connections in this area are expected over the forecast period.

2. A new resort community named Friday Harbour has been approved by the Council of the Town of Innisfil and the Ontario Municipal Board. This 600 acre site is currently under construction and is expected to amount to approximately 1,600 customers over the next ten (10) years.

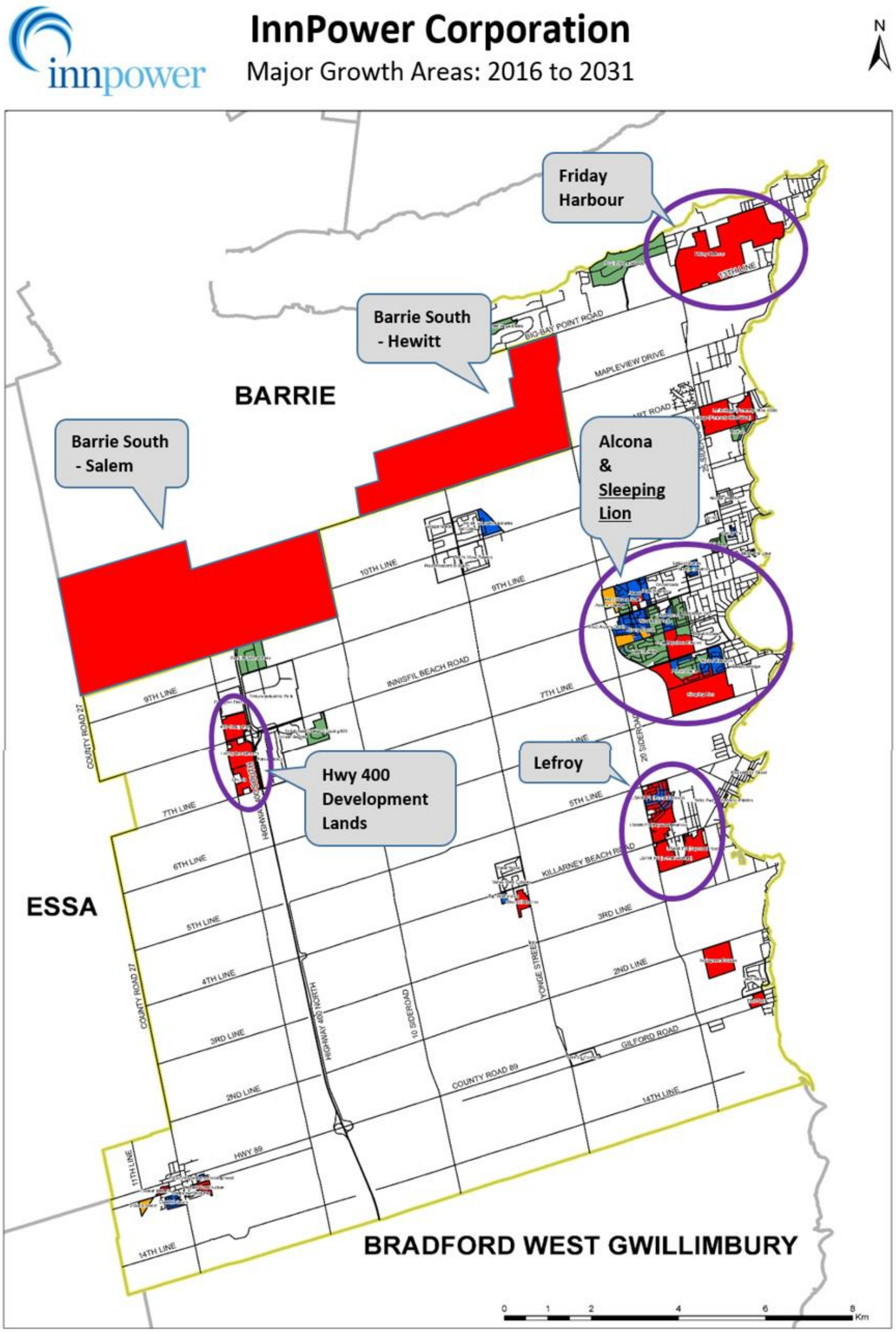
3. There are five (5) commercial development sites located close to the Innisfil Beach Road interchange of Highway 400. Three (3) of the sites were approved in 1990, 1991, and 1993, respectively, and environmental impact assessments are ongoing.

4. The Lefroy area has development approval which will lead to approximately 2,300 new customers.

5. A development named Sleeping Lion is currently being built for an estimated 5,000 residents around the existing Alcona area.

Figure 1-3 depicts the locations of these sites.

Figure 1-3: Areas of immediate and future development



Using growth projections from all available sources, the following comprises the parameters for long range growth projections:

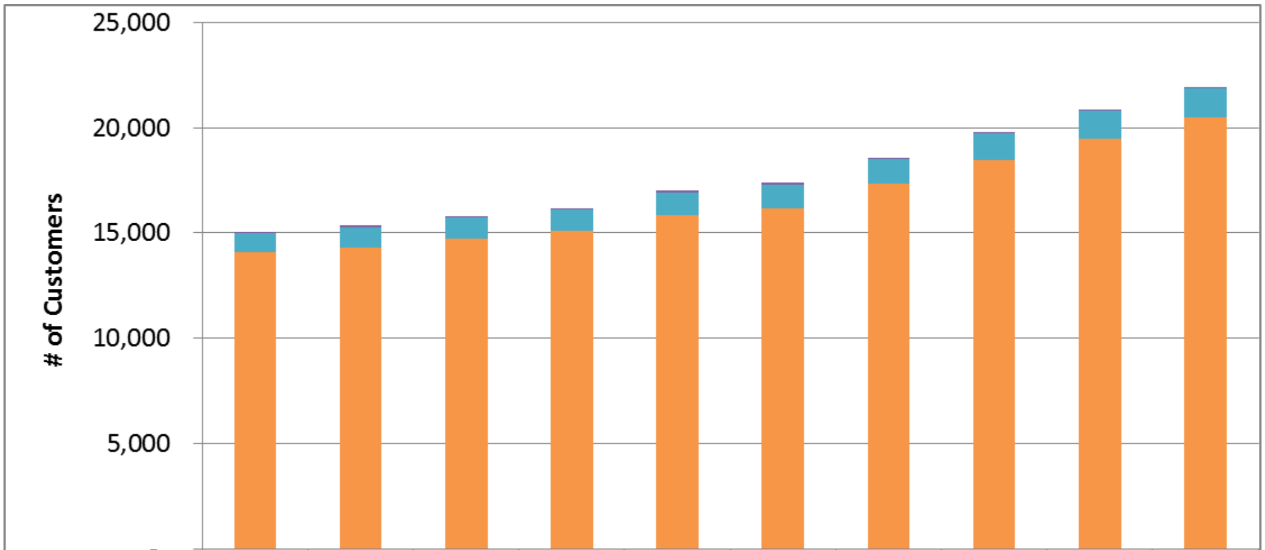
- Town of Innisfil population in 2031: 56,000.
- South Barrie population in 2031: 40,788.
- Friday Harbour development: 1,600 units and commercial load.

1.2.2.2 *Customer Counts*

InnPower's customer base has faced consistent growth over the past ten (10) years and this trend is expected to significantly increase into the next decade. Conservative customer growth estimates have been made by considering a lower absorption rate than the development estimates. Even so, it is predicted that InnPower's customer base will double in the next fifteen (15) years.

InnPower's customer base is mostly residential. Other customers fall into the General Service less than 50 kW ("**GS<50**") and General Service greater than 50 kW ("**GS>50**") classes. Figure 1-4 presents the year-end customer counts for 2012 to 2014 and forecast customer counts for 2015 to 2021 for each customer class. No change in the number of GS>50 customers is expected and the number of GS<50 customers is expected to increase proportionally with the number of residential customers.

Figure 1-4: Year-end (2012-2014) and forecast (2015-2021) customer counts

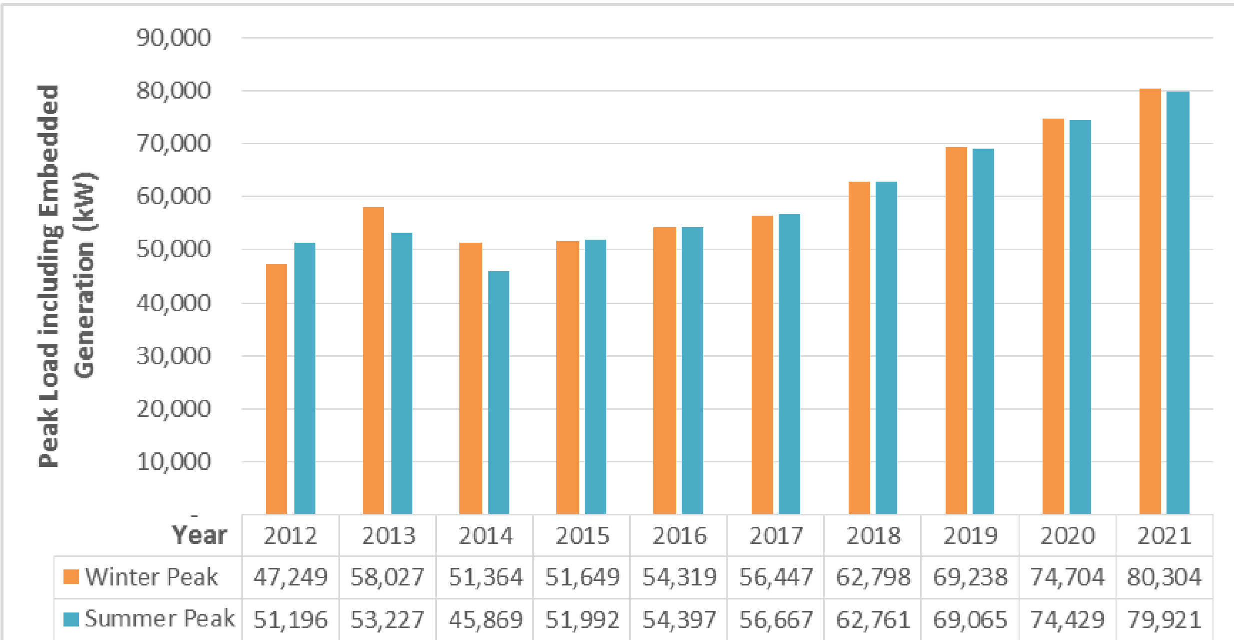


Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
GS>50	69	66	69	74	74	74	74	74	74	74
GS<50	932	960	993	1,012	1,085	1,109	1,178	1,257	1,324	1,392
Residential	14,061	14,315	14,728	15,082	15,836	16,185	17,329	18,480	19,475	20,472

1.2.2.3 *Peak Demand*

Similarly, the peak demand forecast is driven by load growth. Peak demand is expected to increase from approximately 52 MW in 2015 to approximately 80 MW in 2021, including embedded generation. The summer and winter peak loads including embedded generation is presented in Figure 1-5 based on historical data for 2012 to 2015 and forecast data for 2016 to 2021.

Figure 1-5: Historical (2012-2015) and forecast (2016-2021) summer and winter peak load



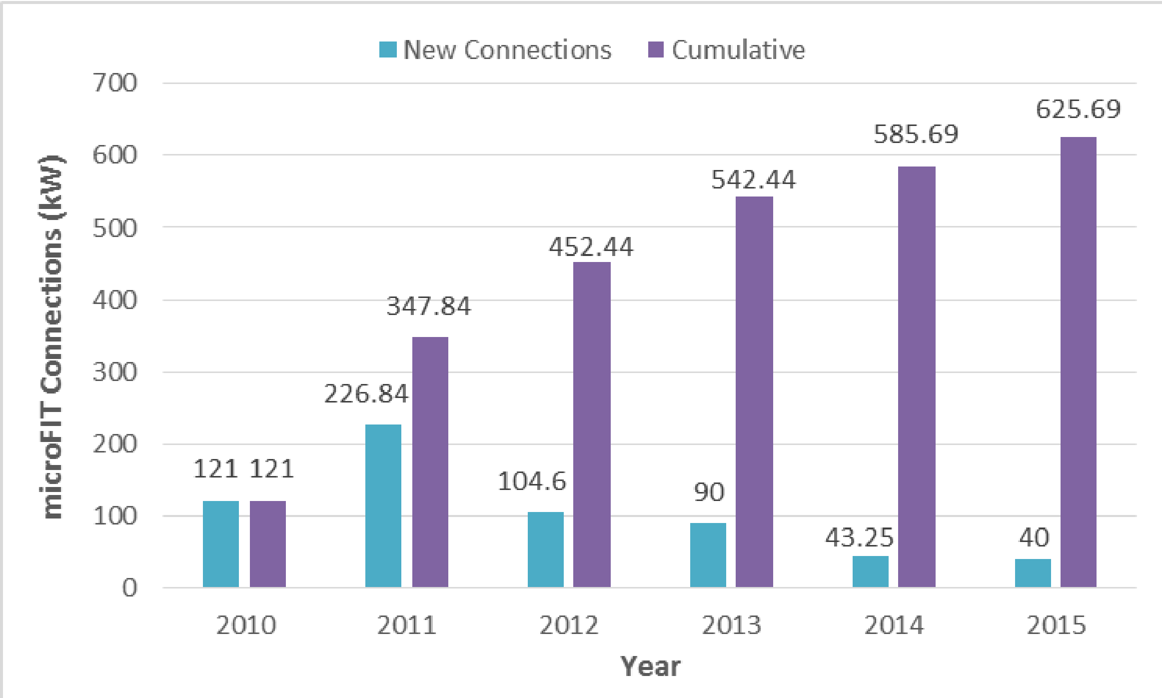
1.2.3 Embedded Generation

All of the generation connected to InnPower's distribution system comes from solar photovoltaics ("**PV**") installed under Feed-in-Tariff ("**FIT**") and microFIT programs. Table 1-2 lists the existing FIT connections, while Figure 1-6 presents the new and cumulative microFIT connections from 2010 to 2015.

Table 1-2: Existing FIT connections

Address	TS/Feeder	DS/Feeder	Type	Capacity (kW)
6037 County Rd 27, Innisfil	Everett/9M6	Cookstown/F4	Solar PV	150
7244 Yonge St	Barrie/13M3	Stroud/F1	Solar PV	225
374 Salem Rd, Barrie	Alliston/9M4	Thornton/F2	Solar PV	216
2044 Commerce Park Dr	Alliston/9M1	Bob Deugo/F1	Solar PV	65
1146 Anna Maria Ave	Alliston/9M1	Brian Wilson/F2	Solar PV	250
2252 Bowman St, Innisfil	Alliston/9M1	Bob Deugo/F1	Solar PV	57
61 Queen St West, Cookstown	Alliston/9M2	N/A	Solar PV	500

Figure 1-6: New and cumulative microFIT connections (2010-2015)



1.2.4 Energy Conservation and Demand Management

InnPower participates in province-wide energy conservation and demand management ("**CDM**") programs administered by the Independent Electricity System Operator ("**IESO**"). The previous CDM framework, spanning 2011 to 2014 included targets for both peak demand savings and energy savings. Table 1-3 summarizes InnPower's previous CDM targets and performance.

Table 1-3: Previous CDM targets and achievements (2011-2014)

Measure	Target (2011-2014)	% of Target Achieved
Net Annual Peak Demand Savings	2.50 MW	49.27%
Net Cumulative Energy Savings	9.20 GWh	84.43%

IESO's current Conservation First Framework ("**CFF**"), spanning 2015 to 2020, focuses solely on energy conservation. InnPower submitted its CDM forecast by market segmentation under the CFF to the IESO in May 2015 and it was approved on 27 July 2015.

The expected energy savings for each CDM program for the years 2015 to 2020 has been summarized in Table 1-4. The anticipated energy savings can be divided into the residential segment, commercial segment, and "industrial" segment (i.e. large commercial segment).

The residential segment corresponds to 61% of the total anticipated energy savings. Most of the residential energy savings are expected to come from the "Appliances" end use category, for which there is currently no CDM program, and the "HVAC" end use category, for which there is currently no opportunity for direct LDC involvement. These end use categories will be the focus of LDC designed programs to address the Unassigned Target listed in Table 1-4.

The commercial segment corresponds to 37% of the total anticipated energy savings. Most of the commercial end use savings are expected to come from the "HVAC", "Plug Loads", and "Domestic Hot Water" end use categories, for which InnPower has historically received few Retrofit and Equipment Replacement Incentive Initiative applications. Collaboration with other LDCs will focus on these end use categories.

The "industrial" segment only corresponds to 2% of the total anticipated energy savings. Energy savings opportunities for InnPower in this segment are small, as InnPower does not currently have any industrial customers. Carryover measures from some of InnPower's larger commercial customers will account for industrial energy savings in the Process and Systems Upgrade Initiative.

Table 1-4: Current CDM targets (2015-2020)

Program	Anticipated Energy Savings (MWh)						
	2015	2016	2017	2018	2019	2020	Total
Retrofit	1,154	651	661	680	817	920	**4,885**
Direct Install Lighting	108	0	0	0	0	0	**108**
High Performance New Construction	57	171	228	228	228	228	**1,140**
Heating and Cooling	61	67	12	13	14	16	**181**
Coupon	166	116	121	127	133	139	**803**
New Construction	0	37	55	92	92	184	**460**
Home Assistance Program	24	26	28	31	35	38	**181**
Audit Funding	0	0	76	76	76	76	**303**
Small Business Lighting	0	49	49	49	42	42	**231**
Process and Systems Upgrade	0	2,042	0	0	0	0	**2,042**
Unassigned Target	0	0	0	892	892	892	**2,676**
Total	**1,570**	**3,158**	**1,230**	**2,188**	**2,328**	**2,535**	**13,010**

InnPower will continue to offer IESO-administered CDM programs, engage in community outreach, collaborate with other LDCs, and design new end use programs to meet its energy conservation target. 76% of InnPower's energy savings target can be achieved with existing IESO provincial programs, such as High Performance New Construction for new homes. The remaining 24% of the energy savings target will require new programs designed for the appropriate market segmentation. InnPower has set aside $823,421 of its CDM budget under the CFF for new program design, which leaves $2,148,812 worth of incentives for the years 2015 to 2020.

1.3 Objectives & Scope of Work

This DSP has been developed to achieve the four performance outcomes established by the OEB: customer focus, operational effectiveness, public policy responsiveness, and financial performance. To realize these four outcomes, InnPower has outlined the following objectives:

- promoting a safer system for both workers and the general public;
- maintaining security and safety by reducing the vulnerability of the grid to unexpected hazards;
- ensuring system capacity to facilitate new customer connections;
- improving cost efficiency through good planning and shared services;
- improving system reliability by deploying Distribution Automation and Supervisory Control and Data Acquisition ("**SCADA**") technology;
- executing a prudent, condition based infrastructure renewal strategy;
- increasing customer participation in CDM programs;
- promoting environmental quality by allowing customers to purchase cleaner, lower-carbon-emitting generation; and
- supporting the deployment of distributed renewable energy generation ("**REG**").

1.4 Outline of Report

This DSP has been organized using the same headings as the Filing Requirements, with the corresponding section number from the Filing Requirements included in brackets for each heading. Text from the Filing Requirements has been included for reference; and is bolded, italicized, and indented.

The report contains four (4) sections, including this introductory section as Section 1. Section 2 provides a high level overview of the DSP, including coordinated planning with third parties and performance measurement for continuous improvement. Section 3 provides an overview of InnPower's asset management process, including an overview of the assets managed and asset lifecycle optimization policies and practices. Section 4 provides a summary of InnPower's capital expenditure plan, including an overview of the capital expenditure planning process, an assessment of the system capability for REG, and justification of material projects.

2 Distribution System Plan (5.2)

Section 2.1 provides an overview of the DSP, Section 2.2 summarizes coordinated planning activities with third parties, and Section 2.3 covers performance measurements to continuously improve asset management and capital expenditure planning processes.

2.1 Distribution System Plan Overview (5.2.1)

This section provides the OEB and stakeholders with a high level overview of the information filed in the DSP, including key elements of the DSP, sources of expected cost efficiencies, the period covered by the DSP, the vintage of the information, an indication of important changes to InnPower's asset management processes, and aspects of the DSP that are contingent on the outcome of ongoing activities or future events.

2.1.1 Key Elements of the DSP (5.2.1a)

key elements of the DS Plan that affect its rates proposal, especially prospective business conditions driving the size and mix of capital investments needed to achieve planning objectives

Table 2-1 presents the capital expenditures by investment category and the system operations and maintenance ("**O&M**") costs for both the historical and forecast period.

Table 2-1: Historical and forecast capital expenditures and system O&M

	Historical ($ '000)					Forecast ($ '000)				
Category	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
System Access	1,750	974	1263	665	1,362	1,754	1,984	1,595	1,598	2,013
System Renewal	654	987	697	465	1,137	1,216	1,140	2,919	2,400	2,109
System Service	586	1,377	2,819	2,358	2,505	2,338	2,829	1,276	1,556	1,402
General Plant	828	1,348	253	14,091	661	1,500	1,423	897	680	706
Net Capital Expenses	3,818	4,686	5,031	17,579	5,665	6,807	7,376	6,686	6,235	6,231
System O&M	1,761	1,787	1,814	1,520	2,099	2,636	2,636	2,636	2,636	2,636

For the years 2017 and 2018, the focus of the capital spending is on system service projects to accommodate load growth, while for the years 2019 to 2021 the focus is on system renewal projects to replace assets which have reached end-of-life. A brief description of the mix of capital investments by investment category over the forecast period are provided below.

2.1.1.1 *System Access*

Capital investments in the system access category over the forecast period are driven by customer service requests, other third party infrastructure development requirements, and mandated service obligations. InnPower has installed approximately 15,000 residential and commercial smart meters, completing the Advanced Metering Infrastructure ("**AMI**") program and implementing time of use ("**TOU**") billing for all eligible customers by June 2011. Internal processes are currently being developed to better utilize smart meter data and improve customer experience. InnPower is also in the process of reviewing the cost implications for upgrading the existing AMI with two-way communication capability to accommodate the system requirements for the implementation of Demand Response programs.

The forecast period for this DSP includes system access allowances for unplanned capital, such as legacy property trespasses of equipment. Physical trespasses include poles installed on private property and aerial trespasses include conductors which pass over private property. Payouts to subdivision developers as part of the Economic Evaluation process can vary considerably between years and are budgeted for each year. An Economic Evaluation is a financial model based on "estimated / actual costs and forecasted revenues … of the expansion project to determine if the future revenue from the customer(s) will pay for the capital cost and on-going maintenance costs of the expansion project."[1] The different levels of Economic Evaluations are:

- Initial Economic Evaluation: An initial economic evaluation (based on estimated costs and forecasted revenues) is drafted in conjunction with the preliminary Subdivision Agreement.
- Subsequent Economic Evaluations: Upon energization, an updated economic evaluation is performed, with determination of transfer price, contribution, and amount payable to the customer. Following energization, an annual review will be conducted over the five year connection horizon. The economic evaluation will be updated with actual number of connections for the corresponding year. Additional payment to customer is determined and made.
- Final Economic Evaluation: Once the five year horizon is complete, InnPower carries out a final economic evaluation based on forecast revenues and actual costs.

The Economic Evaluation model considers several common elements of an expansion, related to the revenue forecast, expense forecast, and capital costs. InnPower is currently evaluating available options to accommodate the required Economic Evaluation payouts while maintaining levelized capital spending. Customer service requests for new or modified customer connections are also budgeted for each year and are driven by customer demand.

Third party infrastructure development requirements initiated by the County of Simcoe are also planned over the forecast period. As part of its transportation engineering plan, the County of Simcoe is widening Innisfil Beach Road ("**IBR**"), between Thornton on the west end to 20th Side Road on the east end, covering a distance of about 12 km. This project requires the relocation of a multi-circuit pole line to accommodate the road widening. The project commenced in 2012 and is expected to continue each year until 2021. The intersection of IBR and Yonge Street is scheduled for expansion in 2017. In the following years, sections of IBR are planned for widening: Yonge Street to 20th Side Road in 2018, Yonge Street to 10th Side Road in 2019, Highway 400 to 10th Side Road in 2020, and Highway 27 to 5th Side Road in 2021.

2.1.1.2 *System Renewal*

Capital investments in the system renewal category over the forecast period are driven by assets at the end of their service life. InnPower's distribution Asset Condition Assessment ("**ACA**"), which was completed in May 2016 based on asset inspection, maintenance, testing, and infrared scanning records, is a key input to this investment category and is included as Appendix E. Over the forecast period of the

[1] Ontario Energy Board, "Distribution System Code," *Last Rev.* Aug. 2014.

DSP, five (5) annual system renewal programs are budgeted each year to address the need to replace distribution assets at the end of their service life. These programs are:

- Substandard Transformer Rehabilitation, which updates legacy and substandard transformer construction within the distribution system;
- the Pole Replacement Program, which replaces poles that have been tested or deemed in need of replacement;
- the Infrastructure Replacements and Betterments Program, which replaces aged or defective devices;
- the Underground Padmounted Transformer and Switchgear Replacement and Painting Program, which repairs and renews switchgears and transformers that are adversely affected by weather conditions and salt contamination; and
- Line Recloser Refurbishments, which has all reclosers on a four-year cycle to rebuild and renew these sectionalizing devices ensuring correct operation every time.

The station ACA, which was completed in January 2016 based on inspection, testing, and infrared scanning results, is also a key input to this investment category and is included as Appendix F. Over the forecast period of the DSP, two (2) annual system renewal programs are budgeted each year to address the need to replace distribution assets at the end of their service life. These programs are:

- the DS Oil Re-inhibit Program, which helps to restore oxidation inhibitor levels inside the main tank of the station transformer to effective levels; and
- Station Rehabilitation projects, which are aimed at repairing the deteriorating infrastructure inside of InnPower's DS.

A number of overhead and underground rebuilds have been scheduled over the forecast period. The subtransmission infrastructure along Lockhart Road between Stroud DS and 25th Side Road will be replaced using a phased approach to maintain reliability on the 44 kV system. The 44 kV pole line north of Highway 89 on 5th Side Road will also be rebuilt using a phased approach starting in 2017, and continuing from 2019 to 2021.

At the distribution level, Ewart Street will receive a line upgrade south of Maple Road where several of the existing poles are sinking lower into the swamp land they were originally constructed on. Several other poles in this section have also been flagged for immediate replacement by pole inspectors. Starting in 2017 and phased over the forecast period, general reliability rebuild projects are scheduled to take place in the Alcona, Cookstown, and Lefroy areas. These projects include infrastructure upgrades and rehabilitation work replacing aged infrastructure to new construction standards for increased reliability. In 2018 and 2020, a two (2) year project will replace aged infrastructure spanning Highway 400 with the latest construction standards. There are two (2) back lot conversion projects each phased over two (2) years in 2019 and 2020, which will relocate legacy backyard infrastructure in order to provide better reliability, and worker and public safety. The forty (40) year-old direct-buried underground cables in Sandy Cove Acres will be replaced from 2019 to 2021to improve reliability. Finally, a project planned for Degrassi Cove in 2021 will replace overhead infrastructure in a heavily wooded section to underground to improve reliability.

In addition to the planned capital projects, unplanned system renewal projects are budgeted each year to allow for replacement of electrical infrastructure damaged by storms or unclaimed vehicle accidents.

2.1.1.3 *System Service*

System service investments over the forecast period are driven by load growth, reliability, and total cost management.

In 2011 InnPower replaced all of the hydraulic reclosers at the Leonard's Beach DS with newer vacuum reclosers that have microprocessor controls. The remaining hydraulic reclosers will be upgraded over the forecast period with the newer vacuum type reclosers. This initiative will help improve reliability by reducing outage duration while assisting efforts to track and mitigate momentary interruptions. In 2016, Stroud DS will be upgraded to vacuum type reclosers, while Sandy Cove DS will be upgraded in 2017 to complete the multi-year DS upgrade project. With the completion of this project InnPower will have SCADA capability between its control room and all of the DS.

In order to improve the reliability of the power delivered to our customers InnPower has systematically invested in upgrading its Distribution Automation and SCADA systems. InnPower has been deploying newer reclosers and SCADA-Mate switches throughout its system, also to improve reliability.

With the new SCADA program that was implemented in 2012 and the new outage management system ("**OMS**") commissioned in 2013, efforts were undertaken in 2014 and 2015 to construct a WiMAX communication network for use by both the Town of Innisfil and InnPower. Because of the increase in the use of unlicensed radio frequency in the area, InnPower and the Town were experiencing issues with intermittent communication caused by radio interference (noise). Due to the strict latency requirements for Distribution Automation and the increasing demand in bandwidth, acquiring a WiMAX 4G communication network operating on a licensed frequency dedicated by Industry Canada for electric utilities became the obvious choice to ensure grid communication reliability. The new communication network will be used by InnPower, the Town of Innisfil Water, and the Town of Innisfil Wastewater for SCADA and other monitoring and control applications.

For continued growth into InnPower's automation, 27.6 kV and 44 kV automated switches will be added each year starting in 2017, replacing several old mid-span openers and air break switches. These new switches provide remote switching capability and real-time data acquisition to better manage outages. Crew time will be reduced during emergency and non-emergency operations and built in functionality can be used for future self-healing configurations.

Automated capacitor controllers will be installed in 2019 and 2020 to monitor and control the amount of reactive power in the system, and from 2019 to 2020 two (2) motorized SCADA controlled padmounted switchgear will be installed each year in strategic locations for faster restoration during outages.

In the past ten (10) years InnPower has designed, installed, and commissioned one (1) DS (Belle Ewart DS). The population increase in InnPower's service territory has created the need to further increase InnPower's power supply capacity. Peak demand including embedded generation has been forecast to increase from approximately 52 MW in 2015 to 80 MW in 2021. Projects have been planned and paced to phase in new DS, capacity upgrades to existing stations, and line extensions to add circuitry to supply the new loads.

The load increase in the area served by the Cedar Point DS and the summer peak loads in 2015 indicate that the transformer will require the station capacity to be increased from a 5 MVA transformer to a 7.5 MVA during the summer of 2016. In an effort to serve the increased loads at Friday Harbour and part of the loads in the Barrie South developments a new DS is planned to be built in 2018 in the Friday Harbour area. Several of InnPower's DS do not have oil containment systems, therefore there are plans to complete one (1) station each year in 2017, 2019, and 2020, in order to mitigate environmental risk and manage cost.

A number of distribution system line upgrades have been planned to accommodate the growing load. Starting in 2016 a project will rebuild the circuitry on McKay Road between 5th Side Road and 10th Side Road as part of the master plan to serve new loads in the Barrie South lands by extending existing circuits. Another project will build a 27.6 kV line on the north side of Big Bay Point Road as part of the master plan to serve the new Friday Harbour developments. The pole line upgrade on Lockhart Road between 10th Side Road (Huronia Road) and Stroud DS will add two distribution circuits on a phased approach which will serve as a backbone link between the Barrie South development lands. Finally, in 2017 the pole line on Mapleview Drive between Prince William Way and Seline Crescent will be rebuilt to serve new residential loads on the south side of Mapleview Drive in the Barrie South lands.

Subtransmission upgrades have also been planned to accommodate the forecast level of load growth. In 2019 and 2020, a 44 kV pole line is planned to be replaced on 5th Side Road between 5th Line and IBR will take place to rebuild and replace the old small conductor infrastructure. This 44 kV line will be constructed to have an additional subtransmission circuit on it to accommodate the new Alliston 9M6 feeder scheduled to reach InnPower within the next decade.

In an effort to serve the increasing power demand and to provide reliable power, two (2) voltage conversion projects have been planned in multiple phases between 2019 and 2020 along the 400 Corridor and in South Alcona.

2.1.1.4 *General Plant*

Construction was completed for InnPower's new head office in 2015. The site includes a new control room and has space for customer service, engineering, finance, a warehouse, and a garage. A controller and software were added to increase functionality providing operators and on-call staff the tools required to maintain reliability. Between the years 2016 and 2020 further system integrations will be undertaken to achieve asset data integration.

InnPower has been modernizing its Information Technology ("**IT**") infrastructure by implementing SCADA software for use by system operators and backend enterprise systems to support the need for better data management and system integration. InnPower is in the process of reviewing the cost implications for upgrading the current IT infrastructure to accommodate the system requirements for the implementation of Demand Response programs. Over the forecast period, investments into the SCADA system have been planned as part of improvements to Distribution Automation, and distribution fault current indicators will be installed for each year except 2018.

In 2017, InnPower has planned for the replacement of a 1993 double bucket truck which was purchased second hand from another power company in 2010 and will be at the end of its useful life. Additionally, the replacement of a 2006 half-ton pickup truck used by Stores will be necessary given its condition and age. Four (4) new smaller technician vehicles will be required in 2017, and two (2) in 2018 to accommodate new full-time staff.

The increase in lines work and subdivision work resulting from the load growth has created the need to add a new line crew in 2018. The addition of this crew will require investment into a new bucket truck, a pickup truck for the foreman, and additional tooling and equipment. A Radial Boom Derrick ("**RBD**") truck will be purchased in the prior year (2017) and a tension machine will be purchased the following year (2019) to spread out the total investment required for the new crew.

In 2020, a 2005 half-ton truck will need to be replaced based on InnPower's Fleet Management Policy (see Section 3.3.1.11). Throughout the five year plan, replacement of smaller technician vehicles has been scheduled also based on the Fleet Management Policy.

Finally, tooling requirements to meet InnPower's ongoing needs has been budgeted for each year of the forecast period.

2.1.2 Anticipated Sources of Cost Savings (5.2.1b)

the sources of cost savings expected to be achieved over the forecast period through good planning and DS Plan execution

InnPower has identified through its planning process a number of anticipated sources of cost avoidance over the forecast period as described below.

Condition Based Asset Replacement

Condition based asset replacement through InnPower's ACA ensures that assets are replaced when they have reached end-of-life; therefore, avoiding the cost of replacing an asset too early or too late. The ACA also identifies assets which have the highest probability of failure. Replacing these assets before a failure occurs prevents outages and avoids the cost of emergency restoration and repair work. One example is the Pole Replacement Program, identified in the ACA through pole testing, which prioritizes the replacement of poles that are most likely to succumb to high winds during a storm. Another example is the Sandy Cove underground cable replacement, which is replacing direct buried cables at the end of their service life. Replacing these cables before a failure avoids expensive power restoration costs and long outage durations.

Distribution Plant Life Extension

Life extension of InnPower's distribution plant extends the useful life of the assets by deferring the capital investment until maintenance is no longer economical. Line reclosers are refurbished on a four (4) year cycle. Overhead 44 kV switches are maintained on a three (3) year cycle. Substation transformer oil is re-inhibited to extend its life. Other DS equipment receive maintenance on a four (4) year cycle. Pole top maintenance and butt treatment is performed where feasible to extend the useful life of poles. Finally, padmounted transformers and switchgear are painted as required to treat rust and prevent moisture ingress into the equipment.

Vehicle Life Extension

Large vehicles receive quarterly maintenance, including hydraulic maintenance, and yearly rust proofing. Small vehicles also receive yearly rust proofing and are maintained on an as-needed basis. Vehicles which are no longer useful may be retired early to avoid unnecessary upkeep costs. Vehicles can also be retired early if the expenses exceed depreciation.

In order to maximize the useful life of its vehicles, InnPower evaluates the following practices for each vehicle:

- the availability to rotate vehicles between users to maximize the mileage driven with respect to the vehicle's age;
- the ability to transfer a vehicle to another department where usage is less severe or to address a need for a spare vehicle or spare parts; and
- analysis of whether the vehicle is in sufficiently good shape to extend its useful life beyond the age and mileage guidelines.

Dual Voltage Equipment

The specification of dual voltage equipment for new developments in the South Barrie lands and Friday Harbour area will allow these developments to be served by the existing 8.32 kV substations until the new 27.6 kV Friday Harbour DS is constructed. Therefore, InnPower is able to defer the construction of Friday Harbour DS until 2018, one (1) year before the capacity in this area is exceeded.

Standardized Designs

InnPower uses USF standards in its designs in order to avoid the cost of making its own standards.

CHEC Membership

As a CHEC member, InnPower has access to a combined pool of staff shared with fifteen (15) other LDCs to perform "back office" functions, including customer service. CHEC is modeled after a cooperative to combine resources and competencies to best meet the requirements of the changing electrical industry and provide a high standard of locally supplied customer service. CHEC is governed by a Board of Directors which is responsible for ensuring that CHEC achieves its objectives, is financially accountable, and is in compliance with all relevant laws, regulations, and by-laws. CHEC has allowed members to exchange ideas on a variety of issues facing utilities, to initiate combined solutions, and to bestow previous experience.

Resource Sharing with the Town of Innisfil

InnPower shares resources with the Town of Innisfil to mutually save costs. InnPower's customer billing is combined with water and wastewater billing. Options to expedite Underground Locate Requests are also being explored. InnPower currently shares its wireless 4G communication network with the Town of Innisfil. As of 2016, InnPower's vehicle maintenance is expected to be performed in the Town of Innisfil's new facility. InnPower will continue to investigate additional shared service models with the Town of Innisfil, the City of Barrie, and the County of Simcoe.

IT Efficiencies

InnPower's IT strategy has been to automate tasks to avoid future costs. During the fourth quarter of 2015, a Customer Information System ("**CIS**") utilization review was conducted to identify area where process change, automation, and new add-ons could be implemented to maximize software and resource utilization. The NorthStar CIS automation platform will allow automation of routine processes. Prophix capital budgeting, forecasting, and planning software was added in 2015 to streamline these processes.

Springboard software, used to automate Human Resource and Safety training software was added in 2012 and Penny software for daily time reporting will be upgraded in 2016.

For engineering IT, additional CYME applications will be added in 2016 for improved planning capabilities. A work order management application will be added to the suite of engineering software in 2016. Between 2016 and 2020, further system integrations will be undertaken to achieve asset data integration. Smart meter data has been integrated into InnPower's OMS. Finally, Geographic Information System ("**GIS**") enhancements are scheduled for 2016 to improve functionality.

SCADA & OMS

The use of OMS when coordinating trouble calls will enable a more efficient deployment of resources when responding to outages. InnPower's OMS was recently upgraded to include smart meter data, which will allow the detection of service level outages on the OMS. InnPower's SCADA is equipped with fault locating capabilities to better direct crews to the location of the fault.

Automated Switching

System service projects to install automated switches will avoid the emergency and non-emergency crew time costs of manual switching.

Voltage Conversion

Voltage conversion projects avoid costs due to line losses by reducing the supplied current for the same supplied power.

Oil Containment

Planned projects to install oil containment systems in InnPower's DS are planned to avoid the potential cost of an expensive clean-up from an oil spill.

2.1.3 Period Covered by DSP (5.2.1c)

the period covered by the DS Plan (historical and forecast years)

This DSP covers a historical period of 2012 to 2016, where 2016 is the Bridge Year. The forecast period is 2017 to 2021, where 2017 is the Test Year.

2.1.4 Vintage of the Information (5.2.1d)

an indication of the vintage of the information on investment 'drivers' used to justify investments identified in the application (i.e. the information should be considered "current" as of what date?)

The information contained within this DSP should be considered "current" as of the end of 2015. Both ACA reports were completed based on information collected in 2015 and were finalized in May 2016.

2.1.5 Important Changes to Asset Management Processes (5.2.1e)

where applicable, an indication of important changes to the distributor's asset management process (e.g. enhanced asset data quality or scope; improved analytic tools; process refinements; etc.) since the last DS Plan filing

InnPower has not previously filed a DSP. Since its last rate filing application, InnPower has changed the frequency of its pole testing program from an eight (8) year cycle to a six (6) year cycle. The poles are tested using non-destructive devices that measure the moisture content of the wood just above ground level. The higher the moisture level within the wood relates to a higher level of deterioration. When a threshold level of moisture is detected, a resistograph is used to measure and calculate the remaining strength of the pole. The pole testing results are logged and pole replacement is scheduled as required. A pole replacement rate of 0.2% per year has been budgeted over the forecast period, which differs from the 4% per year previously assumed.

InnPower has moved to a more formalized condition based asset renewal program. The station ACA identifies and prioritizes equipment in InnPower's DS for replacement or refurbishment based on condition. Similarly, the distribution ACA identifies and prioritizes InnPower's distribution system assets for replacement or refurbishment based on available condition data.

InnPower continues to modernize its asset management policies and practices. InnPower is currently performing a cost-benefit analysis for performing diagnostic testing on underground testing. Due to evidence of copper theft at its DS, InnPower is considering security system implementation at each of its DS with access to an on-call security guard service. InnPower is also exploring options for enhanced resource sharing with the Town of Innisfil, including combining resources for Underground Locate Requests. It is anticipated that in 2016 vehicle maintenance will be done at the Town of Innisfil's new Operation Centre.

The implementation of remedial actions recommended from an AMI security audit completed in 2013 are still in progress. It is expected that additional security audits on smart meters will be performed as both the meters and the Regional Network Interface evolve. Another security audit has been scheduled for 2017. As a member of the PowerStream testing group, InnPower continues to test the latest Sensus technology to ensure its benefits and security. Installation of the next generation of smart meters commenced in 2014, enabling two-way communication for in-home devices with which consumers can monitor their electricity usage.

Since its last rate filing application, construction was completed for InnPower's head office at 7251 Yonge Street in Innisfil, Ontario. The site is in a commercially zoned area within the Town of Innisfil Roads & Parks administration campus. The operational hub is expected to achieve operational synergies between InnPower and the Town of Innisfil, such as the Town's fleet fuelling and maintenance centre expected to be constructed in 2017. The new building is LEED certified and has space for customer service, engineering, finance, a warehouse, and a garage. The new head office replaces the old site which consisted of three (3) wood frame buildings, two (2) used school portables, and outdoor storage for line hardware. Two (2) of the old lots were sold to the Town of Innisfil, while the outdoor storage lot is still in use. The new building has extra space for the anticipated future growth needs. It has been designed such that part of the building can be leased out to a commercial party until required.

Finally, since its last rate filing application, InnPower has purchased its first electric vehicle, which will avoid the carbon dioxide greenhouse gas emissions of a gasoline vehicle.

2.1.6 DSP Contingencies (5.2.1f)

aspects of the DS Plan that relate to or are contingent upon the outcome of ongoing activities or future events, the nature of the activity (e.g. Regional Planning Process) or event (Board decision on LTLT) and the expected dates by which such outcomes are expected or will be known.

System access investments are contingent on the needs of InnPower's customers and other third parties who initiate these projects. In particular, the IBR road widening project is contingent on the County of Simcoe's construction schedule.

The 44 kV subtransmission line rebuilds along 5th Side Road in 2019 and 2020 have been planned to accommodate an additional 44 kV circuit for the Alliston 9M6 feeder scheduled to reach InnPower within the next ten (10) years to serve the growing load, and is contingent on the construction of the new feeder.

The Regional Planning process concluded that a near term solution in the Barrie-Innisfil area requires Barrie TS to be rebuilt and upgraded and the autotransformers at Essa TS to be retired. This near term solution would address the infrastructure requirements for the forecast period of the DSP; however, the medium and long term transmission system plans in the area could potentially play a major role in a future DSP submitted by InnPower.

2.2 Coordinated Planning with Third Parties (5.2.2)

2.2.1 Consultation Descriptions (5.2.2a)

a description of the consultation(s), including

- ***the purpose of the consultation (e.g. Regional Planning Process);***
- ***whether the distributor initiated the consultation or was invited to participate in it;***
- ***the other participants in the consultation process (e.g. customers; transmitter; OPA);***
- ***the nature and prospective timing of the final deliverables (if any) that are expected to result from or otherwise be informed by the consultation(s) (e.g. Regional Infrastructure Plan; Integrated Regional Resource Plan); and***
- ***an indication of whether the consultation(s) have or are expected to affect the distributor's DS Plan as filed and if so, a brief explanation as to how.***

2.2.1.1 *PowerStream – Collaboration*

Purpose of the consultation:

On-going collaboration with PowerStream is undertaken to coordinate planning activities that occur close to the boundaries of the service territories. The most recent consultations are focusing on the possibility of adding conductors to PowerStream's pole line infrastructure to add conductors to serve Barrie Lands expansion. Other collaboration activities may arise in the future.

Whether InnPower initiated the consultation or was invited to participate in it:

InnPower initiated the consultation.

Other participants in the consultation process:

The only other participant in the consultation process is PowerStream.

Nature and prospective timing of final deliverables:

The consultation is on-going as of 8 March 2016. It is not known when final deliverables, if any, will be issued. Since this is an on-going activity, additional collaboration opportunities may yield additional timelines and deliverables in the future.

Whether the consultation has or is expected to affect the DSP:

This collaboration may affect InnPower's plans over the forecast period, but at this early stage of the collaboration it is too soon to predict.

2.2.1.2 *Town of Innisfil – Service Sharing*

Purpose of the consultation:

The purpose of this consultation is to consider collaboration options between utility owners in the Town of Innisfil. Service sharing opportunities that were discussed include joint locating services, a shared GIS, and shared payroll service.

Whether InnPower initiated the consultation or was invited to participate in it:

InnPower initiated the consultation.

Other participants in the consultation process:

The only other participant in the consultation process is the Operations department of the Town of Innisfil.

Nature and prospective timing of final deliverables:

This consultation is on-going and the nature and prospective timing of final deliverables is not known at this point.

Whether the consultation has or is expected to affect the DSP:

InnPower and the Town of Innisfil are planning to combine utility locating services over the forecast period. The cost savings expected to arise from this collaboration do not presently exist, so have not been incorporated into the DSP. Other service sharing opportunities such as a shared GIS and shared payroll service are under consideration and may or may not be realized over the forecast period.

2.2.1.3 *City of Barrie – Utilities Coordination Meeting*

Purpose of the consultation:

The purpose of this consultation is for the City of Barrie to present its capital plans to utility owners.

Whether InnPower initiated the consultation or was invited to participate in it:

InnPower was invited to participate in the consultation by the City of Barrie.

Other participants in the consultation process:

Other participants in the consultation process include the City of Barrie, PowerStream, Enbridge, Bell, Rogers, and other utilities.

Nature and prospective timing of final deliverables:

This is an annual consultation. The final deliverable is the City of Barrie's capital plans for the years, as well as growth and development estimates.

Whether the consultation has or is expected to affect the DSP:
The City of Barrie Utilities Coordination Meeting provides growth estimates for the City of Barrie that InnPower has used to plan its long term growth strategy to serve the South Barrie Lands. In particular, system service investments in each area are planned in accordance with the development plans for that area.

2.2.1.4 *OEB – Smart Grid Working Group & Advisory Committee*

Purpose of the consultation:
This is an Ontario-wide initiative for collaboration with various industry stakeholders to formulate a plan and strategy to implement the OEB's policies.

Whether InnPower initiated the consultation or was invited to participate in it:
InnPower was invited to participate in the consultation by the OEB.

Other participants in the consultation process:
This consultation involved many industry stakeholders and interest groups, including the OEB, several LDCs, the Building Owners and Managers Association, HONI, Schneider Electric, IBM, General Motors, the Ontario Ministry of the Environment, General Electric, DirectEnergy, Kinectrics, and the IESO.

Nature and prospective timing of final deliverables:
The committee evolved into two sub-groups: one to focus on energy storage and the other to focus on data access and cyber security. The work on these two issues is on-going.

Whether the consultation has or is expected to affect the DSP:
The consultation has not and is not expected to affect the DSP.

2.2.1.5 *Town of Innisfil – Administrative Development Advisory Committee Meetings*

Purpose of the consultation:
The Administrative Development Advisory Committee Meetings with the Town of Innisfil allow for the Town of Innisfil to share general information pertaining to its planned capital projects.

Whether InnPower initiated the consultation or was invited to participate in it:
InnPower was invited to participate in the consultation process by the Town of Innisfil.

Other participants in the consultation process:
The only other participant in this consultation process is the Town of Innisfil.

Nature and prospective timing of final deliverables:
This group has been re-branded under the new leadership of the Town of Innisfil; however, the Chief Administrative Officer, the senior leadership of the Town, and InnPower's President continue to meet on a regular basis.

Whether the consultation has or is expected to affect the DSP:
The consultation has not and is not expected to affect the DSP.

2.2.1.6 *Meetings with Developers, Consultants, City of Barrie, and Town of Innisfil*

Purpose of the consultation:

The purpose of this consultation is to collaborate with land developers and other stakeholders to educate them about InnPower's processes and requirements, as well as to obtain information that will assist InnPower in its planning process.

Whether InnPower initiated the consultation or was invited to participate in it:

InnPower initiated the consultation.

Other participants in the consultation process:

Other participants in this consultation process are the City of Barrie, the Town of Innisfil, consultants, land developers, builders, and engineers.

Nature and prospective timing of final deliverables:

InnPower obtains updated subdivision development plans.

Whether the consultation has or is expected to affect the DSP:

The subdivision development plans obtained from these meetings are incorporated into InnPower's planning process in creating this DSP. Development plans affect InnPower's customer growth projections, peak demand projections, and system access program estimates. InnPower aligns its infrastructure works in line with such plans, including the new substation planned in the north-east of InnPower's service territory, the Lockhart Road line rebuild, the Mapleview Drive line extension and line rebuild, the Lockhart Road line extension, the 5th Side Road line rebuild, and the line rebuild south of Belle Ewart DS.

2.2.1.7 *Town of Innisfil – Radio Communication Project Collaboration & Cost Sharing*

Purpose of the consultation:

The purpose of this consultation is to collaborate with the Town of Innisfil to explore cost sharing opportunities for the design, construction, operation, and maintenance of radio communication system for SCADA.

Whether InnPower initiated the consultation or was invited to participate in it:

InnPower initiated the consultation.

Other participants in the consultation process:

Other participants in this consultation process are the Town of Innisfil, and consultants.

Nature and prospective timing of final deliverables:

This collaboration is expected to be completed in the second quarter of 2016. When the project is completed the Town of Innisfil and InnPower will share the cost and usage of a WiMax based communication system that uses radio frequency spectrum allocated by Industry Canada for utility use.

Whether the consultation has or is expected to affect the DSP:

No. Although this project will be completed in Q2 of 2016 it does not impact the 2016 budget as it uses funds allocated in the previous year.

2.2.1.8 *DSP, ACA, and 5 year Budget Presentation and Review*

Purpose of the consultation:
The purpose of this consultation is for InnPower to educate its customers about its DSP, ACA, and five year budget and to obtain feedback.

Whether InnPower initiated the consultation or was invited to participate in it:
InnPower initiated the consultation.

Other participants in the consultation process:
Other participants in this consultation process included InnPower's customers and several interested stakeholders including the Mayor of Innisfil, Town of Innisfil Councillors, and media representatives.

Nature and prospective timing of final deliverables:
The deliverables and plans outlined in the DSP received positive reviews during this presentation; hence InnPower will keep the course as outlined. InnPower will continue to seek feedback from its customers and extend its reach to commercial and industrial customers in the future.

Whether the consultation has or is expected to affect the DSP:
The positive feedback provided stakeholder acceptance for InnPower's DSP and did not prompt any changes to be made to the DSP.

2.2.2 Regional Planning Process (5.2.2b)

where a final deliverable of the Regional Planning Process is available, the final deliverable; where a final deliverable is expected but not available at the time of filing, information indicating:

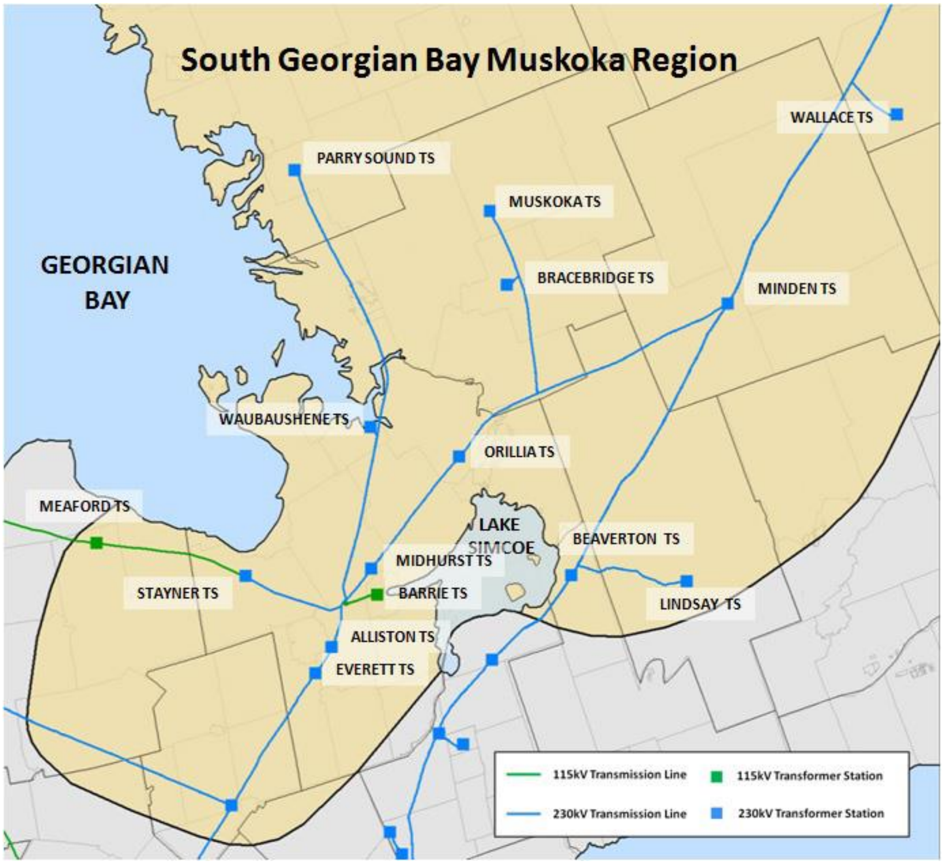
- ***the role of the distributor in the consultation;***
- ***the status of the consultation process; and***
- ***where applicable the expected date(s) on which final deliverables are expected to be issued.***

InnPower is part of the South Georgian Bay/Muskoka planning region, shown in Figure 2-1. The planning region includes the following participants:

- IESO
- HONI Transmission
- HONI Distribution
- InnPower
- Lakeland Power
- Midland PUC
- Newmarket- Tay Power
- Orangeville Hydro
- Orillia Power
- PowerStream
- PowerStream COLLUS
- Veridian Connections

- Wasaga Distribution

Figure 2-1: South Georgian Bay/Muskoka region



A Needs Assessment for the region was initiated on 2 January 2015 and completed on 3 March 2015. Based on the Needs Assessment, a Scoping Assessment was initiated on 23 March 2015 and completed on 22 June 2015. Integrated Regional Resource Plan ("**IRRP**") is underway. Each of these is detailed below.

2.2.2.1 *Needs Assessment*

A Needs Assessment was carried out by HONI for the South Georgian Bay/Muskoka region. This Needs Assessment included a study of transmission system and connection facilities capability up to 2023, which covers station and line loading, thermal and voltage analysis, system reliability, operational issues such as load restoration, and assets approaching end-of-life. The report identified several needs in the region that may require regional coordination, and concluded that these needs should be reviewed further under the IESO-led Scoping Assessment process.

Purpose: To identify if there are any electricity needs in the region that require regional coordination.

Participants: HONI, IESO, PowerStream, InnPower, Veridian, and Orangeville Hydro.

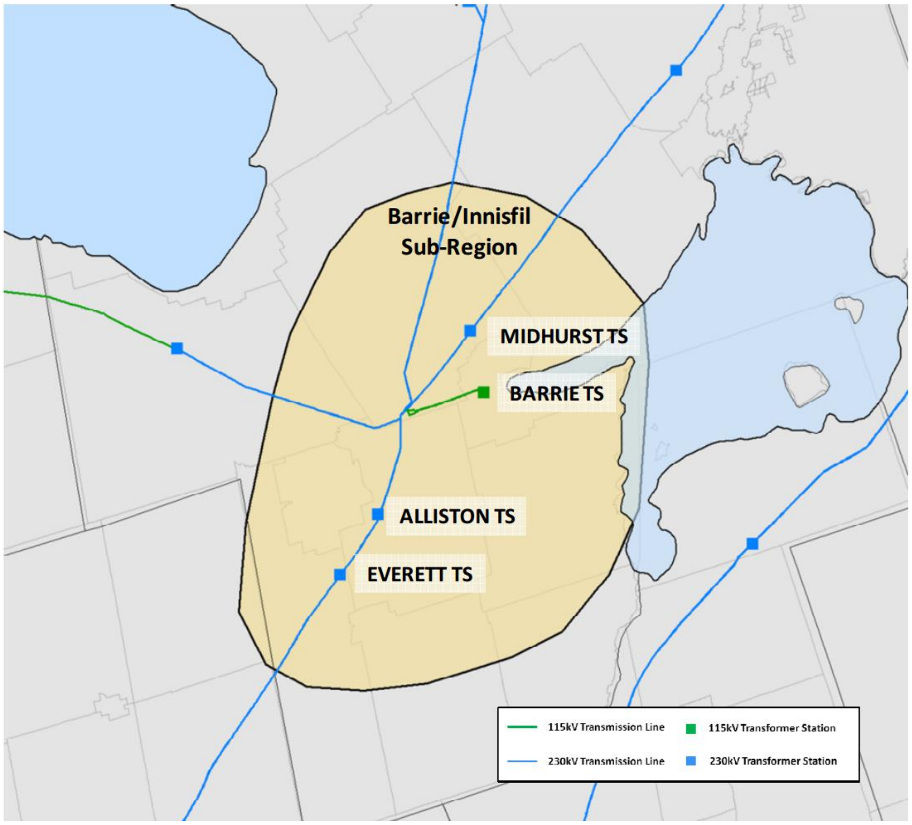
Status: Complete.

Deliverables: Needs Assessment Report issued by HONI on 3 March 2015 (provided in Appendix B).

2.2.2.2 *Scoping Assessment*

The Regional Participants consisting of the IESO, Hydro One and the local distribution companies servicing the region further reviewed the identified needs to determine the best planning approach for the region, and have identified two sub-regions – Barrie/Innisfil (depicted in Figure 2-2) and Parry Sound/Muskoka. The Scoping Assessment Outcome Report defines sub-regions, working groups for each sub-region for the IRRP, the regional planning approach, scopes for each sub-region, and terms of reference. The Scoping Assessment concluded that individual IRRPs are necessary for the Barrie/Innisfil and Parry Sound/Muskoka sub-regions, and that additional needs identified through the Needs Assessment would be addresses by HONI and the affected LDCs.

Figure 2-2: Barrie/Innisfil sub-region



Purpose: To further review the needs identified, in combination with information collected as part of the Needs Assessment and information on potential wires and non-wires alternatives, in order to assess and determine the best planning approach for the whole or parts of the region.

Participants: IESO in collaboration with the South Georgian Bay/Muskoka regional participants.

Status: Complete.

Deliverables: Scoping Assessment Outcome Report issued by IESO on 22 June 2015 (provided in Appendix C).

2.2.2.3 *Integrated Regional Resource Plan*

Working Groups have been established to undertake IRRPs for each sub-region to address the needs in these areas. Identified needs related to the bulk transmission system supplying this region will be addressed in parallel with the IRRP process by the IESO, with results communicated to the Regional Participants.

Purpose: To address the end-of-life of Barrie TS, load growth within the sub-region, and capacity constraints for the 230/115 kV autotransformer at Essa TS.

Participants: HONI, IESO, InnPower, and PowerStream.

Status: In progress.

Timeline: The IRRP is expected to take eighteen (18) months.

Deliverables: The hand-off letter from the IESO regarding the near term wires solutions was provided to HONI on 7 December 2015 (provided in Appendix D). The recommendations of the hand-off letter are:

- to rebuild the existing 115 kV Barrie TS and E3/4B transmission line and to upgrade the voltage of these facilities to 230 kV;
- to upgrade the transformers at Barrie TS from 55/92 MVA units to 75/125 MVA units; and
- to retire the two (2) 230/115 kV autotransformers at Essa TS (T1 and T2).

The Working Group for the Barrie/Innisfil sub-region is continuing to work on the development of medium and long term plans for the sub-region. These include:

- constructing a new 230 kV TS (InnPower TS);
- constructing a new 230kV transmission line from Barrie TS to the InnPower TS site;
- implementing a high voltage distribution system ("**HVDS**") at 230 kV and 27.6 kV egressing from InnPower TS; and
- proposing a 44 kV solution for the load growth in South Barrie.

Effects on the DSP: The Working Group has identified South Barrie as a key load growth point. This area is serviced by both InnPower and PowerStream. The near term solution would address the infrastructure requirements within the current DSP period; however, as the medium and long term plans consider the construction of a new TS, HVDS, and transmission lines within InnPower's service territory the outcome of these plans would potentially play a major role in the DSP submitted by InnPower in the future.

2.2.3 IESO Comment Letter (5.2.2c)

> ***the comment letter provided by the OPA in relation to REG investments included in the distributor's DS Plan (see 5.2.4.2), along with any written response to the letter from the distributor, if applicable.***

The REG Investments Plan for the forecast period was prepared by InnPower and submitted to the IESO on 31 December 2015. This report is presented in Appendix G, and the IESO Comment Letter is presented in Appendix H. InnPower had employed the services of an engineering consulting firm, METSCO Energy Solutions ("**METSCO**"), to analyze its circuits for REG connectivity, calculate available capacity for REG connection on each feeder, and advise on options available to increase REG connection capacity.

Based on METSCO's evaluations, and considering the sum of both existing connections and applications being processed, two (2) distribution feeders have been identified on InnPower's distribution system as having reached the threshold for distributed generation connectivity, as per the criteria described in the IEEE Std 1547-2003, *IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems*. However, METSCO has recommended that InnPower should consider a different methodology than is referenced in IEEE Std 1547, which is based on induction motor simulations (the REG connected to InnPower's system is inverter based). Instead, InnPower should consider a preferred methodology of performing dynamic (real time based) studies using an Electromagnetic Transients Program ("**EMTP**") to calculate real time constraints on each phase of every feeder that would more accurately determine actual constraints on the grid, and to develop methodologies and specific projects to enhance REG connectivity subsequent to the EMTP analysis.

InnPower is currently reviewing METSCO's recommendations and is considering the feasibility of an EMTP study. Therefore, InnPower is not proposing any capital investments at this time to mitigate constraints on the distribution system. InnPower did not provide a written response to the IESO's comment letter.

2.3 Performance Measurement for Continuous Improvement (5.2.3)

This section identifies and defines the methods and measures used to monitor distribution system planning process performance, sets targets, reports on historical performance, and summarizes how this information has been incorporated into the DSP.

2.3.1 Methods and Measures (5.2.3a)

identify and define the methods and measures (metrics) used to monitor distribution system planning process performance, providing for each a brief description of its purpose, form (e.g. formula if quantitative metric) and motivation (e.g. consumer, legislative, regulatory, corporate). These measures and metrics are expected to address, but need not be limited to:

- ***customer oriented performance (e.g. consumer bill impacts; reliability; power quality);***
- ***cost efficiency and effectiveness with respect to planning quality and DS Plan implementation (e.g. physical and financial progress vs. plan; actual vs. planned cost of work completed); and***
- ***asset and/or system operations performance.***

InnPower has identified a number of metrics that it currently tracks or will begin to track over the forecast period which pertain to the three performance measures of customer-oriented performance, cost efficiency and effectiveness, and asset/system performance. These have been summarized in Table 2-2 and are identified and defined in further detail below.

Table 2-2: Performance measures, indicators, and metrics

Performance Measure	Indicator	Motivation	Metric
Customer-oriented performance	Customer satisfaction	Consumer	Customer survey results
	Consumer bill impacts	Consumer	[Not Tracked]
	Reliability	Consumer Regulatory	SAIFI SAIDI CAIDI Outage duration by cause code
	Power quality	Consumer	Number of power quality complaints
	Service quality	Consumer Regulatory	Telephone accessibility Telephone abandon rate Low voltage connections High voltage connections Appointments scheduling Appointments met Missed appointment rescheduling Written response to enquiries Emergency response – rural Emergency response – urban Reconnection performance standards Billing accuracy
Cost efficiency and effectiveness	DSP implementation	Regulatory Corporate	Physical progress vs. plan Financial progress vs. plan Actual vs. planned cost of work completed
	Total operating cost	Consumer Corporate	Total operating cost per customer Total operating cost per km of line
	Customer/employee ratio	Corporate	Customer/employee ratio
	Reduction in overtime	Corporate	Annual overtime cost
Asset/system performance	Distribution losses	Corporate	Percentage line loss
	Power factor	Corporate	Power factor

2.3.1.1 *Customer Survey Results*

Customer survey results are used to gain insights into InnPower's performance relative to customers' needs and expectations. UtilityPULSE completes an annual customer satisfaction survey for CHEC, which InnPower is a member of. Key results of the customer satisfaction survey are customer opinions of InnPower (CHEC) relative to the national and provincial average on issues such as "deals professionally with customer problems" and "provides good value for money". InnPower does not have a specific target for these customer opinions, but strives to be at or better than both the provincial and national averages. The UtilityPULSE survey results have been included as Appendix I.

The scores included in the customer satisfaction survey ranks utilities on customer care, company image, and management operations. The Customer Centric Engagement Index ("**CCEI**") is based on participation in programs, offerings, or services, proactive customer outreach, customer loyalty, and how customers think, feel or act towards InnPower; while the Customer Experience Performance Index ("**CEPI**") accounts for InnPower's customer experiences over the phone, online, and in person. Finally, the scorecard includes customer opinions on outage problems and perceived billing problems. As with other survey results, InnPower does not have a specific target for its customer scorecard, but strives to be at or better than both the provincial and national averages.

2.3.1.2 *Consumer Bill Impacts*

InnPower does not have a specific metric for monitoring consumer bill impacts. However, this mandate will be given due consideration over the forecast period and the necessary measures will be undertaken to minimize and mitigate the impact keeping in mind both the concerns of the customers and the needs of the business.

2.3.1.3 *Reliability*

The key metrics that InnPower tracks to measure reliability are the System Average Interruption Frequency Index ("**SAIFI**"), System Average Interruption Duration Index ("**SAIDI**"), and Customer Average Interruption Duration Index ("**CAIDI**"). SAIFI is the average frequency of sustained power interruptions and is calculated by dividing the total number of customer interruptions over a given year by the total number of customers served. SAIDI is the average outage duration and is calculated by dividing the total number of customer-hours of sustained interruptions over a given year by the number of customers served. CAIDI reflects the average time for electricity service to be restored following an outage and is calculated by dividing the total customer-hours of sustained interruptions over a given year by the total number of sustained interruptions for that year (also by dividing SAIDI by SAIFI). InnPower's SAIFI target is 1.19 or less and its SAIDI target is 2.10 or less. InnPower does not have a specific target for CAIDI.

In addition, the root cause of power interruptions is monitored and analyzed. Each power outage that occurs on InnPower's distribution system is recorded and an outage cause code is assigned. The number of customer interruption hours for each cause code provides a picture of the root cause of power interruptions. There are no targets for root cause of power interruptions, but it is monitored for investment planning purposes.

2.3.1.4 *Power Quality*

InnPower tracks the number of complaints it receives that pertain to power quality. InnPower targets zero (0) unresolved power quality complaints, as a yearly metric.

2.3.1.5 *Service Quality*

The *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 *Energy Competition Act, 1998*. As required by the OEB, InnPower records and submits all performance measures, which are compared with the OEB's established levels to evaluate InnPower's customer service quality. The performance measures are described below, as defined in the *Distribution System Code*.

2.3.1.5.1 Telephone Accessibility

The OEB requires that qualified incoming calls to the distributor's customer care telephone number must be answered within the thirty (30) second time period as established below:

- For qualified incoming calls that are transferred to the distributor's interactive voice response system, the thirty (30) seconds shall be counted from the time the customer selects to speak to a customer service representative.
- In all other cases, the thirty (30) seconds shall be counted from the first ring.

The target for this metric is 65%.

2.3.1.5.2 Telephone Call Abandon Rate

As required by the OEB, the number of qualified incoming calls to a distributor's customer care telephone number that are abandoned before they are answered shall be 10% or less on a yearly basis. A qualified incoming call will only be considered abandoned if the call is abandoned after the thirty (30) second time period has elapsed.

2.3.1.5.3 Connection of New Services

The OEB sets out the following requirements for the connection of new services:

- A connection for a new service request for a low voltage ("**LV**") (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 distributor.
- A connection for a new service request for a high voltage ("**HV**") (greater than 750 V) service must be completed within ten (10) business days from the day on which all applicable service conditions are satisfied, or at such a later date as agreed to by the customer and distributor.

The target for this metric is 90%.

2.3.1.5.4 Appointment Scheduling

When a customer or a representative of a customer requests an appointment with a distributor, the distributor shall schedule the appointment to take place within five (5) business days of the day on which all applicable service conditions are satisfied, or on such a later date as may be agreed upon by the customer and the distributor. This includes Underground Locate Requests. The target for this metric is 90%.

2.3.1.5.5 Appointments Met

When an appointment is either:

- requested by a customer or a representative of a customer; or
- required by a distributor with a customer or a representative of a customer,

the distributor must offer to schedule the appointment during the distributor's regular hours of operation within a window that is no greater than four (4) hours. The distributor must then arrive for the appointment within the scheduled timeframe. This includes Underground Locate Requests. The target for this metric is 90%.

2.3.1.5.6 Rescheduling a Missed Appointment

When an appointment with a customer or a representative of a customer is going to be missed, a distributor must:

- attempt to contact the customer before the scheduled appointment to inform the customer that the appointment will be missed; and
- attempt to contact the customer within one (1) business day to reschedule the appointment.

The target for this metric is 100%.

2.3.1.5.7 Written Responses to Enquiries

A written response to a qualified enquiry shall be sent by a distributor within ten (10) business days. The target for this metric is 80%.

2.3.1.5.8 Emergency Response

Emergency calls (i.e. assistance by the distributor has been requested by fire, police, or ambulance services) must be responded to within two (2) hours in rural areas and within one (1) hour in urban areas. The target for this metric is 80%.

2.3.1.5.9 Reconnection Performance Standards

Where a distributor has disconnected the property of a customer for non-payment, the distributor shall reconnect the property within two (2) business days of the date on which the customer:

- makes payment in full of the amount overdue for payment as specified in the disconnection notice; or
- enters into an arrears payment agreement with the distributor.

The target for this metric is 85%.

2.3.1.5.10 Billing Accuracy

The percentage of bills accurately issued is calculated by subtracting the number of inaccurate bills issued for the year from the total number of bills issued for the year and dividing that number by the total number of bills issued for the year (the total number of bills issued for the year includes original and reissued bills). Accurate bills that need to be cancelled in order to correct another bill shall not be included in the calculation of billing accuracy measure. A distributor should not include customer accounts that are unmetered accounts (e.g. street lighting and unmetered scattered loads) or power generation accounts when calculating the percentage of accurate bills.

A bill is considered inaccurate if:

- the bill contains incorrect customer information, meter readings, or rates; or
- the bill has been issued to the customer and subsequently cancelled due to a billing error; or
- there has been a billing adjustment in a subsequent bill as a result of a previous billing error.

The target for this metric is 98%.

2.3.1.6 *DSP Implementation*

In order to ensure good planning quality and improved productivity, InnPower will be monitoring its physical and financial progress of the DSP execution versus the plan. InnPower will also be monitoring the actual versus planned cost of work completed for this project. As this is InnPower's first DSP filing, no targets have been set for these metrics.

2.3.1.7 *Total Operating Cost*

Total operating cost per customer is calculated by dividing InnPower's total operating cost for a given year by the number of customers it serves. Similarly, the total operating cost per kilometre of line is calculated by dividing InnPower's total operating cost for a given year by the length of primary distribution circuits on its system. InnPower does not have a specific target for either of these metrics.

2.3.1.8 *Customer/Employee Ratio*

InnPower tracks the ratio of the number of its customers to the number of its employees. This ratio is projected to decrease up to 2018 as the number of employees increases to accommodate load growth, and increase after 2018 as new customers are connected to the system. InnPower does not have a specific target for customer/employee ratio.

2.3.1.9 *Reduction in Overtime*

InnPower tracks its overtime costs each year and strives to cut costs by reducing overtime costs. InnPower does not have a specific target for a reduction in overtime costs.

2.3.1.10 *Distribution Losses*

InnPower tracks its distribution losses in kWh and as a percentage of the total energy delivered to its customers. InnPower does not have a specific target for percentage line loss.

2.3.1.11 *Power Factor*

InnPower monitors the power factor at various points in its system, defined as the ratio of the real power supplied to the total power supplied (including reactive power). InnPower does not have a specific target for power factor on its distribution system.

2.3.2 Historical Performance (5.2.3b)

provide a summary of performance and performance trends over the historical period using the methods and measures (metrics/targets) identified and described above. This summary must include historical period data on: 1) all interruptions; and 2) all interruptions excluding loss of supply' for a) the distribution system average interruption frequency index; b) system average interruption duration index; and c) customer average interruption duration index.
Where performance assessments indicate marked adverse deviations from trend or targets (including any established in a previously filed DS Plan), provide a brief explanation and refer to these instances individually when responding to provision 'c)' below.

2.3.2.1 *Customer Survey Results*

Table 2-3 presents CHEC's customer survey results, through which InnPower's customer service is provided, for the year 2014 compared to the national and provincial averages. CHEC (InnPower) exceeded the national and provincial average in each of the customer opinion fields. The UtilityPULSE survey results have been included as Appendix I.

Table 2-3: InnPower customer survey results (2014)

	CHEC/InnPower	National Average	Ontario Average
Deals professionally with customer problems	87%	82%	78%
Pro-active in communicating changes and issues affecting customers	81%	74%	73%
Quickly deals with issues that affect customers	85%	79%	74%
Customer-focused and treats customers as if they are valued	83%	74%	72%
Is a company that is easy to do business with	88%	79%	75%
Cost of electricity is reasonable when compared to other utilites	64%	60%	55%
Provides good value of money	73%	67%	63%
Delivers on its service commitments to customers	89%	84%	82%

Table 2-4 summarizes the customer satisfaction scorecard results for CHEC (InnPower) for 2014 and 2013 as compared to national and provincial averages. InnPower met or exceeded the national and provincial average in each case except for Outage Problems in 2013, although InnPower's reliability metrics were better than industry average in 2013. Customer Care and CCEI decreased from 2013 to 2014, while Billing Problems increased over the same period due to the roll-out of TOU billing and increased rates outside of distribution rates, which customers perceive as billing issues.

Table 2-4: InnPower customer satisfaction scorecard (2013-2014)

	Year	InnPower/CHEC	National Average	Ontario Average
Customer Care	2014	B+	B+	B
	2013	A	B+	B+
Company Image	2014	A	B+	B+
	2013	A	A	A
Management Operations	2014	A	A	A
	2013	A	A	A
Customer Centric Engagement Index (CCEI)	2014	83%	79%	76%
	2013	86%	81%	81%
Customer Experience Performance Index (CEPI)	2014	87%	82%	79%
	2013	87%	83%	83%
Outage Problems	2014	36%	47%	49%
	2013	36%	41%	35%
Billing Problems	2014	12%	16%	25%
	2013	10%	8%	10%

2.3.2.2 *Consumer Bill Impacts*

As stated above, InnPower does not currently have a metric for consumer bill impacts, but will give due consideration to consumer bill impacts over the forecast period.

2.3.2.3 *Reliability*

Figure 2-3 summarizes InnPower's SAIFI performance over the historical period (2012 and up to the third quarter of 2015), including and excluding loss of supply. In 2014, SAIFI excluding loss of supply exceeded the target of 1.19. Figure 2-4 summarizes InnPower's SAIDI performance over the historical period (2012 and up to the third quarter of 2015), including and excluding loss of supply. In 2014, SAIDI excluding loss of supply exceeded the target of 2.10. Finally, Figure 2-5 summarizes InnPower's CAIDI performance over the historical period (2012 and up to the third quarter of 2015), including and excluding loss of supply. CAIDI is highest in 2015, when SAIDI is lowest.

Figure 2-3: SAIFI including and excluding loss of supply (2012-2015)

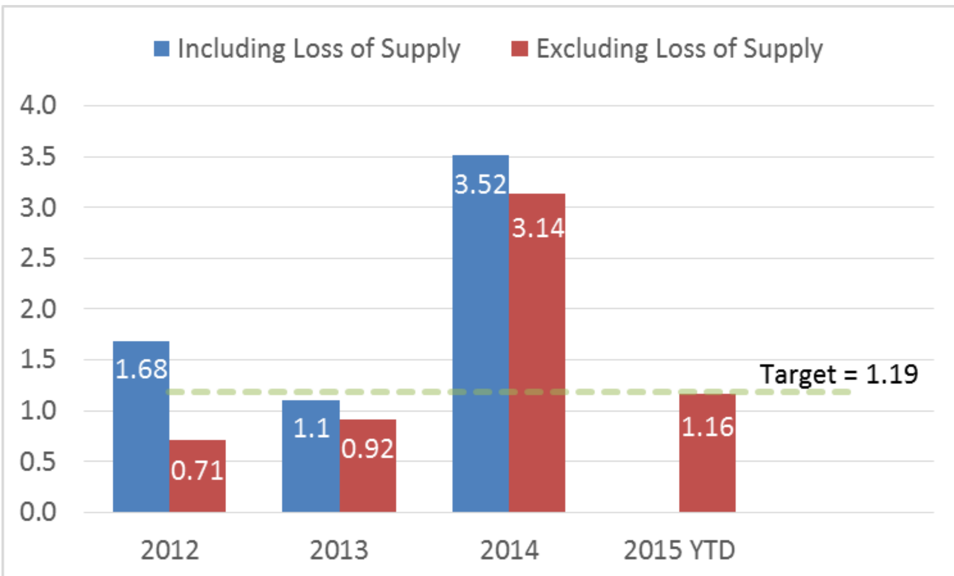


Figure 2-4: SAIDI including and excluding loss of supply (2012-2015)

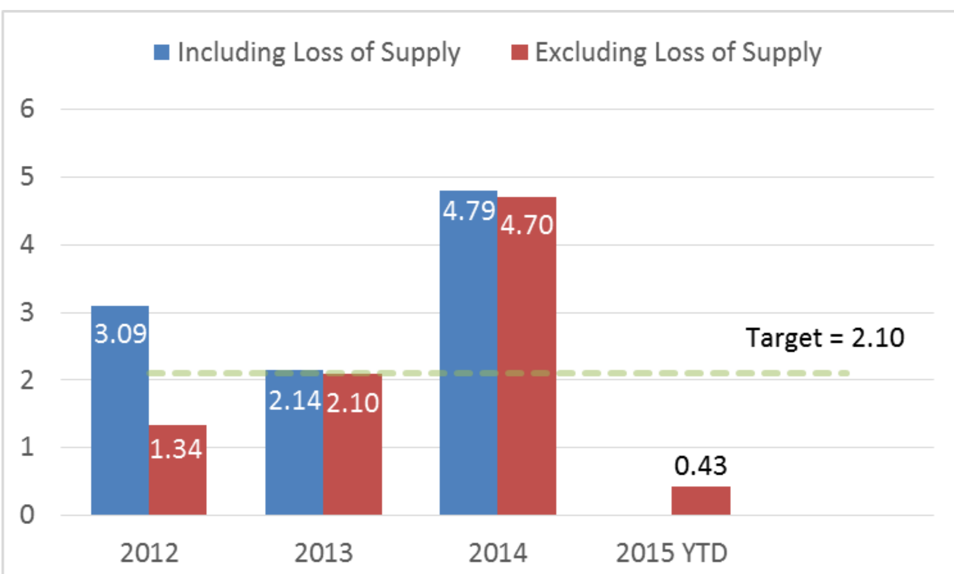
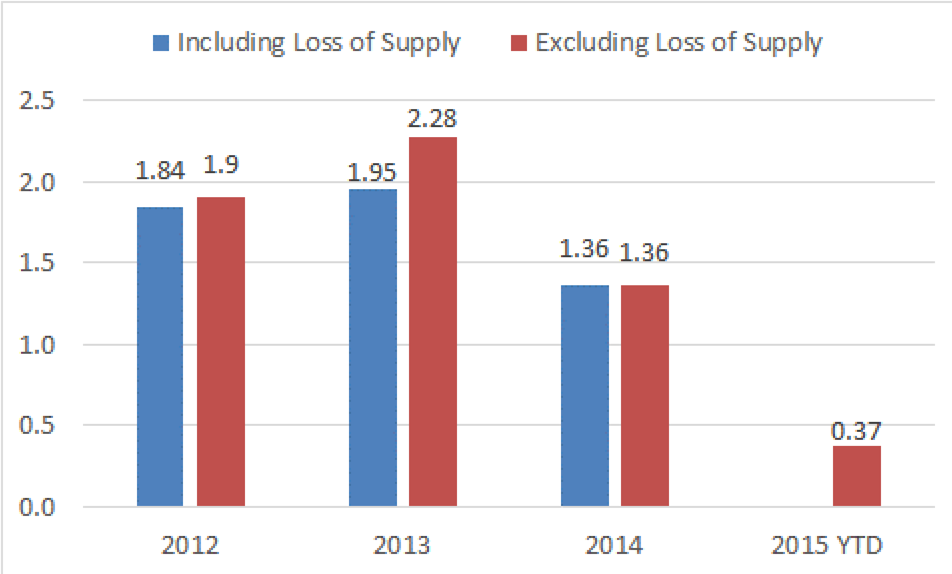


Figure 2-5: CAIDI including and excluding loss of supply (2012-2015)



Most of these outages would qualify as Major Event Days under the IEEE Std 1366-2012 2.5β methodology. During 2014 there were a number of major outages due to adverse weather, defective equipment, and foreign interference. On 5 February 2014, a permanent fault on a 27.6 kV circuit due to a failed switchgear tripped the Alliston 9M4 subtransmission feeder and Thornton DS (owned by HONI). During sectionalisation, it was found that the T2 substation transformer out of Brian Wilson DS that supplies a major customer base had sustained a catastrophic failure. In order to restore power, the 27.6 kV circuit had to be reconfigured and temporary switches had to be installed.

Multiple outages occurred on 14 April 2014 due to a major storm that damaged multiple poles owned by HONI, PowerStream, and InnPower. Trees that fell onto power lines due to the severe wind. InnPower lost the 13M3 subtransmission circuit, HONI owned Thornton F2 feeder, and the red phase of Innisfil F2.

During a storm on 3 June 2015, a large broken tree caused an outage on 13M3 (a 44 kV subtransmission supply). Crews isolated the faulted line section and sectionalized power back to InnPower's DS. During restoration, in-rush currents caused the HONI 13M3 subtransmission feeder to trip. The cause for the trip were incorrect protection and control ("**P&C**") settings at the upstream TS owned by HONI.

Multiple outages were experienced on the 17th and 18th of June 2014 due to a downburst. Poles were damaged and trees fell on power lines.

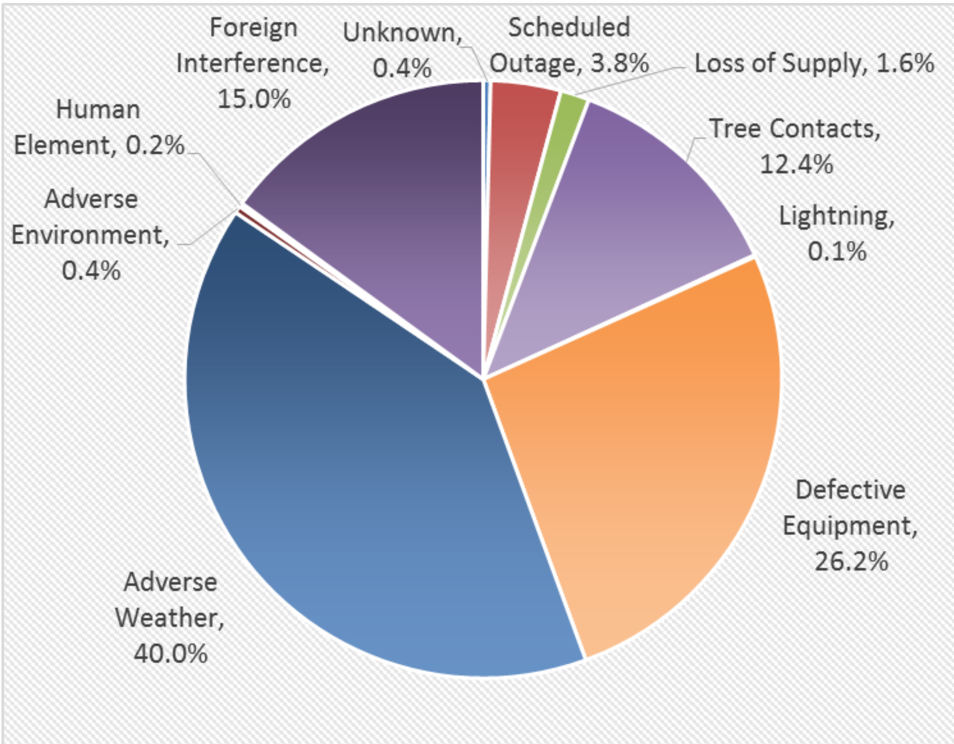
A truck for a third party construction company hit a subtransmission line on 20 June 2014. The Alliston 9M1 supply was therefore lost. During the time of the outage InnPower crews had transferred load from the Alliston 9M2 to 9M1 for scheduled maintenance. Customers fed from both the 44kV subtransmission circuits were therefore affected. Three (3) major InnPower DS were out of power due to a loss of supply.

A major storm on 5 September 2014 caused various outages within InnPower's service territory due to broken poles and trees on power lines. Four (4) InnPower distribution feeders were affected by these outages.

Finally, on 25 September 2014, a construction truck hit a 44 kV subtransmission pole causing an outage on the Alliston 9M2 feeder. Three (3) InnPower DS were impacted by the loss of supply.

Figure 2-6 summarizes the outage duration by cause code for the years 2012 to 2015. Over the historical period, the biggest contributor to customer outages was adverse weather. Other major contributors were defective equipment, foreign interference, and tree contacts.

Figure 2-6: Outage duration by cause code (2012-2015)



2.3.2.4 *Power Quality*

In 2012 and 2013 there were no power quality complaints. In 2014 there was one (1) power quality complaint and in 2015 there was also one (1) power quality complaint, both of which were resolved. Table 2-5 summarizes the power quality complaints received and resolved over the historical period.

Table 2-5: Power quality complaints received and resolved (2012-2015)

Metric	Target	2012	2013	2014	2015
# of Power Quality Complaints	No target	0	0	1	1
# of Unresolved Complaints	0	0	0	0	0

2.3.2.5 *Service Quality*

Table 2-6 summarizes InnPower's historical service quality performance for the years 2012 to 2014 and up to the third quarter of 2015. In 2013, InnPower scored 89.95% on Connection of New LV Services, which is slightly below target. There was a 16% increase in connections in 2013 compared to 2012, which negatively affected this service quality measure. Beginning in 2012, all Underground Locate Requests and Connections of New Services were included in the Appointments Scheduling and Appointments Met metrics. Underground Locate Requests that were not completed within five (5) days did not meet the minimum performance standard, causing substandard performance in these categories in 2012 and 2013. As a result, InnPower initiated a review process for Appointments Scheduling and Appointments Met (including Underground Locate Requests) and implemented process changes in 2014 to improve these metrics.

Table 2-6: Service quality performance (2012-2015)

Measure	Target	2012	2013	2014	2015 YTD
Telephone Accessibility	> 65%	74.60%	67.10%	70.60%	79.62%
Telephone Call Abandon Rate	< 10%	6.78%	9.15%	7.51%	9.63%
Connection of New Services - LV	> 90%	95.25%	89.95%	96.43%	97.49%
Connection of New Services - HV	> 90%	N/A	N/A	N/A	N/A
Appointments Scheduling	> 90%	64.30%	83.00%	94.40%	98.75%
Appointments Met	> 90%	64.35%	88.14%	94.37%	92.00%
Missed Appointment Rescheduling	100%	N/A	N/A	100.00%	N/A
Written Response to Enquiries	> 80%	100.00%	100.00%	98.40%	100.00%
Emergency Response – Urban	> 80%	N/A	N/A	N/A	N/A
Emergency Response - Rural	> 80%	100.00%	100.00%	100.00%	100.00%
Reconnection Performance Standards	> 85%	97.20%	98.60%	98.90%	
Billing Accuracy	> 98%	N/A	N/A	99.95%	

2.3.2.6 *DSP Implementation*

Because this is InnPower's first DSP, it does not have any historical data on DSP implementation.

2.3.2.7 *Total Operating Cost*

Figure 2-7 summarizes InnPower's total operating cost per customer for the years 2012 to 2014. The total operating cost per customer increased by 4% from 2013 to 2014. Going forward, utility costs are expected to keep pace with economic fluctuations; however, InnPower will 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.

Figure 2-7: Total operating cost per customer (2012-2014)

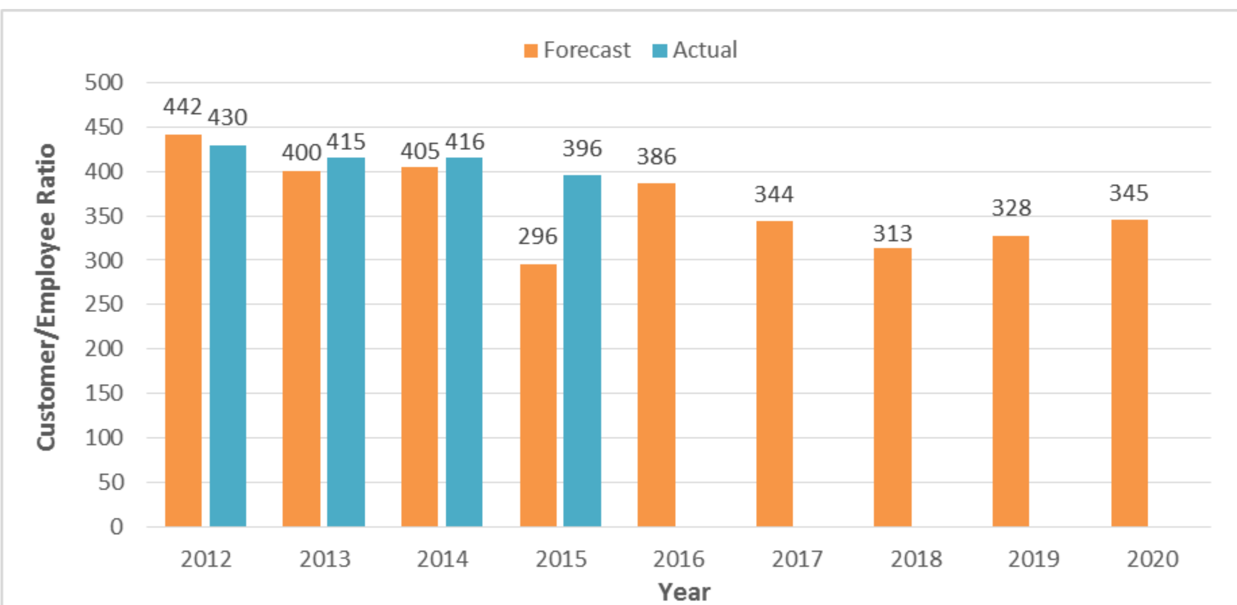
Figure 2-8 summarizes the total operating cost per kilometre of line for the years 2012 to 2014. This measure uses the same total operating cost that is used in Figure 2-7 above. Based on this, there was a 4% increase in total operating cost per kilometre of line from 2013 to 2014. InnPower's growth rate for its service territory is considered to be medium, which has assisted InnPower's ability to fund future capital projects and incur operating costs to support new infrastructure and growth. As a result, the total operating cost per kilometre is expected to increase as capital and O&M costs also increase. InnPower will continue to seek innovative solutions to help ensure that the total operating cost per kilometre of line remains competitive and within acceptable limits for InnPower's customers.

Figure 2-8: Total operating cost per km of line (2012-2014)

2.3.2.8 *Customer/Employee Ratio*

Figure 2-9 presents the forecast customer/employee ratio for the years 2012 to 2020 and the actual values for 2012 to 2015. Over the historical period, InnPower's customer/employee ratio has decreased as new employees are hired to accommodate regional growth. It is expected that the customer/employee ratio will continue to decrease until 2018 as more employees are hired and then begin to increase in 2019 as InnPower's customer base grows.

Figure 2-9: Forecast (2012-2020) and actual (2012-2015) customer/employee ratio



2.3.2.9 *Reduction in Overtime*

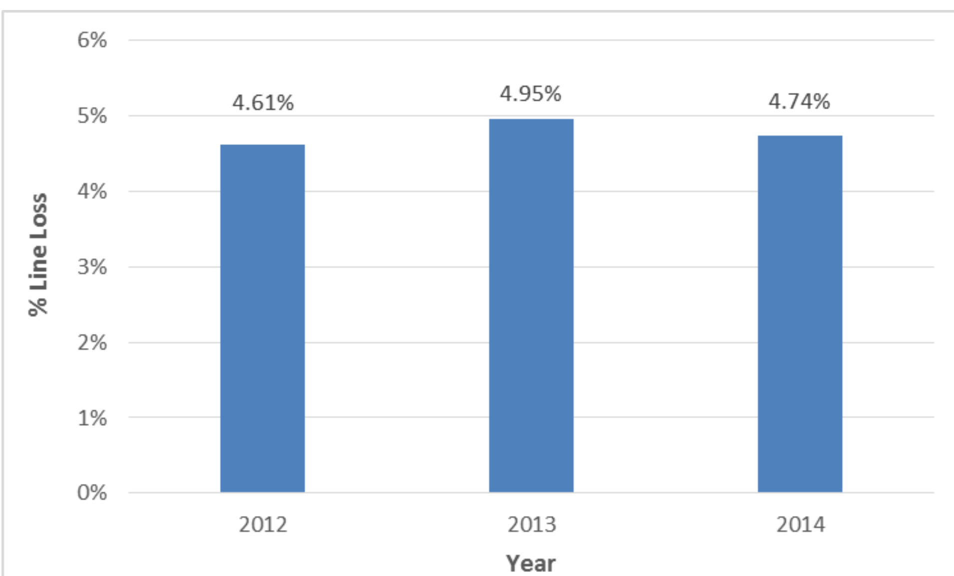
Figure 2-10 presents the historical overtime costs for the years 2012 to 2014 and the forecast overtime cost for the year 2015. The overtime cost was highest in 2014 due to the mount of emergency outage restoration work that was required. InnPower is projecting its overtime cost to be $146,000 in 2015 and is seeking to keep its overtime costs low going forward.

Figure 2-10: Actual (2012-2014) and forecast (2015) overtime costs

2.3.2.10 *Distribution Losses*

Figure 2-11 presents the distribution losses for the years 2012 to 2014, expressed as percentage line loss. The line losses were higher in 2013 due to the higher summer and winter peak demand that year.

Figure 2-11: Distribution losses (2012-2014)



2.3.2.11 *Power Factor*

Table 2-7 presents the average power factor in 2015 at various locations of InnPower's distribution system. The lowest power factor at the system is at the primary metering equipment ("**PME**") on Innisfil F1 that connects to the downstream feeder owned by HONI.

Table 2-7: Power factors on InnPower's distribution system (2015 data)

Location	Power Factor
Alliston TS	
Innisfil Hydro 9M1 PME	0.9890
Innisfil Hydro 9M2 PME	0.9981
Cookstown West DS	0.9346
Innisfil PME - Cookstown W DS-F2	0.9428
Innisfil PME - Cookstown W DS-F4	0.9338
Innisfil Hydro (9M4) PME	0.9797
BHDI - Thornton DS	0.9417
Innisfil PME Innisfil DS (F1)	0.8799
Everett TS	
New Tecumseth PME East (9M2)	0.9255
Innisfil PME - Cookstown W DS-F4	0.9338
Cookstown West DS	0.9346
Innisfil PME - Cookstown W DS-F2	0.9428
Barrie TS	
Innisfil Hydro 13M3 PME	0.9936

2.3.3 Incorporating Performance Trends into DSP (5.2.3c)

explain how this information has affected the DS Plan (e.g. objectives; investment priorities; expected outcomes) and has been used to continuously improve the asset management and capital expenditure planning process.

2.3.3.1 *Customer Survey Results*

InnPower's customer survey results indicate that high reliability and low cost are the most important factors for InnPower's customers. InnPower has planned a number of projects over the forecast period that are driven by reliability. System renewal asset replacement projects replace assets that are at the end of their service life before they cause an outage, while system renewal life extension projects extend the useful life of an asset and prevent outages. In particular, an underground rebuild of a section of Sandy Cove that has direct buried cross-linked polyethylene ("**XLPE**") over forty (40) years age has been planned to mitigate a potentially costly and lengthy outage. InnPower's ongoing maintenance activities are also expected to improve system reliability: the tree trimming program helps to prevent outages due to tree contacts and the pole top maintenance and pole extension program aims to lower SAIDI and SAIFI.

System service and general plant projects have been planned over the forecast period to improve system reliability by reducing outage restoration time. This includes improved SCADA for use with the OMS and DA, as well as station recloser upgrades, automated switch installations, and SCADA controlled padmounted switchgear.

Low cost has been incorporated into the DSP in a number of ways. Assets replaced under the system renewal category are replaced at their end-of-life to get the highest value from the asset. Planned replacements are cheaper than reactive replacements, which may incur emergency after-hours expenses. Life extension programs, such as pole butt treatment, padmounted equipment painting, DS oil treatment, DS rehabilitation, line recloser refurbishments, and vehicle maintenance extend the useful life of assets, also to realize a higher value.

Programs have been excluded from InnPower's DSP where the cost does not justify the apparent benefits to InnPower's customers. These include annual pole maintenance, in-line switch and mid span opener maintenance, overhead transformer inspections (from bucket trucks), fault indicator inspection and testing, load balancing, padmounted transformer and switchgear maintenance, grounding testing, and mapping verification. InnPower is currently performing a cost-benefit analysis of diagnostic cable testing to facilitate better planning for cable replacements. On-call substation security is also being considered via a cost-benefit analysis.

Projects such as oil containment system installation at InnPower's DS are planned to mitigate future oil containment costs in case of an oil leak or transformer failure, as well as mitigate environmental risk.

IT investments into automation software are also expected to reduce costs. The NorthStar CIS automation platform will allow automation of routine processes. Mobile workforce management supports a paperless work order solution for field staff and is currently extended to all departments. The Microsoft Great Plans financial software was updated in 2015 and Prophix capital budgeting software was added in 2015 to streamline budgeting. Automated human resource and safety training compliance software was added in 2012. Time reporting software was upgraded in 2013 and is scheduled to be updated again in 2016.

2.3.3.2 *Consumer Bill Impacts*

Section 2.3.3.1 list a number of projects and programs which are expected to reduce costs. This is one facet of consumer bill impacts.

Another facet of consumer bill impacts is investment pacing, which has been done to ease rate shock. Investments required to accommodate a new overhead line crew have been phased over three (3) years to ease rate impacts. Projects such as voltage conversions and line rebuilds are planned in phases to reduce the rate impact. Yearly programs are budgeted while keeping in mind the rate impacts and in any given year there is additional work that could be done, but this is deferred until the next year whenever possible if it exceeds the budget. InnPower is exploring options to accommodate the required Economic Evaluation payouts for subdivisions while maintaining levelized capital spending.

2.3.3.3 *Reliability*

As seen from Figure 2-6 on outage duration by cause code, the largest interruption duration cause over the historical period was adverse weather. Tree trimming will continue on a three (3) year cycle while increasing the emphasis on evaluating vegetation risk beyond the tree Right of Way ("**ROW"**). The 13M3 service area has the highest concentration of trees amongst all of the tree trimming cycles. Tree trimming is performed by an independent contractor which was chosen through a public tender process. InnPower is continuing to closely monitor the performance of the tree trimming crews to ensure sufficient clearance is maintained to power lines. In 2016, InnPower is planning to engage its tree trimming contractor to look for and identify dangerous and hazardous trees close to the ROW.

The second largest cause for interruptions noted in the chart is defective equipment. Although InnPower had a substantial improvement in outages from defective equipment from 2012 to 2013, the transformer loss at the Brian Wilson DS in 2014 resulted in an increase in this metric. The 2012 defective equipment outages were primarily due to a G&W Viper recloser and arrestor failure at Leonard's Beach DS. The recloser problem was attributed to factory setting error and the arrestor failed atypically. Once repaired, there is no evidence that future trending would occur.

In 2014 smart meter data was integrated with InnPower`s OMS, which expected to improve outage restoration time. Over the forecast period, additional system service and general plant projects have been planned to improve system reliability by reducing outage restoration time. This includes improved SCADA for use with the OMS and Distribution Automation, as well as station recloser upgrades, automated switch installations, and SCADA controlled padmounted switchgear.

2.3.3.4 *Power Quality*

No investments have been planned over the forecast period with power quality as a specific driver, but it is expected that the recloser upgrades at Stroud DS and Sandy Cove DS will assist InnPower with tracking and mitigating momentary interruptions.

2.3.3.5 *Service Quality*

No investments have been planned over the forecast period to specifically address InnPower's service quality measures, which achieve the OEB's minimum performance standards. The meter reading and billing contract will expire in 2016, at which time a new contract will need to be put in place. InnPower has planned upgrades to its CIS that will enhance the services provided to its customers. InnPower is exploring options to use shared resources with the Town of Innisfil to expedite Underground Locate Requests.

2.3.3.6 *DSP Implementation*

A number of investments into engineering IT infrastructure are expected to assist with DSP implementation. Engineering continues its roll-out Map3D solution supplied by AutoDesk which will improve InnPower's planning capabilities. CYME software for distribution system planning, analysis and Connection Impact Assessment ("**CIA**") for distributed generation will be enhanced with additional CYME applications in 2016. A work order management application is planned to be added to the suite of engineering software in 2016. Finally, the GIS will be updated in 2016, which will assist in future planning.

2.3.3.7 *Total Operating Cost*

Section 2.3.3.1 lists the ways that InnPower's planning is expected to reduce costs. In addition, InnPower is always looking to achieve cost savings through improved operational efficiencies. A cost-benefit analysis of an in-house mailing system is currently being conducted. InnPower will continue to seek innovative productivity improvements to help keep operating costs low and within acceptable limits for InnPower's customers, while maintaining the reliability and quality of its distribution system.

Currently, InnPower's monthly bills to its customers includes water and wastewater billing. The wireless connectivity service that is used on InnPower's SCADA system is a shared service with the Town of Innisfil. In 2015, a research consulting firm was retained by the Town of Innisfil to investigate additional opportunities for shared services between municipal entities, South Simcoe Police Services, and InnPower. A shared service model is currently under development. InnPower is exploring options to use shared resources with the Town of Innisfil to expedite Underground Locate Requests. Beginning in 2016, vehicle maintenance for InnPower will be done at the Town of Innisfil's new Operation Centre.

2.3.3.8 *Customer/Employee Ratio*

To accommodate a growing customer base, InnPower is planning to hire additional staff over the forecast period, which will decrease its customer/employee ratio. As the number of customers increase, then the customer/employee ratio will increase.

2.3.3.9 *Reduction in Overtime*

Improved project planning is expected to reduce overtime costs.

2.3.3.10 *Distribution Losses*

A number of system service projects are expected to reduce distribution losses. The voltage conversion projects in the 400 Corridor and South Alcona will reduce distribution losses in their respective areas. The new transformer at Cedar Point DS and planned transformer at Friday Harbour DS will relieve existing parts of the system that are running close to their rated load and therefore these projects should reduce distribution losses. Planned conductor upgrades on the distribution and subtransmission systems will also reduce line losses.

2.3.3.11 *Power Factor*

Investments into automated capacitor controllers in 2019 and 2020 will facilitate the monitoring and control of reactive power on InnPower's system and is expected to improve the power factor on InnPower's system. A System Planning study is underway to review the impact of planned system changes, and where power factor, system losses or voltage drop concerns arise, capacitors and regulators will be applied.

3 Asset Management Process (5.3)

This section provides an overview of InnPower's asset management process, an overview of the assets managed by InnPower, and a presentation of InnPower's asset lifecycle optimization policies and practices.

3.1 Asset Management Process Overview (5.3.1)

This section presents InnPower's asset management objectives and the components of InnPower's asset management process.

3.1.1 Asset Management Objectives (5.3.1a)

a description of the distributor's asset management objectives and related corporate goals, and the relationships between them; where applicable, show and explain how the distributor ranks asset management objectives for the purpose of prioritizing investments;

InnPower is a relatively young LDC that purchased many of its distribution assets from Ontario Hydro (HONI) in 1993. InnPower is anticipating a customer increase of approximately 70% to 100% over the next fifteen (15) to twenty (20) years. In order to accommodate high load growth requirements and compliance with regulatory and distribution system requirements, InnPower has established the following planning objectives which are derived from its asset management philosophy:

1. Ensuring public and worker safety
2. Meeting legislative requirements
3. Mitigating environmental risk
4. Accommodating load growth and customer needs
5. Maintaining system reliability and customer value
6. Managing costs and operational efficiency

These asset management objectives derive directly from InnPower's corporate goals.

3.1.2 Components of the Asset Management Process (5.3.1b)

information regarding the components (inputs/outputs) of the asset management process used to prepare a capital expenditure plan, identify and briefly explain the data sets, primary process steps, and information flows used by the distributor to identify, select, prioritize and/or pace investments; e.g.

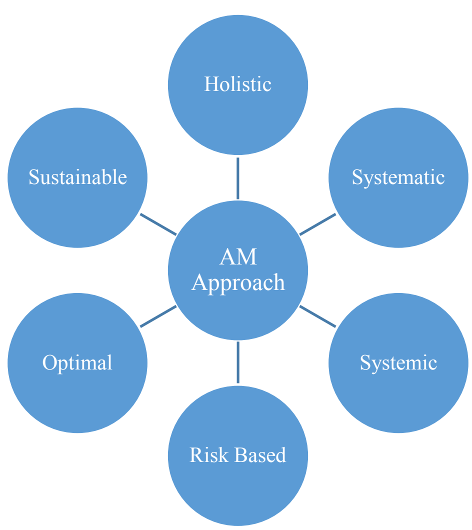
- ***asset register***
- ***asset condition assessment***
- ***asset capacity utilization/constraint assessment***
- ***historical period data on customer interruptions caused by equipment failure***
- ***reliability-based 'worst performing feeder' information and analysis***
- ***reliability risk/consequence of failure analyses.***

Decisions involving investment into fixed assets play a major role in determining the optimal performance of distribution system fixed assets. 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 either case, investments that are either oversized 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 also 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. In summary, the overarching objective of the Asset Management Strategy is to find the right balance between capital investments in new infrastructure and operating and maintenance costs so that the combined total cost over the life of the asset is minimized.

A condition based Asset Management Strategy therefore determines the likelihood of asset failure based on the condition of the asset. A yard stick of asset "Health Indices" is commonly used to quantify condition. InnPower's Asset Management Strategy covers the full life cycle of a fixed asset, from preparation of the asset specification and installation standards – to the scope and frequency of preventative maintenance during the asset's service life – and finally to the determination of the assets end-of-life and retirement from service. At each stage of an asset's life cycle, decisions are made to achieve the right balance between achieving maximum life expectancy, highest operating performance, lowest initial investment (capital costs), and lowest 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.

PAS-55, a specification for asset management, was developed by the British Standards Institute ("**BSI**") and offers one of the best-in-class strategies for risk management associated with fixed assets of electricity distribution systems. The BSI standard was later adopted by the International Organization of Standards ("**ISO**") and published as the ISO 55000 series on asset management. To be compliant with the PAS-55 and ISO 55000 asset management standards, the asset management approach must contain the essential elements documented in Figure 3-1.

Figure 3-1: Essentials of PAS-55/ISO 55000 compliant Asset Management Strategy



In adopting the PAS-55/ISO 55000 Asset Management Strategy, InnPower has moved to a condition based asset replacement and refurbishment strategy. An ACA was completed for InnPower's station and distribution assets, which uses condition to identifies those assets most likely to fail. The next step in PAS-55/ISO 55000 compliance is to move to risk based approach, which considers both the probability and consequence of failure.

Table 3-1 below summarizes the components of InnPower's asset register that is available and used for planning purposes.

Table 3-1: Information comprising InnPower's asset register

Asset Register			
Component	**Owner/Location**	**Asset Information**	**Data Format**
GIS	Engineering	> Pole location and age > Circuit conductor size, voltage, and phase(s) > Overhead switch, transformer, switchgear location and nomenclature	Electronic data
Spreadsheets	Engineering	> Reclosers > Padmounted switchgear > Pole database > Transformer information > SCADA-Mate switches > 44 kV switches	Electronic data
Northstar database	operations	> Transformer data	Electronic data
Financial system	Finance	> IFRS asset value > Asset useful life studies	Paper reports, electronic database
	Finance	> Purchase history > Installation history > Removal history	Paper forms
ACA report	Engineering	> Annual asset condition assessment	Spreadsheet
Outage history	Engineering	> SAIFI, SAIDI stats database > Historical data on customer interruptions caused by equipment failure	Paper/spreadsheet
Maintenance records	Engineering/ Operations	> Transformers, switchgear, poles, stations	Paper
Inspection records	Engineering/ Operations	> Transformers, switchgear, poles, stations	Paper
Asset utilization records	Engineering	> Station and feeder loading	Spreadsheet
General plant	Operations	> General plant information	Paper/spreadsheet
	IT	> General plant information	Paper/spreadsheet
	Finance	> General plant information	Paper/spreadsheet

The ACA identifies assets owned by InnPower that have the highest probability of failure. Figure 3-2 summarizes a practical matrix to sift through a large number of assets, typically employed on distribution systems to objectively identify assets that present the highest risk of in-service failures so that the investments could be targeted into assets that present the highest risk. Numeric health indices, typically normalized to a scale of 0 to 100, are commonly used to express the health and condition of assets, as shown in Figure 3-3 and this allows separation of the assets in good condition that require minimal intervention from those in poor condition, requiring a higher level of investments.

Figure 3-2: Model to identify assets with highest probability of failure

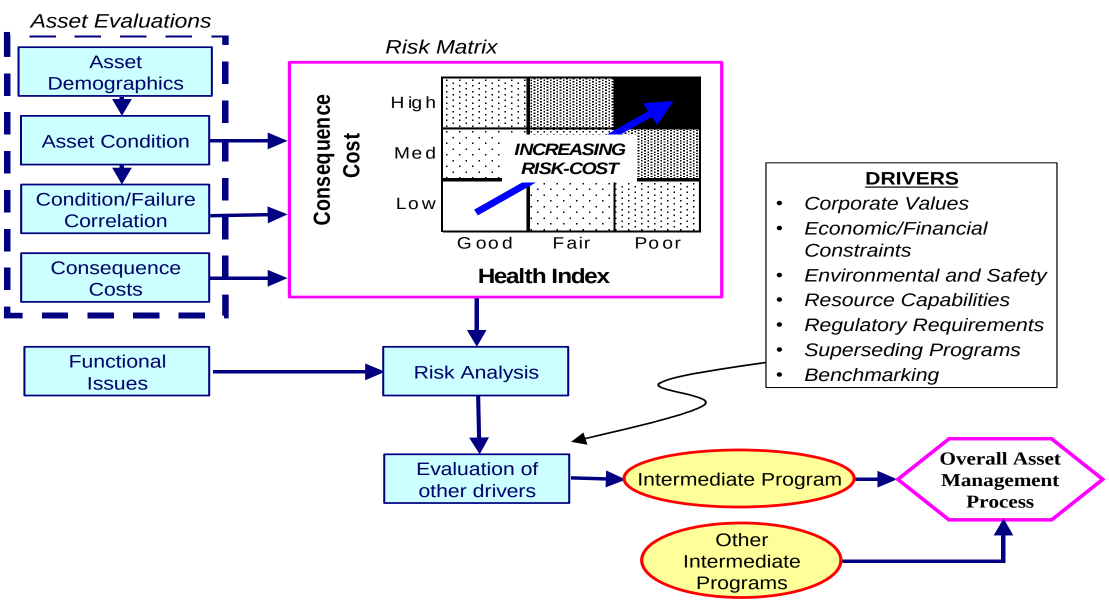
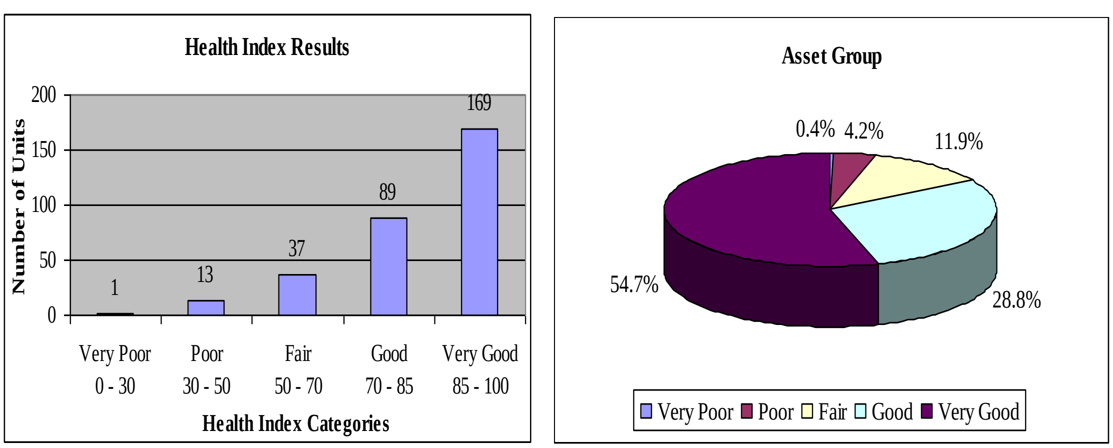


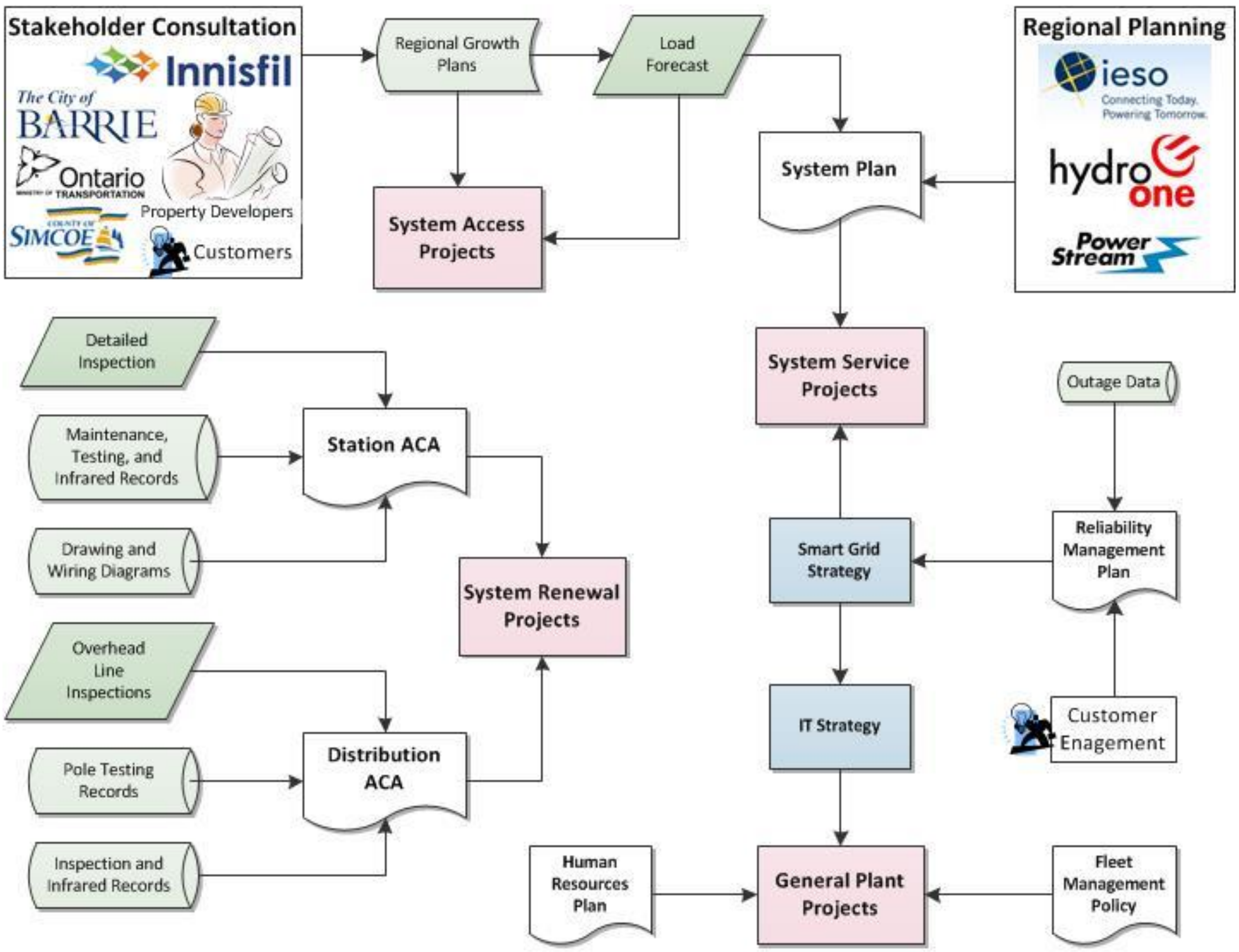
Figure 3-3: Identification of assets with highest probability of failure



System utilization relative to planning criteria (see Section 3.2.4) are also incorporated into the planning process. InnPower does not perform a reliability based "worst performing feeder" analysis, and instead tracks reliability metrics and outage durations by cause code used in planning (see Section 2.3.3.3).

The end result is the development of long-term capital and preventative maintenance investment plans to achieve optimal system performance. This planning exercise is extended to all four (4) categories of investment based on various inputs as documented in Figure 3-4.

Figure 3-4: Planning inputs for project identification



3.2 Overview of Assets Managed (5.3.2)

This section presents a description of InnPower's service area, a summary of the system configuration, the results of the ACA, and InnPower's system utilization relative to planning criteria.

3.2.1 Description of the Service Area (5.3.2a)

> ***a description and explanation of the features of the distribution service area (e.g. urban/rural; temperate/extreme weather; underground/overhead; fast/slow economic growth) pertinent for asset management purposes, highlighting where applicable expectations for the evolution of these features over the forecast period that have affected elements of the DS Plan;***

InnPower has a service area of 292 square kilometres, which includes the entire Town of Innisfil and a portion of the South Barrie lands. The service area is mostly rural (219 square kilometres), with small urban centres (73 square kilometres) including the communities of Stroud, Alcona, Lefroy, Churchill, Cookstown, Gilford, Sandy Cove, and Big Bay Point. The service area is within the temperate climate region of Southern Ontario. 79% of InnPower's primary conductors are overhead and the remaining 21% are underground. Innisfil and South Barrie are both area of high residential growth, which has created the need for additional investment into InnPower's system.

3.2.2 Summary of System Configuration (5.3.2b)

a summary description of the system configuration, including length (km) of underground and overhead systems; number and length of circuits by voltage level; number and capacity of transformer stations

As of January 2016, InnPower owns 833 km of primary conductors, of which 660 km is overhead primary conductor and 173 km is underground primary cable. InnPower operates using primary voltage levels of 8.32/4.80 kV and 27.6/16.0 kV for its distribution feeders, and 44 kV for its subtransmission supply feeders. The number of circuits at each voltage level as well as the associated conductor length are summarized in Table 3-2.

Table 3-2: Summary of system configuration

Voltage Level	Number of Circuits	Underground Cable Length (km)	Overhead Conductor Length (km)	Total Conductor Length (km)
8.32/4.80 kV	21	80	426	506
27.6/16.0 kV	8	92	118	210
44 kV	5	1	116	117
Total	**34**	**173**	**660**	**833**

InnPower owns ten (10) DS cumulatively rated for 75 MVA. Table 3-3 lists the rated nominal capacity of each substation, in MVA.

Table 3-3: Rated capacity of distribution substations

Substation	Output Voltage (kV)	Nominal Capacity (MVA)
Belle Ewart DS	27.6	10
Big Bay Point DS	8.32	5
Bob Deugo DS	27.6	10
Brian Wilson DS	27.6	20
Cedar Point DS	8.32	5
Innisfil DS	8.32	5
Lefroy DS	8.32	5
Leonard's Beach DS	8.32	5
Sandy Cove DS	8.32	5
Stroud DS	8.32	5
Total Nominal Capacity (MVA)		**75**

Two (2) DS within InnPower's service territory are owned by HONI, but supply power to InnPower's customers. These are Thornton DS (5 MVA) and Cookstown West DS (7 MVA).

3.2.3 Results of Asset Condition Assessment (5.3.2c)

information (in tables and/or figures) by asset type (where available) on the quantity/years in service profile and condition of the distributor's system assets, including the date(s) the data was compiled;

InnPower owns the following major electricity distribution assets: substation transformers, substation transformer tap changers, substation reclosers, substation ground grids, substation fences, distribution poles, distribution transformers, overhead switches, and other distribution devices including line reclosers and capacitors. A summary of the asset counts for this major equipment is presented below in Table 3-4.

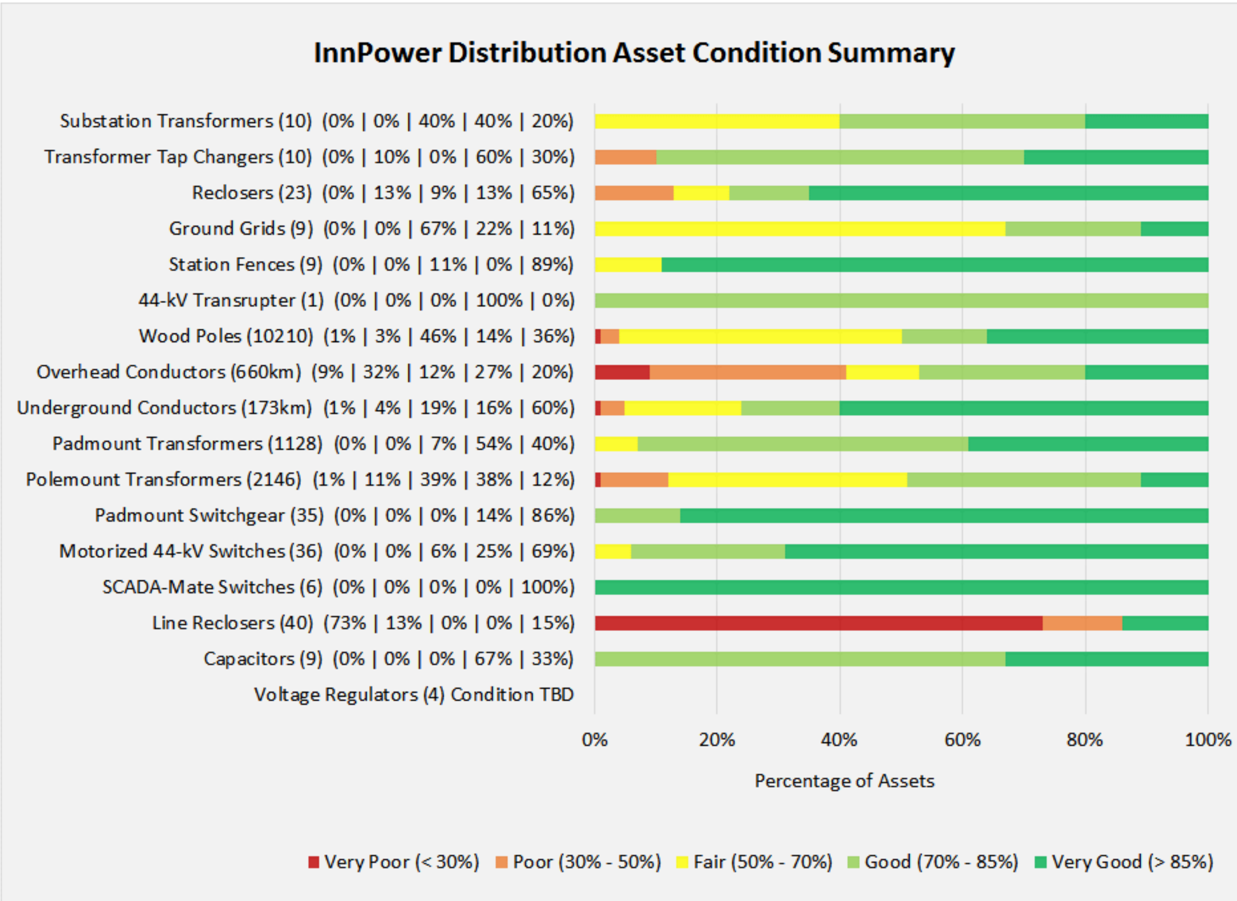
The station ACA was completed in May 2016 and is attached as Appendix F. The distribution ACA was completed in May 2016 and is attached as Appendix E. Based on the condition assessment criteria detailed in the ACA report, the Health Index score has been calculated for each of the assets listed in Table 3-4. Note that Belle Ewart DS, constructed in 2014, was not included in the ACA. Therefore, the ACA asset counts include one (1) less substation transformer, one (1) less tap changer, two (2) less substation reclosers, one (1) less substation ground grid, one (1) less substation perimeter fence, and one (1) less 44-kV Transrupter.

Table 3-4: Summary of major assets owned by InnPower

Asset Class	Asset Count
Substation Transformers	11
Substation Transformer Tap Changers	11
Substation Reclosers	25
Substation Ground Grids	10
Substation Fences	10
44-kV Transrupters	2
Distribution Line Support Poles	10,202
Overhead Primary Conductors	660 km
Underground Primary Conductors	173 km
Distribution Transformers	3,304
Distribution Devices	126
-Distribution Switchgear	35
-Motorized and SCADA-Mate Switches	42
-Line Reclosers	40
-Polemounted Capacitor Banks	9
-Voltage Regulators	4

Figure 3-5 illustrates the summary of Health Index score for all major assets employed on InnPower's distribution system. InnPower owns four (4) voltage regulators whose age and condition are unknown, as indicated in the summary chart.

Figure 3-5: Summary of asset condition

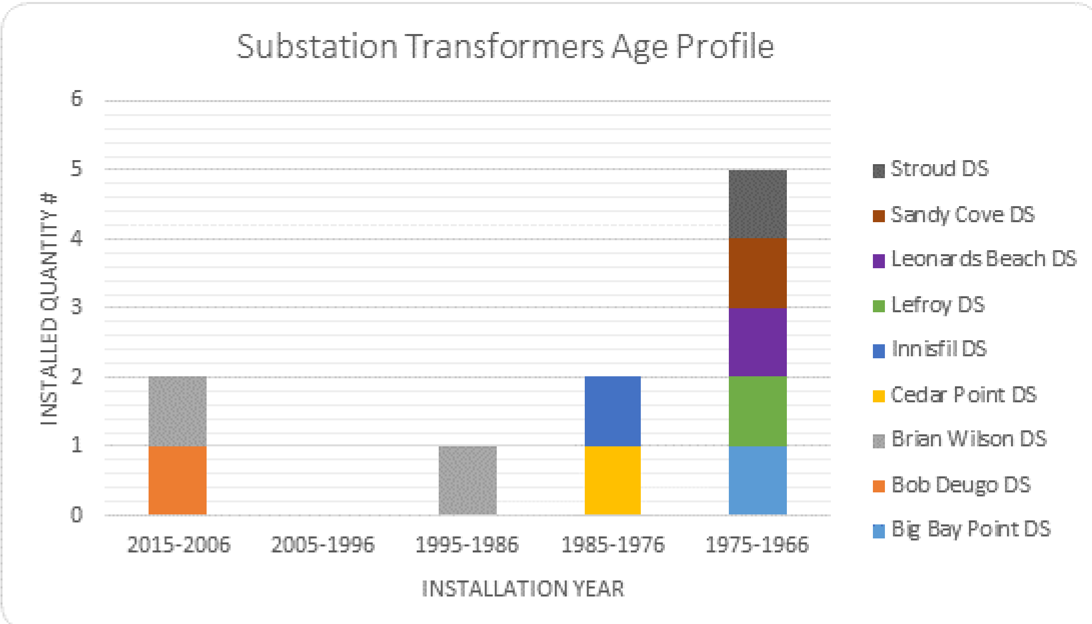


The detailed results of the ACA performed for InnPower are contained in Sections 3.2.3.1 to 3.2.3.11 below.

3.2.3.1 *Substation Transformers*

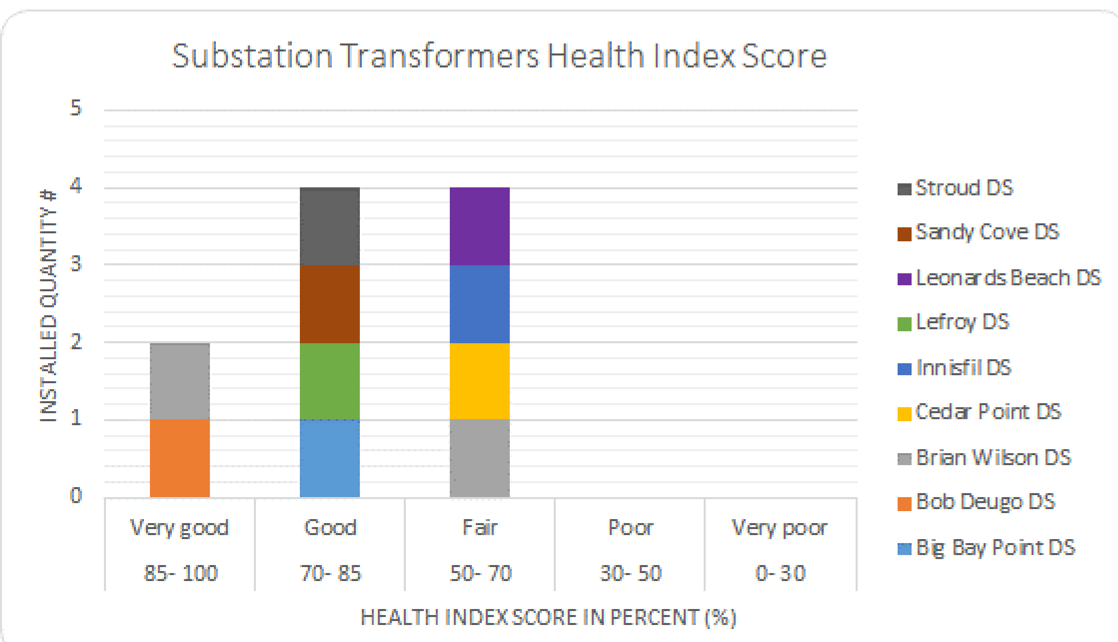
Figure 3-6 represents the age profile of substation transformers employed at different substations of InnPower. It can be observed that half of the transformers have reached 40 or more years of service.

Figure 3-6: Substation transformers age profile



The results of the ACA for substation transformers are summarized in Figure 3-7. The ACA result indicates that there are three (3) power transformers that are in "fair" condition, while the remaining seven (7) transformers are in "good" or "very good" condition.

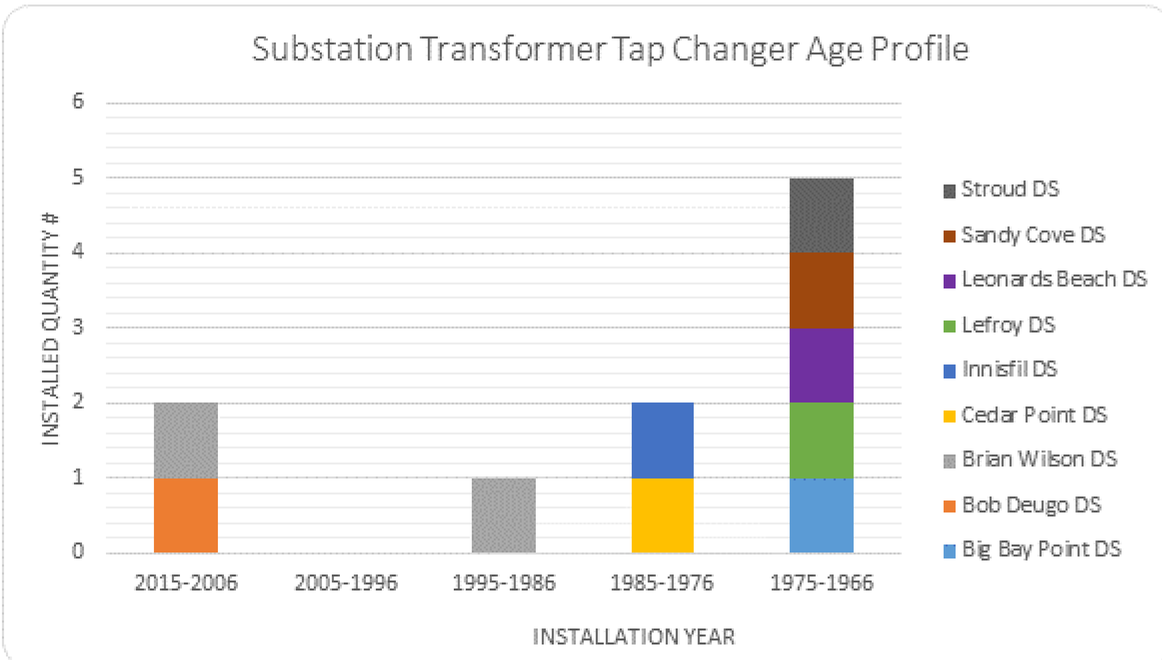
Figure 3-7: Substation transformers Health Index scores



3.2.3.2 *Substation Transformer Tap Changers*

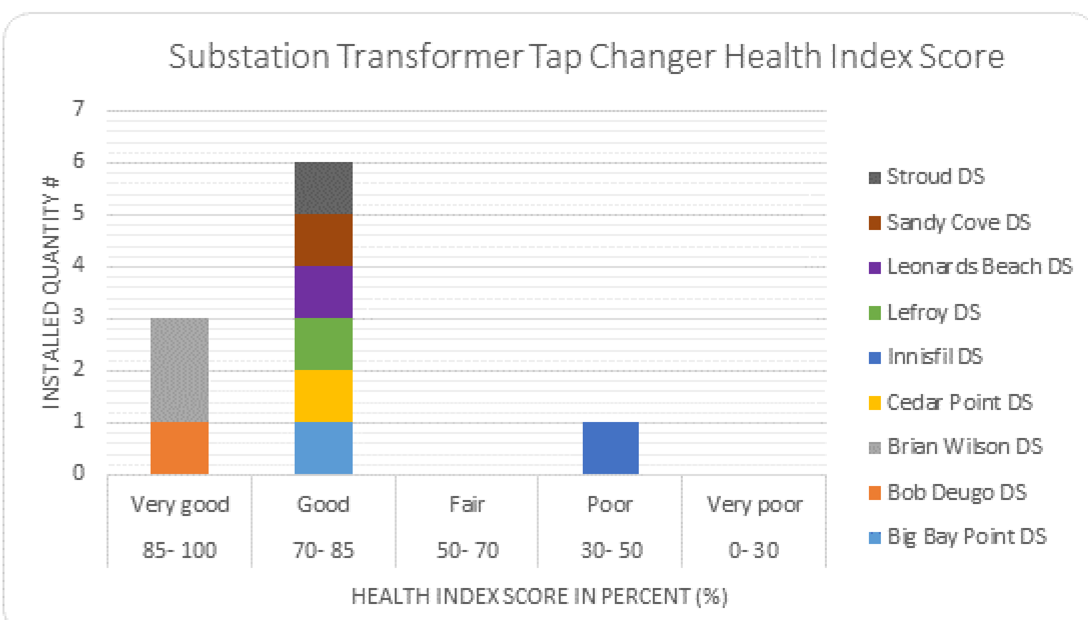
Figure 3-8 represents the age profile of transformer tap changers employed at InnPower. Similar to the transformers, it can be observed that half of the tap changers have reached 40 or more years of service.

Figure 3-8: Substation transformer tap changer age profile



The results of the ACA for transformer tap changers are summarized in Figure 3-9. The ACA result indicates that one (1) tap changer is in "poor" condition, while the remaining nine (9) are in "good" or "very good" condition. Of the six (6) tap changers in "good" condition, five (5) of them have already passed the typical useful life and are likely to degrade to worse condition in the next five to ten years.

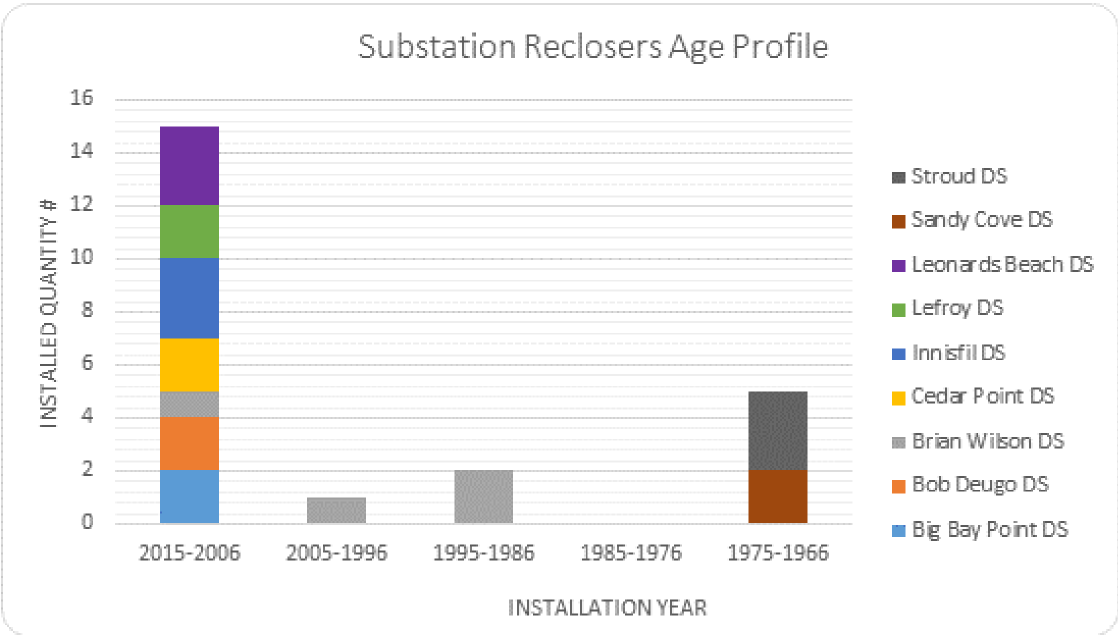
Figure 3-9: Substation transformer tap changer Health Index score



3.2.3.3 *Substation Reclosers*

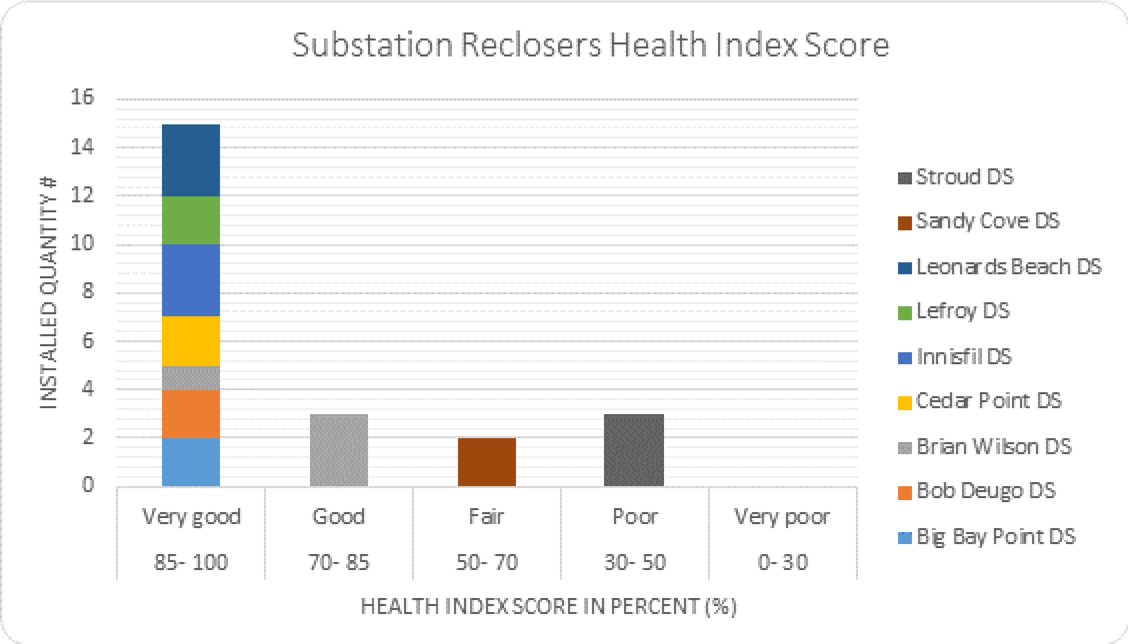
Figure 3-10 represents the age profile of InnPower owned substation reclosers. It can be observed that over 60% of the reclosers are quite new and only five (5) have reached 40 or more years of service.

Figure 3-10: Substation recloser age profile



Based on the service age of substation reclosers, visual inspections, and maintenance test reports (where available), a Health Index score has been calculated for all reclosers, and the results are summarized in Figure 3-11. As indicated by the results, the five (5) aged reclosers are determined in "fair" or "poor" health while the remaining eighteen (18) reclosers are in "good" or "very good" condition.

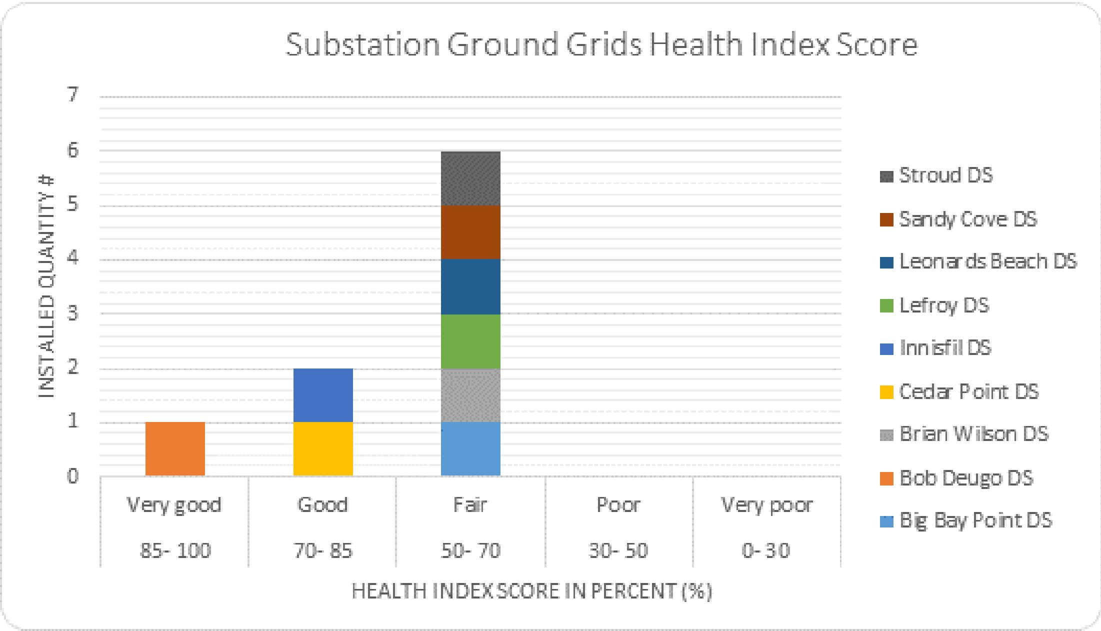
Figure 3-11: Substation recloser Health Index scores



3.2.3.4 *Substation Ground Grids*

Based on the service age of ground grids, the results of visual inspections, and grounding tests, the Health Index score for ground grids was calculated and the results have been summarized in Figure 3-12. As indicated, the ground grids for three (3) substations, Bob Deugo DS, Cedar Point DS, and Innisfil DS, are determined to be in "very good" or "good" condition. The rest are in "fair" condition, mostly due to the fact that substations are aging and the gravel has sunk into the earth below.

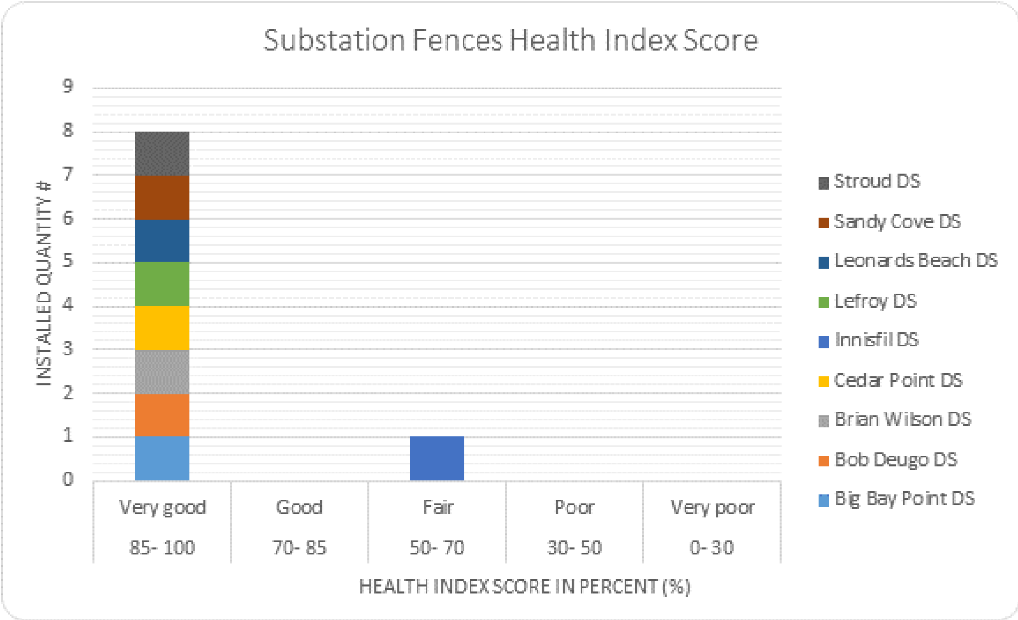
Figure 3-12: Substation ground grid Health Index scores



3.2.3.5 *Substation Fences*

The Health Index score as summarized in Figure 3-13, was calculated for substation perimeter fences. The fences are in "very good" condition for all substations, except Innisfil DS, which received a "fair" rating.

Figure 3-13: Substation fence Health Index scores



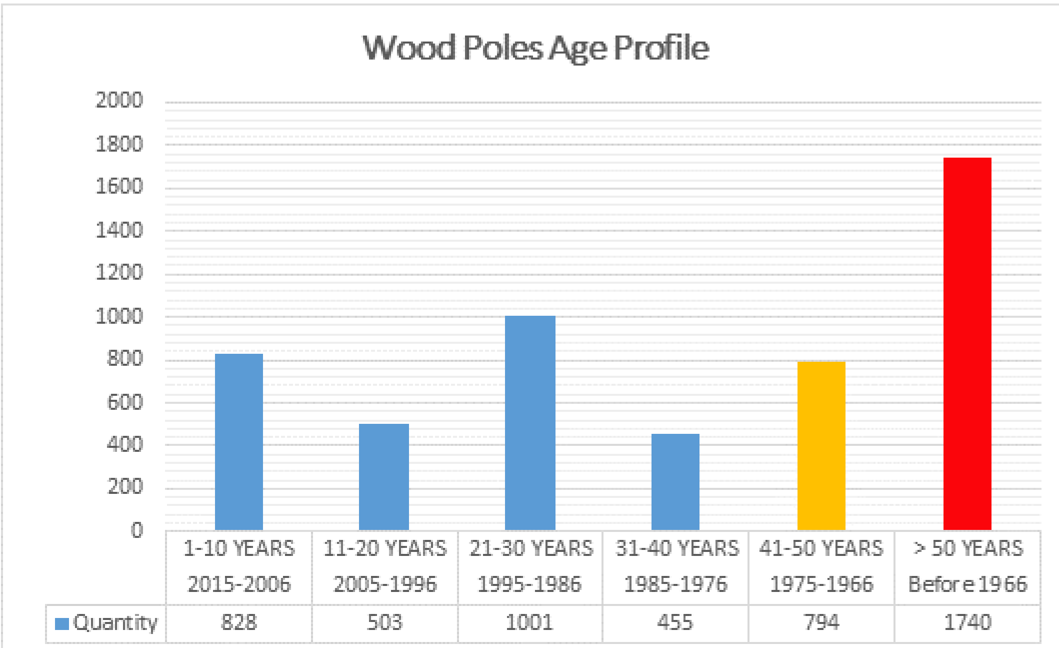
3.2.3.6 *44-kV Transrupters*

Out of the substations assessed in the ACA, InnPower owns one (1) 44-kV Transrupter at Bob Deugo DS, which was installed in 2006 and was assessed to be in "very good" condition.

3.2.3.7 *Distribution Wood Poles*

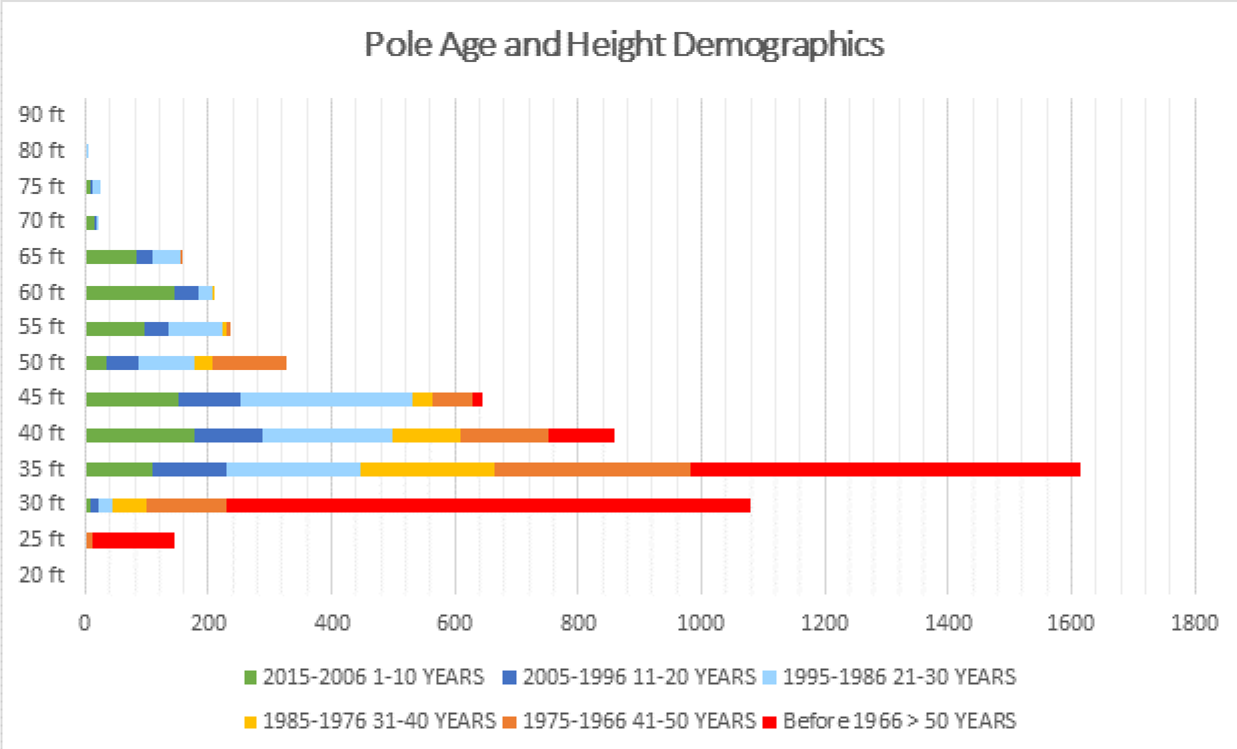
There are approximately 10,210 wood poles employed on InnPower's electricity distribution system. A sample of 5,321 poles were tested between 2013 and 2015. Demographics on the tested wood poles is presented in Figure 3-14. Approximately 15% of the tested poles have been in service for over forty (40) years (shown in yellow) and about 33% (shown in red) are now older than their typical service life of fifty (50) years. Together, almost half of the tested poles have reached forty (40) years of service life.

Figure 3-14: Age demographics of wood poles tested between 2013 and 2015



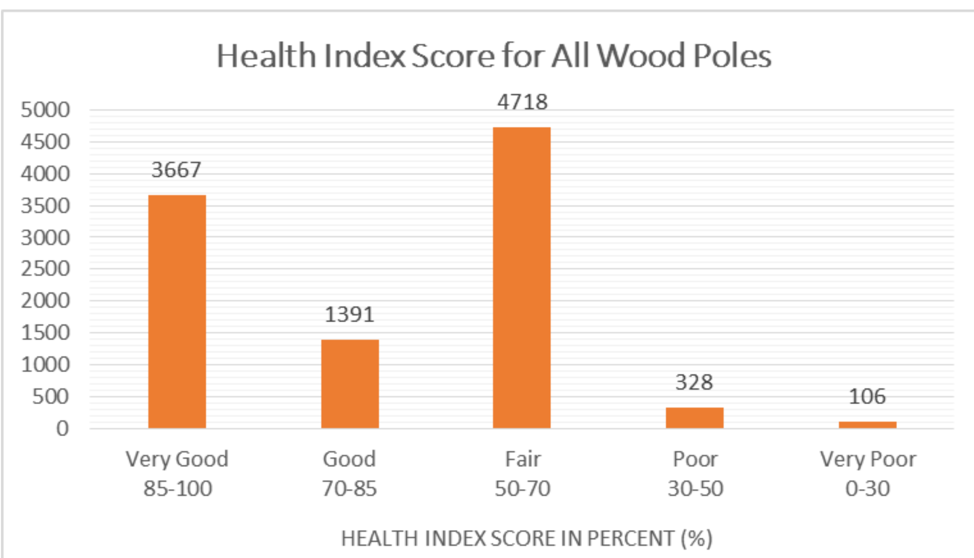
The age profile of all sampled poles with respect to their heights is presented in Figure 3-15. It is readily seen that majority of the aged poles greater than fifty (50) years of service are of 30 feet or 35 feet tall.

Figure 3-15: Age and height profile of wood poles



Using a Health Index algorithm based on service age and testing results, the sampled pole population has been ranked into "very good", "good", "fair", "poor", and "very poor" categories. The results of this analysis were then projected to the entire pole population, as shown in Figure 3-16. Almost 36% of wood pole population are in "very good" condition and 434 poles are in "poor" or "very poor" condition.

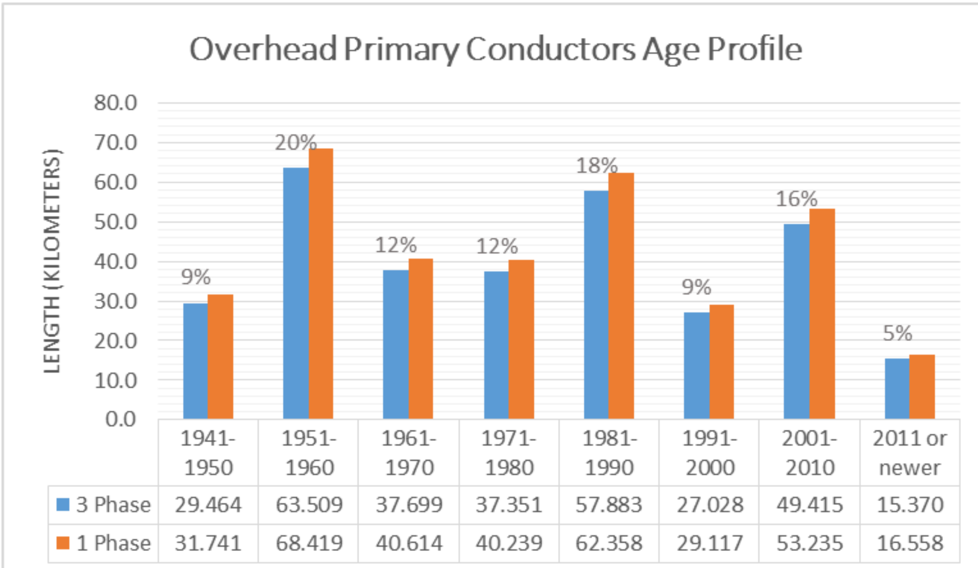
Figure 3-16: Wood pole Health Index scores



3.2.3.8 *Overhead Primary Conductors*

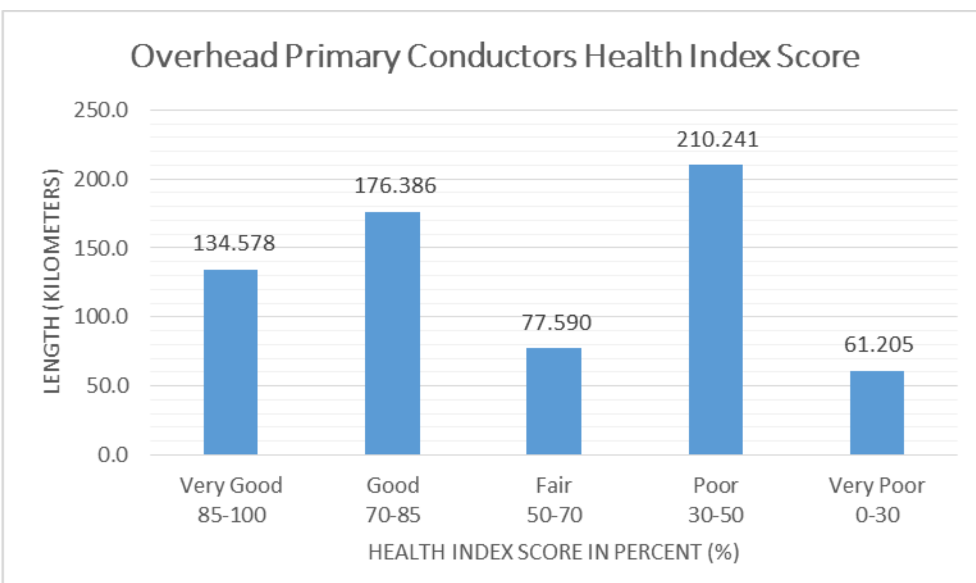
The overhead distribution system owned by InnPower contains approximately 660 kilometres of overhead distribution lines. The overall age profile for primary conductors employed on all voltage levels is presented by phase in Figure 3-17. Approximately 41% of the conductors in service have reached a service age of greater than forty-five (45) years, and these present a higher risk of in-service failure.

Figure 3-17: Age profile for overhead primary conductors



The overall Health Index for the overhead conductors, derived from age information, is summarized in Figure 3-18. It is determined that all the conductors in "poor" and "very poor" condition constitute 41% of the entire population. 20.4% of the lines are in "very good" condition and 26.7% are in "good" condition.

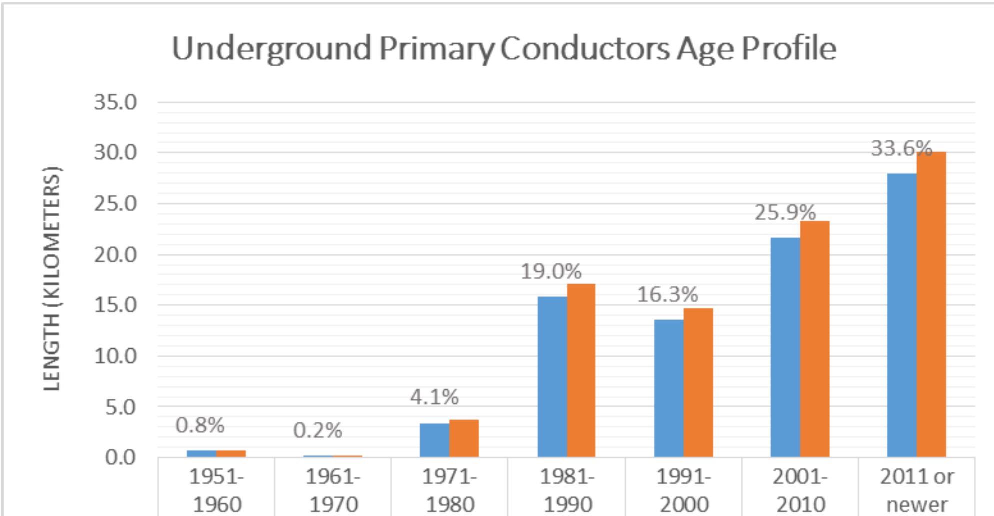
Figure 3-18: Overhead primary conductor Health Index scores



3.2.3.9 *Underground Primary Conductors*

The underground distribution network at InnPower employs 173 kilometers of primary underground conductors. The overall age profile of primary underground conductors is presented in Figure 3-19. Only 5.1% of the total primary underground conductors have been in service for more than 35 years.

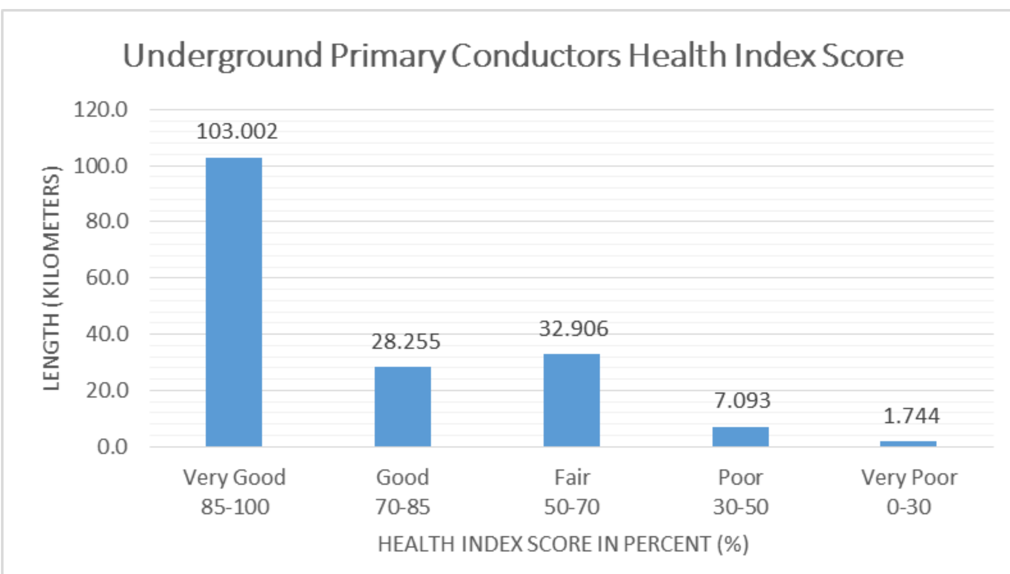
Figure 3-19: Underground primary conductors age profile



	1951-1960	1961-1970	1971-1980	1981-1990	1991-2000	2001-2010	2011 or newer
3 Phase	0.671	0.168	3.414	15.841	13.602	21.606	27.979
1 Phase	0.723	0.182	3.678	17.065	14.653	23.276	30.142

The overall health index for the underground conductors, derived from age information, is summarized in Figure 3-20. It is determined that all the conductors in poor and very poor condition only constitute 5% of the entire population. 59.5% of the cables are in very good condition and 16.3% are in good condition.

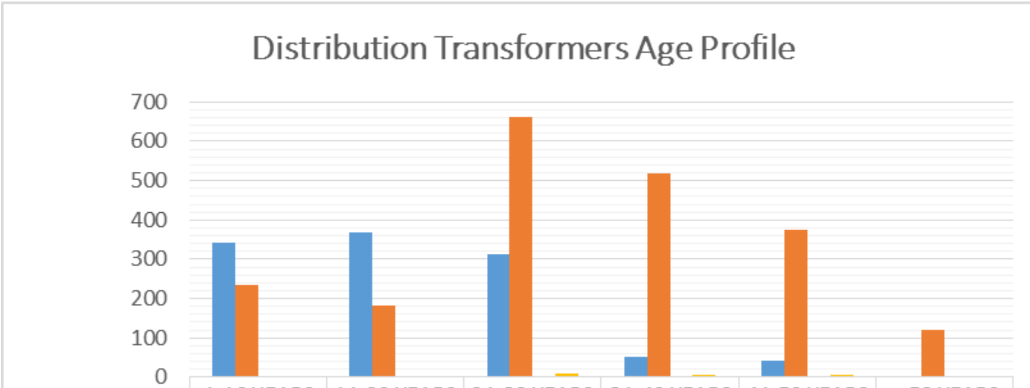
Figure 3-20: Underground primary conductors Health Index scores



3.2.3.10 *Distribution Transformers*

The overall age profile for distribution transformers is displayed in Figure 3-21. As indicated, 23% of the polemount transformers and less than 4% of the padmounted transformers have reached a service age of forty (40) years or more. Together, approximately 16% of the distribution transformers have been in service for more than forty (40) years.

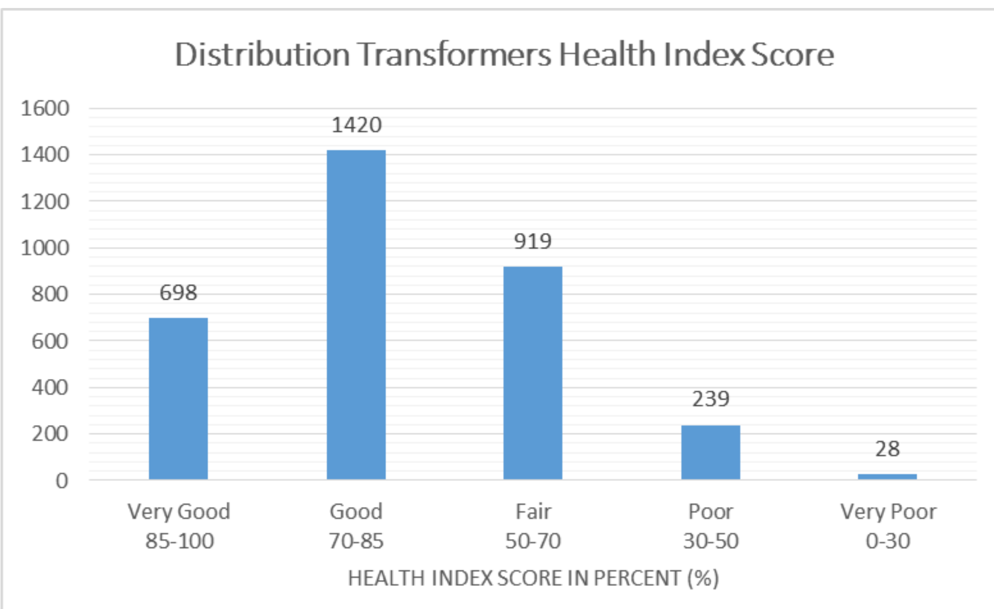
Figure 3-21: Distribution transformer age profile



	1-10 YEARS 2015-2006	11-20 YEARS 2005-1996	21-30 YEARS 1995-1986	31-40 YEARS 1985-1976	41-50 YEARS 1975-1966	> 50 YEARS Before 1966
Padmount	341	368	312	52	41	2
Polemount	233	181	663	517	375	119
Platform	0	0	0	3	0	0
Unknown	1	1	11	7	7	0

The Health Index results for distribution transformers is summarized in Figure 3-22. A "very poor" grading was given to approximately 0.8% of the distribution transformers, with "poor" accounting for approximately 7.2% of the total number of distribution transformers.

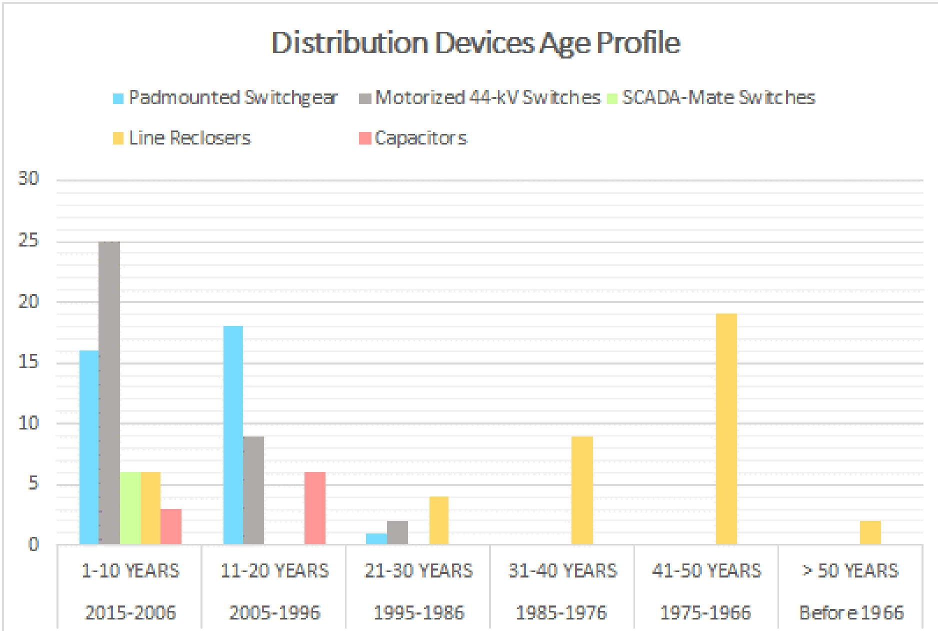
Figure 3-22: Distribution transformers Health Index scores



3.2.3.11 *Distribution Devices*

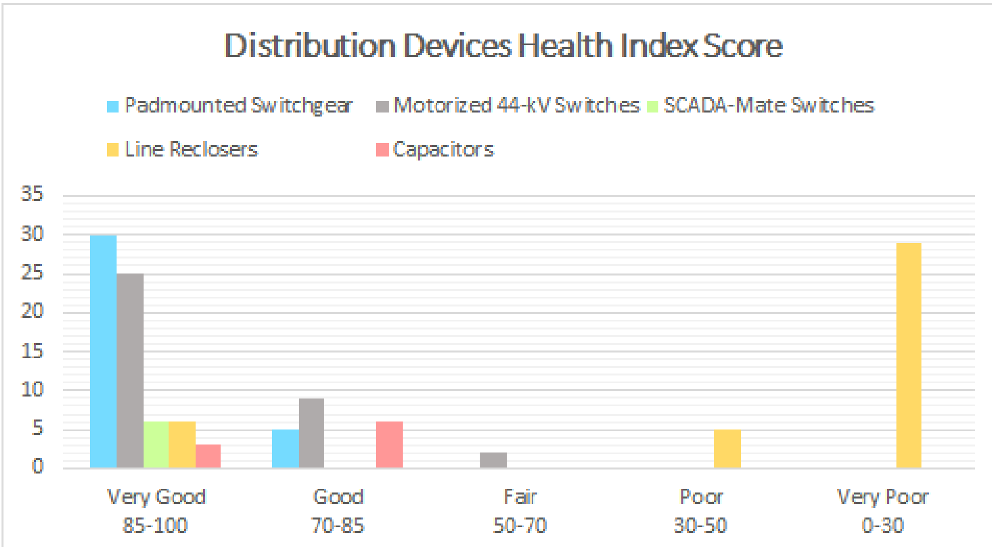
Figure 3-23 displays the age profiles of different distribution devices owned by InnPower. These distribution devices include distribution switchgear; overhead switches of air break, load break, and SCADA types; line reclosers; and polemount capacitor banks.

Figure 3-23: Age profile of distribution devices



As shown, line reclosers make up the vast majority of the aged assets in this class. Derived from age information and IR inspection results, where available, the Health Index result for distribution devices is presented in Figure 3-24. It is observed that all the assets ranked at "very poor" or "poor" condition assets are line reclosers. Approximately 27% of InnPower owned distribution devices are approaching the end of their service life.

Figure 3-24: Distribution Devices Health Index Score



3.2.4 System Utilization (5.3.2d)

an assessment of the degree to which the capacity of existing system assets is utilized relative to planning criteria, referencing the distributor's asset related objectives and targets

- ***where cited as a 'driver' of a material investment(s) included in the capital expenditure plan, provide a level of detail sufficient to understand the influence of this factor on the scope and value of the investment.***

The system utilization relative to planning criteria is presented below for the 44 kV system, substation transformers, and distribution feeders, as excerpted from InnPower's System Plan.

3.2.4.1 *44 kV System Utilization*

There are five (5) 44 kV feeders within InnPower's service territory. Nominally, a 44 kV feeder on InnPower's system is rated for 330 A of current, but since 9M6 only supplies Cookstown West DS, its nominal rating is assumed to be 7 MVA (92 A).

Table 3-5 presents the summer ("**S**") and winter ("**W**") peak load forecast for each 44 kV feeder for the years 2016 to 2021. Feeders which exceed 80% of their current rating are highlighted in yellow. 9M2 exceeds the 80% threshold in 2018, while 9M1 exceeds the 80% threshold in 2020. For the purpose of loop switching, feeders should be loaded to 50% or less of the recloser settings. However, loop switching is not a planning criteria at this time.

Table 3-5: 44 kV feeder summer and winter peak load forecast

44 kV Feeder	Feeder Limit (A)	Peak Load (A)											
		2016		2017		2018		2019		2020		2021	
		S	W	S	W	S	W	S	W	S	W	S	W
9M1	330	190	179	191	180	222	210	254	243	280	269	308	297
9M2	330	252	253	260	261	267	268	273	274	278	279	285	287
9M4	330	169	158	172	162	178	167	184	173	188	177	193	182
9M6	92	18	14	19	15	20	16	21	17	21	17	21	17
13M3	330	130	139	134	144	153	163	174	183	194	203	210	219

Feeders which exceed 80% of their current rating are highlighted in yellow.

3.2.4.2 *Station Transformer Utilization*

Table 3-6 presents the summer and winter peak load forecast for each DS for the years 2016 to 2021. Brian Wilson T1 and T2 are assessed independently of one another. Transformers which exceed 80% of their nominal load are highlighted in yellow and those that exceed 100% of their nominal load are highlighted in orange. Bob Deugo, Brian Wilson T1, and Brian Wilson T2 are forecast to exceed the 80% threshold in 2021. Innisfil, Lefroy, Cedar Point, and Big Bay Point are forecast to exceed the 80% threshold in 2016. Cedar Point is forecast to exceed its nominal rating in 2020 and Big Bay Point is forecast to exceed its nominal rating in 2019. Therefore, there is a need for additional transformer capacity in these two areas.

Table 3-6: Station summer and winter peak load forecast

Transformer	Nominal MVA	Peak Load (MVA)											
		2016		2017		2018		2019		2020		2021	
		S	W	S	W	S	W	S	W	S	W	S	W
Bob Deugo	10	3.7	2.8	3.7	2.8	5.0	4.1	6.4	5.5	7.3	6.4	8.4	7.5
Brian Wilson T1	10	4.2	4.2	4.2	4.3	5.2	5.3	6.3	6.4	7.4	7.4	8.4	8.5
Innisfil	5	3.9	4.6	3.9	4.6	3.9	4.6	4.0	4.6	4.0	4.7	4.0	4.7
Lefroy	5	3.8	4.5	3.8	4.5	3.9	4.5	3.9	4.5	3.9	4.5	3.9	4.5
Cedar Point	5	4.1	3.6	4.3	3.8	4.6	4.0	4.8	4.3	5.0	4.5	5.3	4.8
Belle Ewart	10	4.2	3.5	4.5	3.8	4.8	4.1	5.0	4.3	5.1	4.4	5.4	4.7
Leonard’s Beach	5	3.0	2.7	3.0	2.7	3.0	2.7	3.0	2.7	3.0	2.7	3.0	2.7
Thornton	5	0.9	1.0	0.9	1.0	0.9	1.0	0.9	1.0	0.9	1.0	0.9	1.0
Brian Wilson T2	10	6.5	5.9	6.7	6.1	7.1	6.6	7.6	7.0	7.9	7.3	8.3	7.7
Cookstown West	7	1.4	1.1	1.4	1.1	1.5	1.3	1.6	1.3	1.6	1.3	1.6	1.3
Sandy Cove	5	2.1	2.3	2.1	2.3	2.4	2.6	2.8	3.0	3.1	3.3	3.4	3.6
Big Bay Point	5	3.6	4.1	3.9	4.4	4.3	4.8	4.6	5.1	7.4	7.9	8.4	8.9
Stroud	5	2.8	2.7	2.8	2.8	3.6	3.6	4.5	4.4	2.9	2.8	2.9	2.8

Transformers which exceed 80% of their capacity rating are highlighted in yellow, and those that exceed 100% of their capacity rating are highlighted in orange.

3.2.4.3 *Distribution Feeder Utilization*

Table 3-7 presents the summer and winter peak load forecast for each distribution feeder for the years 2016 to 2021. Feeders with loads exceeding 50% of the recloser setting are highlighted in orange. Given the state of the current system, many feeders are forecast to exceed 50% of their recloser setting before the year 2021. Innisfil F1, Lefroy F1, Cedar Point F2, and Big Bay Point F1 are forecast to exceed the 50% threshold in 2016. Big Bay Point F2 is forecast to exceed the 50% threshold in 2017. Brian Wilson F1, Cedar Point F1, Brian Wilson F3, and Stroud F1 are forecast to exceed the 50% threshold in 2018. Finally, Sandy Cove F1 is forecast to exceed the 50% threshold in 2019.

Table 3-7: Distribution feeder summer and winter peak load forecast

Feeder	Recloser Setting (A)	Peak Load (A)											
		2016		2017		2018		2019		2020		2021	
		S	W	S	W	S	W	S	W	S	W	S	W
BDF1	350	50	39	50	39	50	39	50	39	50	39	50	39
BDF2	350	26	19	26	19	55	47	83	76	103	96	125	118
BWF1	200	88	89	89	90	109	110	133	134	154	155	177	178
BWF2	200	0	0	0	0	0	0	0	0	0	0	0	0
InF1	200	115	130	115	130	115	130	115	130	115	130	115	130
InF2	280	69	93	70	94	71	95	72	95	73	96	73	96
InF3	200	88	97	88	97	88	97	88	97	88	97	88	97
LeF1	280	127	147	127	147	127	147	127	147	127	147	127	147
LeF2	280	94	97	96	99	98	101	99	102	100	103	100	103
LeF3	280	44	65	44	65	44	65	44	65	44	65	44	65
CPF1	280	116	104	132	119	148	135	164	151	179	167	198	186
CPF2	280	170	145	170	145	170	145	170	145	170	145	170	145
BEF1	350	6	6	11	11	17	17	22	22	25	25	31	31
BEF2	350	81	67	83	68	83	68	83	68	83	68	83	68
LBF1	280	133	60	133	60	133	60	133	60	133	60	133	60
LBF3	280	78	128	78	128	78	128	78	128	78	128	78	128
ThF1	225	33	35	33	35	33	35	33	35	33	35	33	35
ThF2	225	31	35	31	35	31	35	31	35	31	35	31	35
BWF3	250	119	105	123	108	127	113	133	119	139	124	144	129
BWF4	200	16	19	18	21	22	24	25	28	27	29	30	33
CWF2	280	41	41	46	46	54	54	56	56	56	56	56	56
CWF4	280	53	33	53	33	53	33	53	33	53	33	53	33
SCF1	280	103	70	103	70	124	92	149	116	171	138	191	159
SCF3	280	42	92	42	92	42	92	42	92	42	92	42	92
BPF1	280	130	147	142	159	198	214	221	238	416	432	482	499
BPF2	280	118	138	130	150	99	118	99	118	99	118	99	118
StF1	280	86	93	88	95	143	150	205	211	90	97	90	97
StF2	280	12	11	12	11	12	11	12	11	12	11	12	11
StF3	280	97	86	97	86	97	86	97	86	97	86	97	86

Feeders which exceed 50% of their current rating are highlighted in orange.

3.3 Asset Lifecycle Optimization Policies and Practices (5.3.3)

This section presents InnPower's asset lifecycle optimization and risk management policies and practices.

3.3.1 Asset Lifecycle Optimization Policies and Practices (5.3.3a)

A description of asset lifecycle optimization policies and practices, including but not necessarily limited to:

- ***a description of asset replacement and refurbishment policies, including an explanation of how (e.g. processes; tools) system renewal program spending is optimized, prioritized and scheduled to align with budget envelopes; and how the impact of system renewal investments on routine system O&M is assessed;***
- ***a description of maintenance planning criteria and assumptions; and***
- ***a description of routine and preventative inspection and maintenance policies, practices and programmes (can include references to the DSC).***

System renewal spending is optimized and prioritized with the distribution ACA (see Appendix E) and the station ACA (see Appendix F). It is scheduled to align with budget envelopes through long term planning and project prioritization. Long term planning helps to smooth rate impacts, while project prioritization helps to limit rate impacts. InnPower's project prioritization process is provided in Section 4.2.3.

Asset lifecycle optimization for an electric utility involves regular inspection and maintenance of the assets. InnPower's asset inspection and maintenance practices are summarized in Table 3-8 below.

Table 3-8: InnPower's asset inspection and maintenance practices and schedules

System	Asset	Practice	Schedule
Overhead	44 kV switches and conductors	Infrared	Yearly
	44 kV switches	Maintenance	3 year cycle
	Poles	Testing	8 year cycle
	Distribution overhead	Infrared	3 year cycle
	Overhead	Tree trimming	3 year cycle
	Capacitor banks	Inspection	Yearly
	Reclosers	Testing/maintenance	4 year cycle
Underground	Distribution underground	Infrared	3 year cycle
Stations	DS	Visual inspection	Monthly
	Station equipment (transformer testing, arrestor, termination, tap changer, etc.)	Maintenance	4 year cycle
	Transformer oil	Oil test (DGA, furan analysis, oxidation inhibitor, PCB)	Yearly
	DS	Infrared	Yearly
Fleet	Large vehicles	Vehicle maintenance, hydraulic maintenance and inspection	Quarterly
	Large vehicles	Dielectric test and CVOR inspection	Yearly
	Large and small vehicles	Engine fluids	Every 3-4 months
	Large and small vehicles	Rust proofing	Yearly

3.3.1.1 *Overhead Lines*

Vegetation and ROW control is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. InnPower has a large rural and urban area where overhead lines are in the proximity to trees. In an effort of mitigating direct contact between trees and distribution assets, tree trimming is conducted on a three (3) year cycle. InnPower does not have any in-house tree trimming personnel or equipment and therefore uses an independent contractor at market rates. Depending on the size, shape and growth aspect of relevant trees, the tree trimmers remove sufficient foliage from the tree to limit the possibility of contact during high wind situations within a three (3) year time frame. Following tree trimming, the independent contractor removes all debris and returns the site to as-found condition. Any pole line damage or anomaly noticed by the tree trimming crew is reported to InnPower for remedial action.

InnPower also contracts out infrared scanning on its high voltage assets on a three (3) year cycle as follows:

- Year 1: All overhead primary voltage three phase and single phase lines (44 kV, 27.6 kV, and 8.32 kV), including DS.

- Year 2: All 44 kV overhead lines including DS, half of the 27.6 kV and 8.32kV three phase overhead primary voltage lines, and half of all underground primary voltage lines.
- Year 3: All 44 kV overhead lines including DS, the other half of the 27.6 kV and 8.32 kV three phase overhead primary voltage lines, and the other half of all underground primary voltage lines.

Any abnormal condition is reported to InnPower for remedial action and critical abnormalities are reported to InnPower for immediate action.

Line patrol is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. Line patrol may highlight problems or identify conditions that warrant a more thorough inspection or the need for maintenance. Visual inspections of major distribution system components identify problems and hazards such as leaning poles, damaged equipment, damaged enclosures, and vandalism. Line patrols can identify potential failures before they occur, thereby improving system reliability, avoiding repair costs, and avoiding insurance claims.

Line patrol includes a visual inspection of all related equipment as follows:

- Conductors and Cables:
  - Low conductor clearance
  - Broken/frayed conductors or tie wires
  - Tree conditions, exposed broken ground conductors
  - Broken strands, bird caging, and excessive or inadequate sag
  - Insulation fraying on secondary (i.e. open wire)
- Poles/Supports:
  - Bent, cracked, or broken poles
  - Excessive surface wear or scaling
  - Loose, cracked, or broken cross arms and brackets
  - Woodpecker or insect damage, bird nests
  - Loose or unattached guy wires or stubs
  - Guy strain insulators pulled apart or broken
  - Guy guards out of position or missing
  - Grading changes or washouts
  - Indication of burning
- Hardware and Attachments:
  - Loose or missing hardware
  - Insulators unattached from pins
  - Conductor unattached from insulators
  - Insulators flashed over or obviously contaminated
  - Tie wires unraveled
  - Ground wire broken or removed
  - Ground wire guards removed or broken
- Vegetation and Right of Way
  - Leaning or broken “danger” trees
  - Growth into line of “climbing” plants
  - Unapproved/unsafe occupation or secondary use

- Civil Infrastructure
  - Buildings that house equipment which need attention
  - Cable chambers, underground vaults, and tunnels which need attention

InnPower's staff perform line patrols whenever driving through InnPower's distribution territory. Distribution system problems are either remedied immediately or scheduled for remedial action. Line patrol is also performed by line personnel and engineering staff when a problem has been identified within a circuit via SCADA or customer calls.

3.3.1.2 *Poles*

Pole top maintenance and pole inspection is a program wherein line staff perform a physical inspection at each pole in a defined route by setting up a line truck to tighten and inspect all hardware (insulators, cross arms, bolts, etc.). Over time, wood poles shrink, wear, and deteriorate to a point that original installations become loose. With weather elements such as wind and ice loading, hardware can eventually loosen and fail. The solution for this is a defined route of approximately one eighth of all poles (approximately 1,250) inspected from a line truck on a yearly basis and all hardware tightened. By staying proactive with this program the aim is to lower the SAIDI and SAIFI reporting and lower emergency calls where expense dollars are currently being drawn from. This program has been budgeted as of 2017.

Pole inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. InnPower owns approximately 10,000 poles within its distribution system incorporating, which include species of Jack Pine, Red Pine, Western Red Cedar, and Yellow Cedar, and range from 30 feet to 90 feet in height. These species are treated with creosote, chromium copper arsenate, or pentachlorophenol to extend the life of the wood. There are no steel or composite poles in service, but there are two (2) installed where the 9M6 feeder enters Innisfil.

The majority of wood pole deterioration occurs at the pole butt where the pole enters the ground. It is the area flush with the ground that receives the greatest impact of moisture and oxygen that enables the rotting of the pole which occurs from the inside-out. Poles are, therefore, tested to see the extent by which that they are hollow. The extent to which the pole is structurally sound correlates to the pole's ability to withstand vertical structural loading such as transformers, switches, and hardware, and horizontal structural loading such as wind shear. Poles that lack structural integrity are at risk of falling down.

InnPower has been implementing a six (6) year pole testing cycle. The poles are tested using non-destructive devices that measure the moisture content of the wood just above ground level. The higher the moisture level within the wood, the greater the extent of the deterioration. When a threshold level of moisture is detected, a resistograph is used to physically measure the extent of the deterioration. The pole testing results are logged and pole replacement is scheduled as required. Along with the pole testing results, the poles are numbered, tagged with a GPS coordinate, tagged with other hardware and nomenclature, and input into the GIS.

Pole replacements are undertaken for a number of reasons, including:

- pole decomposition or structural damage;
- vehicle accidents;

- customer service requests requiring a taller pole or a different pole class;
- road widenings and grade changes;
- line rebuilds; and
- Electrical Safety Authority ("**ESA**") compliance.

InnPower replaces poles which may exhibit a health and safety hazard to the public and staff. Each year, one sixth of InnPower wood poles are tested and rated to determine when they should be replaced or retested. Poles have been identified as needing a subsequent retest may undergo butt treatment whereby the useful life of the pole can be extended. Poles are replaced to current ESA requirements, with an approximate 1-2% replacement program of the poles that are tested annually. Poles are replaced as required to maximize the health and safety of the public, system reliability, and the ability to connect new customers.

3.3.1.3 *Switches*

Switch inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. Fused switches (cut-outs) accept different sizes of fuses, which are used for the protection of lines, equipment or transformers from main feeder amperages. Fused cut-outs are inspected during the infrared scanning process and are replaced once they fail. When fused cut-outs fail with an abnormal frequency, fused cut-out statistics are investigated to see if a manufacturer's defect has occurred. If a manufacturer's defect is suspected, then all related fused cut-outs may be replaced as an act of due diligence. Failure to do so would not only decrease reliability and the safety of operational personnel would be compromised.

Load break and air break switches are located predominately on the 44 kV system and perform switching operations to allow for maintenance and emergency procedures. Along with inspections carried out by the infrared scanning process, these switches are maintained on a four (4) year cycle.

There are numerous in-line switches and mid span openers on the 44 kV, 27.6 kV, and 8.32 kV system, but these are not currently maintained.

Switch replacements are undertaken for a number of reasons, including:

- mechanical or electrical failure;
- vehicle accidents;
- lightning strikes;
- new customer requirements;
- road reconstruction;
- line rebuilds or circuit reconfigurations;
- ESA compliance;
- upgrades for system security involving the SCADA system; and
- systematic failures involving a particular manufacturer or style.

3.3.1.4 *Reclosers*

Recloser inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. These devices are programmable switches that open and close depending on how the current limits are set. The load is broken within an oil bath or vacuum chamber for dielectric purposes. After a number of operations, the oil bath becomes contaminated with carbon, which is formed by the oxidation of the oil by the arc quenching process. The carbon impregnated oil loses dielectric properties and needs to be inspected and the oil replaced. The oil reclosers are inspected and rebuilt once every four (4) years and undergo regular infrared scans. Damaged reclosers are replaced as required.

3.3.1.5 *Overhead Transformers*

Overhead transformer inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. Transformers are able to transform high distribution voltage into low voltage (less than 750 V) that can be utilized by customers. All transformers have had their mineral oil tested and verified so that as of 2005, all transformers are polychlorinated biphenyl (“**PCB**”) free (less than 50 ppm). Transformers are visually inspected according to the Minimum Inspection Requirements in the Distribution System Code (every 3 years urban and every 6 years rural).

The typical line patrol inspections address the following issues:

- hot connects via infrared scanning;
- general appearance;
- loose wires; and
- bird or animal nests.

Transformers are changed with different sized units as needed. Transformers are replaced when they fail due to lightning strike, vehicle accident, potential oil leakage, or internal/external problems.

3.3.1.6 *Voltage Regulators*

Voltage regulator inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. Voltage regulators are single-phase devices that are situated on high voltage lines, far away from the DS. When line losses drop the voltage potential below acceptable levels, the voltage regulators increase the line voltage to within CSA standards. Innisfil has four (4) voltage regulators in the distribution system. These devices are patrolled and undergo infrared scanning. The devices are not physically removed from service for inspection; however, they are visually inspected on a monthly basis.

3.3.1.7 *Capacitors*

Capacitor inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. When ac power flows through the conductor, there is a loss of power in the conductor due to its resistance and reactance. Capacitor banks are installed to reduce line losses, improve power factor, and balance feeders for easier switching. InnPower has nine (9) sets of capacitor banks in its distribution system and additional locations may be identified when system planning activities are completed. Capacitors are inspected annually and damaged capacitors are repaired or replaced as required.

3.3.1.8 *Underground Cables*

Underground primary cable inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. With respect to underground systems, riser poles are checked by overhead patrols with a visual check of cable, cable guards, terminators, and arrestors.

While it is not possible to visually inspect underground cable directly, the system may be checked for exposed cable and or grade changes that may indicate that the cable has been brought too close to the surface. InnPower is performing a cost-benefit analysis on diagnostic testing of underground cables on an on-going basis to better ascertain cable condition and to plan for replacement. Cables with a premature failure rate are repaired or replaced as required.

Underground secondary service inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. Old bus work loses its insulation due to ultraviolet radiation and other weather related factors, and is becoming a danger to working utility staff and wildlife. The old secondary buss is removed from service and a new, larger bus is installed. Secondary services with a premature failure rate are repaired or replaced as required.

3.3.1.9 *Padmounted Switchgear and Transformers*

Padmounted switchgear inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. Switching cubicles are visually inspected according to the Minimum Inspection Requirements in the Distribution system Code (every 3 years urban and every 6 years rural) also undergo infrared scanning every three (3) years. Damaged switching cubicles are repaired or replaced as required.

Padmounted transformer inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. Underground transformers have their lids opened and all connections are inspected with infrared scans. Damaged transformers or components are repaired or replaced as required. All transformers have the mineral oil tested and verified so that all transformers are PCB free (less than 50 ppm). Transformers are visually inspected according to the Minimum Inspection Requirements in the Distribution System Code (every 3 years urban and every 6 years rural). All padmounted transformers are numbered and their secondary services are tagged, as are the high voltage elbows. Typically, padmounted transformer inspections address the following issues:

- hot connects;
- lock and penta-bolt in place;
- general appearance;
- pad/vault placement;
- leaking oil;
- loose wires; and
- bird or animal nests.

High voltage elbow and underground cable terminator inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. The standard for underground distribution is to use 28 kV class equipment even on 8.32 kV distribution. This standardization improves reliability and allows for easier voltage conversion upgrades. Elbows and terminators are visually inspected according to the Minimum Inspection Requirements in the Distribution system Code (every 3 years urban and every 6 years rural), and undergo infrared scans. Damaged elbows and terminators are repaired or replaced as required. InnPower does not log the number of elbows or cable terminators in its distribution system. Instead, they are tracked by the connecting switch, transformer, or switchgear.

3.3.1.10 *Distribution Stations*

DS inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. Monthly inspections are undertaken for both rural and urban distribution station sites. The inspection involves the following parameters:

- theft of copper;
- vegetation;
- fencing;
- litter;
- health and safety;
- station grounding (visual);
- condition of SCADA building;
- transformer temperature; and
- recloser operations.

Annual DS maintenance includes weed and vegetation control, grass cutting, snow plowing, and SCADA maintenance. On a four (4) year rotation, InnPower's DS are taken out of service so that major maintenance can be performed. This maintenance service includes the following:

- bus connection inspection and tightening;
- ground resistance test;
- transformer oil analysis;
- switch cleaning and lubrication;
- inspection and cleaning of terminators, insulators, and arrestors; and
- cleaning of site, structures, and hardware.

Substation maintenance crews generally perform major service over a one (1) to two (2) day period. Failure to perform major service could affect system reliability and the life-span of the related equipment.

There are ten (10) privately owned 44 kV transformer stations connected to InnPower's distribution system. InnPower performs monthly inspections on privately-owned stations to assure continued integrity with respect to reliability and health and safety. Since privately-owned stations are connected directly to InnPower's system, power quality problems at the private station can affect other customers on InnPower's system. InnPower's inspection forms are sent directly to the private station owners so that any remedial action can be undertaken.

3.3.1.11 *Vehicles*

The primary criteria best suited for the decision to replace InnPower vehicles is given in the Fleet Management Policy provided in Figure 3-8 below. Vehicles deteriorate differently depending on factors such as quality of manufacture and the severity of usage. The Fleet Management Policy is not intended to be a stringent set of rules that does not allow for the flexibility needed for asset management, but is a working target.

Table 3-9: InnPower's Fleet Management Policy

Vehicle	Replacement Age	Replacement Usage
Pickup truck, van, car	10 years	200,000 km
Dump truck (all sizes)	10 to 20 years	220,000 km or 10,000 hours
Large specialized equipment	10 to 20 years	10,000 hours

Different vehicles and equipment also wear out more rapidly than others depending on their usage type and frequency. To incorporate vehicles and equipment not referenced in the above criteria, there must be a second type of criteria used for this type of evaluation in addition to the above or on an individual basis. Table 3-10 presents the secondary criteria for vehicle assessment.

Table 3-10: Secondary criteria for vehicle assessment

Factor	Points
Age	One point for each year of chronological age, based on in-service data.
Kilometres/Hours	One point for each 16,000 km, 640 hours = 1 Point
Type of Service	1, 3 or 5 points are assigned based on the type of service that the vehicle receives. For instance, a road patrol car would be given a 5 because it is in severe duty service. In contrast, an administrative sedan would receive a 1.
Reliability	Points are assigned as 1, 3, or 5 depending on the frequency that a vehicle is in the shop for repair. A 5 would be assigned to a vehicle that is in the shop two or more times per month on average, while a 1 would be assigned to a vehicle in the shop an average of every three months or less.
M&R Costs	1 to 5 points are assigned based on total life M&R costs (not including repair of accident damage). A 5 is assigned to a vehicle with life M&R costs equal to or greater than the vehicle's original purchase price, while a 1 is given to a vehicle with life M&R costs equal to 20% or less of its original purchase cost.
Condition	This category takes into consideration body condition, rust, interior condition, accident history, anticipated repairs, etc. A scale of 1 to 5 points is used with 5 being poor condition.
Point Ranges	Under 18 points Condition I Excellent 18 to 22 points Condition II Good 23 to 27 points Condition III Qualifies for replacement 28 points and above Condition IV Needs immediate consideration

In order to maximize the useful life of its vehicles, InnPower evaluates the following practices for each vehicle:

- the availability to rotate vehicles between users to maximize the mileage driven with respect to the vehicle's age;
- the ability to transfer a vehicle to another department where usage is less severe or to address a need for a spare vehicle or spare parts; and
- analysis of whether the vehicle is in sufficiently good shape to extend its useful life beyond the age and mileage guidelines.

InnPower also analyzes factors which may decrease the useful life of a vehicle, including:

- other facets or technologies required of the vehicle that can no longer receive maintenance support or uses parts or updates that can no longer be supplied;
- analysis if the vehicle a "lemon" (i.e. expenses exceed depreciation), which may warrant an early retirement date;
- analysis if the vehicle no longer has a useful purpose or is in sufficiently poor shape to warrant an early retirement date;
- sufficient mechanical or structural damage caused by an accident or abnormal wear; and
- a mechanical analysis supporting the early retirement of a vehicle.

Large vehicles receive quarterly maintenance, including hydraulic maintenance, and yearly rust proofing. Small vehicles also receive yearly rust proofing and are maintained on an as-needed basis. Vehicles which are no longer useful may be retired early to avoid unnecessary upkeep costs.

3.3.1.12 *Property and Equipment*

InnPower owns eleven (11) distribution substation sites and one (1) 6.5 acre head office site. These sites have the grass cut and snow plowed as required. InnPower also owns numerous registered easements and non-registered easements for distribution assets registered on title, requiring on-going monitoring in an effort to protect the easement rights of InnPower. The head office requires interior maintenance, including the repair and replacement of office equipment.

Computer hardware includes the phone system, photocopiers, fax machines, printers, monitors, personal computers, network servers, power supplies, network cables, and wireless equipment,. The parameters for the replacement of computer hardware are as follows:

- improved space and speed requirements from new software;
- new technologies not supported by existing equipment;
- existing equipment not supported by suppliers; and
- Reliability problems from existing equipment.

When the need for expansion occurs and new computer equipment is purchased, displaced computer equipment is re-used or re-cycled to other areas of the corporation where appropriate.

3.3.2 Asset Lifecycle Risk Management Policies and Practices (5.3.3b)

> ***A description of asset life cycle risk management policies and practices, assessment methods and approaches to mitigation, including but not necessarily limited to the methods used; types of information inputs and outputs; and how conclusions of risk analyses are used to select and prioritize capital expenditures.***

Asset lifecycle risk management involves consideration of both the probability and consequence of failure. InnPower's asset management framework is condition based, which focuses on the probability of failure , and is not generally a risk based approach. InnPower will continue to analyze options to move to a risk based asset management philosophy.

4 Capital Expenditure Plan (5.4)

This section describes InnPower's five (5) year capital expenditure plan over the forecast period, including a summary of the plan, an overview of InnPower's capital expenditure planning process, an assessment of InnPower's system to connect new REG, a summary of capital expenditures, and justification of capital expenditures.

4.1 Summary (5.4.1)

This section includes an analysis of InnPower's ability to connect new load, a summary of capital expenditures over the forecast period, a description of the investments, and the list of material capital expenditures. This section also includes a description of expenditures related to a Regional Planning Process, a description of how customer engagement activities has affected the capital expenditure plan, and a description of how InnPower expects its system to develop over the forecast period with respect to load and customer growth, smart grid development, and REG accommodation. Finally, this section lists which investments have been planned as a result of customer preferences, technology based opportunities, and innovative processes, services, business models, or technologies.

4.1.1 Ability to Connect New Load (5.4.1a)

> ***information on the capability of the distributor's system to connect new load or generation customers in sufficient detail to convey the basis for the scope and quantum of investments related to this 'driver';***

Analysis of the capability of InnPower's distribution system to connect new load is presented below, based on InnPower's System Plan.

InnPower's distribution system can be divided into five (5) clusters based on geography and connectivity. The 27.6 kV system includes Bob Deugo DS, Brian Wilson T1 and T2, and Belle Ewart DS. The 8.32 kV south-east system includes Innisfil DS, Lefroy DS, and Cedar Point DS. The 8.32 kV north-east system includes Leonard's Beach DS, Lefroy DS, and Big Bay Point DS. The 8.32 kV west system includes Cookstown West DS and Thornton DS. Finally, Stroud DS is analyzed on its own since it is far from the other clusters.

Each of the clusters was analyzed based on the load forecast up to 2021. The cluster approach to capacity planning allows transformers to be loaded to 66% in the case of a three (3) transformer network, or 75% and 80% in the cases of four (4) and five (5) transformer networks, respectively. Traditional back to back station arrangements allow for only 50% loading of a transformer. The "N-1 Contingency" for a cluster of stations is determined by removing the largest transformer from the cluster and analyzing the cluster's ability to support the peak load with the remaining transformers. When the total load exceeds the N-1 Contingency there is a need for additional transformer capacity and when the load exceeds 80% of the N-1 Contingency there is a need to plan for additional transformer capacity. Feeders should be loaded up to a maximum of 50% of their recloser capacity in order to back up one another.

4.1.1.1 *27.6 kV System*

The 27.6 kV system includes Bob Deugo DS, Brian Wilson T1 and T2, and Belle Ewart DS. Each of these transformers except for Belle Ewart DS are forecast to reach 80% of their nominal rating in 2021. The system is able to withstand an N-1 Contingency due to the extra capacity provided by Belle Ewart

DS; however, in the current feeder configuration, Belle Ewart DS does not tie to Brian Wilson F1 or Brian Wilson F4.

Brian Wilson F1 and Brian Wilson F3 both exceed 50% of their recloser ratings. A load transfer from Brian Wilson F3 to Brian Wilson F4 would be feasible but not necessary, since Brian Wilson F3 is backed up by Belle Ewart F2, which has a recloser setting of 350 A. Brian Wilson F1 is located away from the other 27.6 kV feeders, which would make any load transfer impractical.

4.1.1.2 *8.32 kV South-East System*

The 8.32 kV south-east system includes Innisfil DS, Lefroy DS, and Cedar Point DS. These three (3) stations are connected to Cookstown West F2 and Stroud F1; although both of these feeders are far away and Cookstown West F2 is too long to support load from Innisfil DS.

The total peak load in the 8.32 kV south-east system is forecast to be greater than the N-1 Contingency in 2017, therefore additional transformation is required in this area in 2016. With a standard size 5 MVA transformer, the peak load is still forecast to be above 80% of the N-1 Contingency. Although increasing the size of the new transformer does not help the N-1 Contingency analysis if that transformer is lost, it eases the system in case any of the other transformers are lost.

Lefroy DS is unusual because it has three (3) feeders with 280 A of recloser capacity, which is 12 MVA at 8.32 kV, but only 5 MVA of transformer capacity. When the feeder load is nominally adjusted (i.e. 40% of recloser setting) the total station load would be 4.8 MVA; which would be too high to back up either Cedar Point DS or Innisfil DS in case of a loss of a transformer. Ideally the station's peak load should be closer to 80% of its nominal rating, or 4 MVA for these stations.

Innisfil F1, Lefroy F1, and Cedar Point F2 are all forecast to exceed 50% of their recloser capacity in 2016, while Cedar Point F1 is forecast to exceed 50% of its recloser capacity in 2018. The load on Stroud F1 is forecast to exceed 50% of its recloser capacity in 2018 and 2019, but this cannot be transferred onto the south-east system since it is too far and is transferred from Stroud DS in 2020. Two (2) new feeders are required in this cluster.

4.1.1.3 *8.32 kV North-East System*

The 8.32 kV north-east system includes Leonard's Beach DS, Lefroy DS, and Big Bay Point DS. In addition, Sandy Cove F1 can either tie to Stroud F2 or Stroud F3, of which Stroud F2 is the lighter loaded feeder.

Big Bay Point DS is forecast to reach 80% of its nominal rating in 2016 and to exceed 100% of its nominal rating in 2019. This indicates additional transformer capacity is needed in the north-east in 2018. Five (5) additional feeders are required to distribute the load to the feeders' nominal ratings, but this could be reduced to four (4) feeders if some load were transferred onto Stroud F2 (however, that would introduce new problems by making it more difficult to back up Stroud DS in case of a loss of a transformer). Note that two (2) feeders at 27.6 kV would be able to replace five (5) feeders at 8.32 kV.

4.1.1.4 *8.32 kV West System*

The 8.32 kV west system includes Cookstown West DS and Thornton DS. Innisfil F3 can tie with Cookstown West F2, but it is too far away to support load and so is excluded from the analysis. This cluster is lightly loaded and is not forecast to exceed any of the transformer or feeder load limits during the planning period of this DSP.

4.1.1.5 *Stroud DS*

Stroud DS is analyzed on its own since it is far from the other clusters. Stroud F1 can tie to Lefroy F2, but Lefroy F2 already has over 3% voltage drop at maximum load. Stroud F2 and Stroud F3 can both tie to Sandy Cove F1, but Sandy Cove F1 is too heavily loaded to back up Stroud.

There are difficulties backing up Stroud DS in case of a loss of transformer. Stroud DS can be backed up by tying Stroud F1 to Lefroy F2 (but this is a long 8.32 kV circuit and some load may need to be moved from Lefroy DS also) and moving load from Sandy Cove F1 onto Big Bay Point F2 to tie with Stroud F2 and F3.

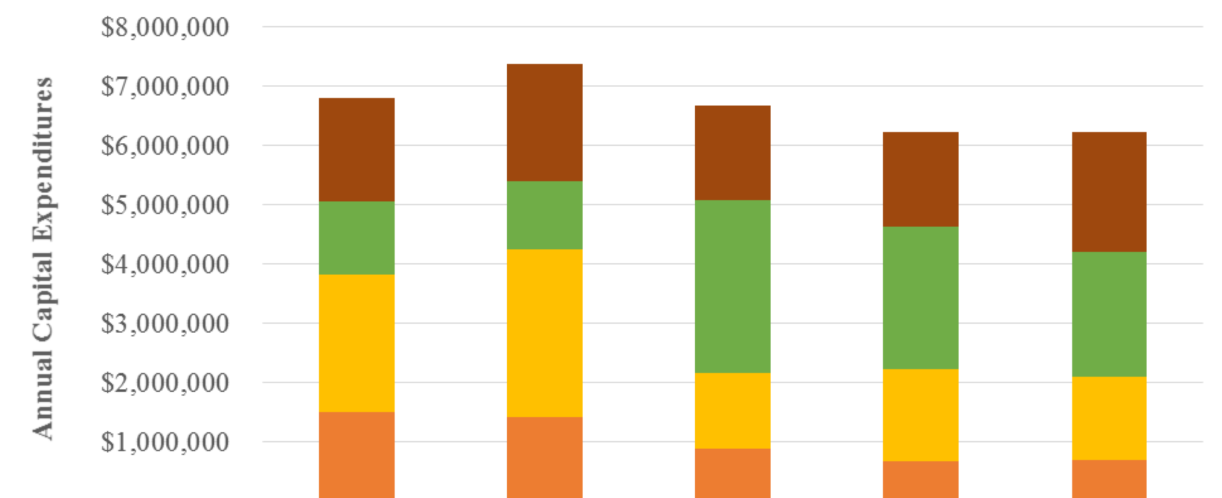
Stroud F1 is forecast to reach 75% of its recloser setting in 2019, but this load should be transferred onto a new substation constructed in the north-east of Innisfil. A feeder tie between Stroud F1 and Stroud F2 would allow Stroud F2 to back up Stroud F1 when the load is forecast to be high in 2018 and 2019.

4.1.2 Capital Expenditures over the Forecast Period (5.4.1b)

> ***total annual capital expenditures over the forecast period, by investment category (see section 5.4);***

Figure 4-1 presents the total annual capital expenditures over the forecast period, by investment category.

Figure 4-1: Total capital expenditures over the forecast period by investment category



Year	2017	2018	2019	2020	2021
System Access	$1,753,806	$1,984,220	$1,594,757	$1,598,442	$2,013,380
System Renewal	$1,215,739	$1,140,219	$2,919,105	$2,399,973	$2,109,321
System Service	$2,337,760	$2,828,750	$1,275,800	$1,556,279	$1,402,122
General Plant	$1,500,135	$1,423,156	$896,813	$680,317	$706,287

4.1.3 Description of Investments (5.4.1c)

a brief description of how for each category of investment, the outputs of the distributor's asset management and capital expenditure planning process have affected capital expenditures in that category and the allocation of the capital budget among categories;

4.1.3.1 *System Access*

System access investments over the forecast period are generally initiated by customer service requests and other third party infrastructure requests, and as such do not relate to InnPower's asset management process. InnPower is currently evaluating available options to accommodate the required Economic Evaluation payouts while maintaining levelized capital spending. Capital expenditure pacing is applied to third party infrastructure development projects, where possible, through collaboration with regional planners. The County of Simcoe IBR road widening project has been phased over all five (5) years of the forecast period.

4.1.3.2 *System Renewal*

System renewal projects planned over the forecast period have been selected to meet InnPower's asset management and planning objectives of ensuring public and worker safety, managing costs, and maintaining system reliability. InnPower's capital expenditure planning process determines the investment pacing and spending level of system renewal projects for each year, while InnPower's asset management process determines which assets to invest in.

Line reclosers are refurbished on a four (4) year cycle, as per InnPower's asset management policies. Assets selected for replacement under the Substandard Transformer Rehabilitations and Infrastructure Replacements and Betterments programs are based on inspections and line patrols. Work scheduled under the DS Oil Re-inhibit and Station Rehabilitation programs is based on the results of the stations ACA. Poles selected for replacement under the Pole Replacement Program are based on pole testing results and supported by the distribution ACA. Assets are selected for the Padmounted Transformer and Switchgear Replacements and Painting Program based on the results of the distribution ACA. Overhead and underground rebuilds are based on line inspections and are supported by the distribution ACA.

System renewal programs have been excluded from InnPower's DSP where the cost does not justify the apparent benefits to InnPower's customers. This includes annual pole maintenance, in-line switch and mid span opener maintenance, overhead transformer inspections (from bucket trucks), fault indicator inspection and testing, load balancing, padmounted transformer and switchgear maintenance, grounding testing, and mapping verification.

4.1.3.3 *System Service*

System service projects planned over the forecast period have been selected to meet InnPower's asset management and planning objectives of accommodating load growth, managing costs, maintaining system reliability, and mitigating environmental risk. System service investments due to load growth are planned for construction the year before they are needed. The Cedar Point DS upgrade has been planned for 2016 and the new Friday Harbour DS has been planned for 2018. Other system service investments are planned around these major expenditures to help smooth rates.

4.1.3.4 *General Plant*

Capital investments into IT infrastructure are planned to align InnPower's IT capabilities with the capabilities of its distribution system. IT infrastructure projects planned over the forecast period have been selected to meet InnPower's asset management and planning objectives of managing costs and maintaining system reliability.

Vehicle replacements are scheduled in accordance with InnPower's Fleet Management Policy to manage vehicle maintenance costs (see Section 3.3.1.11). Where possible, vehicle and other tooling investments have been spread out over the forecast period to smooth rates.

4.1.4 List of Material Capital Expenditures (5.4.1d)

> ***a list and brief description including total capital cost (table format recommended) of material capital expenditure projects/activities, sorted by category;***

4.1.4.1 *System Access*

Table 4-1 lists the system access material capital expenditures over the forecast period. 50% of the cost of Base 1 is budgeted under system access and includes unplanned expenses such as legacy overhead plant property trespassing costs. Base 2 includes unplanned, partially recoverable jobs for the Town of Innisfil, the County of Simcoe, or the Ontario Ministry of Transportation ("**MTO**"). Base 3 includes 100% recoverable Purchase Order jobs, including new service, REG connections, and MTO jobs outside of the ROW. Base 4 includes new subdivisions, and the difference between the capital costs and contributed capital is due to the result of the Economic Evaluation. Metering costs are also budgeted under system access.

As part of its transportation engineering plan, the County of Simcoe is widening IBR, between Thornton on the west end to 20th Side Road on the east end, covering approximately 12 km. This project requires relocating multi-circuit pole line infrastructure to accommodate their requirements. The project was started in 2012 and is expected to continue each year until 2021. The intersection of IBR and Yonge Street is scheduled for expansion in 2017. In the following years, sections of IBR are planned for widening: Yonge Street to 20th Side Road in 2018, Yonge Street to 10th Side Road in 2019, Highway 400 to 10th Side Road in 2020, and Highway 27 to 5th Side Road in 2021.

Table 4-1: System access material capital expenditures over the forecast period

Project	2017 Budget	2018 Budget	2019 Budget	2020 Budget	2021 Budget
Base and Metering					
Base 1 (50%)	$116,880	$122,725	$134,998	$148,497	$163,346
Base 2	$34,254	$35,970	$39,567	$43,523	$47,876
- contributions	-$11,486	-$10,175	-$11,193	-$12,311	-$13,542
Base 3	$945,557	$1,087,390	$1,359,237	$1,699,046	$2,123,808
- contributions	-$945,557	-$1,087,390	-$1,359,237	-$1,699,046	-$2,123,808
Base 4	$5,558,640	$9,349,360	$9,349,360	$9,349,360	$9,349,360
- contributions	-$4,446,912	-$8,254,960	-$8,254,960	-$8,254,960	-$8,254,960
Metering	$230,000	$270,000	$250,000	$250,000	$250,000
County Road Widening					
Intersection Widening IBR & Yonge St	$430,000				
- contributions	-$157,570				
Road Widening IBR between Yonge St & 20 SR		$745,000			
- contributions		-$273,700			
Road Widening IBR between Yonge St & 10 SR			$137,500		
- contributions			-$50,515		
Road Widening IBR between Hwy 400 & 10 SR				$117,500	
- contributions				-$43,167	
Road Widening IBR between Hwy 27 & 5 SR					$745,000
- contributions					-$273,700

4.1.4.2 *System Renewal*

Table 4-2 lists the system renewal material capital expenditures over the forecast period. The remaining 50% of the cost of Base 1 is budgeted under system renewal and includes unplanned repairs to InnPower's distribution system due to storm damage and unclaimed vehicle accidents.

Seven (7) ongoing projects are budgeted year over year to address the need to remove and replace rotten and damaged infrastructure, and substandard or defective devices that pose a danger to the public and safety of workers. These projects are:

- Substandard Transformer Rehabilitation, in which legacy and substandard distribution transformers are updated;
- the Pole Replacement Program, in which aged and failing poles that have been tested or deemed in need of replacement are replaced;
- the Infrastructure Replacements and Betterments program, in which other aged or defective devices are replaced;
- Underground Padmounted Transformer and Switchgear Replacements and Painting, in which helps switchgear and transformers adversely affected by weather conditions and salt contamination are replaced or maintained;
- the DS Oil Re-inhibit program, in which the oil oxidation inhibitor levels inside the main tank of the station transformer are restored to effective levels;
- Station Rehab projects, which are aimed at performing repairs to deteriorating infrastructure in our aging distribution stations; and
- Line Recloser Refurbishments, in which reclosers are maintained on a four (4) year cycle to ensure correct operation.

A number of overhead and underground rebuilds have been scheduled over the forecast period. The subtransmission infrastructure along Lockhart Road between Stroud DS and 25th Side Road will be replaced using a phased approach to maintain reliability on the 44 kV system. The 44 kV pole line north of Highway 89 on 5th Side Road will also be rebuilt using a phased approach starting in 2017, and continuing from 2019 to 2021.

At the distribution level, Ewart Street will receive a line upgrade south of Maple Road where several of the existing poles are sinking lower into the swamp land they were originally constructed on. Several other poles in this section have also been flagged for immediate replacement by pole inspectors. Starting in 2017 and phased over the forecast period, general reliability rebuild projects are scheduled to take place in the Alcona, Cookstown, and Lefroy areas. These projects include infrastructure upgrades and rehabilitation work replacing aged infrastructure to new construction standards for increased reliability. In 2018 and 2020, a two (2) year project will replace aged infrastructure spanning Highway 400 with the latest construction standards. There are two (2) back lot conversion projects each phased over two (2) years in 2019 and 2020, which will relocate legacy backyard infrastructure in order to provide better reliability, and worker and public safety. The forty (40) year-old direct-buried underground cables in Sandy Cove Acres will be replaced from 2019 to 2021to improve reliability. Finally, a project planned for Degrassi Cove in 2021 will replace overhead infrastructure in a heavily wooded section to underground to improve reliability.

Table 4-2: System renewal material capital expenditures over the forecast period

Project	2017 Budget	2018 Budget	2019 Budget	2020 Budget	2021 Budget
Base and Annual Reliability Programs					
Base 1 (50%)	$116,885	$122,725	$128,861	$135,304	$148,834
Substandard Transformer Rehab	$85,000	$30,000	$31,500	$33,075	
Pole Replacement Program	$126,470	$148,500	$155,925	$163,721	$171,907
Infrastructure Replacements and Betterments	$150,253	$157,766	$165,654	$173,936	$182,633
DS Oil Re-inhibit Treatment	$27,527	$57,806	$60,696	$30,000	
Padmounted Transformer & Switchgear Replacements & Painting	$43,710	$45,895	$48,190	$50,599	$53,129
Station Rehab	$104,300	$109,853	$115,346	$242,226	$115,680
Transformers	$100,000	$110,000	$121,000	$133,100	$146,410
Overhead and Underground Rebuilds					
Ewart Street Rebuild	$105,000	$50,000	$52,500	$56,700	$131,274
Reliability Rebuild – Subtransmission: Lockhart Road	$170,650	$89,933	$294,429	$203,060	$213,214
Reliability Rebuild – Subtransmission: 5th Side Road	$75,000		$550,000	$225,000	$225,000
Reliability Rebuild – Distribution: Cookstown	$50,000	$52,500	$55,125	$200,880	$156,000
Reliability Rebuild – Distribution: Lefroy	$22,500	$47,250	$49,613	$52,093	$54,697
Reliability Rebuild – Distribution: Alcona	$22,500	$47,250	$49,613	$52,093	$54,697
Reliability Rebuild – Distribution: 400 Crossing		$22,500		$75,000	
Everton Back Lot Conversion			$155,000	$135,000	
Sandy Cove - U/G cable replacement			$700,000	$250,000	$250,000
Parkview rear lot 1 phase relocate to street front			$135,000	$135,000	
Degrassi Cove U/G conversion					$150,000

4.1.4.3 *System Service*

Table 4-3 lists the system service material capital expenditures over the forecast period.

In 2017, the hydraulic reclosers at Sandy Cove DS will be upgraded to vacuum type reclosers with electronic controls, which will complete InnPower's multi-year project to enable SCADA capability between the control room and the DS. Several of InnPower's DS do not currently have oil containment systems and it is planned to complete one (1) station each year in 2017, 2019, 2020, and 2021. These systems are installed to avoid potential clean-up costs and limit environmental risk.

27.6 kV and 44 kV automated switches will be added each year starting in 2017, replacing several old mid-span openers and air break style switches. These new switches provide remote switching capability and real-time data acquisition to better manage outages. Crew time will be reduced during emergency and non-emergency operations and built in functionality can be used for future smart grid, self-healing configurations. From 2019 to 2021, two (2) motorized SCADA controlled padmounted switchgear will be installed each year in strategic locations for faster restoration during outages. Automated capacitor controller will be installed in 2019 and 2020 to monitor and control the amount of reactive power in the system.

In order to serve the increased loads at Friday Harbour and part of the loads in the South Barrie Hewitt developments a new 10 MVA, 44-27.6 kV DS will be built in the Friday Harbour area. A re-poling project in 2017 will run from the future site of Friday Harbour DS to the Friday Harbour development and the DS will be constructed in 2018.

A line rebuild is planned in 2017 on Lockhart Road from Stroud DS to Huronia Road to add two (2) distribution circuits which will serve as a backbone link between the Salem and Hewitt lands. Another line rebuild and extension is planned on Mapleview Drive from Prince William Way to Seline Crescent to serve new load. A rebuild planned on 5th Side Road between McKay Road and Salem Road will extend the existing circuits to serve new loads in the South Barrie lands. Another distribution system rebuild is planned in 2020 and 2021 to serve new developments south of Belle Ewart DS.

From 2019 to 2021, a 44 kV pole line rebuild and replacement project has been planned on 5th Side Road between 5th Line and IBR. This project will replace the old small conductor infrastructure and have an additional 44 kV circuit on to accommodate the new Alliston 9M6 feeder scheduled to reach InnPower within the next ten (10) years for load growth.

Two (2) voltage conversion projects have been planned to upgrade the 8.32 kV infrastructure to 27.6 kV in the 400 Corridor and Alcona South. Both projects have been phased over three (3) years from 2019 to 2021. These projects will improve InnPower's load serving capability and are expected to improve system reliability.

Table 4-3: System service material capital expenditures over the forecast period

Project	2017 Budget	2018 Budget	2019 Budget	2020 Budget	2021 Budget
SCADA and Stations Upgrades					
Sandy Cove DS automation	$125,000				
DS Transformer Oil Containment	$45,000		$49,613	$52,093	$54,698
Distribution SCADA controlled load interrupting gang switch	$75,000	$78,750	$82,688	$86,821	$91,162
Subtransmission SCADA controlled switches			$148,500	$155,925	
SCADA PME motorized switchgear			$165,000	$173,250	$181,913
Capacitor IntelliLink to SCADA			$65,000	$65,000	
Load Growth					
Re-poling: Big Bay Point Road – Friday Harbour DS to Friday Harbour Development (North)	$362,570				
Re-poling: Lockhart Road – Huronia Road to Stroud DS	$618,932				
Re-poling: Mapleview Drive – Prince William Way to Seline Crescent	$837,831				
Re-poling 5th Side Road – McKay Road to Salem Road	$273,427				
Friday Harbour DS		$2,750,000			
New Subtransmission Feeder: Line upgrade 5 SR from 5th Line to IBR			$315,000	$330,750	$347,288
Line Rebuild for new developments south of Belle Ewart DS				$219,940	$230,937
Voltage Conversion					
400 Corridor Voltage Conversion & Servicing			$250,000	$262,500	$275,625
Alcona South Voltage Conversion			$200,000	$210,000	$220,500

4.1.4.4 *General Plant*

Table 4-4 lists the general plant material capital expenditures over the forecast period.

IT general hardware and software requirements are budgeted each year, as well as finance IT, engineering IT, and system supervisory requirements to support day to day business and operations activities.

In 2017, the replacement of a 1993 double-bucket truck will be necessary as this truck was purchased second hand from another power company in 2010 and will be at the end of its useful life. Two (2) locator mini-vans will be purchased in 2017. Existing vehicles have been scheduled for replacement based upon InnPower's Fleet Management Policy (see Section 3.3.1.11). In 2019, two (2) technician vehicles will need to be replaced. In 2020, one (1) half-ton truck is scheduled for replacement; and in 2021, one (1) half-ton truck and one (1) one-ton truck are scheduled for replacement.

The increase in lines work and subdivision work resulting from the load growth has created the need to add a new line crew in 2018. An RBD will be purchased in the prior year (2017) to spread out the investment. In 2018, a new double-bucket truck and tooling will be purchased. A new tension machine will be purchased in 2019, again to spread out the investment.

Table 4-4: General plant material capital expenditures over the forecast period

Project	2017 Budget	2018 Budget	2019 Budget	2020 Budget	2021 Budget
IT Hardware and Software					
IT Hardware	$165,000	$150,000	$150,000	$150,000	$150,000
IT Software	$95,000	$95,000	$95,000	$95,000	$95,000
Finance IT	$77,000	$50,000	$60,000	$50,000	$50,000
Engineering IT	$167,325	$145,516	$119,000	$100,000	$105,000
System Supervisory	$32,400	$47,408	$49,778	$52,266	$54,880
Vehicles and Tooling					
Replacement Double Bucket Truck - 1993 Altec	$373,500				
Locator Vehicle Mini-van (x2)	$63,000				
RBD - new Crew	$250,000				
65' Double Bucket-new crew		$400,000			
Tooling for Bucket & RBD		$150,000			
Tension Machines			$200,000		
Tech Vehicle - Ford Escape 2009 & 2010 Replacement (#88 & 95)			$95,918		
Fleet vehicle replacement 2005 1/2 ton (#87)				$51,750	
Fleet vehicle replacement 2011 1/2 ton (#96)					$54,337
Fleet vehicle replacement 2011 1 ton (#101)					$60,000

4.1.5 Expenditures related to a Regional Planning Process (5.4.1e)

information related to a Regional Planning Process or contained in a Regional Infrastructure Plan that had a material impact on the distributor's capital expenditure plan, with a brief explanation as to how the information is reflected in the plan;

The hand-off letter that resulted from the IRRP regarding the near term wires solutions was provided to HONI by the IESO on 7 December 2015 and is attached as Appendix D. The recommendations of the hand-off letter are:

- to rebuild Barrie TS and the E3/4B transmission line and to upgrade the voltage of these facilities from 115 kV to 230 kV;
- to upgrade the transformers at Barrie TS from 55/92 MVA units to 75/125 MVA units; and
- to retire the two 230/115 kV autotransformers at Essa TS (T1 and T2).

The Working Group for the Barrier/Innisfil sub-region is continuing to work on the development medium and long term plans for the sub-region. These include:

- constructing a new TS (InnPower TS);
- constructing a new 230kV transmission line from Barrie TS to the InnPower TS site;
- implementing a HVDS egressing from InnPower TS; and
- proposing a 44 kV solution for the load growth in South Barrie.

The Working Group has identified South Barrie as a key load growth point. This area is serviced by both InnPower and PowerStream. The near term solution would address the infrastructure requirements within the current DSP period; however, as the medium and long term plans consider the construction of a new TS, HVDS, and transmission lines within InnPower's service territory the outcome of these plans would potentially play a major role in the DSP submitted by InnPower in the future.

From 2019 to 2021, a 44 kV pole line rebuild and replacement project has been planned on 5th Side Road between 5th Line and IBR. This project will replace the old small conductor infrastructure and have an additional 44 kV circuit on to accommodate the new Alliston 9M6 feeder scheduled to reach InnPower within the next ten (10) years for load growth.

4.1.6 Customer Engagement Activities (5.4.1f)

a brief description of customer engagement activities to obtain information on their preferences and how the results of assessing this information are reflected in the plan;

To determine customer expectations with respect to InnPower's DSP and five-year Business Plan, InnPower gathered feedback from customers from various forums, including the 2013 and 2014 UtilityPULSE Customer Satisfaction Survey (see Appendix I) and direct feedback from customers. The sources for direct feedback from customers are listed in Table 4-5, including counts for each activity.

Table 4-5: Customer outreach in 2015

Event	Customer Outreach	
Calls from customers	22,000	calls
Walk-ins to the front office	6,000	walk-ins
AM/PM appointments with customers	497	appointments
Scheduled appointments	5,173	appointments
InnPower's open house and tour of the new Corporate Operations/Admin Centre	500	attendees
Annual community events in Innisfil (Wing Ding, Summerfest, Family Day, Sandy Cove Acres Home Show and Celebrate Lake Simcoe)	37,750	cumulative participants
customer educational sessions – conservation, OESP, and understanding your electricity bill	9	sessions
CDM site visits with GS<50 and GS>50 rate class customers	61	site visits
2017 COS Rate Overview Session	16	attendees

With multiple data sources, trends are reviewed by the respective organizational teams and feedback is provided to the managers for review at monthly meetings. The following concerns have been identified by InnPower's customers:

4.1.6.1 *Cost*

Customers believe that "high bills" or "high rates/charges" are deemed as billing issues rather than a consequence of the amount of electricity they are consuming. There is a growing concern among residential customers over electricity costs as it relates to its portion of a household budget, particularly as housing costs rise and disposable incomes fall. Customers often have difficulty understanding their bills and bridging the gap between distribution and commodity costs, a known issue in the industry at large that is not specific to InnPower. As a result, customers assume that InnPower is responsible for all of the rate increases, since InnPower's name appears on their bill.

4.1.6.2 *Reliability*

For the cost of electricity, customers expect a certain level of reliability from their distributors. Most customers are willing to accept a certain frequency and duration of outages, understanding that some events are unavoidable and that there are costs associated with maintaining and improving reliability.

4.1.6.3 *Paying for Future Projects/Improvements*

Although customers understand that costs are associated with service reliability, InnPower's survey results indicate that only 46% of respondents expressed a willingness to pay in order to improve system performance, while an equivalent 46% of respondents were not willing to incur any additional costs. This is summarized in Table 4-6 below.

Table 4-6: Customer survey results – willingness to pay

Willingness to Pay for Further Improvements	
$0	46%
$ 1 - 2	7%
$ 3 - 4	5%
$ 5 - 6	21%
$ 7 - 8	1%
$ 9 - 10	11%
$ 11 +	1%
Don't Know	9%

4.1.6.4 *Aspects of the DSP Affected by Customer Feedback*

Customers support long term planning for utility investment, even beyond a five year period. InnPower has utilized the aforementioned feedback to determine customers' wants versus needs in development of the DSP. The capital plans outlined in InnPower's DSP balance the requirements to meet existing customer demand, predicted load growth, and expected reliability. Scoped projects and programs are deferred or removed from the plan to align InnPower's budget envelopes with customer expectations.

4.1.7 System Development over the Forecast Period (5.4.1g)

a brief description of how the distributor expects its system to develop over the next five years, including in relation to load and customer growth, smart grid development and/or the accommodation of forecasted renewable energy generation projects;

4.1.7.1 *Load and Customer Growth*

Based on information currently available InnPower will see increased load growth in the following areas during the five year horizon: South Barrie – Hewitt Secondary Plan and Salem Secondary Plan, Friday Harbour, 400 Corridor, Alcona, Churchill, Cookstown, Gilford, Lefroy, Alcona South, and Stroud.

The *Barrie-Innisfil Boundary Adjustment Act, 2009* extended the southern boundary of Barrie to include 2,335 hectares (approximately 5,700 acres) of land previously in the Town of Innisfil, effective 1 January 2010. It is expected, based on conservative estimates, that the number of residences constructed in the South Barrie lands starting in 2018 will be 3,600 units by the end of 2020, adding approximately 1,200 units per year on average. This will likely result in a load increase of 17.1 MW.

Table 4-7 : Barrie South (Annexed Area) Development Plan 2011-2031

CITY OF BARRIE
DETAILED HOUSING AND POPULATION FORECAST BY GROWTH AREA, 2011-2031

Growth Area	Growth Period	Housing Units				Gross Population in New Units	Population Decline in Existing Units	Net Population Increase
		Low Density	Medium Density	High Density	Total			
Annexed Area	2011-2016	-	-	-	-	-	(8)	(8)
	2011-2021	3,560	1,372	941	5,872	16,062	(16)	16,046
	2011-2026	6,168	2,533	1,688	10,389	28,215	(23)	28,191
	2011-2031	7,892	3,664	2,330	13,887	37,344	(31)	37,313

Source: Watson & Associates Economists Ltd.

Note: Population excludes Census undercount

Figure 4-2 : Barrie South – Hewitt Development Plan

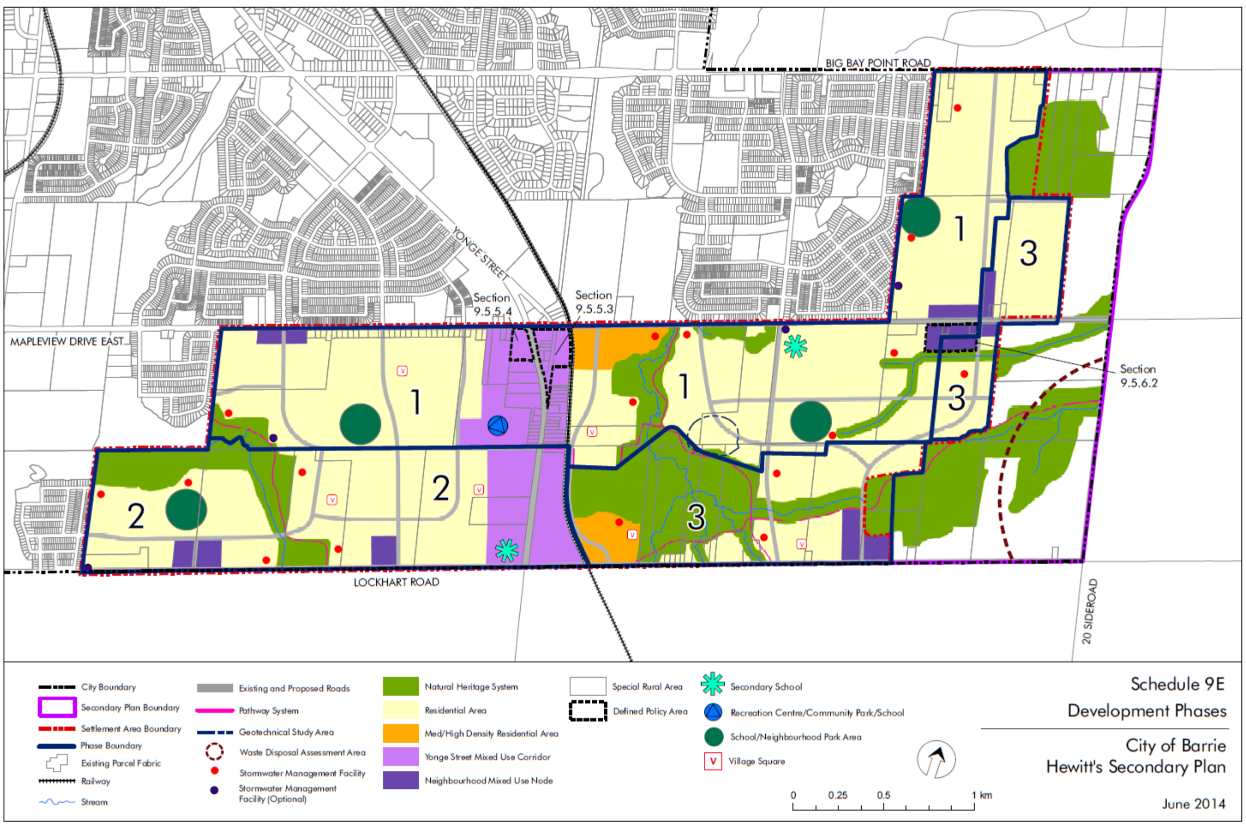
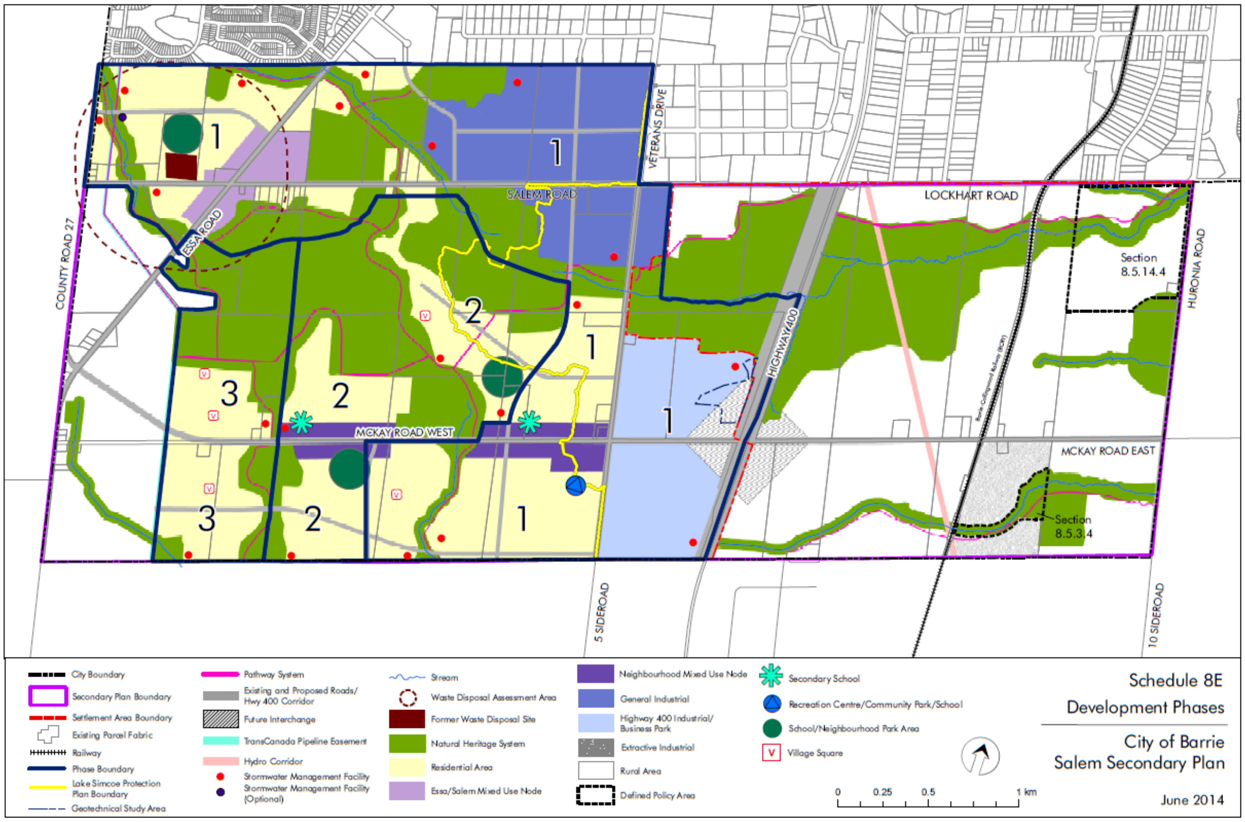


Figure 4-3 : Barrie South – Salem Development Plan

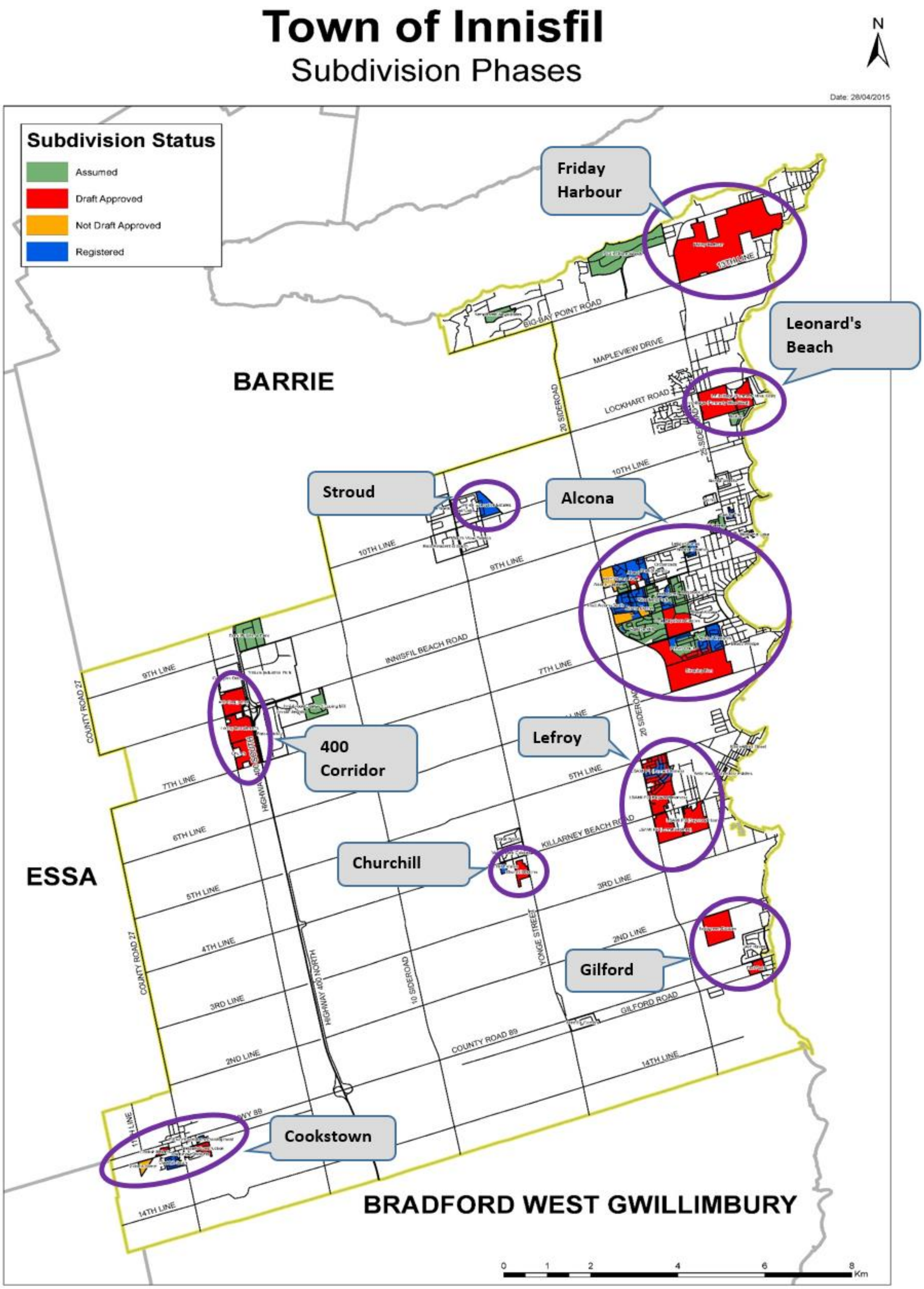


There are a number of new subdivision construction projects planned in the Town of Innisfil. The development areas are depicted in Figure 4-4. The number of residential units expected to be constructed with the Town of Innisfil during the next five (5) years is presented in Table 4-8.

Table 4-8: Town of Innisfil planned residential units (2016-2020)

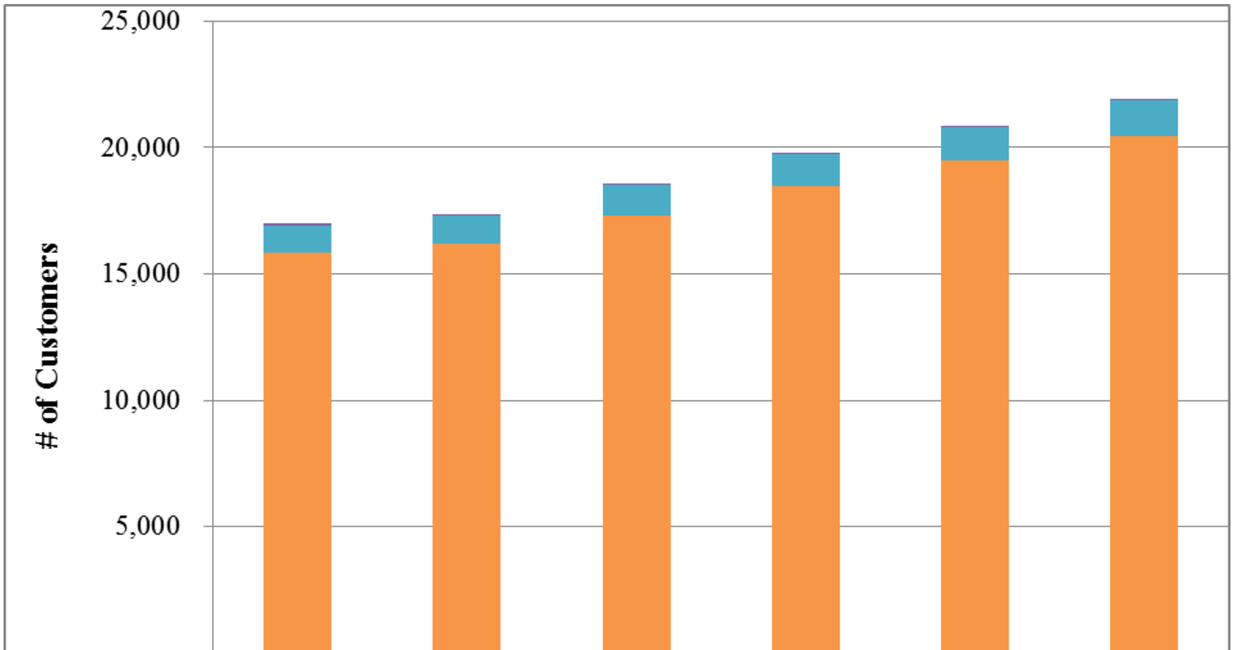
Area	Planned Number of Residential Units				
	2016	2017	2018	2019	2020
Alcona	145.8	91.8	163.2	178.8	150
Alcona South (Sleeping Lion)	0	60	60	60	60
Churchill	0	7.2	7.2	3	3.6
Gilford	0	3	3	3	3
Cookstown	30.6	18	28.8	10.2	0
Stroud	6	6	6	1.2	0
Friday Harbour	150	90	90	90	90
Lefroy	72	72	72	54.6	42
Total	**404.4**	**348**	**430.2**	**400.8**	**348.6**

Figure 4-4: Town of Innisfil new subdivision map



Based on the available information, InnPower has forecast its customer growth up to 2021, as shown in Figure 4-5. The number of residential customers is forecast to increase by 35% from the 2015 year-end count to 2021. Likewise, the number of GS<50 customers is forecast to increase by 34% over the same period. No change has been forecast in the number of GS>50 customers.

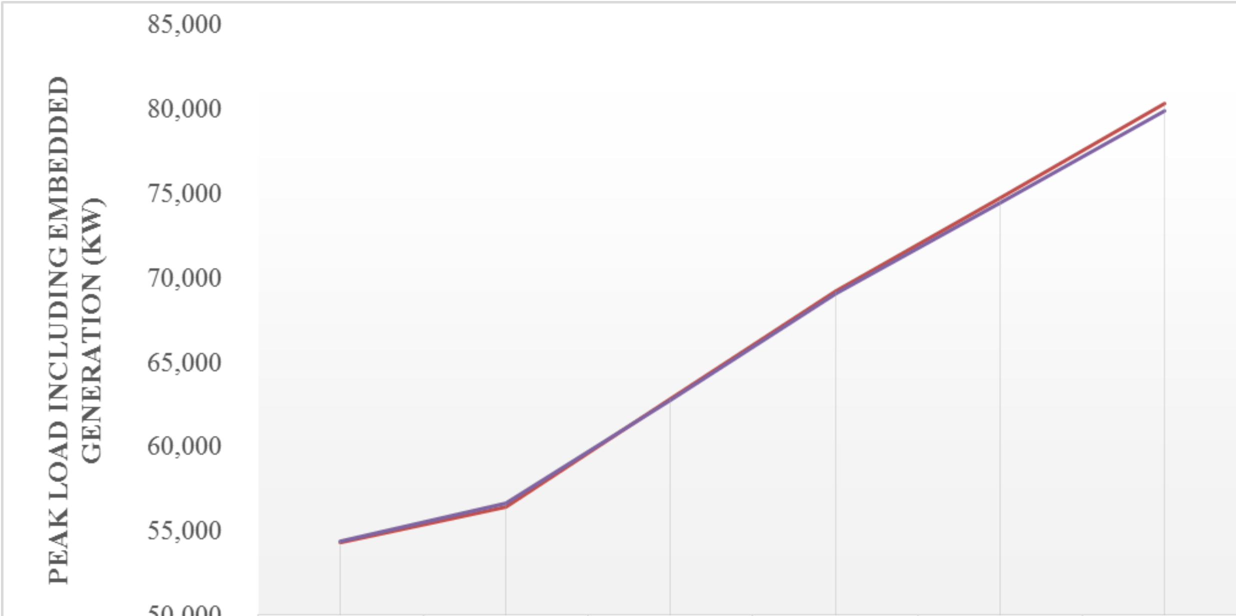
Figure 4-5: InnPower forecast customer growth (2016-2021)



Year	2016	2017	2018	2019	2020	2021
GS>50	74	74	74	74	74	74
GS<50	1,085	1,109	1,178	1,257	1,324	1,392
Residential	15,836	16,185	17,329	18,480	19,475	20,472

Figure 4-6 presents the forecast winter and summer peak load including embedded generation. The load is projected to increase dramatically: approximately 55% higher than the 2015 peaks.

Figure 4-6: InnPower forecast load growth (2016-2021)



YEAR	2016	2017	2018	2019	2020	2021
Winter Peak	54,319	56,447	62,798	69,238	74,704	80,304
Summer Peak	54,397	56,667	62,761	69,065	74,429	79,921

To accommodate the increase in residential growth several capacity upgrade projects have been planned over the forecast period, including new DS, capacity upgrades to existing stations, and line builds to add circuitry to supply the new loads.

4.1.7.2 *Smart Grid Development*

InnPower is planning to finish upgrading its legacy station hydraulic reclosers to newer vacuum type reclosers with electronic controls by 2017. Stroud DS will be upgraded in 2016 and Sandy Cove DS will be upgraded in 2017. One (1) automated capacitor controller will be installed each year in 2019 and 2020 to monitor and control the reactive power in InnPower's distribution system.

27.6 kV and 44 kV automated switches will be added each year started in 2017, replacing several old mid-span openers and air break style switches. These new switches provide remote switching capability and real-time data acquisition to better manage outages. Crew time will be reduced during emergency and non-emergency operations and built-in functionality can be used for future smart grid, self-healing configurations. Two (2) motorized SCADA controlled padmounted switchgear will be installed each year from 2019 to 2021 at strategic locations for faster restoration during outages.

4.1.7.3 *REG Accommodation*

Currently, two (2) of InnPower's distribution feeders have reached their threshold REG capacity recommended by IEEE Std 1547, and six (6) other feeders are within 20 kW of this threshold. InnPower is considering performing a static voltage regulation study and a dynamic Electro-Magnetic Transients Program ("**EMTP**") study to determine whether the REG constraints can be relieved from some of its feeders or whether investments into REG accommodation need to be made.

4.1.8 Customer Preferences/Technology Based Opportunities/Innovation (5.4.1h)

a list and brief description including where applicable total capital cost (table format recommended) of projects/activities planned:

- ***in response to customer preferences (e.g., data access and visibility; participation in distributed generation; load management);***
- ***to take advantage of technology-based opportunities to improve operational efficiency, asset management and the integration of distributed generation and complex loads; and***
- ***to study or demonstrate innovative processes, services, business models, or technologies.***

A number of InnPower's projects and programs are in response to customer preferences, to take advantage of technology based opportunities, or to study or demonstrate innovative processes, services, business models, or technologies. Table 4-9 lists the project/programs in the Test Year (2017) and identifies which projects/programs are in response to customer preferences, technology based opportunities, and innovative processes, services, business models, or technologies.

4.1.8.1 *Customer Preferences*

Through InnPower's customer engagement, certain factors such as safety, serviceability, reliability, and cost have all been identified as concerns at a residential and business level. Customers have indicated that they would like reliability maintained and have an obvious and demonstrated preference towards safety. Groups that represent new subdivision developments are concerned about service delivery to new subdivisions. InnPower's infrastructure system renewal projects and system service projects address these at a broad level.

InnPower uses the information derived from customer engagement to ensure its decisions are aligned with customer preferences and that its decisions are valid based on the customer feedback generally. InnPower will continue to ensure that its prioritization of capital expenditures is aligned with customer expectations and preferences over the forecast period, and anticipates that its plan to service new developments and its goal of maintaining reliability within the system will achieve the stated alignment.

4.1.8.2 *Technology Based Opportunities*

In taking advantage of technology based opportunities to improve operational efficiency, InnPower will continue to evaluate options with respect to technology as it becomes available throughout the forecast period. In 2016 the backbone of the SCADA system will be upgraded to a WIMAX based system operating on the 1.8 GHz spectrum and a 18 GHz system for its backbone connectivity, which is shared with the Town of Innisfil, and the rollout of the SCADA system to all municipal substations will be completed in 2017. The WIMAX based system will support the following systems:

- Fleet Management
- Distribution Automation, including fault detection with the use of radio controlled fault current indicators and automatic Fault Detection, Isolation, and Restoration;
- integration of Distributed Generation; and
- the OMS.

During its recent mandate to encourage Smart Grid innovation, the Ministry of Energy introduced the Smart Grid fund. InnPower participated in the application process and was a co-applicant for a proposal that, if successful, will help detect faults occurring within large station class transformer windings at a very early stage. This application is currently being evaluated.

The Ministry of Transportation introduced the Electric Vehicle Chargers Ontario Program in January 2016 and InnPower participated in this program by submitting an application for funding a total of ten (10) electric vehicle charging stations. This application is still under review.

4.1.8.3 *Innovative Processes, Services, Business Models or Technologies*

The demonstration of innovative processes is of continuing importance, therefore InnPower has been automating daily business activities such as inventory management and work order management. These projects will eliminate paper, allow for analytics reporting, and provide efficiencies over the current processes. Some specific examples of innovative efforts that are being considered include, inter alia, 3-D modeling of substations, mobile notebooks for use in fleet vehicles, upgrades to system PCs, and server upgrades.

InnPower will also continue to keep up with new releases of the engineering analysis software it utilizes for pole calculations and circuit design/simulation to ensure sound engineering principles are adhered to in all its design. InnPower's Engineering and Operations departments are working closely to ensure all construction jobs are thoroughly reviewed and approved by both a Professional Engineer and the Operations manager. This has and will result in efficiencies as further process automation is implemented within the five-year horizon.

InnPower is currently collaborating with the Town of Innisfil to conduct a pilot study that will consolidate buried utility locating requirements. This is expected to achieve cost savings and will use novel locate automation software.

Given the new requirements of the OEB to enhance reliability tracking metrics, InnPower is working closely with the developers of its OMS to automate the reporting of customer specific reliability metrics. This work has been planned for 2016. InnPower is continuing to improve its GIS in order to enhance design efficiency and to improve information sharing. The central GIS database will be expanded to house all important data pertaining to assets and will be used as the hub for intelligent data harvesting, such as asset performance analysis

Table 4-9: Projects in response to customer preferences, technology opportunities, and innovation

Investment Category	Project Description	(1) Customer Preference (2) Technology Based (3) Innovative Process	2017 Budget
System Access	Base 1 (50%)	1	$ 116,880
	Base 2	1	$ 34,254
	- contributions for Base 2		-$ 11,486
	Base 3	1	$ 945,557
	- contributions for Base 3		-$ 945,557
	Base 4	1	$ 5,558,640
	- contribution		-$ 4,446,912
	Metering	1,2	$ 230,000
	Road Works		
	Intersection Widening IBR & Yonge St	1	$ 430,000
	- contributions		-$ 157,570
System Renewal	Base 1 (50%)	1	$ 116,885
	Substandard Transformer Rehab	1	$ 85,000
	Pole Replacement Program	1	$ 126,470
	Infrastructure Replacements and Betterments	1	$ 150,253
	Line Reclosure Refurbishments - 4 Year Cycle	1	$ 15,945
	DS Oil Re-inhibit Treatment	1	$ 27,527
	Padmounted Transformer and Switchgear Replacements and Painting	1	$ 43,710
	Station rehab	1	$ 104,300
	Ewart Street Rebuild - Phased Approach	1	$ 105,000
	Transformers	1	$ 100,000
	Reliability Rebuild: Subtransmission - Lockhart Road	1	$ 170,650
	Reliability Rebuild: Subtransmission - 5 Side Road	1	$ 75,000
	Reliability Rebuild: Distribution - Cookstown	1	$ 50,000
	Reliability Rebuild: Distribution - Alcona	1	$ 22,500
	Reliability Rebuild: Distribution - Lefroy	1	$ 22,500
System Service	Distribution SCADA controlled load interrupting gang switch	1,2	$ 75,000
	Repoling: Big Bay Point Road - Friday Harbour DS to Friday Harbour Development (North)	1	$ 362,570
	Repoling: Lockhart Road - Huronia Road to Stroud DS	1	$ 618,932
	Sandy Cove DS automation	1,2	$ 125,000
	Repoling: Mapleview Drive - Prince William Way to Seline Crescent	1	$ 837,831
	Repoling: 5 SR - McKay Road to Salem Rd	1	$ 273,427
	DS Transformer oil containment		$ 45,000
General Plant	IT Hardware	1,2	$ 165,000
	IT Software	1,2	$ 95,000
	Furniture and Equipment		$ 15,000
	Buildings and Fixtures		$ 15,000
	Finance IT	2	$ 77,000
	Engineering IT	1,2	$ 167,325
	Measuring Tools & Equipment IT & Meter	2	$ 23,000
	Fleet Tools		$ 15,750
	Stores Equipment		$ 5,250
	Tools, Shop and Garage Equipment		$ 24,150
	Measurement and Testing Equipment	2	$ 28,000
	Replacement Double Bucket Truck - 1993 Altec		$ 373,500
	Fleet vehicle replacement 1-2006 Ford 1/2 ton		$ 45,000
	Locator Vehicle Mini-van (x2)		$ 63,000
	Technologist Vehicle - NEW		$ 43,500
	Inspector vehicle - NEW		$ 43,500
	Distribution Fault Current Indicators	2	$ 18,760
	System Supervisory	2,3	$ 32,400
	RBD - new Crew		$ 250,000

4.2 Capital Expenditure Planning Process Overview (5.4.2)

The capital budget process at InnPower is an integral planning tool and ensures that appropriate resources are available to maintain and grow its capital infrastructure. It is the responsibility of each department to contribute in the preparation of the capital and operating budget, with the assistance of the Finance department. The responsibility of the Finance department is to coordinate the capital budget and forecast process and present a Preliminary Capital Budget to Senior Management for approval. Once the Preliminary Capital Budget and long range forecast has been approved by Senior Management, it is presented to InnPower's Board of Directors as follows:

1. The Senior Management team presents a Preliminary Capital Budget and long range forecast at the next meeting of the Board of Directors.
2. The feedback received from the Board of Directors is shared with the various department managers to make any revisions to the budget and long range forecast, as necessary.
3. The revised final version is then presented to the Board of Directors for approval.
4. It is then the responsibility of the Board of Directors, on behalf of the stakeholders, to approve the budget.
5. Once approved the complete finance package is presented to the shareholder, the Town of Innisfil.

Once the Board of Directors approves the annual budget, the budget amounts do not change but rather provide a plan against which actual results may be evaluated. In addition to the capital needs of the distribution system, InnPower plans for the required maintenance of its assets considering both performance and safety.

Budget Directives

InnPower compiles budget information for the three major components of the budgeting process:

1. revenue forecasts;
2. operating, maintenance, and administration **("OM&A")** expense forecast; and
3. capital budget forecast.

1. Revenue Forecast

InnPower's revenue forecast is based on the forecasted energy consumption, peak load, and customer counts for the 2017 Test Year. InnPower prepares a weather normalized load forecast by customer class and monthly customer class data for the weather sensitive customer classes using the regression analysis and by average usage and forecasted customer growth for the non-weather sensitive customer classes. The forecast results are then used to calculate the 2017 Test Year revenue requirement at existing rates and proposed rates.

2. OM&A Expense Forecast

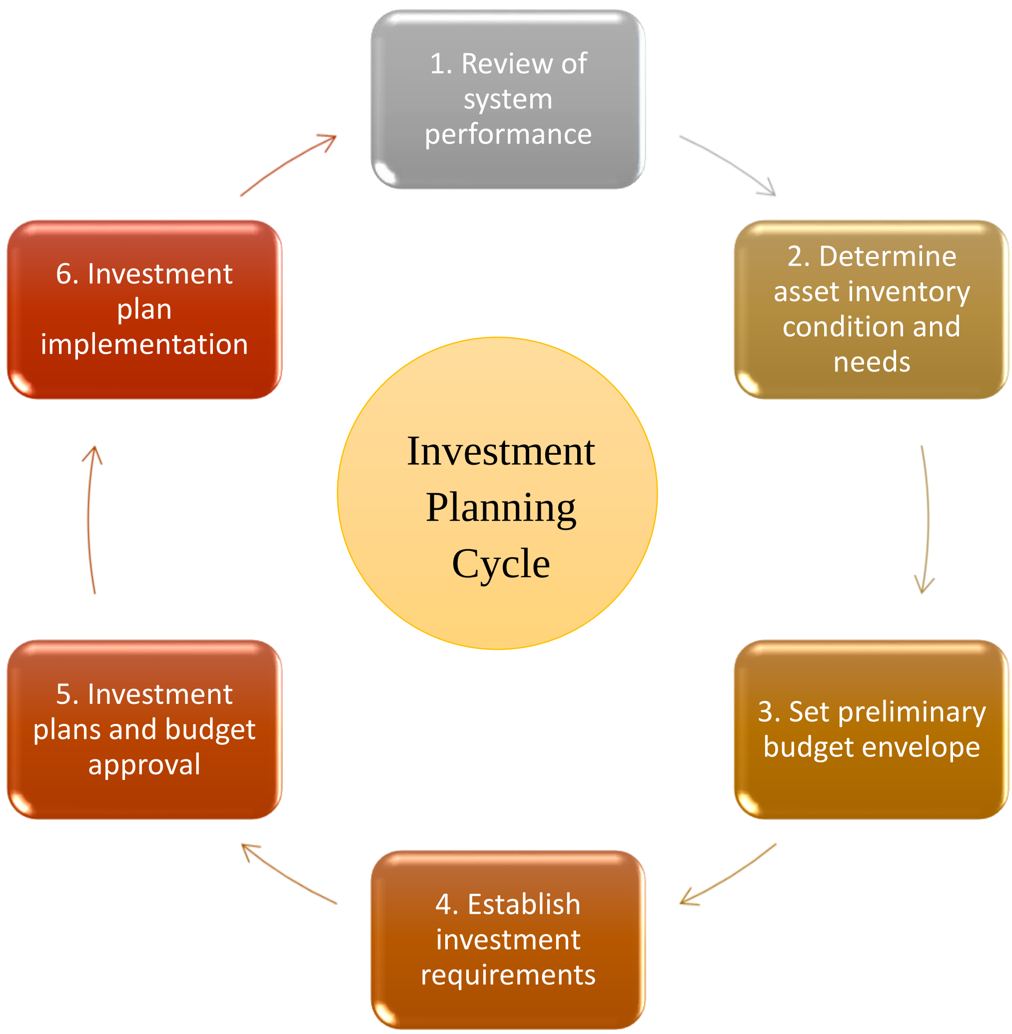
InnPower allocates available person-hours to the various OM&A programs and activities planned and budgeted for each year. Any remaining hours are allocated to identified capital projects. InnPower employs contract labour, utilizing long term contracts as well as on-demand labour, and such contract work is determined based on the level of work load and expertise required. InnPower reviews and establishes the budget based on historical trends and known factors as opposed to simply applying an arbitrary inflation factor. Labour costs are in accordance with InnPower's Collective Agreement.

3. Capital Budget

InnPower's Asset Management Plan identifies the capital projects required and projected to be required over a five year period based on the best available information for each year. The capital budget forecast is influenced significantly by growth, customer requests including road works, reliability and the conversion of aging infrastructure, and the cost of support systems. All proposed capital projects for the Bridge Year and Test Year will be completed and in service in their respective year. InnPower acknowledges that, where the priority of projects changes, or factors outside of its influence change, InnPower may be required to re-evaluate the future year's capital project forecast.

InnPower's investment planning process is cyclical between years, as is presented in Figure 4-7 below. This process is linked to InnPower's asset management objectives (Section 3.1.1), which guide the capital investment decision making.

Figure 4-7: InnPower's investment planning cycle



4.2.1 Planning Objectives, Assumptions, and Criteria (5.4.2a)

a description of the distributor's capital expenditure planning objectives, planning criteria and assumptions used, explaining relationships with asset management objectives, and including where applicable its outlook and objectives for accommodating the connection of renewable generation facilities;

InnPower has six (6) capital expenditure planning objectives, which align with its asset management objectives as follows:

1. Health and Safety, both public and emplyee
2. Legislative Requirements
3. Environmental Risk Mitigation
4. Growth and Power Delivery (Capacity Planning) and focus on meeting customer needs
5. Reliability Improvement and focus on customer value
6. Cost Management and focus on efficiency

InnPower's capacity planning criteria relating to objective 3, have been summarized in Table 4-10 below.

Table 4-10: Planning criteria for system parameters

System Parameter	Maximum Value
44 kV Feeder Load	330 A
Station Transformer Load	100% of nameplate
Distribution Feeder Load	50% of recloser capacity
Feeder Voltage Drop - Normal	3% at maximum load
Feeder Voltage Drop - Emergency	As per Table 4-11

The Hydro One breakers protecting the 44 kV feeders are set to a nominal 330 A; however, the conductors have a nominal capacity of 565 A. These feeders tend to be loaded in excess of 50% of 330A and it is therefore assumed that an outage of a 44kV feeder will result in a power flows exceeding the nominal breaker settings. In these cases, InnPower requests Hydro One to increase the breaker settings until the faulted line is repaired.

While a transformer can operate at 100% of its rated load, planning for a transformer upgrade starts at 80% of its nominal load due to the length of time required to commission a station. Transformer planning also accounts for the loss of a single transformer in a network.

Distribution feeders are planned in loop systems with the intention of picking up loads on adjacent feeders if lines are damaged or stations are taken out of service. Therefore, the planning threshold for a distribution feeder is 50% of its recloser setting, to allow two feeders to be tied together. In some cases, it is acceptable that overhead lines must be radially constructed and that customers in those areas cannot be restored until lines are rebuilt; but underground lines should always be part of loop systems with full backup. The 50% limit is based on the lesser of the two reclosers where back to back feeders have different settings. Distribution Automation can allow more sophisticated restoration schemes including breaking feeders up into multiple segments for backup. InnPower does not yet employ such systems.

There are a number of impacts of voltage drop on the distribution system. Voltages at the customer service entrance should be maintained within safe limits for the customer at full and minimum loads. Voltage drop is impacted by the presence of distributed generation and large users, and is often at extremes when feeders are in backup arrangements. Local transformers have taps for making semi-permanent adjustments to voltage levels, however these are uncontrollable and can generate high voltages when loads are low. The emergency system voltage fall within the requirements of CAN3-C235-83, *Preferred voltage levels for AC systems, 0 to 50 000 V*, as summarized in Table 4-11 below.

Table 4-11: Voltage variation limits on InnPower's distribution system

Nominal System Voltage	Voltage Variation Limits			
	Extreme Operating Conditions			
		Normal Operating Conditions		
120/240	106/212	110/220	125/250	127/254
120/208	110/190	112/194	125/216	127/220
347/600	306/530	318/550	360/625	367/635
600	530	550	625	635

4.2.2 Non-Distribution System Alternatives to Relieving System Capacity (5.4.2b)

if not otherwise specified in (a), the distributor's policy on and procedure whereby non-distribution system alternatives to relieving system capacity or operational constraints are considered, including the role of Regional Planning Processes in identifying and assessing alternatives;

InnPower does not have a policy on distribution system alternatives for relieving system capacity and such initiatives were not a deliverable of the Regional Planning Process. However, customers can participate in demand management programs administered by the IESO. Currently there are seven (7) General Service customers participating in demand management programs, for a contracted 930 kW per annum. In addition, there are 310 residential customers that participate in the "peaksaver PLUS" program with programmable thermostats and in home devices that provide real time meter and pricing information. The residential program provides an annual savings of 164 kW. All annual savings are reported to the IESO and the transmitter (HONI) to determine peak demand with conservation savings.

4.2.3 Project Prioritization (5.4.2c)

a description of the process(es), tools and methods (including where relevant linkages to the distributor's asset management process) used to identify, select, prioritise and pace the execution of projects in each investment category (e.g. analysis of impact of planned capital expenditures on customer bills);

4.2.3.1 *Project Identification*

The projects that InnPower selects for its capital budget are the ones that are required to ensure the safety, efficiency, and reliability of its distribution system, and to complete other projects as needed to allow InnPower to carry out its obligation to distribute electricity within its service area as defined by the Distribution System Code.

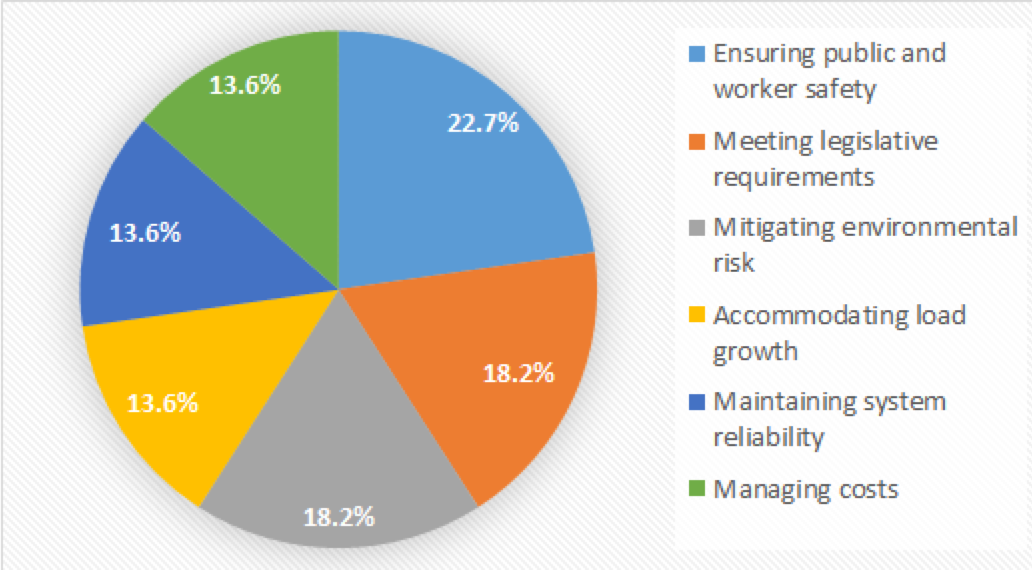
- System access projects such as development and county/municipal pole relocation projects are identified throughout the year by external stakeholders. These projects are non-discretionary in nature and are budgeted and scheduled to meet the timing needs of the external proponents.
- System renewal projects are discretionary in nature. The project needs for a particular period are supported by a combination of asset inspection, individual asset performance, and the ACA.
- System service projects are discretionary in nature and ensure that any forecasted load changes that constrain the ability of the system to provide consistent service delivery are dealt with in a timely manner.
- General plant projects, such as fleet vehicle acquisition or replacement, software/hardware, etc., are discretionary in nature and are identified internally by specific departments (engineering, customer service, finance, operations, administration, etc.) and supported through specific business cases for the particular need.

4.2.3.2 *Project Selection and Prioritization:*

Non-discretionary projects are automatically selected and prioritized based on externally driven schedules and needs. Most System Access projects fall into this category and may involve multi-year investments to meet proponent needs. A system of project prioritization is applied that takes into account growth rates, safety, reliability, performance, condition, age, and other drivers internal or external to InnPower. Material Investments information provided in Appendix A includes a copy of a capital project summary template that InnPower utilizes as a means of capturing project specific information.

Discretionary projects are selected and prioritized based on value and risk assessments for each project and impact on rates. Most system renewal, system service, and general plant projects fall into this category. Some projects, such as the Pole Replacement Program, Infrastructure Replacements and Betterments, and Substandard Transformer Rehabilitation, typically involve multi-year program investments to meet asset management needs. In order to increase the objectivity of its project prioritization process, InnPower assigns weights to its capital expenditure planning objectives, which are depicted in Figure 4-8.

Figure 4-8: Weighted priorities for asset management and capital expenditure planning



Projects are then scored for each of the capital expenditure planning objectives using the probability and consequence risk matrix depicted in Table 4-12. Multiplying the result by the objective weight and summing each of the six (6) objectives provides an overall score for each project.

Table 4-12: Probability and consequence risk matrix

	CONSEQUENCE				
PROBABILITY	SMALL	MODERATE	SIGNIFICANT	SEVERE	WORST CASE
MOST LIKELY	9	24.5	66.5	180.8	491.4
VERY LIKELY	7.5	20.4	55.4	150.6	409.5
LIKELY	5	13.6	36.9	100.4	273.0
UNLIKELY	2.5	6.8	18.5	50.2	136.5
VERY UNLIKELY	1	2.7	7.4	20.1	54.6

System renewal projects and some of the system service projects (e.g. re-poling) are subdivided into those assets that are expected to fail (i.e. critical assets) and those assets for which replacement is a matter of economic value (i.e. recommended for replacement). Where the rate impact is too high, those projects may be deferred to later years.

InnPower has ranked and prioritized all of its projects planned in the Test Year (2017) which are both material and discretionary. Table 4-13 presents the prioritized list of discretionary and material projects that have been budgeted in 2017, and those discretionary and material projects which have been deferred.

The construction of Friday Harbour DS has been deferred to 2018, while the load growth project at Big Bay Point has been deferred to outside of the five-year planning period. The installation rate of SCADA controlled load interrupting gang switches was reduced to half, with the most critical locations prioritized. InnPower closely monitors its assets as per its ACA and inspection/maintenance process in order to defer a portion of the system renewal and re-poling projects.

Table 4-13: Prioritized list of discretionary and material projects

Project	Score	Status	Cost
Reliability Rebuild – Subtransmission: Lockhart Road – Critical	642	Budgeted	$170,650
Reliability Rebuild – Subtransmission: 5th Side Road – Critical	642	Budgeted	$75,000
Station Rehab – Critical	633	Budgeted	$104,300
Re-poling: Big Bay Point Road – Friday Harbour DS to Friday Harbour Development (North)	600	Budgeted	$362,570
Reliability Rebuild – Distribution: Cookstown	589	Budgeted	$50,000
Re-poling: Mapleview Drive – Prince William Way to Seline Crescent	581	Budgeted	$837,831
Re-poling: Lockhart Road – Huronia Road to Stroud DS – Critical	507	Budgeted	$618,932
Re-poling: 5th Side Road – McKay Road to Salem Road	507	Budgeted	$273,427
Transformers	425	Budgeted	$100,000
Ewart Street Rebuild	375	Budgeted	$105,000
Replacement Double Bucket Truck – 1993 Altec	371	Budgeted	$373,500
RBD – new Crew	236	Budgeted	$250,000
IT Hardware	218	Budgeted	$165,000
IT Software	218	Budgeted	$95,000
Sandy Cove DS automation	210	Budgeted	$125,000
Locator Vehicle Mini-van (x2)	204	Budgeted	$63,000
Engineering IT	191	Budgeted	$167,325
Finance IT	188	Budgeted	$77,000
Pole Replacement Program – Critical	187	Budgeted	$126,470
Infrastructure Replacements and Betterments	134	Budgeted	$150,253
Substandard Transformer Rehab	142	Budgeted	$85,000
Distribution SCADA controlled load interrupting gang switch – Critical	122	Budgeted	$75,000
Total Budgeted Cost (Discretionary and Material Projects Only):			**$4,450,258**
Re-poling: Lockhart Road – Huronia Road to Stroud DS – Recommended	84	Deferred	$200,886
Friday Harbour DS	84	Deferred	$2,680,000
Reliability Rebuild – Subtransmission: Lockhart Road – Recommended	72	Deferred	$85,650
Reliability Rebuild – Subtransmission: 5th Side Road – Recommended	72	Deferred	$75,000
Pole Replacement Program – Recommended	44	Deferred	$126,681
Distribution SCADA controlled load interrupting gang switch – Recommended	34	Deferred	$75,000
Station Rehab – Recommended	31	Deferred	$104,944
Load growth: Big Bay Point – 20th Side Road to McCormick Gate	8	Deferred	$150,000
Total Deferred Cost (Discretionary and Material Projects Only):			**$3,498,161**

4.2.4 Customer Engagement (5.4.2d)

if not otherwise included in c) above, details of the mechanisms used by the distributor to engage customers for the purpose of identifying their needs, priorities and preferences (e.g. surveys, system data analytics, and analyses – by rate class – of customer feedback, inquiries, and complaints); the stages of the planning process at which this information is used; and the aspects of the DS Plan that have been particularly affected by consideration of this information;

As detailed in Section 4.1.6, InnPower obtains customer feedback via the 2013 and 2014 UtilityPULSE Customer Satisfaction Survey, as well as direct feedback in the form of customer calls, walk-ins to InnPower's front office, AM/PM appointments with customers, scheduled appointments, open house events, community events, customer complaints, customer educational sessions, CDM site visits, and the 2017 COS Rate Overview Session. This information has been used to develop this DSP that balances the requirements of existing customer demand, predicted load growth, and expected reliability. Scoped projects and programs are deferred or reduced in scope to align InnPower's budget envelopes with customer expectations. In the Test Year (2017) InnPower has deferred/cut $4,463,000.

4.2.5 REG Investment Prioritization (5.4.2e)

if different from that described above, the method and criteria used to prioritise REG investments in accordance with the planned development of the system, including the impact if any of the distributor's plans to connect distributor-owned renewable generation project(s).

InnPower has not planned any REG investments over the forecast period.

4.3 System Capability Assessment for Renewable Energy Generation (5.4.3)

This section includes a list of applications from renewable generators over 10 kW or connection in InnPower's service area, the forecast number and capacity of new FIT and microFIT connections, an assessment of InnPower's capacity to connect REG, a summary of the REG connection constraints on the system, and a summary of constraints on embedded distributors.

4.3.1 Applications for Renewable Generators over 10 kW (5.4.3a)

applications from renewable generators over 10kW for connection in the distributor's service area;

There are currently no applications from renewable generators over 10 kW for connection in InnPower's service area.

4.3.2 Forecast REG Connections (5.4.3b)

the number and the capacity (in MW) of renewable generation connections anticipated over the forecast period based on existing connection applications, information available from the OPA and any other information the distributor has about the potential for renewable generation in its service area (where a distributor has a large service area, or two or more non-contiguous regions included in its service area, a regional breakdown should be provided);

Table 4-14 summarizes the forecast number and capacity of FIT and microFIT connections anticipated each year of the forecast period. The forecast number of new FIT connections is based on the average rate of connections over the past six (6) years, two (2) per year, and the capacity is based on the average FIT project size of 200 kW. The forecast number of new microFIT connections includes future net metering options and the capacity is based on the average microFIT project size of 9 kW.

Table 4-14: Number and capacity of REG connections anticipated over the forecast period

	2017	2018	2019	2020	2021
Forecast # of new FIT connections	2	2	2	2	2
Forecast capacity of new FIT connections (kW)	400	400	400	400	400
Forecast # of new microFIT connections	8	16	18	20	22
Forecast capacity of new microFIT connections (kW)	72	144	162	180	198

For additional information, refer to InnPower's REG Investments Plan in Appendix G and the IESO Comment Letter in Appendix H.

4.3.3 Capacity to Connect REG (5.4.3c)

the capacity (MW) of the distributor's distribution system to connect renewable energy generation located within the distributor's service area;

The capacity to connect REG is constrained by the guidelines set out in IEEE Std 1547-2003, *IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems*, which states that an unintentional island will not form if the aggregate REG capacity is less than one third of the minimum load, based on simulations of different scenarios involving synchronous generators. However, since solar PV does not actively regulate the voltage on the feeder, this ratio is overly conservative. As per IEEE Std 1547-2003, REG must disconnect within 2 seconds if the voltage falls below 0.88 p.u. This means that if the ratio of the REG capacity to the load is 77% or less (0.88 squared), then the voltage relays will disconnect the REG and prevent islanding. A 3:2 ratio of minimum load to REG capacity can be used as conservative estimate to rule out islanding.

Minimum load of a feeder is not generally a known quantity. InnPower estimates minimum load of a feeder as 25% of the peak load. This is a reasonable assumption, and in fact is conservative for the purpose of this analysis, as only the minimum daytime load is relevant for comparison to solar PV.

Table 4-15 presents the REG capacity based on anti-islanding guidelines for each feeder in InnPower's distribution system. The minimum load estimation is based on 25% of the lesser of the forecast 2016 winter and summer peaks. The connected and in-progress REG only includes microFIT projects (10 kW or less), since FIT projects require a direct transfer trip. The remaining REG capacity for the entire feeder is presented based on both 33% and 67% of the minimum load.

Table 4-15: Capacity to connect REG based on anti-islanding guidelines

Feeder	2016 Minimum Load Estimation (kVA)	Connected and In-Progress microFIT (kW)	Remaining REG Capacity – 33% of Min. Load (kW)	Remaining REG Capacity – 67% of Min. Load (kW)
Belle Ewart F1	68	0	23	45
Belle Ewart F2	798	86	180	446
Big Bay Point F1	469	11	146	302
Big Bay Point F2	426	20	122	264
Bob Deugo F1	463	0	154	309
Bob Deugo F2	225	50	25	100
Brian Wilson F1	1045	102	246	594
Brian Wilson F2*	0	0	N/A	N/A
Brian Wilson F3	1248	135	281	697
Brian Wilson F4	197	28	38	103
Cedar Point F1	373	30	94	219
Cedar Point F2	523	35	139	314
Cookstown West F2	149	40	10	59
Cookstown West F4	120	19	21	61
Innisfil F1	415	50	88	227
Innisfil F2	250	40	43	127
Innisfil F3	315	110	-5	100
Lefroy F1	458	50	103	255
Lefroy F2	340	20	93	207
Lefroy F3	158	20	33	85
Leonard's Beach F1	215	0	72	143
Leonard's Beach F3	280	3	91	184
Sandy Cove F1	253	10	74	159
Sandy Cove F3	153	0	51	102
Stroud F1	311	20	84	187
Stroud F2	40	0	13	27
Stroud F3	310	30	73	177
Thornton F1	120	70	-30	10
Thornton F2	110	20	17	53

** All of Brian Wilson F2 load is to be transferred to Belle Ewart F2 in 2016 (when the Belle Ewart DS transformer is repaired and the station is re-energized). Since all system planning and load forecast studies are based on this circuit reconfiguration, to be consistent with other reports this table shows the intended REG feeder connectivity scheme).*

4.3.4 REG Connection Constraints (5.4.3d)

> ***constraints related to the connection of renewable generation, either within the distributor's system or upstream system (host distributor and/or transmitter);***

Two (2) feeders, Innisfil F3 and Thornton F1, exceed the REG capacity limit recommended by IEEE Std 1547-2003. Six (6) feeders are within 30 kW of the recommended REG capacity limit: Belle Ewart F1, Bob Deugo F2, Cookstown West F2, Cookstown West F4, Stroud F2, and Thornton F2. These constraints warrant further investigation. As such, InnPower is planning to perform a dynamic EMTP study to ensure that the installed REG downstream of any reclosing device disconnects prior to reclosing and that an island is unable to form downstream of any protection device.

4.3.5 Embedded Distributor Constraints (5.4.3e)

> ***constraints for an embedded distributor that may result from the connections.***

Some Hydro One customers are served by Innisfil F1 and Thornton DS via a long term load transfer agreement, which ends in 2018. Innisfil F1 does not have any REG constraints, but Thornton F1 exceeds the REG capacity limit recommended by IEEE Std 1547-2003 and Thornton F2 is within 17 kW of this limit.

4.4 Capital Expenditure Summary (5.4.4)

Table 4-16 presents the historical and forecast capital expenditures and system O&M. The historical period includes the audited actual expenditures for 2012 to 2014, the unaudited actual expenditures for 2015, and the forecast expenditures for 2016 (includes 0 months of actual data).

System service spending is forecast to be higher in 2017 and 2018 to complete a number of line extensions in 2017 and to construct Friday Harbour DS in 2018. Subsequently, the system renewal spending is planned to be lower in 2017 and 2018, but is forecast to increase in 2019 with the introduction of underground rebuild projects required to replace aging cables and additional subtransmission rebuilds.

Table 4-16: Historical and forecast capital expenditures and system O&M

Category	Historical															Forecast				
	2012			2013			2014			2015			2016			2017	2018	2019	2020	2021
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual*	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000	$ '000	$ '000	$ '000	$ '000
System Access	-	1,224	-	-	638	-	-	1,263	-	-	896	-	-	1,362	-	1,754	1,984	1,595	1,598	2,013
System Renewal	-	654	-	-	838	-	-	697	-	-	471	-	-	1,137	-	1,216	1,140	2,919	2,400	2,109
System Service	-	310	-	-	1,730	-	-	2,551	-	-	2,945	-	-	2,505	-	2,338	2,829	1,276	1,556	1,402
General Plant	-	1,631	-	-	1,545	-	-	520	-	-	13,226	-	-	661	-	1,500	1,423	897	680	706
Total	-	3,818	-	-	4,751	-	-	5,031	-	-	17,537	-	-	5,665	-	6,807	7,376	6,686	6,235	6,231
System O&M	-	1,761	-	-	1,787	-	-	1,814	-	-	1,520	-	-	2,099	-	2,636	2,636	2,636	2,636	2,636

**0 months of actual data included in 2016.*

4.4.1 Variances and Trends in Capital Expenditures

While year over year 'Plan vs. Actual' variances for individual investment categories are expected, explanatory notes should be provided where

- ***for any given year "Total" 'Plan' vs. 'Actual' variances over the historical period are markedly positive or negative; or***
- ***a trend for variances in a given investment category is markedly positive or negative over the historical period.***

From 2012 to 2013, system access spending decreased by 48% due to decreased spending in third party infrastructure development requests (-$500k) and customer service requests (-$132k). System renewal spending increased by 28% due to increased spending on Substandard Transformer Rehabilitation (+$152k), and Padmounted Transformer Replacements (+$65k). System service spending increased by 459% due to increased spending on Repoling/Line Extensions (+$1,361k), Line reclosers (+$111k), and Distribution Station upgrade/automation (+$136k). General plant spending decreased by 5% due to decreased spending on land (-$527k), and engineering IT systems-both hardware and software (-$85k).

From 2013 to 2014, system access spending increased by 98% due to increased spending on customer service requests (+$627k). System renewal spending decreased by 17% due to decreased spending on substandard transformer rehab (-$48k), and because of decreased spending in Padmounted Transformer and Switchgear Replacements and Painting (-$74k). System service spending increased by 47% because Belle Ewart DS was constructed in 2014 (+$2,337k). General plant spending decreased by 66% because there were no expenses associated with the new building construction in 2014 (-$1,015k), and no expenses for fleet vehicles (-$64k).

From 2014 to 2015, system access spending decreased by 29% due to fewer customer service requests (-$620k). System renewal decreased by 32% due to decreased spending on the Pole Replacement Program (-$287k). System service spending increased by 15% due to an increase in spending on repoling for capacity upgrade (+$1,619k), subtransmission switch automation (+$175k), Distribution Station improvements (+$730k), SCADA switch enhancements (+$184k), and radio communication system improvements (+$138k). General plant spending increased by 2,443% because the new building construction costs were capitalized in 2015 (+$12,435k). In addition to the new building, there was increased spending on yard/material handing vehicles (+$112k), a new pole bunk in the yard (+$69k).

From 2015 to 2016, system access spending is forecast to increase by 52% due to the planned increase in spending on customer service requests (+$304k), and for the relocation of pole line for County of Simcoe road widening works (+$152k). System renewal spending is forecast to increase by 142% due to the budgeted increase in spending on Station Rehabilitations (+$199k), unplanned overhead system repairs (+$138k), transformers (+$120k), Overhead Rebuilds (+$102k), the Pole Replacements Program (+$86k), and Padmounted Transformers and Switchgear Replacements and Painting (+$53k). System service spending is forecast to decrease by 15% due to a reduction in spending on planned subtransmission switch automation (-$175k), planned Distribution Station system enhancements (-$676k), planned SCADA switch enhancements (-$184k), planned repoling for capacity upgrade (-$857k), and planned radio system upgrade (-$138k). General plant spending is forecast to decrease by 95% because the new building construction costs were capitalized in 2015 (-$12,435k), the pole bunk costs was also capitalized in 2015 (-$69k), and due to a reduction is spending on vehicles (-$146k).

Over the forecast period, the system access budget varies due to the forecast external demand, mostly due to County Road Widening projects. System renewal budgets are higher in 2019 to 2021 when InnPower is planning to commence its Everton Back Lot Conversion and Sandy Cove Underground Rebuild projects. The system service budget is higher in 2017 and 2018 due to a number or re-poling projects in 2017 to service new load and the construction of Friday Harbour DS (also to service new load). The projected system renewal spending has been decreased in 2017 and 2018 when system service spending is higher. System service spending is, therefore, lower from 2019 to 2021. General plant expenditures are forecast to be higher in 2017 and 2018, largely due to the requirement to purchase two (2) new bucket trucks and an RBD in these years.

4.5 Justifying Capital Expenditures (5.4.5)

This section provides the necessary data, information, and analyses to support the capital expenditure levels proposed in this DSP.

4.5.1 Overall Plan (5.4.5.1)

To support the overall quantum of investments included in a DS Plan by category, a distributor should include information on:

- ***comparative expenditures by category over the historical period;***
- ***the forecast impact of system investment on system O&M costs, including on the direction and timing of expected impacts;***
- ***the 'drivers' of investments by category (referencing information provided in response to sections 5.3 and 5.4), including historical trend and expected evolution of each driver over the forecast period (e.g. information on the distributor's asset-related performance and performance targets relevant for each category, referencing information provided in section 5.2.3);***
- ***information related to the distributor's system capability assessment (see section 5.4.3)***

For comparative expenditures by category over the historical period, as well as the forecast system O&M costs, refer to Table 4-16.

Capital investments proposed in this DSP are expected to reduce O&M costs relative to the "do nothing" option, in particular because O&M costs are expected to increase if the level of investment is not maintained. System renewal investments are expected to reduce system O&M costs by reducing the probability of asset failure through the selection of aging and poor-condition assets for replacement.

The drivers of investment by category are as follows:

4.5.1.1 *System Access*

Projects/activities in this category are driven by customer service requests, third party requests, and statutory, regulatory, and other obligations as required by the OEB to provide customers with access to the InnPower distribution system. These drivers are entirely outside of InnPower's control. Projects for

2017 in this area include a large road widening project by the County of Simcoe and a significant number of new residential services and development.

4.5.1.2 *System Renewal*

Projects/activities in this category are driven by asset failures and asset failure risk. The system renewal projects are selected in accordance with the asset management process.

Significant system renewal projects/programs are targeted line rebuilds and spot asset replacements, the most significant of which are listed below.

Transformer Replacements

InnPower plans to replace approximately 50 transformers per year over the forecast period based on the results of the ACA, which indicates that approximately 270 transformers are expected to be in "Very Poor" or "Poor" condition. A further analysis indicates that approximately 175 transformers are reporting long term peak loads of 150 to 300% of their rating, and of those approximately 70 are at least 40 years old. InnPower has planned programs to replace transformers, but they are also replaced as part of overhead rebuilds or as part of customer service requests where a capacity upgrade is required. Priority will be given to the transformers in the worst condition.

Pole Replacements

InnPower is planning to replace wood poles that are reaching end of life. The ACA predicts that approximately 435 poles are currently in "Very Poor" or "Poor" condition. InnPower will manage the replacement of these assets through general pole line rebuilds and spot replacement programs as needed to maintain the system. Pole line relocations can also contribute to pole replacements where the pole line has degraded. Specific rebuild projects that have been planned include:

- Ewart Street Rebuild: a 53 pole project including a critical circuit tie between Cedar Point DS and Lefroy DS. Inspections determined that more than 60% of the poles are in "Very Poor" or "Poor" condition. The project will take place over five (5) years.
- Lockhart Road Rebuild: the subtransmission circuit in this section spans 105 poles and 55 poles have been scheduled for replacement. The subtransmission feeder serves three (3) DS and backs up another three (3) DS. The ACA reported that 35% of the poles are in "Fair" or "Poor" condition and age demographics indicate that 67% of the poles are 40 years or older. The project will take place over five (5) years.
- 5th Side Road: this subtransmission line section is 5.6 km and spans 102 poles. It serves three (3) DS, backs up another four (4) DS, and serves three (3) customers at 44 kV. During a recent pole testing program 83% of poles displayed cracks, mechanical damage, pole top feathering, split and/or rot, while the age demographics show that 52% of the poles are 40 years or older. Therefore, InnPower has planned to replace 60 poles over the next five (5) years.
- Cookstown Rebuild: a 44 pole rebuild project. Inspections determined that approximately 60 poles have significant deterioration or critical damage. This project will target the most critical poles in a planned rebuild and will take place over five (5) years.

Station Rehabilitation

Most of InnPower's DS are 40 to 50 years old. The station ACA, completed in May 2016, provides a detailed assessment of the condition of InnPower's DS and lists a number of recommendations with respect to improvements to be made. InnPower has planned to address one (1) DS per year to act on the recommendations. This on-going project started in 2016 and has been budgeted for each year of the forecast period.

4.5.1.3 *System Service*

Projects/activities in this category are driven by safety, reliability, and operational efficiency. Projects in this category include distribution system SCADA and automation, substation automation, re-poling to serve new loads, and new substations. Projects are selected and assessed against planning criteria.

4.5.1.4 *General Plant*

Projects/activities in this category are driven by renewal of non-system physical plant including buildings, fleet, and IT capital spending.

4.5.1.5 *REG Requirements*

Forecast REG requirements are detailed in Section 4.3. There are some constraints on the connection of new REG on some feeders of the InnPower system. An Engineering Study is proposed to consider the situation and determine if mitigation is required. Further reference can be found in the REG Investments Plan (Appendix G) and the IESO Comment Letter (Appendix H).

4.5.2 Material Investments (5.4.5.2)

The focus on this section is on projects/activities that meet the materiality threshold set out in Chapter 2 of the Filing Requirements. For InnPower this threshold is $50,000.

Table 4-17 lists the Material Investments for the Test Year (2017). For each of these projects/programs, a detailed write-up, highlighting the drivers, justification, and analysis, is provided in Appendix A.

Table 4-17: List of Material Investments for the Test Year (2017)

Category	Type	Program/Project Name	2017 Budget
System Access	Program	Base 1A – Customer Service Requests	$116,880
System Access	Program	Base 3 – Purchase Order Jobs*	$0
System Access	Program	Base 4 – New Residential Subdivisions**	$1,111,728
System Access	Program	Metering	$230,000
System Access	Project	Intersection Widening IBR & Yonge St	$272,430
System Renewal	Program	Base 1B – Unplanned Repair/Replace	$116,885
System Renewal	Program	Substandard Transformer Rehab	$85,000
System Renewal	Program	Pole Replacement Program	$126,470
System Renewal	Program	Infrastructure Replacements and Betterments	$150,253
System Renewal	Program	Station Rehab	$104,300
System Renewal	Program	Transformers	$100,000
System Renewal	5 year project	Ewart Street Rebuild	$105,000
System Renewal	5 year project	Reliability Rebuild – Lockhart Road	$170,650
System Renewal	4 year project	Reliability Rebuild – 5th Side Road	$75,000
System Renewal	5 year project	Reliability Rebuild – Cookstown	$50,000
System Service	Project	Sandy Cove DS Automation	$125,000
System Service	5 year project	Distribution SCADA Controlled Load Interrupting Gang Switch	$75,000
System Service	Project	Re-poling: Big Bay Point Road	$362,570
System Service	Project	Re-poling: Lockhart Road	$618,932
System Service	Project	Re-poling: Mapleview Drive	$837,831
System Service	Project	Re-poling 5th Side Road	$273,427
General Plant	Program	IT Hardware	$165,000
General Plant	Program	IT Software	$95,000
General Plant	Program	Finance IT	$77,000
General Plant	Program	Engineering IT	$167,325
General Plant	Project	Replacement Double Bucket Truck – 1993 Altec	$373,500
General Plant	Project	Locator Vehicle Mini-van (x2)	$250,000
General Plant	Project	RBD - new Crew	$63,000

** 100% recoverable* *** After Economic Evaluation*

Appendix A: Material Investments

2017 Material Investments

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Capital Project Summary

to meet
Ontario Energy Board
Filing Requirements
for
Electricity
Transmission
and
Distribution
Applications

Chapter 5
Section 4.5.2

Material Investments

2017 System Access Projects

innpower

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name: **Base 1-A**

Project number: BASE 1-A **Budget Year:** 2017

Investment Category: System Access

Project Summary

This budget includes the cost for non-contributed portions of projects related to customer service requests that result in the need to modify InnPower's infrastructure, including works due to trespassing of InnPower assets on private properties.

Total capital and non-capitalized O&M costs (5.4.5.2.A.i)

	Historical Capital Costs				
	2012	2013	2014	2015	2016
Total cost					$ 137,500
Contributions					$ -
Net cost					$ 137,500
O&M expense					undetermined

	Future Capital Costs				
	2017	2018	2019	2020	2021
Total cost	$ 116,880	$ 122,725	$ 134,998	$ 148,497	$ 163,346
Contributions	$ -	$ -	$ -	$ -	$ -
Net cost	$ 116,880	$ 122,725	$ 134,998	$ 148,497	$ 163,346
O&M expense	undetermined	undetermined	undetermined	undetermined	undetermined

Customer Attachments and Load (5.4.5.2 A.ii)

Varies. Project are performed as and when requests are received. Unplanned work.

Project Dates & Expenditure Timing (5.4.5.2.A.iii)

Start Date:	01-Jan-17			
In Service Date:	31-Dec-17			
Expenditure Timing	2017: Q1	2017: Q2	2017: Q3	2017: Q4
	25%	25%	25%	25%

Schedule Risks & Risk Mitigation (5.4.5.2.A.iv)

InnPower schedules work on such projects based on resource loading. These are typically not as urgent as repair work, however, to meet customer expectations InnPower coordinates the work closely between operations and the customer.

InnPower has worked to improve its internal job processing capability to ensure the increase in the budget is spent in a timely manner. Therefore, it is our expectation that the funds will be spent as projected.

Comparative Information on Expenditure from Equivalent Projects (5.4.5.2.A.v)

Not applicable.

General Information on Project (5.4.5.2.A)	
	Total Capital and OM&A costs associated with REG investment (5.4.5.2.A.vi)
	None
	Leave to Construct Approval (5.4.5.2.A.vii)
	Not applicable.
	Related Project Reference Material i.e. Images, Drawings and or Reference Material
	Line construction activities will follow InnPower's standards for distribution design and construction.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Project Name: Base 1-A
	Investment Benefits, measured against: Efficiency, Customer Value & Reliability (5.4.5.2.B.1)
	Main Driver (5.4.5.2.B.1.a-1):
	System Access
	- Main "Trigger" (5.4.5.2.B.1.a-1.1):
	Customer service requests for connections (both new and modification to existing)
	Secondary Driver (5.4.5.2.B.1.a-2):
	None
	Objective or Performance Target to be Achieved (5.4.5.2.B.1.a-3):
	Primary: Customer value; Secondary: Reliability
	Background information that ties in with Asset Management Process (5.4.5.2.B.1.a-3.i):
	When replacing failed assets consideration is given to ensure the new infrastructure meets current standards.
	Overview of Investment Prioritization Justification (5.4.5.2.B.1.b)
	Safety, customer needs, imminent failure of asset/reliability.
	Project Identification and Selection (5.4.5.2.B.1.b-1)
	Usually customer requests for service are received through our customer service department and processed in our engineering department. The list of projects is compiled from such requests and is selected based on criteria described above in 5.4.5.2.B.1.b
	Project Prioritization (5.4.5.2.B.1.b-2)
	InnPower uses the methodology stated in the Asset Management process to prioritize projects.
	Project Pacing (5.4.5.2.B.1.b-3)
	Depending on the urgency of the work, InnPower would pace the projects based on resource availability.
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)
	Customer request for asset relocation is analyzed by the engineering department, and once validated, a project plan is developed based on field visits, best practices to meet customer needs while maintaining or improving cost efficiency and system operational objectives.
	- Alternate Considerations - Design (5.4.5.2.B.1.c-1)
	InnPower's Asset Management process typically includes evaluation of alternate design options for the relocation of assets under this program.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	- Alternate Considerations - Schedule (5.4.5.2.B.1.c-2)
	InnPower strives to perform all work under this program during regular business hours, however, we offer the customer the option for weekend work (depending on the need) as an alternate schedule. We also work with the customer to arrange work by others that need to be done by the customer to be coordinated with our work to keep the overall schedule at a minimum, thus reducing travel and staging costs.
	- Alternate Considerations - Funding/Ownership (5.4.5.2.B.1.c-3)
	Alternate funding options are not applicable for these project, unless the customer requests for design changes beyond what InnPower considers as a requirement to eliminate trespassing. In such cases a contribution will be required from the customer.
	Effect of Investment on System Operation Efficiency and Cost-Effectiveness (5.4.5.2.B.1.c.i)
	As the assets replaced under this program are not pre-planned specific efficiency evaluations are not performed during the budgeting process. However, the replacement of assets to new standards will result in improved performance and cost effectiveness.
	Net Benefits Accruing to Customers as a Result of the Investment (5.4.5.2.B.1.c.ii)
	Timely service delivery would be the most notable benefit; failure avoidances due to the newer infrastructure are some of the side benefits.
	Impact of the Investment on Reliability Performance including on the Frequency and Duration of Outages (5.4.5.2.B.1.c.iii)
	Although this project was not triggered by the need for greater reliability, the overall result would contribute to higher reliability due to the design of the new works following new design standards.
	Projected Improvement to SAIFI (System Average Interruption Frequency): N/A
	Projected Improvement to SAIDI (System Average Interruption Duration Index) : N/A
	Impact of the Driver(s), "Trigger" or other, on the DESIGN of the Project (5.4.5.2.B.1.c-4)
	Projects for works pertaining to customer service requests for connections (both new and modification to existing) and relocating trespassing assets are designed to conform to current engineering standards and meet the immediate and foreseeable service needs of the customer base.
	Impact of the Driver(s), "Trigger" or other, on the COMPONENT CHARACTERISTICS of the Project (5.4.5.2.B.1.c-5)
	The characteristics of the components selected for each job is determined by InnPower's internal engineering process with approval from a Professional Engineer. Only components preapproved by InnPower's Engineer is used.
	Impact of the Driver(s), "Trigger" or other, on the WORK PLAN of the Project (5.4.5.2.B.1.c-6)
	InnPower uses past practice to ascertain the duration of the project, evaluate the schedule for obtaining approvals from external agencies, and to develop an effective work plan.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Investment Benefits, measured against: Safety (5.4.5.2.B.2)
	Upgrading of our infrastructure contribute to enhancing safety by ensuring proper line clearances with the implementation of new standards, which increases worker and public safety.
	Investment Benefits, measured against: Cyber-security, Privacy (5.4.5.2.B.3)
	Not applicable.
	Investment Benefits, measured against: Co-ordination, Interoperability (5.4.5.2.B.4)
	Co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)
	It is not common to involve third parties on jobs under this program.
	Potential to Enable Future Technological Functionality (5.4.5.2.B.4.b-1)
	Not applicable.
	Potential to Address Future Operational Requirements (5.4.5.2.B.4.b-2)
	Through internal consultation with the operations department, InnPower develops designs to accommodate future needs for adding devices to improve operational performance in a cost effective manner.
	Investment Benefits, measured against: Economic Development (5.4.5.2.B.5)
	We routinely consult with joint use customers to leave room on poles for connection of cable, telecom and fiber.
	Investment Benefits, measured against: Environmental Benefits: (5.4.5.2.B.6)
	Not applicable.

Project Name Base 1-A	
Category-specific requirements for System Access Investments (5.4.5.2.C.a)	
Category-specific requirements for System Access Projects (5.4.5.2.C.a)	**Factors Affecting the Timing/Priority (5.4.5.2.C.a.i)**
	Third party approval; customer timing, as well as other prioritization methodology: Safety, customer needs, imminent failure of asset.
	Factors Relating to Customer Preferences or Input from Customers and Other Third Parties (5.4.5.2.C.a.ii)
	Input from third parties and customer is routinely considered through the project to ensure all stakeholder needs are met.
	Factors Affecting the Final Cost of the Project (5.4.5.2.C.a.iii)
	Initial consultation with customer is usually free, however, field visits and surveys, design engineering, material, and construction costs make up most of the final cost of the project. Over and above these costs, based on specific project needs such jobs would have other costs such as: surface reinforcements depending on subsurface condition that may require hydro vacuuming, additions services for cribbing and pole reinforcement.
	Cost Efficiency: Minimizing Controllable Costs (5.4.5.2.C.a.iv)
	We look for ways to minimize controllable costs by: effective supervision both in design engineering and field oversight, careful review of invoices, evaluating work practices for optimal project execution. For larger projects we routinely go out for tender pricing. Our project management practices further ensures project accountability.
	Other Planning Objectives Met by this Project or Intentionally Combined (5.4.5.2.C.a.v)
	N/A
	Options Considered for Technically Feasible Project Design and/or Implementation Options (5.4.5.2.C.a.vi)
	During the project planning process we routinely evaluate options during design and construction.
	Summary of the Results of the Analysis on Feasibility of Above Options (5.4.5.2.C.a.vii)
	See note 1 (page 8)
	- Least Cost Option: Comparison of the Life Cycle Cost of All Options Considered (5.4.5.2.C.a.vii-1)
	See note 1
	- Cost Efficient Option: Comparison of Net Project Benefits and Costs Over the Service Life (5.4.5.2.C.a.vii-1.i)
	See note 1
	- Cost and Benefit of a Project Configured Solely to Meet the Obligation (5.4.5.2.C.a.vii-2.i)
	See note 1

Category-specific requirements for System Access Projects (5.4.5.2.C.a)	
	- Cost and Benefit of this Project in Comparison to the Above (5.4.5.2.C.a.vii-2.ii)
	See note 1
	- Cost and Benefit of this Project in the Context of Technically Feasible Options (5.4.5.2.C.a.vii-2.ii.a)
	See note 1
	Results of the 'Final Economic Evaluation' per section 3.2 of the DSC (5.4.5.2.C.a.viii)
	Economic Evaluation is typically not performed for such jobs.
	Nature and Magnitude of the System Impacts, the Costs for System Modifications, and Cost Recovery Means (5.4.5.2.C.a.ix)
	System impacts include system reliability, and system operating improvements. Cost recovery is achieved through customer contributions, where applicable; however such contributions are logged under jobs tied to Base 3.

Note 1: These are projects that are un-planned during the budgeting process, and are reactionary jobs based on customer requests that are received during the course of the budget year. On such jobs feasibility studies are generally performed on alternate design and construction options and jobs are selected and prioritized based on InnPower's stated methodology.

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Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name **Base 3**

Project number: BASE 3 **Budget Year:** 2017

Investment Category: System Access

Project Summary

This budget item consists of numerous 100% recoverable projects which required either connection from InnPower' distribution system to new residential or commercial customers requesting service layouts, distributed generation (microFiT or FIT) customers requesting connection, recoverable capital trouble calls and 100% recoverable purchase order (RPO) projects and fully recoverable subdivision repair works.

InnPower anticipates approximately 160 residential / commercial layout & microFiT / FIT customers' layouts, recoverable capital trouble calls and RPO projects in 2017. InnPower's obligation to connect new customers is governed by the Electricity Act, 1998, Schedule 28.

Total capital and non-capitalized O&M costs (5.4.5.2.A.i)

	Historical Capital Costs				
	2012	2013	2014	2015	2016
Total cost				$ 901,869	$ 900,530
Contributions				-$ 878,974	-$ 900,530
Net cost				$ 22,895	$ -
O&M expense				undetermined	undetermined

	Future Capital Costs				
	2017	2018	2019	2020	2021
Total cost	$ 945,557	$1,087,390	$1,359,237	$1,699,046	$2,123,808
Contributions	-$ 945,557	-$1,087,390	-$1,359,237	-$1,699,046	-$2,123,808
Net cost	$ -	$ -	$ -	$ -	$ -
O&M expense	undetermined	undetermined	undetermined	undetermined	undetermined

Customer Attachments and Load (5.4.5.2 A.ii)

Various. The projects that fall within this program vary in complexity, number of customers connected, types of customers, underground / overhead, single phase / three phase, alternative energies, and planned / unplanned projects.

Project Dates & Expenditure Timing (5.4.5.2.A.iii)

Start Date:	01-Jan-17			
In Service Date:	31-Dec-17			
Expenditure Timing	2017: Q1	2017: Q2	2017: Q3	2017: Q4
	25%	25%	25%	25%

General Information on Project (5.4.5.2.A)	
	Schedule Risks & Risk Mitigation (5.4.5.2.A.iv)
	Schedule for servicing lots and connecting new customers is driven by the schedule provided by the customer. Risk is mitigated through consultation with new residential or industrial / commercial customers and receipt of a completed Customer Service Layout Request from the customer. Asset failure / damage caused by third parties varies for each situation. Depending upon the complexity of the damage some may require immediate action so that power can be restored or damaged assets can be replaced. All microFiT applications require InnPower to acknowledge receipt of application within 15 days of receipt of the Connection Application provided that IESO has granted acceptance for Micro FIT. Other larger projects (Fully Recoverable Pole Relocations outside of MTO Right of Way Corridor) within this category, InnPower works closely with consultant who provide the schedule and InnPower works to that scheduled date with regards to the completion of designs, cost estimates and Applications for Encroachment Permits. Once in receipt of the Encroachment Permit, InnPower works closely with the municipality (Town of Innisfil or City of Barrie) for Municipal Consents and Road Occupancy Permits.
	Comparative Information on Expenditure from Equivalent Projects (5.4.5.2.A.v)
	Estimates for capital contribution amounts for the various projects under this program are developed from previous similar projects.
	Total Capital and OM&A costs associated with REG investment (5.4.5.2.A.vi)
	There are no REG investment associated with these expansions.
	Leave to Construct Approval (5.4.5.2.A.vii)
	Leave to Construct approval is not required for this item.
	Related Project Reference Material i.e. Images, Drawings and or Reference Material
	Projects constructed and connected under this program are designed in accordance with InnPower Condition of Service and design standards and material specifications.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Project Name: Base 3
	Investment Benefits, measured against: Efficiency, Customer Value & Reliability (5.4.5.2.B.1)
	Main Driver (5.4.5.2.B.1.a-1):
	System Access 90%
	- Main "Trigger" (5.4.5.2.B.1.a-1.1):
	Customer service requests for connections (both new and modification to existing)
	Secondary Driver (5.4.5.2.B.1.a-2):
	System Service 10%
	- Secondary "Trigger" (5.4.5.2.B.1.a-2.1):
	Meets system operational objectives: other performance/functionality
	Objective or Performance Target to be Achieved (5.4.5.2.B.1.a-3):
	Primary: Customer value; Secondary: Efficiency;
	Additional: Economic Development and Safety
	Background information that ties in with Asset Management Process (5.4.5.2.B.1.a-3):
	Assets for projects under this program are issued, recovered and disposed of per InnPower Asset Management Process.
	Overview of Investment Prioritization Justification (5.4.5.2.B.1.b)
	Projects in this program are primarily driven by customer requests as is the investment prioritization under this program. Recoverable Capital Trouble Calls require high prioritization as typically assets have been damaged and require immediate replacement.
	Project Identification and Selection (5.4.5.2.B.1.b-1)
	Projects in this program are driven by customer service requests or urgency of a trouble call with damaged assets.
	Project Prioritization (5.4.5.2.B.1.b-2)
	Projects in this program are driven by customer service requests and urgency of a trouble call with damaged assets.
	Project Pacing (5.4.5.2.B.1.b-3)
	We do not apply a methodology for pacing such projects as they are scheduled per customer requirements or need for immediate repair of damaged assets.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)
	- Alternate Considerations - Design (5.4.5.2.B.1.c-1)
	For the design of service connections InnPower reviews the installation requirements and proposes design options to the customer for consideration, while offering advice of preferred options, and when requested we offer costs for each option (i.e. overhead design versus underground, etc.). For trouble calls assets are typically replaced on a like-for-like basis, however to current construction standards / practices and material specifications. Larger projects that fall under this program require the input of all department and alternatives are considered for all larger projects which still meet InnPower technical and operational requirements.
	- Alternate Considerations - Schedule (5.4.5.2.B.1.c-2)
	Schedule is customer driven or by the seriousness of the trouble call.
	- Alternate Considerations - Funding/Ownership (5.4.5.2.B.1.c-3)
	Projects that fall under this program are 100% funded by the party requesting either connection or relocation. Payment for Recoverable Trouble Calls are typically processed through insurance and investigation.
	Effect of Investment on System Operation Efficiency and Cost-Effectiveness (5.4.5.2.B.1.c.i)
	The new facilities will be designed and constructed as per InnPower standards, specifications and system requirements to create a system that services the customers in an efficient and cost-effective manner providing system flexibility under normal and emergency conditions.
	Net Benefits Accruing to Customers as a Result of the Investment (5.4.5.2.B.1.c.ii)
	The program creates access for residential customers to receive reliable electricity supply from InnPower Distribution System, and the required service connection for customers to sell energy from distributed generators to the grid. Recoverable Trouble Calls provide replacement capital for assets damaged by others if found responsible without impacting the utility capital costs. Asset relocations as requested by MTO when outside of their Right of Way corridor is recoverable 100% without impacting the utilities capital budget.
	Impact of the Investment on Reliability Performance including on the Frequency and Duration of Outages (5.4.5.2.B.1.c.iii)
	Projects installed under this program are not intended for reliability improvements, however all new construction is in accordance with InnPower current standards and specification which lend themselves to more reliable performance reducing the frequency of outages. Construction is coordinated and performed with minimum interruption to existing customers.
	Projected Improvement to SAIFI (System Average Interruption Frequency Index: N/A
	Projected Improvement to SAIDI (System Average Interruption Duration Index: N/A

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Impact of the Driver(s), "Trigger" or other, on the DESIGN of the Project (5.4.5.2.B.1.c-4)
	The impact of the "Trigger" (i.e. Customer service requests for connections - both new and modification to existing) on the design is such that all works under this program are typically designed to provide cost effective and timely solutions to customer needs while ensuring compliance to InnPower standards, specifications and operational requirements.
	Impact of the Driver(s), "Trigger" or other, on the COMPONENT CHARACTERISTICS of the Project (5.4.5.2.B.1.c-5)
	All components supplied and installed for projects under this program are in accordance with material listing, previously reviewed and approved by InnPower.
	Impact of the Driver(s), "Trigger" or other, on the WORK PLAN of the Project (5.4.5.2.B.1.c-6)
	Schedule is determined entirely by developer and consultants.
	Investment Benefits, measured against: Safety (5.4.5.2.B.2)
	These projects are not intended to address safety concerns with the distribution system however are designed and constructed in accordance with InnPower's established standards and specifications and industry standards and specifications which provide the highest level of both public and operational personnel safety.
	Investment Benefits, measured against: Cyber-security, Privacy (5.4.5.2.B.3)
	Not applicable to projects under this program
	Investment Benefits, measured against: Co-ordination, Interoperability (5.4.5.2.B.4)
	These projects do not usually require considerations for interoperability; however, a coordinated effort is required as noted below
	Co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)
	Customer connections for projects under this program do not require coordination with regional planning bodies, however, for projects pertaining to MTO relocations the work is designed and coordinated closely with other utilities - i.e. telephone / cable TV / fiber optics and their agents/consultants.
	Potential to Enable Future Technological Functionality (5.4.5.2.B.4.b-1)
	System are designed and coordinated with other utilities which enable future technological functionality and this is mainly for MTO pole relocation projects (that fall outside their right-of- way).
	Potential to Address Future Operational Requirements (5.4.5.2.B.4.b-2)
	Projects under this program are all unique. However if it is identified during the design stage with the customers and consultant that where operational requirements can be addressed, these are incorporated into the design and this is typically with larger recoverable jobs such as MTO pole relocation projects.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Investment Benefits, measured against: Economic Development (5.4.5.2.B.5)
	Increase in customer within the service territory triggers economic development and business prosperity which attracts additional development. InnPower ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Investment Benefits, measured against: Environmental Benefits: (5.4.5.2.B.6)
	Not applicable to projects under this program.

Project Name: Base 3

Category-specific requirements for System Access Investments (5.4.5.2.C.a)

Category-specific requirements for System Access Projects (5.4.5.2.C.a)

Factors Affecting the Timing/Priority (5.4.5.2.C.a.i)

Schedule of work is based on customer expectations and schedule provided by customers or external agencies.

Factors Relating to Customer Preferences or Input from Customers and Other Third Parties (5.4.5.2.C.a.ii)

Theses projects are customer initiated and are designed to meet customer's identified requirements and schedule.

Factors Affecting the Final Cost of the Project (5.4.5.2.C.a.iii)

The final cost for projects can vary depending on both field conditions and schedule requirements: underground subsurface conditions, work completed schedule requirements (weekends / holidays or during evenings), or emergency use of hydro-vacuum system due to proximity of other services for recoverable trouble calls.

Cost Efficiency: Minimizing Controllable Costs (5.4.5.2.C.a.iv)

InnPower ensures that all projects under this program are in accordance with InnPower standards which have been designed to minimize overall costs which are based on established construction practices and approved standard materials.

Further efforts are made to inform the customer of field connection requirements and schedules to ensure they are ready for the installation (completing any work they are required to perform; i.e. make the site ready for connection) - this will reduce the need for return site visits, which in turn will reduce the overall cost impact to the customer.

Other Planning Objectives Met by this Project or Intentionally Combined (5.4.5.2.C.a.v)

Not applicable to projects under this program.

Options Considered for Technically Feasible Project Design and/or Implementation Options (5.4.5.2.C.a.vi)

InnPower ensures that all projects under this program are in accordance with InnPower standards which have been designed to minimize overall costs which are based on established construction practices and approved standard materials.

Summary of the Results of the Analysis on Feasibility of Above Options (5.4.5.2.C.a.vii)

InnPower established standards and construction practices and the use of preapproved Standard materials result in a cost effective installation. If alternatives are requested by the customer, InnPower will invest the resources to evaluate the cost / benefits of the proposal.

Category-specific requirements for System Access Projects (5.4.5.2.C.a)	
	- Least Cost Option: Comparison of the Life Cycle Cost of All Options Considered (5.4.5.2.C.a.vii-1)
	Since all projects in this program are fully funded by the customer or agency requesting the work, various cost options are typically presented to the party requesting the work for their evaluation and selection. InnPower supports the effort to minimize costs, and offers advice to guide the decision making process.
	- Cost Efficient Option: Comparison of Net Project Benefits and Costs Over the Service Life (5.4.5.2.C.a.vii-2)
	InnPower routinely provides and explains the cost benefit options when outlining the project plan with the customer to ensure the best decisions are made.
	- Cost and Benefit of a Project Configured Solely to Meet the Obligation (5.4.5.2.C.a.vii-2.i)
	This requirement is met by InnPower during the design stage of the project, where InnPower presents available options for the completion of the project.
	- Cost and Benefit of this Project in Comparison to the Above (5.4.5.2.C.a.vii-2.ii)
	As noted above, the final cost and benefit for the various projects under this program will depend on the customer's preference. However, InnPower works closely with the requestor to ensure a fully informed decision is made in choosing work scope and schedule.
	- Cost and Benefit of this Project in the Context of Technically Feasible Options (5.4.5.2.C.a.vii-2.ii.a)
	As part of InnPower's standard design process efforts to introduce new technologies or alternate technological options are considered and presented with cost benefit information to the customer for consideration.
	Results of the 'Final Economic Evaluation' per section 3.2 of the DSC (5.4.5.2.C.a.viii)
	Not applicable to projects under this program. Please see write up for Base 4 for information on subdivision connections and Economic Evaluation calculations.

Category-specific requirements for System Access Projects (5.4.5.2.C.a)	**Nature and Magnitude of the System Impacts, the Costs for System Modifications, and Cost Recovery Means (5.4.5.2.C.a.ix)**
	The projected increase in customer connections anticipated not only in 2017 but over the five year horizon will require system firming improvements to ensure the increased capacity requirements are met. In meeting such needs, system modifications have been proposed in the capital budget under "System Service" projects that support the expansion of our grid through the design and construction of distribution stations and upgrading pole lines. In the long term planning process it is anticipated that InnPower may require a Transmission Station to fully support the ~80MW of load anticipated to be added in the Barrie South development lands. Cost recovery for such projects will vary; direct service costs for individual residents are collected as described above in this report. However, InnPower's distribution system will see a sizable impact due to the large number of customer connections expected in the next 15 years. This requires substantial regional planning and cooperation, which will likely result in major system modifications, and the costs will need to be recovered through the rate base and possible capital injection through outside sources.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name **Base 4**

Project number: BASE 4 **Budget Year:** 2017

Investment Category: System Access

Project Summary

This budget item consists of numerous projects which are required for expansion and connection from InnPower' distribution system to new residential subdivisions / developments. For 2017 InnPower anticipates servicing 1900 residential units.

Total capital and non-capitalized O&M costs (5.4.5.2.A.i)

	Historical Capital Costs				
	2012	2013	2014	2015	2016
Total cost				$1,557,550	$3,273,806
Contributions				-$1,267,955	-$2,637,868
Net cost				$ 289,595	$ 635,938
O&M expense				See Note 1	See Note 1

	Future Capital Costs				
	2017	2018	2019	2020	2021
Total cost	$ 5,558,640	$ 9,349,360	$ 9,349,360	$ 9,349,360	$9,349,360
Contributions	-$ 4,446,912	-$ 8,254,960	-$ 8,254,960	-$ 8,254,960	-$8,254,960
Net cost	$1,111,728	$1,094,400	$1,094,400	$1,094,400	$1,094,400
O&M expense	See Note 1	See Note 1	See Note 1	See Note 1	See Note 1

Customer Attachments and Load (5.4.5.2 A.ii)

The number of lots serviced, the number of customer attachments and customer loads are different for each specific project within this budget item.

Project Dates & Expenditure Timing (5.4.5.2.A.iii)

Start Date:	01-Jan-17			
In Service Date:	31-Dec-17			
Expenditure Timing	2017: Q1	2017: Q2	2017: Q3	2017: Q4
	10%	35%	35%	20%

Schedule Risks & Risk Mitigation (5.4.5.2.A.iv)

Schedule for servicing lots and connecting new customers is driven by the schedule provided by the developers / builders and their consultants for the various projects. Through regular meetings with the developers / consultants InnPower is aware of the timetable for various projects proposed during the given budget year.

General Information on Project (5.4.5.2.A)	
	Comparative Information on Expenditure from Equivalent Projects (5.4.5.2.A.v)
	Estimates for capital contribution for the various projects listed under this program are developed from historical information of previous similar projects. The electrical distribution systems for these developer driven projects are supplied and installed by the developer's contractor. As per InnPower's Subdivision Agreement, the developer's electrical consultant upon completion of the installation by its contractor is required to provide a capitalization of assets. This capitalization is the basis of the capital cost for the various projects listed within Base 4.
	Total Capital and OM&A costs associated with REG investment (5.4.5.2.A.vi)
	There are no REG investment associated with these expansions.
	Leave to Construct Approval (5.4.5.2.A.vii)
	Leave to Construct approval is not required for this item.
	Related Project Reference Material i.e. Images, Drawings and or Reference Material
	Developments are constructed and connected in accordance with InnPower Condition of Service, design standards and material specifications.
Note 1:	
The increase in capital infrastructure to service the new customer connections will results in an increase in the number of padmount transformers, underground cables and systems, and switchgear installations. These will require on-going operational and maintenance costs. Although these costs have been tracked by InnPower as part of the overall O&M budget tracking process in the past, detailed cost comparison are not readily available to calculate the exact impact of this budget on the O&M costs.	

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Project Name: Base 4
	Investment Benefits, measured against: Efficiency, Customer Value & Reliability (5.4.5.2.B.1)
	Main Driver (5.4.5.2.B.1.a-1):
	System Access 90%
	- Main "Trigger" (5.4.5.2.B.1.a-1.1):
	Customer service requests for connections (both new and modification to existing)
	Secondary Driver (5.4.5.2.B.1.a-2):
	System Service 10%
	- Secondary "Trigger" (5.4.5.2.B.1.a-2.1):
	Meets system operational objectives: other performance/functionality
	Objective or Performance Target to be Achieved (5.4.5.2.B.1.a-3):
	Primary: Customer value; Secondary: Efficiency;
	Additional: Economic Development and Safety
	Background information that ties in with Asset Management Process (5.4.5.2.B.1.a-3.i):
	As per the Economic Evaluation in accordance with the OEB Distribution System Code - DSC and Subdivision Agreement.
	Overview of Investment Prioritization Justification (5.4.5.2.B.1.b)
	Projects in this program are driven by customer service requests, as is the investment prioritization under this program. Assets are transferred as per the Economic Evaluation in accordance with the OEB Distribution System Code - DSC and Subdivision Agreement.
	Project Identification and Selection (5.4.5.2.B.1.b-1)
	Projects in this program are driven by customer service requests.
	Project Prioritization (5.4.5.2.B.1.b-2)
	Projects in this program are driven by customer service requests.
	Project Pacing (5.4.5.2.B.1.b-3)
	The pacing of the projects are dependent on the timing (and rate) of customer/developer servicing requests received.
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)
	- Alternate Considerations - Design (5.4.5.2.B.1.c-1)
	Typically designed by developer's electrical consultant with review and input by InnPower.
	- Alternate Considerations - Schedule (5.4.5.2.B.1.c-2)
	Schedule is determined entirely by the land developer. So far the construction work has been performed by Developer's underground lines contractor.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	- Alternate Considerations - Funding/Ownership (5.4.5.2.B.1.c-3)
	The funding/ownership is as per the Economic Evaluation in accordance with the OEB Distribution System Code - DSC and Subdivision Agreement.
	Effect of Investment on System Operation Efficiency and Cost-Effectiveness (5.4.5.2.B.1.c.i)
	The new facilities will be designed and constructed as per InnPower standards, specifications and system requirements. This will create a system that services the customers in an efficient and cost-effective manner, providing system flexibility under normal and emergency conditions.
	Net Benefits Accruing to Customers as a Result of the Investment (5.4.5.2.B.1.c.ii)
	The program creates access for residential customers to receive reliable electricity supply from the InnPower Distribution System.
	Impact of the Investment on Reliability Performance including on the Frequency and Duration of Outages (5.4.5.2.B.1.c.iii)
	Systems installed under this program are not intended for reliability improvements, however all new construction of electrical distribution systems is underground in accordance with InnPower standards and specification which lend themselves to a more reliable performance; by reducing the frequency and duration of outages. Construction is coordinated and performed with minimum interruption to existing customers.
	Projected Improvement to SAIFI (System Average Interruption Frequency Index: N/A
	Projected Improvement to SAIDI (System Average Interruption Duration Index: N/A
	Impact of the Driver(s), "Trigger" or other, on the DESIGN of the Project (5.4.5.2.B.1.c-4)
	Design by developer's electrical consultant in accordance with InnPower standards, specifications and operational requirements.
	Impact of the Driver(s), "Trigger" or other, on the COMPONENT CHARACTERISTICS of the Project (5.4.5.2.B.1.c-5)
	All components supplied and installed for projects under this program are in accordance with InnPower's approved material listing previously reviewed and approved by InnPower.
	Impact of the Driver(s), "Trigger" or other, on the WORK PLAN of the Project (5.4.5.2.B.1.c-6)
	Schedule is determined entirely by developer and its consultants.
	Investment Benefits, measured against: Safety (5.4.5.2.B.2)
	These projects are not intended to address safety concerns within the distribution system, however projects are designed and constructed in accordance with InnPower's established standards and specification and industry standards and specifications which provide the highest level of both public and operational personnel safety.
	Investment Benefits, measured against: Cyber-security, Privacy (5.4.5.2.B.3)
	Not applicable to projects under this program.

<table>
<tr><td rowspan="12">Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)</td><td>Investment Benefits, measured against: Co-ordination, Interoperability (5.4.5.2.B.4)</td></tr>
<tr><td>Co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)</td></tr>
<tr><td>Customer connections for projects under this program do not impact inter-utility. Electrical distribution systems for projects under this program are designed and coordinated by the developer's consultant which typically results in co-ordination with other utilities - i.e. telephone / cable tv / fiber optics / gas.</td></tr>
<tr><td>Potential to Enable Future Technological Functionality (5.4.5.2.B.4.b-1)</td></tr>
<tr><td>Systems are design and coordinated with other utilities which enable future technological functionality.</td></tr>
<tr><td>Potential to Address Future Operational Requirements (5.4.5.2.B.4.b-2)</td></tr>
<tr><td>Projects under this program are all unique however if it observed during the design stage with the developers consultant that there are operational requirements that can be addressed these are incorporated into the design. These include strategic switching functionality with radio controlled switches to enable future circuit ties, and/or enable distribution automation.</td></tr>
<tr><td>Investment Benefits, measured against: Economic Development (5.4.5.2.B.5)</td></tr>
<tr><td>Increase in customer within the service territory triggers economic development and business prosperity which attracts additional development.

InnPower ensures that its policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.</td></tr>
<tr><td>Investment Benefits, measured against: Environmental Benefits: (5.4.5.2.B.6)</td></tr>
<tr><td>Not applicable to projects under this program.</td></tr>
<tr></tr>
<tr><td colspan="2">Note 1:</td></tr>
<tr><td></td><td>The increase in capital infrastructure to service the new customer connections will results in an increase in the number of padmount transformers, underground cables and systems, and switchgear installations. These will require on-going operational and maintenance costs. Although these costs have been tracked by InnPower as part of the overall O&M budget tracking process in the past, detailed cost comparison are not readily available to calculate the exact impact of this budget on the O&M costs.</td></tr>
</table>

Project Name Base 4	
Category-specific requirements for System Access Investments (5.4.5.2.C.a)	
Category-specific requirements for System Access Projects (5.4.5.2.C.a)	**Factors Affecting the Timing/Priority (5.4.5.2.C.a.i)**
	The schedule of work is based on customer expectations and the schedule provided by the developer and its consultant.
	Factors Relating to Customer Preferences or Input from Customers and Other Third Parties (5.4.5.2.C.a.ii)
	These projects are customer initiated and are designed to meet customer identified requirements.
	Factors Affecting the Final Cost of the Project (5.4.5.2.C.a.iii)
	Economic Evaluation as per OEB - Distribution System Code is a factor affecting the final cost of the project. The final costing of the project is determined by the capitalization numbers of the project as provided by the developer's consultant and number of customers that get connected within the 5 Year Connection Horizon.
	Cost Efficiency: Minimizing Controllable Costs (5.4.5.2.C.a.iv)
	A comparison of developer provided capitalization of cost verses the initial cost estimate and a 3rd party contractor verification of project costs is conducted. InnPower ensures that all expansions are in accordance with InnPower standards which have been designed to minimize overall costs and are based on established construction practices and approved standard materials.
	Other Planning Objectives Met by this Project or Intentionally Combined (5.4.5.2.C.a
	Not applicable to projects under this program.
	Options Considered for Technically Feasible Project Design and/or Implementation Options(5.4.5.2.C.a.vi)
	InnPower ensures that all expansions are in accordance with InnPower standards which have been designed to minimize overall costs which are based on established construction practices and approved standard materials.
	Summary of the Results of the Analysis on Feasibility of Above Options (5.4.5.2.C.a.vii)
	The use of standardized preapproved materials, InnPower's established standards and construction practices, result in a cost effective installation of the electrical distribution system. If alternatives are requested by the customer, InnPower will invest the resources required to evaluate the cost / benefits of the proposal.
	- Least Cost Option: Comparison of the Life Cycle Cost of All Options Considered (5.4.5.2.C.a.vii-1)
	See Note 2
	- Cost Efficient Option: Comparison of Net Project Benefits and Costs Over the Service Life (5.4.5.2.C.a.vii-2)
	See Note 2

Category-specific requirements for System Access Projects (5.4.5.2.C.a)	
	- Cost and Benefit of a Project Configured Solely to Meet the Obligation (5.4.5.2.C.a.
	See Note 2
	- Cost and Benefit of this Project in Comparison to the Above (5.4.5.2.C.a.vii-2.ii)
	See Note 2
	- Cost and Benefit of this Project in the Context of Technically Feasible Options (5.4.5.2.C.a.vii-2.ii.a)
	See Note 2
	Results of the 'Final Economic Evaluation' per section 3.2 of the DSC (5.4.5.2.C.a.viii)
	Economic Evaluation are done as prescribed under the OEB - Distribution System Code. The final costing of the project is determined by the capitalization numbers of the project as provided by the developer's consultant and the number of customers that get connected within the 5 year connection horizon. Capitalized number are compared to the initial cost estimates and also to other similar projects in our service territory. Actual customer connections are reviewed on an annual basis (anniversary date of energization), economic evaluations are re-calculated and rebates are issued based on the actual number of customer connected and actual revenue stream of the project as per the Economic Evaluation and the OEB Distribution System Code for the 5 year connection horizon.
	Nature and Magnitude of the System Impacts, the Costs for System Modifications, and Cost Recovery Means (5.4.5.2.C.a.ix)
	The projected increase in customer connections are anticipated for not only 2017 but over the five year horizon. This will require system firming improvements to ensure the increased capacity requirements are met. In meeting such needs, system modifications have been proposed in the capital budget under "System Service" projects that support the expansion of our grid through the design and construction of distribution stations and upgrading pole lines. In the long term planning process it is anticipated that InnPower may require a Transmission Station to fully support the ~80MW of load anticipated to be added in the Barrie South development lands. Cost recovery for such projects will vary; direct service costs are addressed through the process described above in 5.4.5.2.C.a.viii and the Economic Evaluation model. InnPower's distribution system will see a sizable impact due to the large number of customer connections anticipated in the next 15 years. This requires substantial regional planning and cooperation, and will likely result in major system modifications, and the costs will need to be recovered through the rate base and by possible capital injections by outside sources.

Note 2:	
	InnPower works closely with Developers and their electrical consultants to careful review the subdivision needs, for both current and future, and ensure that all design conforms to our goals for the optimization of the grid for operational efficiency, reliability, and cost effectiveness, while ensuring the needs of the Developer are met. In this process lifecycle costs are considered, as well as the feasibility of design to meet obligation to service new customers. This process takes into consideration feasible scenarios for design (including technical feasibility for transformation options, cabling options, switchgear and control options) while weighing the cost against benefit to ensure the best decisions are made.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name: **Intersection widening: IBR & Yonge Street**

Project number: DO 001 **Budget Year:** 2017

Investment Category: System Access

Project Summary:

This project pertains to asset relocation for the road intersection widening project at Innisfil Beach Road (IBR) and Yonge Street, and is part of a multi-year project for widening a large section of IBR. This Project will involve the installation of approximately 24 poles, ranging in height from 40′ to 85′, installation of 3500m of new conductor and relocation of 5 transformers. Together these projects involve the relocation of InnPower assets to support road relocation and road reconstruction projects as determined by the County of Simcoe; and which are contributed by the County of Simcoe as follows: 50% of Labour, Vehicles and Subcontractor Costs. Materials are supplied by InnPower Corporation.

The County of Simcoe has proposed improvements to County Road 21 (Innisfil Beach Road) from County Road 27 to County Road 39. The improvements are to widen and resurface the road to 4 lanes (from 2 lanes, one in each direction) to increase its capacity, improve existing driveways, correct storm drainage problems, replace aged culverts, improve illumination and eliminate safety concerns. The overall distance is approximately 12.1 kilometers and includes four (4) intersections. The planned works was commenced in 2012 and spans a total of eight (8) years.

InnPower owns and operates both sub-transmission and distribution assets in this area. All of our current primary assets are overhead type. The pole line along Innisfil Beach Road has two (2) 44kV sub-transmission circuits from Alliston TS and at least one (1) distribution circuit along the entire area. There are several service drops on many of the poles, for both overhead and underground service.

Total capital and non-capitalized O&M costs (5.4.5.2.A.i)

	Historical Capital Costs				
	2012	2013	2014	2015	2016
Total cost	$	$ -	$ -	$	$
Contributions	-$	$ -	$ -	-$	-$
Net cost	$	$ -	$ -	$	$
O&M expense	undetermined	undetermined	undetermined	undetermined	undetermined

	Future Capital Costs				
	2017	2018	2019	2020	2021
Total cost	$ 430,000	$ 745,000	$ 137,500	$ 117,500	$ 745,000
Contributions	-$ 157,570	-$ 273,700	-$ 50,515	-$ 43,167	-$ 273,700
Net cost	$ 272,430	$ 471,300	$ 86,985	$ 74,333	$ 471,300
O&M expense	undetermined	undetermined	undetermined	undetermined	undetermined

Customer Attachments and Load (5.4.5.2 A.ii)

Not Applicable

Project Dates & Expenditure Timing (5.4.5.2.A.iii)

Start Date:	01-Jan-17			
In Service Date:	31-Dec-17			
Expenditure Timing	2017: Q1	2017: Q2	2017: Q3	2017: Q4
	10	60	30	0%

General Information on Project (5.4.5.2.A)

Schedule Risks & Risk Mitigation (5.4.5.2.A.iv)

The schedule for the overall project is provided below. The initiation and timing of these projects are dictated by the County of Simcoe. Consequently the timing and value of investment required by InnPower is subject to change. Schedule is determined by the County and through meetings and discussion with the County, InnPower is informed of these types of projects. The projections of our expenditures noted above are based on feedback received from the County on their most recent schedule. Our risk mitigation efforts include advanced planning to ensure resource needs are met, and open communication between all stakeholders to help identify any conflicts or other project requirements, such as getting approvals from Metrolinx/GO Transit for rail crossing, etc.).

Schedule for Work

Year	Scope
2012	Intersection widening at IBR and 10th Sideroad
2013	No works
2014	No works
2015	Intersection widening at IBR and 20th Sideroad
2016	Intersection widening at IBR and 5th Sideroad
2017	Intersection widening at IBR and Yonge Street
2018	IBR road widening from Yonge street to 20th Sideroad
2019	IBR road widening from 10th Sideroad to Yonge Street
2020	IBR road widening from Highway 400 to 10th Sideroad
2021	IBR road widening from Highway 27 to 5th Sideroad

Comparative Information on Expenditure from Equivalent Projects (5.4.5.2.A.v)

The table above contains costs of past projects. Typical project costs are based on previous projects and established cost estimates for similar projects.

Total Capital and OM&A costs associated with REG investment (5.4.5.2.A.vi)

Not Applicable

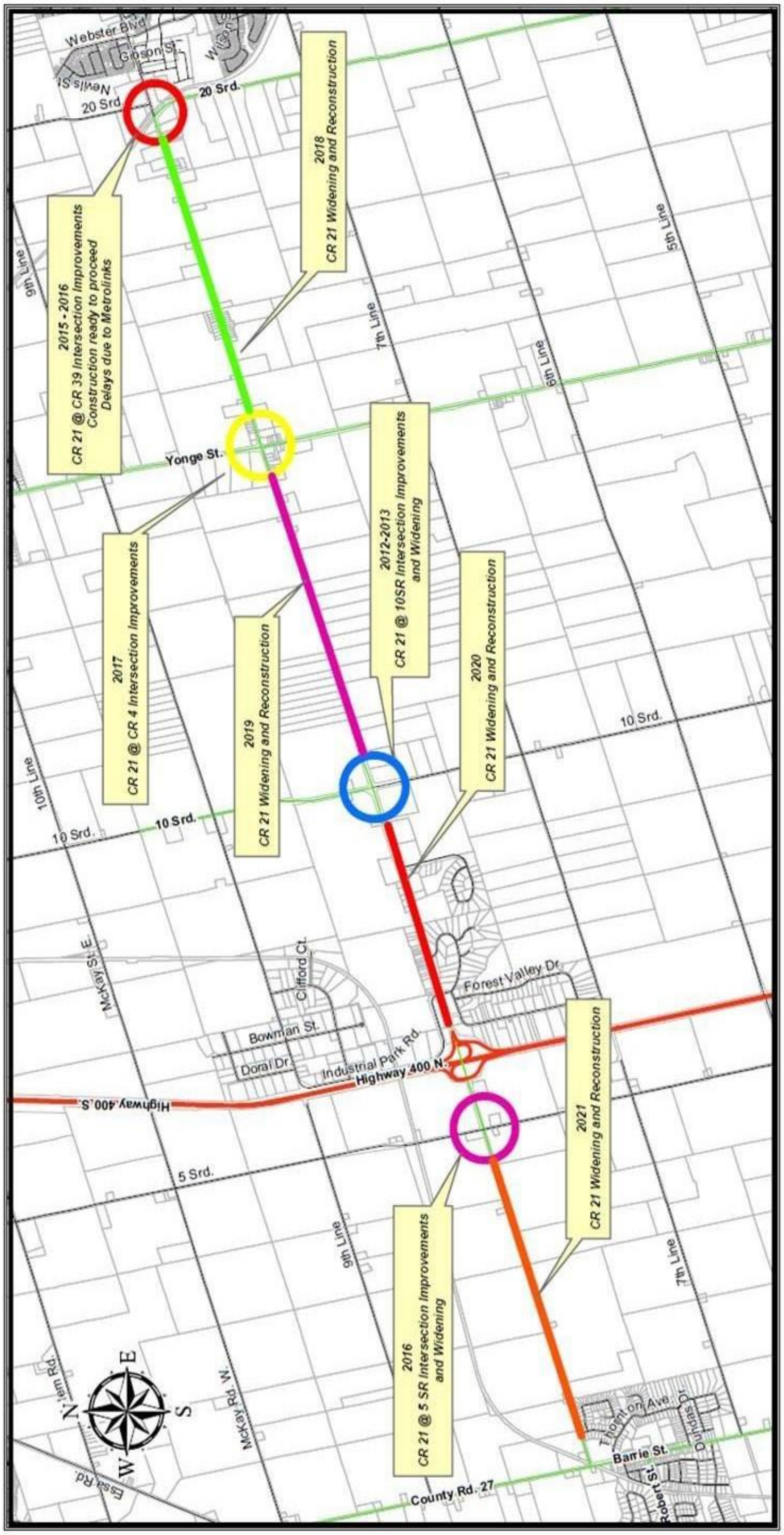
Leave to Construct Approval (5.4.5.2.A.vii)

Not Applicable

General Information on Project (5.4.5.2.A)

Related Project Reference Material; i.e. Images, Drawings and or Reference Material

The annotated map below provides an illustration for the proposed works.



Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Project Name: Intersection widening: IBR & Yonge Street
	Investment Benefits, measured against: Efficiency, Customer Value & Reliability (5.4.5.2.B.1)
	Main Driver (5.4.5.2.B.1.a-1):
	System Access
	- Main "Trigger" (5.4.5.2.B.1.a-1.1):
	Third party infrastructure development (relocating pole line for road widening)
	Secondary Driver (5.4.5.2.B.1.a-2): None
	- Secondary "Trigger" (5.4.5.2.B.1.a-2.1): None
	Objective or Performance Target to be Achieved (5.4.5.2.B.1.a-3):
	Primary: Customer value; **Secondary:** Efficiency;
	Additional: Co-ordination, Interoperability and Safety
	Background information that ties in with Asset Management Process (5.4.5.2.B.1.a-3a):
	Our Asset Management process allows for this project as it supports obligatory works as described above.
	Overview of Investment Prioritization Justification (5.4.5.2.B.1.b)
	County road works are given high priority to prevent County project delays
	Project Identification and Selection (5.4.5.2.B.1.b-1)
	Projects under this program are determined by the County
	Project Prioritization (5.4.5.2.B.1.b-2)
	Mandatory Projects with High Priority
	Project Pacing (5.4.5.2.B.1.b-3)
	Schedule as determine by County of Simcoe

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)
	- Alternate Considerations - Design (5.4.5.2.B.1.c-1)
	InnPower co-ordinates project design and discusses design alternatives for projects under this program with the respective organization from which the request originates to relocate distribution assets. In designing the works for each of the project phases the engineers have taken into consideration the optimal design to bring the installation to current standards, improve overall layout, and accommodate future requirements. In instances where the poles need to be moved, InnPower will be replacing existing poles with new poles to meet current standards. The new poles are typically larger in diameter and therefore stronger. Hence, this upgrade work is expected to result in greater reliability for the grid as a whole, as these poles carry two main sub-transmission lines that feed InnPower's service area. A possible alternate design for this work would be to install underground cable for both the sub-transmission and distribution circuitry. The cost for this scope will be higher than the estimates provided above. Another possible alternate design is to re-route the sub-transmission circuitry to the various distribution stations using alternate infrastructure already existing, and rebuild only the distribution circuitry on Innisfil Beach Road at a lower cost. This option was not considered as InnPower does not own or operate alternate infrastructure where this option could be executed. In completing the design InnPower has, and will continue to use in-house resources as much as possible to meet the time lines for construction while maintaining efficiency. Both projects completed to date used in-house engineers for the design. It is however, customary for InnPower to contract out the line-build works. Albeit, the successful contractor was selected through a competitive tendering process.
	- Alternate Considerations - Schedule (5.4.5.2.B.1.c-2)
	Schedule as determine by County of Simcoe
	- Alternate Considerations - Funding/Ownership (5.4.5.2.B.1.c-3)
	InnPower follows the Public Service Works on Highways Act, 1990 and associated regulations governing the recovery of costs related to road reconstruction work by collecting contributed capital for 50% of the labour; labour saving devices, and equipment rentals. Capital contributions toward the cost of all customer demand projects are collected by InnPower in accordance with the DSC and the provisions of its Conditions of Service. All assets installed under this project are fully owned by InnPower.
	Effect of Investment on System Operation Efficiency and Cost-Effectiveness (5.4.5.2.B.1.c.i)
	While relocating the facilities, InnPower considers 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 System Service work required in the future and contribute to higher system operation efficiency and cost effectiveness in the long term.
	Net Benefits Accruing to Customers as a Result of the Investment (5.4.5.2.B.1.c.ii)
	Although public safety was not a primary driver, the renewal of the infrastructure will result in an incremental increase in public safety.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Impact of the Investment on Reliability Performance including on the Frequency and Duration of Outages (5.4.5.2.B.1.c.iii)
	This program is not intended to improve system reliability performance. However, adoption of new design standards and installation of new and standardized equipment can contribute to lower asset failure risks resulting in less service interruptions.
	Projected Improvement to SAIFI (System Average Interruption Frequency Index): N/A
	Projected Improvement to SAIDI (System Average Interruption Duration Index): N/A
	Impact of the Driver(s), "Trigger" or other, on the DESIGN of the Project (5.4.5.2.B.1.c-4)
	Line relocations are generally executed on a like-for-like basis, however the opportunity is taken to consider project alternatives which may include: underground or overhead options, use of alternate routings, increasing conductor sizing. The optimal solution for immediate and future system needs is selected.
	Impact of the Driver(s), "Trigger" or other, on the COMPONENT CHARACTERISTICS of the Project (5.4.5.2.B.1.c-5)
	Components used on such projects are typically a direct replacement of existing type (due to like-for-like replacement strategy) except when needed to upgrade to current standards and specifications.
	Impact of the Driver(s), "Trigger" or other, on the WORK PLAN of the Project (5.4.5.2.B.1.c-6)
	Work plan is determined by County and could be impacted by other stakeholders including approval agencies.
	Investment Benefits, measured against: Safety (5.4.5.2.B.2)
	These projects are not intended to address safety concerns with the distribution system, however, facilities will be built to current standards to maintain and potentially improve safety. This program will have no adverse impact on health and safety protection and performance.
	Investment Benefits, measured against: Cyber-security, Privacy (5.4.5.2.B.3)
	Cyber-Security and Privacy are not applicable to this project.
	Investment Benefits, measured against: Co-ordination, Interoperability (5.4.5.2.B.4)
	Typically plant relocations at this level does not impact inter-utility coordination, regional planning activities, or interoperability.
	Co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)
	The execution of these projects are dictated by the County of Simcoe and therefore co-ordinated with their office, their agents, and related approval bodies.
	Potential to Enable Future Technological Functionality (5.4.5.2.B.4.b-1)
	Distribution Lines are designed to the latest standard for operational needs, and consideration is given to include, where necessary, monitoring equipment and sensors.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Potential to Address Future Operational Requirements (5.4.5.2.B.4.b-2)
	Plant replacement is designed in consideration of present and future operational needs, which could include controllable primary switching devices.
	Investment Benefits, measured against: Economic Development (5.4.5.2.B.5)
	Although not directly related to economic development, these projects are often done in support of county and municipal projects targeted at economic development. InnPower ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Investment Benefits, measured against: Environmental Benefits: (5.4.5.2.B.6)
	Not applicable to these types of projects.

Project Name: Intersection widening: IBR & Yonge Street

Category-specific requirements for System Access Investments (5.4.5.2.C.a)

Category-specific requirements for System Access Projects (5.4.5.2.C.a)

Factors Affecting the Timing/Priority (5.4.5.2.C.a.i)

The schedule for this project is determined by the County of South Simcoe. InnPower staff works closely with the County to ensure the circuit alterations are made in a timely manner in order to avoid delays with County work.

Factors Relating to Customer Preferences or Input from Customers and Other Third Parties (5.4.5.2.C.a.ii)

InnPower is always open to discussion and co-ordination of the design for these types of projects with the County. The designs for all projects within the municipal right of way are reviewed by the County and Town as municipal consent and approval is required prior to construction. Consideration is given by the road authority to co-ordinate all utilities within the right of way in the least disruptive manner.

Factors Affecting the Final Cost of the Project (5.4.5.2.C.a.iii)

The primary cost factors for this project were:
- Project consultation, scoping, and engineering design.
- Project execution costs, including material, labour, and contractor costs.
- To save costs and improve efficiency, InnPower has, and will continue to use in-house resources as much as possible to meet the time lines for construction. Both projects completed to date used in-house engineers for the design. It is however, customary for InnPower to contract out the line-build works. Albeit, the successful contractor was selected through a competitive tendering process.

Cost Efficiency: Minimizing Controllable Costs (5.4.5.2.C.a.iv)

50% of Labour, labour saving devices and equipment rental are recoverable.

Other Planning Objectives Met by this Project or Intentionally Combined (5.4.5.2.C.a.v)

InnPower combines work to reduce overall costs and increase efficiency. The most common opportunity is to coordinate County road reconstruction projects with InnPower projects, so that system upgrades planned for the future can be incorporated into these types of projects while the road and the boulevard are under construction. InnPower may also be able to reschedule other projects to align with the road authority to maximize these benefits and minimize overall impact to the residents of the community, thus enabling InnPower to maximize the amount of work that can be completed at the lowest cost to benefit ratepayers.

Category-specific requirements for System Access Projects (5.4.5.2.C.a)	
	Options Considered for Technically Feasible Project Design and/or Implementation (5.4.5.2.C.a.vi)
	InnPower co-ordinates project design and discusses design alternatives for each project with the road authority originating the request to relocate distribution assets. Designs are typically like for like to minimize overall project cost which are based on established construction practices and approved standard materials. A possible alternate design for this work would be to install underground cable for both the sub-transmission and distribution circuitry. The cost for this scope will be higher than the estimates provided above. Another possible alternate design is to re-route the sub-transmission circuitry to the various distribution stations using alternate infrastructure already existing, and rebuild only the distribution circuitry on Innisfil Beach Road at a lower cost. This option was not considered as InnPower does not own or operate alternate infrastructure where this option could be executed.
	Summary of the Results of the Analysis on Feasibility of Above Options (5.4.5.2.C.a.vii)
	Option to install underground cable for both sub-transmission and distribution feeders would result in much higher cost.
	- Least Cost Option: Comparison of the Life Cycle Cost of All Options Considered (5.4.5.2.C.a.vii-1)
	InnPower is using the "least cost option" for this project by adopting to a "like-to-like" replacement strategy wherever possible.
	- Cost Efficient Option: Comparison of Net Project Benefits and Costs Over the Service Life (5.4.5.2.C.a.vii-2)
	The design methodology used for this project is based on minimalistic enhancements, except where required by current standards, and the implementation methodology is based on using cost effective labour and therefore over the service life of this project our currently prescribed approach will result in the most cost efficient option.
	- Cost and Benefit of a Project Configured Solely to Meet the Obligation (5.4.5.2.C.a.vii-2.i)
	The costs presented in the table above are based on the criteria to "meet the obligation", and no additional costs have been added.
	- Cost and Benefit of this Project in Comparison to the Above (5.4.5.2.C.a.vii-2.ii)
	For this project, the scope for the "least cost" option is the same for "meet the obligation" option and therefore a comparison of the two options was not required.

Category-specific requirements for System Access Projects (5.4.5.2.C.a)	
	- Cost and Benefit of this Project in the Context of Technically Feasible Options (5.4.5.2.C.a.vii-2.ii.a)
	The cost and benefits of using the "like-for-like" replacement strategy where possible will result in lesser overall life cycle cost to the customer.
	Results of the ‘Final Economic Evaluation’ per section 3.2 of the DSC (5.4.5.2.C.a.viii)
	Projects under this program are not applicable to an Economic Evaluation as per OEB - DSC.
	Nature and Magnitude of the System Impacts, the Costs for System Modifications, and Cost Recovery Means (5.4.5.2.C.a.ix)
	As per agreement with County for cost recovery, as noted above.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name: Metering

Project number: DB 001 **Budget Year:** 2017

Investment Category: System Access

Project Summary:

This program includes the installation of InnPower Corporation's metering assets, in compliance with Measurement Canada standards. The work includes:

(1) Installation of residential and commercial meters at new service locations;
(2) Upgrade of metering installations for expanded service requirements;
(3) Replacement metering for residential and commercial services;
(4) Multi-residential metered customers.

Total capital and non-capitalized O&M costs (5.4.5.2.A.i)

	Historical Capital Costs				
	2012	2013	2014	2015	2016
Total cost	$ 50,794	$ 96,757	$120,569	$ 95,342	$147,500
Contributions	$ -	$ -	$ -	$ -	$ -
Net cost	$ 50,794	$ 96,757	$120,569	$ 95,342	$147,500
O&M expense	undetermined	undetermined	undetermined	undetermined	undetermined

	Future Capital Costs				
	2017	2018	2019	2020	2021
Total cost	$230,000	$270,000	$250,000	$250,000	$250,000
Contributions	$ -	$ -	$ -	$ -	$ -
Net cost	$230,000	$270,000	$250,000	$250,000	$250,000
O&M expense	undetermined	undetermined	undetermined	undetermined	undetermined

Customer Attachments and Load (5.4.5.2 A.ii)

n/a

Project Dates & Expenditure Timing (5.4.5.2.A.iii)

Start Date:	01-Jan-17			
In Service Date:	31-Dec-17			
Expenditure Timing	2017: Q1	2017: Q2	2017: Q3	2017: Q4
	25%	25%	25%	25%

Schedule Risks & Risk Mitigation (5.4.5.2.A.iv)

Schedule risk for the installation of meters at new service locations is due to customer delays or restricted access to work sites. InnPower corporation co-ordinates the connection of new services with customers to mitigate this risk.

General Information on Project (5.4.5.2.A)	
	Comparative Information on Expenditure from Equivalent Projects (5.4.5.2.A.v)
	The per unit cost for material and labour were derived from historical data on equivalent projects. This cost was then corrected to account for changes in exchange rates, labour and material increases.
	Total Capital and OM&A costs associated with REG investment (5.4.5.2.A.vi)
	n/a
	Leave to Construct Approval (5.4.5.2.A.vii)
	n/a
	Related Project Reference Material i.e. Images, Drawings and or Reference Material
	n/a

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Project Name: Metering
	Investment Benefits, measured against: Efficiency, Customer Value & Reliability (5.4.5.2.B.1)
	Main Driver (5.4.5.2.B.1.a-1):
	System Access.
	- Main "Trigger" (5.4.5.2.B.1.a-1.1):
	Mandated service obligations – metering.
	Secondary Driver (5.4.5.2.B.1.a-2): None
	- Secondary "Trigger" (5.4.5.2.B.1.a-2.1): None
	Objective or Performance Target to be Achieved (5.4.5.2.B.1.a-3):
	Primary: Customer value; Secondary: None
	Additional: Cyber-security, Privacy
	Background information that ties in with Asset Management Process (5.4.5.2.B.1.a-3.i):
	This project is for new services. InnPower's asset management objective includes accommodating load growth. These asset management goals are derived directly from InnPower's corporate goals.
	Overview of Investment Prioritization Justification (5.4.5.2.B.1.b)
	This is a mandatory project and a regulatory requirement.
	Project Identification and Selection (5.4.5.2.B.1.b-1)
	n/a
	Project Prioritization (5.4.5.2.B.1.b-2)
	High priority as this is a mandatory project and a regulatory requirement.
	Project Pacing (5.4.5.2.B.1.b-3)
	The project is paced depending on customer request for new connections.
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)
	- Alternate Considerations - Design (5.4.5.2.B.1.c-1)
	Metering asset management is governed by Measurement Canada regulation and customer requirements for new and upgraded services.
	- Alternate Considerations - Schedule (5.4.5.2.B.1.c-2)
	n/a
	- Alternate Considerations - Funding/Ownership (5.4.5.2.B.1.c-3)
	n/a

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Effect of Investment on System Operation Efficiency and Cost-Effectiveness (5.4.5.2.B.1.c.i)
	Customer connection projects are driven by customer requests and the customer’s specific technical requirements. InnPower Corporation utilizes a set of design standards that have been engineered and approved in order to build efficiencies into the process. Customer connection requests are fulfilled consistent with InnPower Corporation's Conditions of Service. The projects are designed to meet the customer requirements and maintain system reliability and efficiency.
	Net Benefits Accruing to Customers as a Result of the Investment (5.4.5.2.B.1.c.ii)
	Benefits to the customer include timely service and supply of electricity coupled with Time of Use (TOU) pricing and data visibility.
	Impact of the Investment on Reliability Performance including on the Frequency and Duration of Outages (5.4.5.2.B.1.c.iii)
	InnPower Corporation uses smart meter outage flags in its Outage Management System to predict and analyze outages. This leads to a faster outage response and improved reliability indices.
	Projected Improvement to SAIFI (System Average Interruption Frequency Index): n/a
	Projected Improvement to SAIDI (System Average Interruption Duration Index): n/a
	Impact of the Driver(s), "Trigger" or other, on the DESIGN of the Project (5.4.5.2.B.1.c-4)
	The design is based on InnPower Corporation's standards, customer requirements for new and upgraded services, conditions of service, and is governed by Measurement Canada regulations.
	Impact of the Driver(s), "Trigger" or other, on the COMPONENT CHARACTERISTICS of the Project (5.4.5.2.B.1.c-5)
	n/a
	Impact of the Driver(s), "Trigger" or other, on the WORK PLAN of the Project (5.4.5.2.B.1.c-6)
	The work plan on the project is based upon customer connection requests and regulatory requirements.
	Investment Benefits, measured against: Safety (5.4.5.2.B.2)
	n/a
	Investment Benefits, measured against: Cyber-security, Privacy (5.4.5.2.B.3)
	InnPower Corporation's Smart Meter and related AMI network have been procured through Sensus. Sensus' system supports a multi-layered security approach including: access control, authorization, authentication, encryption and data integrity protocols. As part of its continuous improvement model, InnPower Corporation performs periodic security assessments to identify opportunities for enhanced system hardening.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Investment Benefits, measured against: Co-ordination, Interoperability (5.4.5.2.B.4)
	Co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)
	Co-ordination with utilities and regional planning is not required. InnPower Corporation coordinates with customers as required by the scope of work involved.
	Potential to Enable Future Technological Functionality (5.4.5.2.B.4.b-1)
	A component of this investment supports the capital investment required for the ongoing operation, maintenance, and installation of the Smart Metering infrastructure.
	Potential to Address Future Operational Requirements (5.4.5.2.B.4.b-2)
	A component of this investment supports the capital investment required for the ongoing operation, maintenance, and installation of the Smart Metering infrastructure.
	Investment Benefits, measured against: Economic Development (5.4.5.2.B.5)
	InnPower Corporation ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Investment Benefits, measured against: Environmental Benefits: (5.4.5.2.B.6)
	The Smart Meter infrastructure supports the province's conservation culture. Smart metering also provides environmental benefits through reduction of in field visits associated with manual meter reading.

<table>
<tr><td colspan="2">Project Name: Metering</td></tr>
<tr><td colspan="2">Category-Specific requirements for System Access Investments (5.4.5.2.C.a)</td></tr>
<tr><td rowspan="16">Category-specific requirements for System Access Projects (5.4.5.2.C.a)</td><td>Factors Affecting the Timing/Priority (5.4.5.2.C.a.i)</td></tr>
<tr><td>This is a mandatory project and a regulatory requirement. The timing of the project is based on customer requests for new or upgraded connections.</td></tr>
<tr><td>Factors Relating to Customer Preferences or Input from Customers and Other Third Parties (5.4.5.2.C.a.ii)</td></tr>
<tr><td>Metering for new and upgraded connection projects are customer initiated and are designed to meet customer identified requirements.</td></tr>
<tr><td>Factors Affecting the Final Cost of the Project (5.4.5.2.C.a.iii)</td></tr>
<tr><td>InnPower Corporation considers the following as general risks to project cost:
a. Customer delays or restricted access to work sites
b. Inclement weather
c. Delays to material shipment from vendors</td></tr>
<tr><td>Cost Efficiency: Minimizing Controllable Costs (5.4.5.2.C.a.iv)</td></tr>
<tr><td>InnPower conducts meter reverification through Measurement Canada which extends the life of existing meter assets reducing's replacement costs.</td></tr>
<tr><td>Other Planning Objectives Met by this Project or Intentionally Combined (5.4.5.2.C.a.v)</td></tr>
<tr><td>n/a</td></tr>
<tr><td>Options Considered for Technically Feasible Project Design and/or Implementation Options (5.4.5.2.C.a.vi)</td></tr>
<tr><td>Metering work is Measurement Canada and customer driven and the technology is primarily based on the metering products available from a sole source supplier.</td></tr>
<tr><td>Summary of the Results of the Analysis on Feasibility of Above Options (5.4.5.2.C.a.vii)</td></tr>
<tr><td>Metering supplier selected as part of the RFP process for the smart meter implementation program.</td></tr>
<tr><td>- Least Cost Option: Comparison of the Life Cycle Cost of All Options Considered (5.4.5.2.C.a.vii-1)
n/a</td></tr>
<tr><td>- Cost Efficient Option: Comparison of Net Project Benefits and Costs Over the Service Life (5.4.5.2.C.a.vii-2)
n/a</td></tr>
</table>

Category-specific requirements for System Access Projects (5.4.5.2.C.a)	
	- Cost and Benefit of a Project Configured Solely to Meet the Obligation(5.4.5.2.C.a.vii-2.i)
	n/a
	- Cost and Benefit of this Project in Comparison to the Above (5.4.5.2.C.a.vii-2.ii)
	n/a
	- Cost and Benefit of this Project in the Context of Technically Feasible Options (5.4.5.2.C.a.vii-2.ii.a)
	n/a
	Results of the 'Final Economic Evaluation' per section 3.2 of the DSC (5.4.5.2.C.a.viii)
	n/a
	Nature and Magnitude of the System Impacts, the Costs for System Modifications, and Cost Recovery Means (5.4.5.2.C.a.ix)
	System expansion, if required, to connect customers within this category is governed by InnPower Corporation's Conditions of Service.

Capital Project Summary

to meet
Ontario Energy Board
Filing Requirements
for
Electricity
Transmission
and
Distribution
Applications

Chapter 5
Section 4.5.2

Material Investments

2017 System Renewal Projects

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name **Base 1-B**

Project number: BASE 1-B **Budget Year:** 2017

Investment Category: System Renewal

Project Summary

This Project includes all unplanned repair and/or replacement of capital assets due to failure or imminent failure and costs for the repair/replacement of assets damaged during unreported accidents (jobs processed as "capital trouble calls").

Total capital and non-capitalized O&M costs (5.4.5.2.A.i)

	Historical Capital Costs					
	2012	2013	2014	2015	2016	
Total cost					$ 137,500	
Contributions					$ -	
Net cost					$ 137,500	
O&M expense					undetermined	

	Future Capital Costs					
	2017	2018	2019	2020	2021	
Total cost	$ 116,885	$ 122,725	$ 128,861	$ 135,304	$ 148,834	
Contributions	$ -	$ -	$ -	$ -	$ -	
Net cost	$ 116,885	$ 122,725	$ 128,861	$ 135,304	$ 148,834	
O&M expense	undetermined	undetermined	undetermined	undetermined	undetermined	

Customer Attachments and Load (5.4.5.2 A.ii)

The number of customer attachments and load is different for each specific project within the program. Due to the reactionary nature of these projects a detailed listing of individual projects is not available at this time.

Project Dates & Expenditure Timing (5.4.5.2.A.iii)

Start Date:	01-Jan-17				
In Service Date:	31-Dec-17				
Expenditure Timing	2017: Q1	2017: Q2	2017: Q3	2017: Q4	
	25%	25%	25%	25%	

Schedule Risks & Risk Mitigation (5.4.5.2.A.iv)

As these investments are done on an as-needed basis, the risk of completion will depend on finding resources to perform the work. Since most of the work pertains to emergency replacement, the risk of not completing the work is minimal.

Comparative Information on Expenditure from Equivalent Projects (5.4.5.2.A.v)

Please see table above

General Information on Project (5.4.5.2.A)	
	Total Capital and OM&A costs associated with REG investment (5.4.5.2.A.vi)
	There are no Capital and OM&A costs associated with REG investments
	Leave to Construct Approval (5.4.5.2.A.vii)
	An application for request a "Leave to Construct" is typically not required for work pertaining to damage replacement.
	Related Project Reference Material i.e. Images, Drawings and or Reference Material
	Line construction activities will follow InnPower's standards for distribution design and construction.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Project Name: Base 1-B
	Investment Benefits, measured against: Efficiency, Customer Value & Reliability (5.4.5.2.B.1)
	Main Driver (5.4.5.2.B.1.a-1):
	System Renewal
	- Main "Trigger" (5.4.5.2.B.1.a-1.1):
	Assets/asset systems at end of service life due to failure
	- Secondary "Triggers" (5.4.5.2.B.1.a-2.1): Assets/asset systems at end of service life due to failure risk or high performance risk
	Objective or Performance Target to be Achieved (5.4.5.2.B.1.a-3):
	Primary: Reliability;
	Additional: Safety, and Customer value
	Background information that ties in with Asset Management Process (5.4.5.2.B.1.a-3a):
	When replacing failed assets consideration is given to ensure that the new infrastructure meets current standards.
	Overview of Investment Prioritization Justification (5.4.5.2.B.1.b)
	The replacement of failed (in-service) assets are typically performed immediately, and therefore does not get processed through our prioritization methodology.
	Project Identification and Selection (5.4.5.2.B.1.b-1)
	These projects are driven from failure and require immediate replacement, hence, no specific project/job identification is required.
	Project Prioritization (5.4.5.2.B.1.b-2)
	Overall failure repairs/replacements receive a high priority.
	Project Pacing (5.4.5.2.B.1.b-3)
	Work schedule is generally determined by the timing (rate) of failure.
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)
	- Alternate Considerations - Design (5.4.5.2.B.1.c-1)
	Alternative designs are generally not considered as these projects require immediate replacement of the failed asset, and are replaced like-for-like.
	- Alternate Considerations - Schedule (5.4.5.2.B.1.c-2)
	Alternate schedule options are not generally considered, as these jobs require immediate replacement of damaged assets. Capital replacement works during storm restoration is prioritized based on our restoration prioritization methodology.
	- Alternate Considerations - Funding/Ownership (5.4.5.2.B.1.c-3)
	No alternatives are considered for funding such repair/replacement work.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Effect of Investment on System Operation Efficiency and Cost-Effectiveness (5.4.5.2.B.1.c.i)
	Not applicable due to like-for-like replacement.
	Net Benefits Accruing to Customers as a Result of the Investment (5.4.5.2.B.1.c.ii)
	When failed assets are replaced with new assets, designed to latest engineering standards, InnPower will likely see an improvement in its customer reliability performance. Timely repair/replacement of assets will reduce customer inconvenience due to prolonged and frequent outages and improve our customer experience and goodwill.
	Impact of the Investment on Reliability Performance including on the Frequency and Duration of Outages (5.4.5.2.B.1.c.iii)
	Timely replacement of damaged assets results in a reduction in outage duration which will impact the following metrics: (1) System Average Interruption Duration Index (SAIDI), (2) Customer Average Interruption Duration Index (CAIDI), and (3) Customers Experiencing Long Interruption Duration (CELID), in the near term. In the long term it will also result in a reduction in the number of outages, and have a positive impact on the following metrics: (1) System Average Interruption Frequency Index (SAIFI), and (2) Customers Experiencing Multiple Interruptions (CEMI), due to the installation of newer infrastructure built to latest engineering standards.
	Projected Improvement to SAIFI (System Average Interruption Frequency Index): Yes, but cannot be quantified due to the reactionary nature of these projects.
	Projected Improvement to SAIDI (System Average Interruption Duration Index): Yes, but cannot be quantified due to the reactionary nature of these projects.
	Impact of the Driver(s), "Trigger" or other, on the DESIGN of the Project (5.4.5.2.B.1.c-4)
	Although emergency replacement follows a "like-for-like" replacement strategy, we consider design enhancement or upgrading to a better standard where appropriate.
	Impact of the Driver(s), "Trigger" or other, on the COMPONENT CHARACTERISTICS of the Project (5.4.5.2.B.1.c-5)
	Although emergency replacement follows a "like-for-like" replacement strategy, we consider component characteristics enhancement where appropriate.
	Impact of the Driver(s), "Trigger" or other, on the WORK PLAN of the Project (5.4.5.2.B.1.c-6)
	Our work plan is determined by the urgency of the repair/replacement.
	Investment Benefits, measured against: Safety (5.4.5.2.B.2)
	With this project primarily driven by failure, and the replacement of a failed asset with a new asset, safety to the public is enhanced.
	Investment Benefits, measured against: Cyber-security, Privacy (5.4.5.2.B.3)
	Not applicable.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Investment Benefits, measured against: Co-ordination, Interoperability (5.4.5.2.B.4)
	Not applicable.
	Co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)
	In instances where our pole line accommodates third party attachments we will work closely with the renters to facilitate the moving of their infrastructure.
	Potential to Enable Future Technological Functionality (5.4.5.2.B.4.b-1)
	Not applicable.
	Potential to Address Future Operational Requirements (5.4.5.2.B.4.b-2)
	Not applicable.
	Investment Benefits, measured against: Economic Development (5.4.5.2.B.5)
	Not applicable.
	Investment Benefits, measured against: Environmental Benefits: (5.4.5.2.B.6)
	Not applicable.

Project Name: Base 1-B	
Category-specific requirements for System Renewal Investments (5.4.5.2.C.b)	
Category-Specific Requirements for System Renewal Projects (5.4.5.2.C.b)	**Description of the Characteristics of the Assets Targeted (5.4.5.2.C.b.i)**
	This program funds the replacement of assets that incur damage or unplanned failure or those that are about to fail, therefore the specific asset characteristics are not known during the budgeting process. However, typical assets replaced under this program include station equipment, poles, wires, and attending line or underground equipment and hardware.
	- Consequences of Asset Performance Deterioration or Failure
	Consequences of failure will vary depending on the nature and extent of each damage; the most common consequence is the loss of power to those served below the closest upstream interrupting device. InnPower routinely considers ways to minimize the impact and inconvenience to customers through the implementation of strategic switching options to enable sectionalization of the affected area and to perform step-restoration.
	Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)
	This project is reactive in nature and initiated by unforeseen causes which lead to failure of IPC's assets with the possibility of service interruptions. These unplanned interruptions will impact IPC's reliability targets. Overall asset performance and life cycle optimization is achieved during the replacement of damaged assets, through close adherence to InnPower's current engineering and operating standards.
	Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)
	Due to this project being reactive in nature, typical life cycle varies with each and every failure.
	- Performance Record of the Assets Targeted (5.4.5.2.C.b.i.2a)
	Varies, depending on the asset being replaced.
	Number of Customers Affected by given Asset Failure (5.4.5.2.C.b.i.3)
	Customers impacted by given failures varies case by case.

Category-Specific Requirements for System Renewal Projects (5.4.5.2.C.b)	
	Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)
	The quantitative customer impact by given failures varies case by case. The factors used for quantitative analysis of customer impact include: the number of customers affected due to power loss, and loss of revenue to commercial and industrial customers due to power loss. The risk to the quantitative measures of customer impact include reliability metrics, and other performance measures that quantify customer experience. InnPower routinely reviews its customer experience metrics including reliability metrics (System Average Interruption Duration Index (SAIDI), and System Average Interruption Frequency Index (SAIFI), these are included in InnPower's RRR report to the Ontario Energy Board) to identify areas that need improvement. InnPower is working towards further implementing routine outage data analytics for the early identification of problem areas through the introduction of the following metrics: Customers Experiencing Long Interruption Duration (CELID), and Customers Experiencing Multiple Interruptions (CEMI).
	Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)
	Replacement of damaged assets that cause power loss to customers requires prompt corrective work to restore power and reduce customer inconvenience. InnPower consistently looks for ways to improve customer experience during power loss; it works closely with municipal entities to achieve synergies through resources sharing to further enhance customer experience.
	Value of Customer Impact (5.4.5.2.C.b.i.6)
	Value of customer impact varies with each interruption or incident, depending on the nature.
	Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)
	With this project being reactive, replacements must be done when identified.
	Investment Intensity (Asset Replacement Rate; 5.4.5.2.C.b.ii.a):
	Varies based on the nature and the extent of damage.
	Project Priority Relative to Other Projects (5.4.5.2.C.b.ii.b)
	This project is non-discretionary and is not subjected to prioritization.
	Impact on System O&M Costs (5.4.5.2.C.b.iii)
	Although projects completed under this program are not intended to address O&M costs, the renewal of infrastructure will improve MTBF metrics (Mean Time Between Failure) of the assets replaced which will likely have a positive impact on O&M costs. The cost savings on O&M however cannot be calculated during budgeting as these are reactionary projects.
	- O&M Cost Impact of Not implementing Project
	Not applicable.

Category-Specific Requirements for System Renewal Projects (5.4.5.2.C.b)	**Impact on Reliability Performance and/or Safety Factors (5.4.5.2.C.b.iv)**
	Both reliability and safety are secondary benefits as older assets are being replaced.
	Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)
	As with most system renewal work the benefits of the project include: greater reliability, safety, and improved customer experience. The timing of the work is determined by the failure of the asset.
	Like for Like Renewal Analysis, Alternatives Comparison (like-for-like vs. not like- for-like, timing, rate of replacement, etc.). (5.4.5.2.C.b.vi)
	With the damage/failure or imminent failure of an asset the reactive replacement is typically done on a like-for-like basis. The timing is not a factor as this is a reactive project.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name: **Ewart Street Rebuild – Phased Approach**

Project number: DO 009 **Budget Year:** 2017

Investment Category: System Renewal

Project Summary:

This project will rebuild approximately 2 kilometers of the existing 3-phase pole line along Ewart Street in the Belle Ewart Area. There are a total of 53 poles in this section of line. This section also has a vital circuit tie between InnPower's Cedar Point F2 feeder and Lefroy F1 feeder at Switch No. S5006. None of the 53 poles meet current design requirements. Our current standard requires 3 phase poles to be a minimum 45 foot and class 3. 96% (all except 2) of the poles are 40 feet or shorter, with 10 poles 30 feet or shorter. 9 out of 10 poles would be 40 years or older in 2017.

Several poles in this section of line were listed in last year's Pole Testing report as needing immediate replacement.

As this area has a relatively high water table, over the years poles have sunk into the swamp lands. During the replacement of these poles additional technical design and field methods of cribbing and driving piles will be required to ensure that the poles and the anchors are securely installed.

During the Asset Condition Assessment a large sample of poles were inspected and 61% of the sample had an overall pole condition rating of either "significant deterioration" or "critical damage" requiring immediate remedial action. 83% of the sampled poles showed significant deterioration or critical damage to the top of the poles.

InnPower has given careful consideration to pacing the overall replacement over six years, with eleven poles planned for replacement in 2017.

Total capital and non-capitalized O&M costs (5.4.5.2.A.i)

	Historical Capital Costs				
	2012	2013	2014	2015	2016
Total cost					$101,790
Contributions					$ -
Net cost					$101,790
O&M expense					undetermined

	Future Capital Costs				
	2017	2018	2019	2020	2021
Total cost	$105,000	$ 50,000	$ 52,500	$ 56,700	$131,274
Contributions	$ -	$ -	$ -	$ -	$ -
Net cost	$105,000	$ 50,000	$ 52,500	$ 56,700	$131,274
O&M expense	undetermined	undetermined	undetermined	undetermined	undetermined

Customer Attachments and Load (5.4.5.2 A.ii)

Approximately 1 MW; however, since the pole line contains a circuit tie, during an outage potentially a large load up to 2.2 MW can be impacted.

General Information on Project (5.4.5.2.A)

Project Dates & Expenditure Timing (5.4.5.2.A.iii)

Start Date:	01-Jan-17			
In Service Date:	31-Dec-17			
Expenditure Timing	2017: Q1	2017: Q2	2017: Q3	2017: Q4
	70%	30%		

Schedule Risks & Risk Mitigation (5.4.5.2.A.iv)

For this project the completion schedule depends on timely design, approvals, obtaining locates and road occupancy permits, and arranging field crews with the proper equipment to work in areas of soft terrain as parts of the pole line are in swampy areas.

InnPower's project management process will address all these areas of concern to ensure timely completion.

Comparative Information on Expenditure from Equivalent Projects (5.4.5.2.A.v)

Material and Labour Estimating costs and project methodology from previous projects.

Total Capital and OM&A costs associated with REG investment (5.4.5.2.A.vi)

Not Applicable to this Project.

Leave to Construct Approval (5.4.5.2.A.vii)

Not Applicable to this Project.

General Information on Project (5.4.5.2.A)

Related Project Reference Material i.e. Images, Drawings and or Reference Material

Ewart Street Rebuild Project

General Information on Project (5.4.5.2.A)

Distribution Asset Condition Assessment - Ewart Street Sample Observations

The table below presents the conditions of the poles that were sampled - based on the condition rating outlined in the Distribution Asset Condition Assessment report.

Condition Rating	Corresponding Condition
A	Good; no problem
B	Normal aging
C	Fair; some deterioration
D	Fair-poor; significant deterioration
E	Bad; critical damage; remediation required

	POLE CONDITION		
	Overall Pole Condition	Pole Top Condition	Shell Condition
A	11%	11%	0%
B	0%	0%	0%
C	**28%**	**6%**	**42%**
D	**50%**	**72%**	**58%**
E	**11%**	**11%**	**0%**
	100%	100%	100%

The replacement of the poles on Ewart Street would have an added benefit to reliability and system performance. During the inspection the pole line hardware, primary conductor clearances and condition of connections were found to be in less than optimum condition as noted in the tables below.

	POLE LINE HARDWARE			PRIMARY CONDUCTOR	
	Visual Inspection	Corrosion /Rust	Condition of Bolts/Fasteners	Clearance from Finished Grade	Condition of Connection
A	17%	17%	0%	0%	0%
B	0%	0%	0%	0%	0%
C	**0%**	**0%**	**0%**	**21%**	**0%**
D	**50%**	**50%**	**100%**	**50%**	**100%**
E	**33%**	**33%**	**0%**	**29%**	**0%**
	100%	100%	100%	100%	100%

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Project Name: Ewart Street Rebuild
	Investment Benefits, measured against: Efficiency, Customer Value & Reliability (5.4.5.2.B.1)
	Main Driver (5.4.5.2.B.1.a-1):
	System Renewal.
	- Main "Trigger" (5.4.5.2.B.1.a-1.1):
	Assets/asset systems at end of service life due to failure risk.
	Secondary Driver (5.4.5.2.B.1.a-2):
	System Renewal.
	- Secondary "Trigger" (5.4.5.2.B.1.a-2.1):
	Assets/asset systems at end of service life due to high performance risk.
	Objective or Performance Target to be Achieved (5.4.5.2.B.1.a-3):
	Primary: Reliability; Secondary: Customer value.
	Additional: Co-ordination, Interoperability and Safety
	Background information that ties in with Asset Management Process (5.4.5.2.B.1.a-3):
	This project meets the objectives of ensuring public and worker safety, maintaining system reliability, and managing costs, which are part of InnPower's Asset Management Process objectives.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Overview of Investment Prioritization Justification (5.4.5.2.B.1.b)
	Prioritization based on assets that require attention as a result of ACA Inspection and Annual Pole Inspection Program.
	Project Identification and Selection (5.4.5.2.B.1.b-1)
	This project was identified based on a variety of factors: crew observation of sinking poles due to placement of poles on swamp land; restricted access to work on pole line (impairing outage restoration during most of the year); results from routine pole testing; and identification (flagging) of poles during the 2015 Asset Condition Assessment inspection.
	Project Prioritization (5.4.5.2.B.1.b-2)
	High Priority, using the Asset Management Process based evaluation.
	Project Pacing (5.4.5.2.B.1.b-3)
	This project has been paced over 6 years to reduce its impact on the capital budget.
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)
	- Alternate Considerations - Design (5.4.5.2.B.1.c-1)
	Not applicable to this project as the project is a like for like replacement.
	- Alternate Considerations - Schedule (5.4.5.2.B.1.c-2)
	Schedule is coordinated with locates and approval of other agencies.
	- Alternate Considerations - Funding/Ownership (5.4.5.2.B.1.c-3)
	Project is funded entirely by InnPower.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Effect of Investment on System Operation Efficiency and Cost-Effectiveness (5.4.5.2.B.1.c.i)
	The infrastructure will be upgraded to current standards and will improve reliability. Since this section of circuitry has a backbone (trunk line) circuit tie between two main circuits serving the area, the newer and more reliably built infrastructure will be more dependable during storms.
	Net Benefits Accruing to Customers as a Result of the Investment (5.4.5.2.B.1.c.ii)
	Avoid system interruptions and increase reliability due to upgrading old infrastructure. The pole line sinking into the ground has caused concern over line clearances and this will be addressed during the pole replacement.
	Impact of the Investment on Reliability Performance including on the Frequency and Duration of Outages (5.4.5.2.B.1.c.iii)
	Increase reliability of the system and reduction in the duration of outages through replacement of aged assets. Our current Outage Management System (OMS) is not robust enough to report predictions in reliability improvement, hence, the specific improvement to SAIDI and SAIFI have not been presented below. InnPower is looking into enhancing its OMS database and software functionality to include the option to perform such analysis.
	Projected Improvement to SAIFI (System Average Interruption Frequency Index): *see comments above.*
	Projected Improvement to SAIDI (System Average Interruption Duration Index): *see comments above.*
	Impact of the Driver(s), "Trigger" or other, on the DESIGN of the Project (5.4.5.2.B.1.c-4)
	InnPower will be designing the line using a like for like replacement strategy.
	Impact of the Driver(s), "Trigger" or other, on the COMPONENT CHARACTERISTICS of the Project (5.4.5.2.B.1.c-5)
	Components are selected based on current approved materials list and specific design for the project, which are both reviewed and approved by a professional engineer.
	Impact of the Driver(s), "Trigger" or other, on the WORK PLAN of the Project (5.4.5.2.B.1.c-6)
	The work plan will be arranged to target the poles identified in the Pole Testing report as a priority. The plan will also include contingency plans to improve truck access to the existing pole line.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Investment Benefits, measured against: Safety (5.4.5.2.B.2)
	Safety will be enhanced by: replacing end of life poles; addressing primary line clearance issues caused by sinking poles; improved overall reliability.
	Investment Benefits, measured against: Cyber-security, Privacy (5.4.5.2.B.3)
	This project will not compromise cyber security or privacy.
	Investment Benefits, measured against: Co-ordination, Interoperability (5.4.5.2.B.4)
	The work will be coordinated with third party attachment companies. InnPower will also coordinate this work with a local Jewish community who have their ERUV line mounted on this pole line, to ensure their religious routines are not negatively impacted by this pole work.
	Co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)
	Co-ordinated with utilities - 3rd party attachments (Bell and Rogers).
	Potential to Enable Future Technological Functionality (5.4.5.2.B.4.b-1)
	Not applicable to this project.
	Potential to Address Future Operational Requirements (5.4.5.2.B.4.b-2)
	Additional switches / cutouts to permit additional sectionalizing of system during emergency conditions.
	Investment Benefits, measured against: Economic Development (5.4.5.2.B.5)
	Not applicable to this project.
	Investment Benefits, measured against: Environmental Benefits: (5.4.5.2.B.6)
	Not applicable to this project.

Project Name: Ewart Street Rebuild	
Category-specific requirements for System Renewal Investments (5.4.5.2.C.b)	
Category-Specific Requirements for System Renewal Projects (5.4.5.2.C.b)	**Description of the Characteristics of the Assets Targeted (5.4.5.2.C.b.i)**
	Assets to be replaced in this project include: All components of distribution primary pole line construction i.e. poles, cross arms, conductors, pin type insulators, tie switch, open bus secondary, polemounted transformers, service connections etc.
	- Consequences of Asset Performance Deterioration or Failure
	Localized outages within urbanized areas in Belle Ewart. Inability to make use of the circuit tie switch that enables InnPower to better manage outage restoration or planned work in a timely manner. Increase capital expenses and longer restoration time to replace failed assets in swamp land if the poles were to fail during most of the year when the water table would restrict access to our crews and their equipment.
	Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)
	Assets have performed as originally designed and have had years of life as expected from these types of assets.
	Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)
	Have achieved or exceeded typical life cycle of asset.
	- Performance Record of the Assets Targeted (5.4.5.2.C.b.i.2a)
	Assets have performed as originally design.
	Number of Customers Affected by given Asset Failure (5.4.5.2.C.b.i.3)
	Varies as to the degree of outage and assets affected; total customers served by this pole line is approximately 250. However, if the asset failure impacts the ability to use the tie switch, depending on the extent of sectionalization required, up to 700 customers can get affected.
	Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)
	Varies as to the degree of outage and assets affected. Approximately 250 customers are served by this pole line. During access restriction if a single outage was to last three days, this outage (to 250 customers) would worsen InnPower's SAIDI by 1.125.
	Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)
	Duration of outage varies depending upon the asset that has failed; as this area is very close to Innisfil's water front the summer time gets very busy with beach goers visiting the area. A outage to this line would negatively affect customer experience.

Category-Specific Requirements for System Renewal Projects (5.4.5.2.C.b)	**Value of Customer Impact (5.4.5.2.C.b.i.6)**
	Depend upon type of asset failure and the number of customers connected. An exact monetary value for the impact was not calculated.
	Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)
	Availability of resources and materials or acceleration of asset failure or eminent asset failure.
	Investment Intensity (Asset Replacement Rate; 5.4.5.2.C.b.ii.a):
	Low for like for like replacement.
	Project Priority Relative to Other Projects (5.4.5.2.C.b.ii.b)
	Medium priority; scheduled for Q1 and Q2 of the year.
	Impact on System O&M Costs (5.4.5.2.C.b.iii)
	Additional switching / cost of crews would be required with increased number of outages due to aged assets.
	- O&M Cost Impact of Not implementing Project
	Overall cost impact would be minor.
	Impact on Reliability Performance and/or Safety Factors (5.4.5.2.C.b.iv)
	New assets would reduce outages due to failures and improve system reliability.
	Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)
	Outage mitigation if project is completed prior to asset failure.
	Like for Like Renewal Analysis, Alternatives Comparison (like-for-like vs. not like-for-like, timing, rate of replacement, etc. (5.4.5.2.C.b.vi)
	Typical installation is like for like replacement to current utility standard.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name: Infrastructure Replacements and Betterments

Project number: DO 004 **Budget Year:** 2017

Investment Category: System Renewal

Project Summary

Infrastructure Betterments for 2017 are as follows: Replace suspect porcelain dead end bells within distribution system. Secondary buss replacement. Replace rotting wood cross arms. Replace defective in-line sub-transmission switches (44kV), and distribution switches (27.6 kV and 8.32 kV) and distribution cut-outs. Replace 44kV arrestors that were installed to an old standard that resulted in multiple failures.

Total capital and non-capitalized O&M costs (5.4.5.2.A.i)

	Historical Capital Costs				
	2012	2013	2014	2015	2016
Total cost	$163,797	$181,259	$156,029	$185,862	$ 143,098
Contributions	$ -	$ -	$ -	$ -	$ -
Net cost	$163,797	$181,259	$156,029	$185,862	$143,098
O&M expense	Undetermined				

	Future Capital Costs				
	2017	2018	2019	2020	2021
Total cost	$150,253	$157,766	$165,654	$173,936	$182,633
Contributions	$ -	$ -	$ -	$ -	$ -
Net cost	$150,253	$157,766	$165,654	$173,936	$182,633
O&M expense	Undetermined				

Customer Attachments and Load (5.4.5.2 A.ii)

The customer attachments and load impacted by this project will vary depending on the location and type of assets that are being replaced.

Project Dates & Expenditure Timing (5.4.5.2.A.iii)

Start Date:	01-Jan-17			
In Service Date:	31-Dec-17			
Expenditure Timing	2017: Q1	2017: Q2	2017: Q3	2017: Q4
	30%	35%	25%	10%

Schedule Risks & Risk Mitigation (5.4.5.2.A.iv)

Timely consultation among the design and constructions teams to ensure proper resource allocation assist in ensuring the work is done on schedule. Should a lack of resource be identified as a challenge to timely project completion InnPower will use outside resources, both engineering and line contractors, to complete the work.

General Information on Project (5.4.5.2.A)	
	Comparative Information on Expenditure from Equivalent Projects (5.4.5.2.A.v)
	Please see above table for comparative information on equivalent projects completed in the past 5 years.
	Total Capital and OM&A costs associated with REG investment (5.4.5.2.A.vi)
	This project will not impact the capital and OM&A costs associated with REG investment.
	Leave to Construct Approval (5.4.5.2.A.vii)
	Not required for this project.
	Related Project Reference Material i.e. Images, Drawings and or Reference Material
	N/A

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Project Name Infrastructure Replacements and Betterments
	Investment Benefits, measured against: Efficiency, Customer Value & Reliability (5.4.5.2.B.1)
	Main Driver (5.4.5.2.B.1.a-1):
	System Renewal
	- Main "Trigger" (5.4.5.2.B.1.a-1.1):
	Assets/asset systems at end of service life due to failure risk.
	Secondary Driver (5.4.5.2.B.1.a-2):
	None
	- Secondary "Trigger" (5.4.5.2.B.1.a-2.1):
	Assets/asset systems at end of service life due to substandard performance.
	Objective or Performance Target to be Achieved (5.4.5.2.B.1.a-3):
	Primary: Reliability; Secondary: Customer value.
	Additional: Safety
	Background information that ties in with Asset Management Process (5.4.5.2.B.1.a-3.i):
	Maintaining system reliability is one of the criteria noted in the Asset Management plan.
	Overview of Investment Prioritization Justification (5.4.5.2.B.1.b)
	Based on the description for Asset Management objectives noted in our Asset Management Plan.
	Project Identification and Selection (5.4.5.2.B.1.b-1)
	Work performed under this project is identified and selected based on: Operations crew's observations in regards to asset deterioration, failure rate of assets, Asset Condition Assessment Report, OMS data analysis (future), industry/peer experiences with specific assets, and information published in ESA Bulletins.
	Project Prioritization (5.4.5.2.B.1.b-2)
	Medium. Projects are prioritized based on InnPower's Asset Management Process.
	Project Pacing (5.4.5.2.B.1.b-3)
	The strategy used over the past few years to address system issues such as deteriorating infrastructure through diligent planning and investment to address the main causes for system failure has resulted in InnPower maintaining its reliability performance at acceptable levels. InnPower will continue to implement careful assessment of asset condition to optimize investment. Such preplanning will enable the work to be paced evenly.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)
	- Alternate Considerations - Design (5.4.5.2.B.1.c-1)
	Alternate designs are routinely considered in replacing or upgrading assets under this project: In addressing the problem with 44kV arrestor design InnPower reviewed various design options to arrive at the optimal design to ensure long term reliability. InnPower has explored the use of Fiber cross arms to improve reliability and to increase life span. The ergonomic design will assist line crews during cross arm installation as it increases field safety, as the alternate (steel) is much heavier and poses a threat to worker safety.
	- Alternate Considerations - Schedule (5.4.5.2.B.1.c-2)
	Jobs that fall under this category are planned and scheduled to optimize both engineering and field resources.
	- Alternate Considerations - Funding/Ownership (5.4.5.2.B.1.c-3)
	InnPower will fund this project.
	Effect of Investment on System Operation Efficiency and Cost-Effectiveness (5.4.5.2.B.1.c.i)
	New improved switches are more dependable over the long term and hence improves system operating efficiency.
	Net Benefits Accruing to Customers as a Result of the Investment (5.4.5.2.B.1.c.ii)
	Proactively identifying and replacing problem assets improve customers experience due to reduce outages.
	Impact of the Investment on Reliability Performance including on the Frequency and Duration of Outages (5.4.5.2.B.1.c.iii)
	The replacement of deteriorating cross arms, switches, and dead end bells will help stabilize, if not reduce, the frequency of outages. The impact on specific reliability indices has not been calculated.
	Projected Improvement to SAIFI (System Average Interruption Frequency Index): *Not calculated*
	Projected Improvement to SAIDI (System Average Interruption Duration Index): *Not calculated*
	Impact of the Driver(s), "Trigger" or other, on the DESIGN of the Project (5.4.5.2.B.1.c-4)
	In addressing failure risk we typically perform a root cause analysis to analyze the failure modes and therefore the new design takes into consideration the root cause and strives to prevent future failure through improved design; example: 44kV arrestor failure and replacement project.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Impact of the Driver(s), "Trigger" or other, on the COMPONENT CHARACTERISTICS of the Project (5.4.5.2.B.1.c-5)
	In the root causes analysis process component characteristics are reviewed to ascertain if improved features need to be considered in the new devices to be installed. Example: Porcelain dead end bell replacement project: we replaced with silicone polymer type suspension insulators or insulated strain rods.
	Impact of the Driver(s), "Trigger" or other, on the WORK PLAN of the Project (5.4.5.2.B.1.c-6)
	InnPower schedules the work plan based on internal collaboration to ensure in-house resources can be used as much as possible to reduce cost; however, outside contracting options are considered to ensure our committed needs are met.
	Investment Benefits, measured against: Safety (5.4.5.2.B.2)
	Reduce risk of flash over, crew safety when operating switches; to prevent frequent failure during switching operation.
	Investment Benefits, measured against: Cyber-security, Privacy (5.4.5.2.B.3)
	N/A
	Investment Benefits, measured against: Co-ordination, Interoperability (5.4.5.2.B.4)
	Co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)
	Through our participation in industry organization including the ESA, EDA, CHEC group, and USF, we are able to share information with other utilities to assist others to proactively work towards improving safety, reliability and system performance.
	Potential to Enable Future Technological Functionality (5.4.5.2.B.4.b-1)
	N/A
	Potential to Address Future Operational Requirements (5.4.5.2.B.4.b-2)
	Replacing switches prone to frequent failure assist our operating crews to operate system.
	Investment Benefits, measured against: Economic Development (5.4.5.2.B.5)
	N/A
	Investment Benefits, measured against: Environmental Benefits: (5.4.5.2.B.6)
	N/A

Project Name Infrastructure Replacements and Betterments	
Category-specific requirements for System Renewal Investments (5.4.5.2.C.b)	
Category-Specific Requirements for System Renewal Projects (5.4.5.2.C.b)	**Description of the Characteristics of the Assets Targeted (5.4.5.2.C.b.i)**
	This project addresses a wide variety of issues throughout InnPower's sub-transmission and distribution system. The assets targeted during 2017 and in the years following include: (1) Porcelain dead end bells. These cause frequent flash over due to fracture and chip. They also collect contaminants (not self cleaning) which contribute to tracking of current, which can result in flash over and pole fires. (2) Secondary buss. The secondary busses that were installed many years ago had jackets that are peeling off, which fall off the cable over time and cause uninsulated bare spots on the wires. (3) Replace rotting wood cross arms. (4) Replace defective in-line 44kV, 27.6 kV and 8.32 kV switches and distribution cut-outs: Failure modes include the seizure of contacts which make them inoperable. (5) Replace 44kV arrestors: These were installed to an old standard where the arrestor broke off at the attachment point.
	- Consequences of Asset Performance Deterioration or Failure
	Fault conditions on the circuit and therefore tripping overcurrent devices. Asset life is also compromised.
	Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)
	Since InnPower inherited its assets from Ontario Hydro it did not have specific installation data including the age of assets; however, based on the high failure rate of some of the components noted above such assets were at the end of their life and therefore the implementation of this project was timely, and the continued investment over for the next 5 years will enable InnPower to meet its performance goals.
	Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)
	Based on the unavailability of installation year data InnPower is unable to provide conclusive information on life cycle, however, detail condition based assessment process enables InnPower to project remaining life for asset category and plan accordingly.
	- Performance Record of the Assets Targeted (5.4.5.2.C.b.i.2a)
	The planning process took into consideration field observation, failure rates, and Asset Inspection logs. However, due to the lack of detail historical records on the performance of some of these assets InnPower is planning on implementing an Outage Management System based performance tracking process that is intended to enable detail performance information in the future.

Category-Specific Requirements for System Renewal Projects (5.4.5.2.C.b)	
	Number of Customers Affected by given Asset Failure (5.4.5.2.C.b.i.3)
	Various
	Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)
	The projects targeted by this program include both sub-transmission and distribution systems and therefore have an impact on a large customer base. However, it is not isolated to a particular circuit and therefore the exact customer benefits cannot be readily ascertained.
	Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)
	The timely replacement of deteriorating assets noted above will help stabilize, if not improve, InnPower performance, which will help improve overall customer experience.
	Value of Customer Impact (5.4.5.2.C.b.i.6)
	Although InnPower does not have a formal process at the moment to calculate the cost of failure to the various customer classes, It does have a list of critical customers and both industrial and commercial customers, which is used in the decision making process in project selection and prioritization.
	Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)
	Other factors that influence the timing of the projects include: feedback from customers, new evidence of deteriorating assets (through the infrared scanning program, or line inspection program) that would indicate a higher level of failure risk that previously calculated, evidence from outage records indicated a high failure risk, other line rebuild work planned for the area for large scale reliability upgrade or capacity increase that could be combined to reduce cost.
	Investment Intensity (Asset Replacement Rate; 5.4.5.2.C.b.ii.a):
	As this is a medium priority project the rate of asset replacement is determined by the risk posed by individual asset category, and the number of assets that need to be replaced (system wide). However, given InnPower preplanning process the intensity is spread out evenly over the five year forecast period.
	Project Priority Relative to Other Projects (5.4.5.2.C.b.ii.b)
	This is a medium priority project.
	Impact on System O&M Costs (5.4.5.2.C.b.iii)
	Historically InnPower has not tracked repair costs for specific assets types and vintages - the anticipated reduction in asset failures however is expected to have a positive impact on system O&M costs.

<table>
<tr><td rowspan="6">Category-Specific Requirements for System Renewal Projects(5.4.5.2.C.b)</td><td>Impact on Reliability Performance and/or Safety Factors (5.4.5.2.C.b.iv)</td></tr>
<tr><td>The replacing of deteriorated assets prior to failure will improve safety for public and workers, and contributed to stabilizing, if not improving, reliability performance.</td></tr>
<tr><td>Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)</td></tr>
<tr><td>This project has been planned to optimize customer benefits for reliable power. This project will enhance overall reliability including storm resilience, and provide system flexibility for future upgrades (it is preferred to add components to a well built and reliable infrastructure).

The well planned and paced out schedule will reduce large one-time expenses for system-wide corrective work, and reduce rate-shock to customers.</td></tr>
<tr><td>Like for Like Renewal Analysis, Alternatives Comparison (like-for-like vs. not like-for-like, timing, rate of replacement, etc. (5.4.5.2.C.b.vi)</td></tr>
<tr><td>Like for like replacement strategy is not the preferred option taken into consideration for this type of work. Instead, InnPower seeks to enhance both design and component characteristics in the most cost efficient manner to ensure overall system performance is improved.</td></tr>
</table>

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name: **Pole Replacement Program**

Project number: DO 003 **Budget Year:** 2017

Investment Category: System Renewal

Project Summary:

There are approximately 10210 wood poles employed on InnPower's electricity distribution system. A sample of 5321 poles were tested between 2013 and 2015. Approximately 15% of the tested poles have been in service for over 40 years and about 33% are now older than their typical service life of 50 years. Together, almost half of the tested poles have reached 40 years of service life.

This project involves the replacement of wood poles identified by pole testing as having a high risk of failure. All poles receive a visual, sound, divot (where diggable) tests, as well as a Resistograph test.

The consultant who performed the Asset Condition Assessment on wooden poles provided a recommendation to replace 106 wood poles in very poor condition and 328 in poor condition in 2017. After 2017, it was recommended to allocate capital budget for replacing 304 poles per year between 2018 and 2021.

Total capital and non-capitalized O&M costs (5.4.5.2.A.i)

	Historical Capital Costs				
	2012	2013	2014	2015	2016
Total cost	$446,005	$395,175	$401,651	$114,432	$200,914
Contributions	$ -	$ -	$ -	$ -	$ -
Net cost	$446,005	$395,175	$401,651	$114,432	$200,914
O&M expense	Undetermined				

	Future Capital Costs				
	2017	2018	2019	2020	2021
Total cost	$126,470	$148,500	$155,925	$163,721	$171,907
Contributions	$ -	$ -	$ -	$ -	$ -
Net cost	$126,470	$148,500	$155,925	$163,721	$171,907
O&M expense	Undetermined				

Customer Attachments and Load (5.4.5.2 A.ii)

Various. During this program poles in multiple locations are replaced, and therefore customer attachment and loads cannot be readily reported during the budgeting period.

Project Dates & Expenditure Timing (5.4.5.2.A.iii)

Start Date:	01-Jan-17			
In Service Date:	31-Dec-17			
Expenditure Timing	2017: Q1	2017: Q2	2017: Q3	2017: Q4
	25%	25%	25%	25%

General Information on Project (5.4.5.2.A)	
	Schedule Risks & Risk Mitigation (5.4.5.2.A.iv)
	Factors that affect the schedule of the pole replacement program include pole and other attending equipment lead times, engineering design and approval, crew and field equipment availability, and third party cooperation (for hydro vacuuming services, locating services, road occupancy permitting, and municipal or other approval agency consents as required). Each of the above entities have the potential to pose a risk to the timely work completion. InnPower mitigates these risks through the planning process which includes close communication with all parties involved, and thorough schedule risk assessment throughout the project planning and execution phases. InnPower also uses the option to employ contractors for both engineering design and approval, and field labour to meet scheduling requirements.
	Comparative Information on Expenditure from Equivalent Projects (5.4.5.2.A.v)
	Expenditure from the previous years have been presented in the table above.
	Total Capital and OM&A costs associated with REG investment (5.4.5.2.A.vi)
	This project is not associated with an REG investment and therefore OM&A costs related to REG will not be incurred.
	Leave to Construct Approval (5.4.5.2.A.vii)
	This project does not require "Leave to Construct" under Section 92 of the Ontario Energy Board Act 1998.

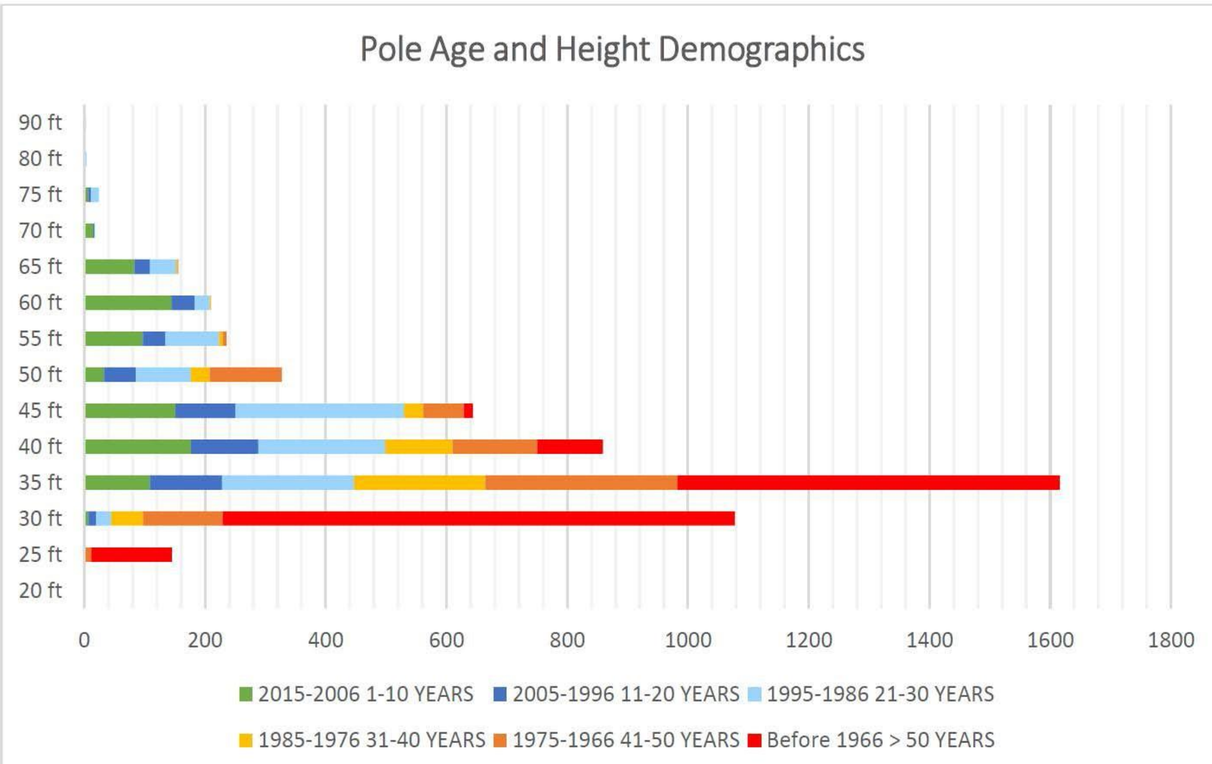
General Information on Project (5.4.5.2.A)

Related Project Reference Material i.e. Images, Drawings and or Reference Material

TYPICALLY LIKE FOR LIKE REPLACEMENT USING CURRENT CONSTRUCTION STANDARD PRACTICES

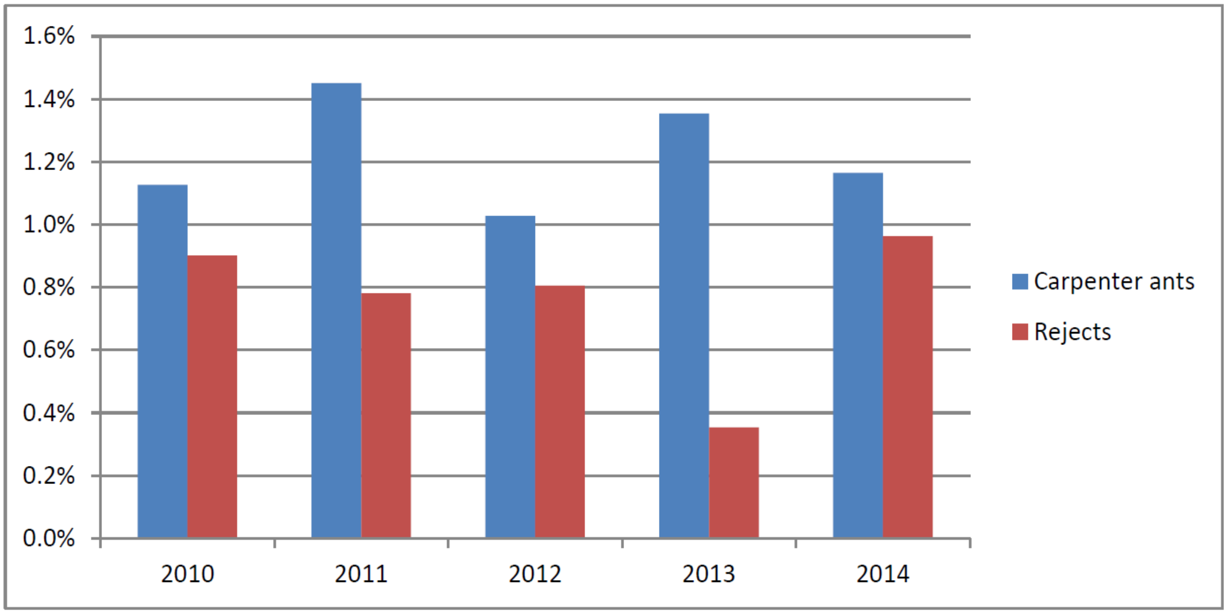
Wood Pole Demographic Information

Pole Material	Sample Size	Asset Age (in years)					
		2015-2006	2005-1996	1995-1986	1985-1976	1975-1966	Before 1966
	#	1-10	11-20	21-30	31-40	41-50	>50
Wood	5321	828	503	1001	455	794	1740



General Information on Project (5.4.5.2.A)

Pole Testing Data Summary: Percent Reject Poles and Percent Carpenter Ant Infestation



Further detailed information on the Asset Demographics and Condition Assessment of wooden poles is presented in Section 4.1.1 of the Distribution Asset Condition Assessment Report (Appendix E)

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Project Name Pole Replacement Program
	Investment Benefits, measured against: Efficiency, Customer Value & Reliability (5.4.5.2.B.1)
	Main Driver (5.4.5.2.B.1.a-1):
	System Renewal.
	- Main "Trigger" (5.4.5.2.B.1.a-1.1):
	Assets/asset systems at end of service life due to failure risk.
	- Secondary "Trigger" (5.4.5.2.B.1.a-2.1): None
	Objective or Performance Target to be Achieved (5.4.5.2.B.1.a-3):
	Primary: Reliability
	Additional Safety
	Background information that ties in with Asset Management Process (5.4.5.2.B.1.a-4):
	This project meets the objectives of ensuring public and worker safety, maintaining system reliability, and managing costs, which are part of InnPower's Asset Management Process objectives.
	Overview of Investment Prioritization Justification (5.4.5.2.B.1.b)
	Annual Wood Pole Testing and Asset Condition Assessment identifies worst condition poles within the system.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Project Identification and Selection (5.4.5.2.B.1.b-1)
	Poles to be replaced under this program are identified through the annual Pole Inspection Program.
	Project Prioritization (5.4.5.2.B.1.b-2)
	Poles identified to be replaced are prioritized based on prioritization method stated in the Asset Management Process (AMP).
	Project Pacing (5.4.5.2.B.1.b-3)
	InnPower's annual testing program and systematic and routine follow up to ensure the "rejected" poles are replaced in a timely manner help maintain a well-paced asset replacement schedule.
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)
	- Alternate Considerations - Design (5.4.5.2.B.1.c-1)
	For sub-transmission and primary distribution lines InnPower typically uses a like-for-like replacement methodology, except where the pole design needs to be upgraded to meet current engineering design standards. In such situations the pole is designed to the improved standard. For Service Stub Pole replacement consideration is given to converting overhead infrastructure to underground with the option presented to the residents for their input and contribution.
	- Alternate Considerations - Schedule (5.4.5.2.B.1.c-2)
	Generally poles listed on the "reject" list need to be replaced in the short term. As such it is not advised that such work be postponed; however, InnPower looks to reduce the possibility of re-work by collaborating such pole replacement work with the designers of pole line upgrade projects that have been planned in the area to combine the work into a single project.
	- Alternate Considerations - Funding/Ownership (5.4.5.2.B.1.c-3)
	N/A

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Effect of Investment on System Operation Efficiency and Cost-Effectiveness (5.4.5.2.B.1.c.i)
	Pro-active replacement which is routinely performed during regular business hours is often a more cost effective way of replacing a pole compared to waiting until its failure. We expect our well managed pole inspection and replacement program to result in better storm response and stable reliability performance.
	Net Benefits Accruing to Customers as a Result of the Investment (5.4.5.2.B.1.c.ii)
	System Reliability and Outage Mitigation.
	Impact of the Investment on Reliability Performance including on the Frequency and Duration of Outages (5.4.5.2.B.1.c.iii)
	Timely and pro-active replacement of poles at the end of their lives will help better manage outages caused by pole failure, stabilizing reliability performance which are measured by both the outage frequency and outage duration metrics. Since the poles to be replaced are re-active in nature, depending of the results obtained each year, specific SAIDI and SAIFI predictions were not calculated.
	Projected Improvement to SAIFI (System Average Interruption Frequency Index): *See comment above.*
	Projected Improvement to SAIDI (System Average Interruption Duration Index): *See comment above.*
	Impact of the Driver(s), "Trigger" or other, on the DESIGN of the Project (5.4.5.2.B.1.c-4)
	Design is the same, except where required to bring installation to current standards, as typically it is like for like replacement.
	Impact of the Driver(s), "Trigger" or other, on the COMPONENT CHARACTERISTICS of the Project (5.4.5.2.B.1.c-5)
	Component are to current InnPower standards and specifications.
	Impact of the Driver(s), "Trigger" or other, on the WORK PLAN of the Project (5.4.5.2.B.1.c-6)
	The work plan, triggered by the need to replace asset at the end of service life due to failure risk, is developed and executed in collaboratively with stakeholders in a manner that will minimize cost and risk.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	**Investment Benefits, measured against: Safety (5.4.5.2.B.2)**
	This project will provide reliability and safety benefits as the project involves the replacement of wood poles that are at risk of failure.
	Investment Benefits, measured against: Cyber-security, Privacy (5.4.5.2.B.3)
	Cyber-Security and Privacy are not applicable to this project.
	Investment Benefits, measured against: Co-ordination, Interoperability (5.4.5.2.B.4)
	Co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)
	Pole replacements coordinated with all utilities, regional planning and / or links with 3rd Parties.
	Potential to Enable Future Technological Functionality (5.4.5.2.B.4.b-1)
	Not applicable with this project.
	Potential to Address Future Operational Requirements (5.4.5.2.B.4.b-2)
	Consideration is given to the sizing of new poles in height and class to plan ahead for any requirements for future line re-build projects.
	Investment Benefits, measured against: Economic Development (5.4.5.2.B.5)
	InnPower ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within it communities.
	Investment Benefits, measured against: Environmental Benefits: (5.4.5.2.B.6)
	Not applicable with this project.

Project Name Pole Replacement Program	
Category-specific requirements for System Renewal Investments (5.4.5.2.C.b)	
Category-Specific Requirements for System Renewal Projects (5.4.5.2.C.b)	**Description of the Characteristics of the Assets Targeted (5.4.5.2.C.b.i)**
	Wood poles used in the sub-transmission, and distribution systems (primary and secondary/service) that have been identified for replacement under the pole inspection program.
	- Consequences of Asset Performance Deterioration or Failure
	Customer interruption and safety concern shall pole failure result.
	Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)
	This project is reactive in nature and the work required is initiated through InnPower's pole inspection program. This project has a very high probability of impacting InnPower's reliability targets if the poles are not replaced. InnPower uses inspection data, not replying solely on the age of the poles, thus looking for ways to optimize the asset's life.
	Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)
	This project address wood poles that have been identified as having a high risk of failure and as such, these assets are at the end of their useful life. The asset condition relative to their typical life cycle varies in case.
	- Performance Record of the Assets Targeted (5.4.5.2.C.b.i.2a)
	These assets usually perform as expected providing 40 - 50 years of life, except when affected by woodpecker, termites, and ants, or other factors such as damage caused by vehicular contact, burns caused by electrical tracking, and adverse weather conditions including lightning strike.

Category-Specific Requirements for System Renewal Projects (5.4.5.2.C.b)	
	Number of Customers Affected by given Asset Failure (5.4.5.2.C.b.i.3)
	The number of customers impacted varies in each incident or outage depending upon feeder circuits attached.
	Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)
	The quantitative customer impact varies in each incident or outage.
	Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)
	These projects address customer satisfaction as they are required to address assets at risk of failure which would result in a service interruption or safety issues.
	Value of Customer Impact (5.4.5.2.C.b.i.6)
	The value of the customer impact varies in each incident or outage.
	Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)
	Pole inspection program identifies poles requiring immediate replacement. Once a pole is selected the factors affecting timing is primarily engineering approvals for the design and coordinating pole and component delivery and crew coordination. However, in some instances third party cooperation needs to be arranged to complete projects in a timely manner. These include: hydro vacuuming services, locating services, road occupancy permits, and municipal or other approval agency consents.
	Investment Intensity (Asset Replacement Rate; 5.4.5.2.C.b.ii.a):
	Budget is established based on historical annual number of replacements as per Pole Inspection Program and estimating based on material and labour rates.

Category-Specific Requirements for System Renewal Projects (5.4.5.2.C.b)	
	Project Priority Relative to Other Projects (5.4.5.2.C.b.ii.b)
	Due to asset failure and potential outages - poles identified for immediate replacement take priority and are replaced as soon as possible and the availability of resources.
	Impact on System O&M Costs (5.4.5.2.C.b.iii)
	These projects do not materially impact system O&M costs.
	- O&M Cost Impact of Not implementing Project
	None
	Impact on Reliability Performance and/or Safety Factors (5.4.5.2.C.b.iv)
	This project will provide reliability and safety benefits as the project involves the replacement of wood poles that are at risk of failure. Failure of the asset would result in a service interruption and a potential risk to public safety.
	Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)
	Poles identified for replacement present a risk to public safety and are scheduled for the budget year.
	Like for Like Renewal Analysis, Alternatives Comparison (like-for-like vs. not like-for-like, timing, rate of replacement, etc.) (5.4.5.2.C.b.vi)
	Poles are typically replaced on like for like basis (and where necessary bring the installation up to current standards), unless through field visit it is determined that there is a better and more cost effective manner in replacing identified end of life wood poles.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name: **Reliability Rebuild: Distribution - Cookstown**

Project number: DO 012-a **Budget Year:** 2017

Investment Category: System Renewal

Project Summary:

This project will rebuild approximately 44 poles in the Cookstown area over a five year period. There are a total of approximately 720 poles in the Cookstown area.

The residents of Cookstown are served by a Hydro One owned distribution station (Cookstown West DS), and InnPower owns and operates two feeders from this station: feeders F2 and F4. The peak load of both feeders together is approximately 1.4MW.

During the Distribution Asset Condition Assessment one in every three poles were inspected with a sample quantity of 244. Based on the rating system established for pole line assessment as noted in Section 3.2.1 and Table 12 "Wood Poles – Overall Pole Condition Grading" of the Distribution Asset Condition Assessment report included in our Distribution System Plan, 61 poles (9%) have been rated as having "significant deterioration" or "critical damage" requiring immediate remedial action. The five year budget noted below targets the replacement of 44 of these 61 poles, and these will be selected from the poles in the worst three quartiles.

InnPower has given careful consideration to pacing the overall replacement over five years, with four main line poles planned for replacement in 2017.

Total capital and non-capitalized O&M costs (5.4.5.2.A.i)

	Historical Capital Costs				
	2012	2013	2014	2015	2016
Total cost					
Contributions					
Net cost					
O&M expense					

	Future Capital Costs				
	2017	2018	2019	2020	2021
Total cost	$ 50,000	$ 52,500	$ 55,125	$ 200,880	$ 156,000
Contributions	$ -	$ -	$ -	$ -	$ -
Net cost	$ 50,000	$ 52,500	$ 55,125	$ 200,880	$ 156,000
O&M expense	Undetermined				

Customer Attachments and Load (5.4.5.2 A.ii)

Approximately 1.4MW ; however, since both circuits contain circuit ties to other InnPower circuits, during an outage potentially a large load up to 2.5 MW can be impacted.

Project Dates & Expenditure Timing (5.4.5.2.A.iii)

Start Date:	01-Jan-17			
In Service Date:	31-Dec-17			
Expenditure Timing	2017: Q1	2017: Q2	2017: Q3	2017: Q4
		50%	50%	

General Information on Project (5.4.5.2.A)	
	Schedule Risks & Risk Mitigation (5.4.5.2.A.iv)
	For this project the completion schedule depends on timely design, approvals, obtaining locates and road occupancy permits, and arranging field crews. InnPower's project management process will address all these areas of concern to ensure timely completion.
	Comparative Information on Expenditure from Equivalent Projects (5.4.5.2.A.v)
	Material and Labour Estimating costs and project methodology from previous projects.
	Total Capital and OM&A costs associated with REG investment (5.4.5.2.A.vi)
	Not Applicable to this Project.
	Leave to Construct Approval (5.4.5.2.A.vii)
	Not Applicable to this Project.

General Information on Project (5.4.5.2.A)

Related Project Reference Material i.e. Images, Drawings and or Reference Material

Cookstown Rebuild Project - Area inside frame shows service area of Cookstown West Feeders F2 and F4

General Information on Project (5.4.5.2.A)

Distribution Asset Condition Assessment - Cookstown Sample Observations

The table below presents the conditions of the poles that were sampled - based on the condition rating outlined in the Distribution Asset Condition Assessment report

Condition Rating	Corresponding Condition
A	Good; no problem
B	Normal aging
C	Fair; some deterioration
D	Fair-poor; significant deterioration
E	Bad; critical damage; remediation required

Overall Pole Condition

Rating	Percentage of sample	Extrapolated Data for Total Population
A	9%	68
B	23%	162
C	59%	428
D	8%	56
E	1%	6
Grand Total	100%	720

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Project Name: Reliability Rebuild: Distribution - Cookstown
	Investment Benefits, measured against: Efficiency, Customer Value & Reliability (5.4.5.2.B.1)
	Main Driver (5.4.5.2.B.1.a-1):
	System Renewal.
	- Main "Trigger" (5.4.5.2.B.1.a-1.1):
	Assets/asset systems at end of service life due to failure risk.
	Secondary Driver (5.4.5.2.B.1.a-2):
	System Renewal.
	- Secondary "Trigger" (5.4.5.2.B.1.a-2.1):
	Assets/asset systems at end of service life due to high performance risk.
	Objective or Performance Target to be Achieved (5.4.5.2.B.1.a-3):
	Primary: Reliability; Secondary: Customer value.
	Additional: Coordination, Interoperability and Safety.
	Background information that ties in with Asset Management Process (5.4.5.2.B.1.a-3i):
	This project meets the objectives of ensuring public and worker safety, maintaining system reliability, and managing costs, which are part of InnPower's Asset Management Process objectives.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Overview of Investment Prioritization Justification (5.4.5.2.B.1.b)
	Prioritization based on assets that require attention as a result of ACA Inspection.
	Project Identification and Selection (5.4.5.2.B.1.b-1)
	This project was identified based on the pole condition assessment results.
	Project Prioritization (5.4.5.2.B.1.b-2)
	High Priority, based on Asset Management Process based evaluation.
	Project Pacing (5.4.5.2.B.1.b-3)
	This project has been paced over 5 years to reduce its impact on the capital budget.
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)
	- Alternate Considerations - Design (5.4.5.2.B.1.c-1)
	Not applicable to this project as the project is a like for like replacement.
	- Alternate Considerations - Schedule (5.4.5.2.B.1.c-2)
	Schedule is coordinated with locates and approval of other agencies
	- Alternate Considerations - Funding/Ownership (5.4.5.2.B.1.c-3)
	Project is funded entirely by InnPower.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Effect of Investment on System Operation Efficiency and Cost-Effectiveness (5.4.5.2.B.1.c.i)
	The infrastructure will be upgraded to current standards and will improve reliability. Since some of the replacement poles are on the backbone (trunk line) circuit that serve as tie with other circuits in the area the newer and more reliably built infrastructure will be more dependable during storms.
	Net Benefits Accruing to Customers as a Result of the Investment (5.4.5.2.B.1.c.ii)
	Avoid system interruptions and increase reliability due to upgrading old infrastructure.
	Impact of the Investment on Reliability Performance including on the Frequency and Duration of Outages (5.4.5.2.B.1.c.iii)
	Increase reliability of the system and reduction in the duration of outages through replacement of aged assets. Our current Outage Management System (OMS) is not built to report predictions in reliability improvement, hence, the specific improvement to SAIDI and SAIFI have not been presented below. InnPower is looking into enhancing its OMS database and software functionality to include the option to perform such analysis.
	Projected Improvement to SAIFI (System Average Interruption Frequency Index): *see comments above to (5.4.5.2.B.1.c.iii).*
	Projected Improvement to SAIDI (System Average Interruption Duration Index): *see comments above to (5.4.5.2.B.1.c.iii).*
	Impact of the Driver(s), "Trigger" or other, on the DESIGN of the Project (5.4.5.2.B.1.c-4)
	InnPower will be designing the line using a like for like replacement strategy.
	Impact of the Driver(s), "Trigger" or other, on the COMPONENT CHARACTERISTICS of the Project (5.4.5.2.B.1.c-5)
	Components selected based on current approved materials list and design selected.
	Impact of the Driver(s), "Trigger" or other, on the WORK PLAN of the Project (5.4.5.2.B.1.c-6)
	The work plan will be arranged to target the poles in the worst condition as a priority.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Investment Benefits, measured against: Safety (5.4.5.2.B.2)
	Public and worker safety will be improved by replacing pole at the end of their life; improved overall reliability.
	Investment Benefits, measured against: Cyber-security, Privacy (5.4.5.2.B.3)
	This project will not compromise Cyber-security or Privacy.
	Investment Benefits, measured against: Co-ordination, Interoperability (5.4.5.2.B.4)
	The work will be coordinated with third party attachment companies.
	Co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)
	Co-ordinated with utilities - 3rd party attachments (Bell and Rogers).
	Potential to Enable Future Technological Functionality (5.4.5.2.B.4.b-1)
	Not applicable to this project.
	Potential to Address Future Operational Requirements (5.4.5.2.B.4.b-2)
	Additional switches / cutouts to permit additional sectionalizing of system during emergency conditions.
	Investment Benefits, measured against: Economic Development (5.4.5.2.B.5)
	Not applicable to this project.
	Investment Benefits, measured against: Environmental Benefits: (5.4.5.2.B.6)
	Not applicable to this project.

Project Name: Reliability Rebuild: Distribution - Cookstown	
Category-specific requirements for System Renewal Investments (5.4.5.2.C.b)	
Category-Specific Requirements for System Renewal Projects (5.4.5.2.C.b)	**Description of the Characteristics of the Assets Targeted (5.4.5.2.C.b.i)**
	Assets to be replaced in this project include: All components of sub-transmission line construction including poles, conductor, insulators, and lightning arresters; and all components of distribution primary pole line construction - poles, cross arms, conductors, pin type insulators, cut-outs, inline switches, open bus secondary, pole mounted transformers, and service connections.
	- Consequences of Asset Performance Deterioration or Failure
	Negative impact to the sub-transmission system located along the east-west corridor in the south of Cookstown between Highway 27 and 5 Side Road that serves as a backup feed to distribution stations in InnPower's southern territory. Localized outages within urbanized areas in Cookstown. Inability to make use of multiple circuit tie switches that will enable InnPower to better manage outage restoration or planned work in a timely manner.
	Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)
	Assets have performed as originally designed and have had years of life as expected from these types of assets.
	Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)
	Have achieved or exceeded typical life cycle of asset.
	- Performance Record of the Assets Targeted (5.4.5.2.C.b.i.2a)
	Assets have performed as originally designed.
	Number of Customers Affected by given Asset Failure (5.4.5.2.C.b.i.3)
	The assets identified for replacement are spread out across the Cookstown service area among both sub-transmission and distribution infrastructure, hence the number of customers affected would vary based on the degree of outage and assets affected.
	Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)
	Varies as to the degree of outage and assets affected. Approximately 1,500 customers are served by InnPower in the Cookstown area.
	Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)
	Cookstown's approximately 1,500 residents have their own retail and commercial areas in town, and during storm outages InnPower has received a large number of customer complaints relating to the number of outages and the duration of outages. This targeted reliability upgrade project will improve distribution asset performance levels in Cookstown, while having a positive impact on the sub-transmission firming capability to support power delivery to other residents in InnPower's southern territory.

Category-Specific Requirements for System Renewal Projects (5.4.5.2.C.b)	
	Value of Customer Impact (5.4.5.2.C.b.i.6)
	Depends upon type of asset failure and the number of customers connected. An exact monetary value for the impact was not calculated.
	Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)
	Availability of resources and materials or acceleration of asset failure or eminent asset failure.
	Investment Intensity ; Asset Replacement Rate(5.4.5.2.C.b.ii.a)
	Low for like for like replacement.
	Project Priority Relative to Other Projects (5.4.5.2.C.b.ii.b)
	Medium priority schedule for Q2, Q3 of the year.
	Impact on System O&M Costs (5.4.5.2.C.b.iii)
	Additional switching / cost of crews would be required with increased number of outages due to aged assets.
	- O&M Cost Impact of Not implementing Project(5.4.5.2.C.b.iii-a)
	Overall cost impact would be minor.
	Impact on Reliability Performance and/or Safety Factors (5.4.5.2.C.b.iv)
	New assets would reduce outages due to failures and improve system reliability.
	Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)
	Outage mitigation if project is completed prior to asset failure.
	Like for Like Renewal Analysis, Alternatives Comparison (like-for-like vs. not like- for-like, timing, rate of replacement, etc.) (5.4.5.2.C.b.vi)
	Typical installation is like for like replacement to current utility standard.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name **Reliability Rebuild: Subtransmission - 5 Side Road**

Project number: DO 011-B **Budget Year:** 2017

Investment Category: System Renewal

Project Summary

This project will rebuild the existing main subtransmission feeder pole line that serves as the primary feed to three distribution stations (DS) with a total nominal rating of 17.5 MVA and a peak rating of 13.4 MVA. This subtransmission feeder also serves as the backup feed to another four DS's during the loss of their primary supply for a peak rating of 25 MVA of load. The Tanger Outlet Mall, Innisfil Sewage Plant, and Innisfil Pumping Station #3, (5.5 MVA load) are three (3) primary metered customers served by this pole line. InnPower considers work on subtransmission feeders for reliability improvements to have priority over DS and distribution feeder work. This section of line spans approximately 5.6 km and approximately 102 poles.

During a recent pole testing program 83% of poles displayed cracks, mechanical damage, pole top feathering, split and/or rot. The age demographics show that 52% of the poles are 40 years or older.

Given the large loads served by this subtransmission feeder pole line and the large impact of an outage, the selective replacement over the next five (5) years of 60% of the worst poles (60 poles) will be required to meet its performance requirements.

Total capital and non-capitalized O&M costs (5.4.5.2.A.i)

	Historical Capital Costs				
	2012	2013	2014	2015	2016
Total cost					
Contributions					
Net cost					
O&M expense					

	Future Capital Costs				
	2017	2018	2019	2020	2021
Total cost	$ 75,000	$ -	$ 550,000	$ 225,000	$ 225,000
Contributions	$ -	$ -	$ -	$ -	$ -
Net cost	$ 75,000	$ -	$ 550,000	$ 225,000	$ 225,000
O&M expense	Undetermined				

Customer Attachments and Load (5.4.5.2 A.ii)

Subtransmission feeder pole line serves as the primary feed to three distribution stations (DS) with a total nominal rating of 17.5 MVA and a peak rating of 13.4 MVA. This subtransmission feeder also serves as the backup feed to another four DS's during the loss of their primary supply for a peak rating of 25 MVA of load.

Project Dates & Expenditure Timing (5.4.5.2.A.iii)

Start Date:	01-01-17			
In Service Date:	31-12-17			
Expenditure Timing	2017: Q1	2017: Q2	2017: Q3	2017: Q4
	20%	40%	40%	

General Information on Project (5.4.5.2.A)	
	Schedule Risks & Risk Mitigation (5.4.5.2.A.iv)
	For this project the completion schedule depends upon timely design, approvals, obtaining locates and road occupancy permits, arranging field crews and sub-transmission/distribution station loading. The risks are mitigated with alternative supply from Alliston 9M1 / 9M4.
	Comparative Information on Expenditure from Equivalent Projects (5.4.5.2.A.v)
	The estimated material and labour costs and project methodology for this pole line rebuild is from previous like for like pole rebuild projects.
	Total Capital and OM&A costs associated with REG investment (5.4.5.2.A.vi)
	Not Applicable to this Project
	Leave to Construct Approval (5.4.5.2.A.vii)
	Not Applicable to this Project
	Related Project Reference Material i.e. Images, Drawings and or Reference Material
	N/A

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Project Name: Reliability Rebuild: Subtransmission - 5 Side Road
	Investment Benefits, measured against: Efficiency, Customer Value & Reliability (5.4.5.2.B.1)
	Main Driver (5.4.5.2.B.1.a-1):
	System Renewal
	- Main "Trigger" (5.4.5.2.B.1.a-1.1):
	Assets/asset systems at end of service life due to failure risk.
	Secondary Driver (5.4.5.2.B.1.a-2):
	System Service
	- Secondary "Trigger" (5.4.5.2.B.1.a-2.1):
	System efficiency / performance improvement (flexibility to operate subtransmission system).
	Objective or Performance Target to be Achieved (5.4.5.2.B.1.a-3):
	Primary: Efficiency; Secondary: Reliability.
	Additional Co-ordination, Interoperability and Safety.
	Background information that ties in with Asset Management Process (5.4.5.2.B.1.a-3.i):
	Upgrade overhead pole line with wooden cross arms (on majority of both subtransmission and distribution lines) to new armless construction and conductor upgrade from 336.4 kcmil to 556.5 kcmil to accommodate future feeder loading due to load growth in the provincially designated employment lands, and for 44 kV back up. This project meets the objectives of ensuring public and InnPower personnel safety, maintaining system reliability, and managing costs, which are part of InnPower's Asset Management Process
	Overview of Investment Prioritization Justification (5.4.5.2.B.1.b)
	This subtransmission feeder supplies critical DS's loads and thus the rebuild of this aged 44 kV pole line is of high priority. This feeder will also provide back up 44 kV supply for the future loads in the provincially designated employment lands.
	Project Identification and Selection (5.4.5.2.B.1.b-1)
	This subtransmission feeder was selected due to its vital role in providing reliable power to InnPower's subtransmission grid, location relative to the proposed load growth / development area, and for the replacement of old existing assets - poles, cross arms and upgrade of the conductors.
	Project Prioritization (5.4.5.2.B.1.b-2)
	High Priority

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Project Pacing (5.4.5.2.B.1.b-3)
	This project has been paced over a five (5) year period (field work will be spread over 4 years as noted in the schedule above) and the work has been carefully selected to address the high risk to InnPower's reliability (if the vital subtransmission system was to incur a prolonged outage due to pole failures), by choosing poles with the risk of failure.
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)
	- Alternate Considerations - Design (5.4.5.2.B.1.c-1)
	N/A - InnPower will be using its standard design for similar circuitry to maintain consistence of design.
	- Alternate Considerations - Schedule (5.4.5.2.B.1.c-2)
	The work on this section of pole line will be scheduled when the sub-transmission feeder (Alliston 9M2) can be taken out of service while switching all the load to other subtransmission feeders. This work will be coordinated with Hydro One and the Ontario Grid Control Centre.
	- Alternate Considerations - Funding/Ownership (5.4.5.2.B.1.c-3)
	Project will be funded and owned by InnPower.
	Effect of Investment on System Operation Efficiency and Cost-Effectiveness (5.4.5.2.B.1.c.i)
	This project will upgrade existing pole line to current standards and decrease subtransmission feeder and associated pole line exposure to interruptions due to failure of deteriorated assets. Replacing selected assets and increasing the feeder and pole line resilience to adverse weather will increase system flexibility for system maintenance and outage restoration.
	Net Benefits Accruing to Customers as a Result of the Investment (5.4.5.2.B.1.c.ii)
	Rebuild of this pole line will result in fewer and shorter power interruptions to customers due to improved system reliability and improved system flexibility to restore customers during power outages.
	Impact of the Investment on Reliability Performance including on the Frequency and Duration of Outages (5.4.5.2.B.1.c.iii)
	The rebuild of this pole line will increase system reliability and reduce the duration of outages due to system flexibility to transfer loads on our 44 kV system. This subtransmission poleline is critical as it serves as the primary feed to three (3) DS's and 3 primary metered customers under normal conditions, and an additional four (4) DS's and several more primary meters customers during emergency conditions. Our current Outage Management System (OMS) is not robust enough to report predictions in reliability improvement, hence, the specific improvement to SAIDI and SAIFI have not been presented below. InnPower is looking into enhancing its OMS database and software functionality to include the option to perform such analysis.
	Projected Improvement to SAIFI (System Average Interruption Frequency Index): *See Above*
	Projected Improvement to SAIDI (System Average Interruption Duration Index): *See Above*
	Impact of the Driver(s), "Trigger" or other, on the DESIGN of the Project (5.4.5.2.B.1.c-4)
	The framing of the proposed poles are driven by the number of circuits required to accommodate future load.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Impact of the Driver(s), "Trigger" or other, on the COMPONENT CHARACTERISTICS of the Project (5.4.5.2.B.1.c-5)
	The components selected for the project are based on current approved materials list and specific design for the project, which are both reviewed and approved by a professional engineer.
	Impact of the Driver(s), "Trigger" or other, on the WORK PLAN of the Project (5.4.5.2.B.1.c-6)
	The final design detailing the pole framing, number of circuits, pole sizes will dictate the resources required and the availability of those resources when required. The work plan will be coordinated with the timing of the outage to be taken on the subtransmission line.
	Investment Benefits, measured against: Safety (5.4.5.2.B.2)
	This project will decrease the probability of power interruption due to failure of deteriorated materials. Minimizing interruptions and outage durations on a holistic basis contributes to community safety by maintain supply to critical electrical distribution infrastructure such as InnPower Distribution Stations and critical Town facilities such as sewage plants, pump stations, streetlights, traffic lights.
	Investment Benefits, measured against: Cyber-security, Privacy (5.4.5.2.B.3)
	N/A
	Investment Benefits, measured against: Co-ordination, Interoperability (5.4.5.2.B.4)
	This project will be coordinated with various third parties: (1) land developers and the Town of Innisfil to ensure future loading needs in the provincially designated employment lands are served; (2) Hydro One - to ensure the feeder outages are coordinated and that loading issues have been addressed, (3) Ontario Grid Control Center to ensure the timing of the work complies their requirements for feeder outage.
	Co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)
	Project will be coordinated with telecommunication utilities for 3rd party attachments (Bell and Rogers). Inquires will be made to the Town of Innisfil to ensure co-ordination with any future proposed projects.
	Potential to Enable Future Technological Functionality (5.4.5.2.B.4.b-1)
	Rebuild of line allows for installation of equipment with remote / SCADA flexibility
	Potential to Address Future Operational Requirements (5.4.5.2.B.4.b-2)
	Decreasing probability of power outages due to failure of deteriorated assets will result in a system that is more flexible to accommodate load switching when required.
	Investment Benefits, measured against: Economic Development (5.4.5.2.B.5)
	This project will increase system capacity to accommodate anticipated load growth in the provincially designated employment lands which will enable economic development.
	Investment Benefits, measured against: Environmental Benefits: (5.4.5.2.B.6)
	Not applicable to this project.

Project Name: Reliability Rebuild: Subtransmission - 5 Side Road	
Category-specific requirements for System Renewal Investments (5.4.5.2.C.b)	
Category-Specific Requirements for System Renewal Projects (5.4.5.2.C.b)	**Description of the Characteristics of the Assets Targeted (5.4.5.2.C.b.i)**
	The assets to be replaced include: primary pole line construction. These include poles, wooden cross arms, conductor size, insulators, and attending hardware and equipment.
	- Consequences of Asset Performance Deterioration or Failure
	Deteriorated assets increase the probability of failure and decrease system reliability. This section of line carries a vital subtransmission feeder for InnPower and serves three (3) distribution stations and 3 primary meters customers on a regular basis and serves as backup feed to another four DS's during the loss of their primary supply for a peak rating of 25 MVA of load. Therefore, a delay in replacing deteriorated poles can result in large scale power outages.
	Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)
	Assets have performed as originally designed and have provided years of service life as expected from these types of assets.
	Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)
	Most assets have achieved or exceeded typical life cycle of the asset.
	- Performance Record of the Assets Targeted (5.4.5.2.C.b.i.2a)
	Assets have performed as originally designed.
	Number of Customers Affected by given Asset Failure (5.4.5.2.C.b.i.3)
	Under emergency conditions this subtransmission line is the supply for up to seven (7) DS and 70 percent of InnPower customers.
	Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)
	Varies as to the cause and degree of severity of the outage. Because the feeder under emergency conditions is the supply to as many as seven (7) DS the quantitative impact is very large when viewed as to the number of customer affected.
	Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)
	Varies as to the cause and degree of severity of the outage. Because the feeder under emergency conditions is the supply to as many as seven (7) DS the qualitative impact is also very large due to the percentage of service territory dependent upon this feeder.
	Value of Customer Impact (5.4.5.2.C.b.i.6)
	Depends upon type of customer and duration of outage. Due to the importance of this feeder to InnPower service territory, a large number of our customers both residential and commercial / institutional would be affected.
	Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)
	Availability of resources and materials. InnPower does not anticipate delays to this project due to the lack of materials or resources.
	Investment Intensity (Asset Replacement Rate; 5.4.5.2.C.b.ii.a):
	Low as typically pole lines achieve or exceed their life as compared to other assets in the field.

Category-Specific Requirements for System Renewal Projects(5.4.5.2.C.b)	
	Project Priority Relative to Other Projects (5.4.5.2.C.b.ii.b)
	Project has high priority schedule due to the number of DS's that receive their 44 kV supply from this pole line. Schedule for the project is design for Q1 and construction is in Q2 and Q3 of 2017.
	Impact on System O&M Costs (5.4.5.2.C.b.iii)
	System O&M costs are not expected to be impacted significantly as a result of this project.
	Impact on Reliability Performance and/or Safety Factors (5.4.5.2.C.b.iv)
	Replacing deteriorated assets just-in-time will stabilize system reliability and avoid danger to workers and public associated with falling poles.
	Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)
	The deteriorated poles selected to be replaced are a priority due to the high risk to InnPower's subtransmission grid - the benefit of replacing these assets will contribute to better reliability and system operating capability.
	Like for Like Renewal Analysis, Alternatives Comparison (like-for-like vs. not like- for-like, timing, rate of replacement, etc. (5.4.5.2.C.b.vi)
	Typical installation is like for like replacement to current utility standard.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name **Reliability Rebuild: Subtransmission - Lockhart Road**

Project number: DO 011-A **Budget Year:** 2017

Investment Category: System Renewal

Project Summary

This project will rebuild the existing main subtransmission feeder pole line that that serves as the primary feed to three distribution stations (DS) with a total nominal rating of 15 MVA and a peak rating of 9.5 MVA. This subtransmission feeder also serves as the backup feed to another three DS's during the loss of their primary supply for a peak rating of 25 MVA of load. The Stroud Plaza and Kempenfelt Centre (2 MVA load) are two (2) primary metered customers served by this pole line. InnPower considers work on subtransmission feeders for reliability improvements to have priority over DS and distribution feeder work. This section of line spans approximately 5.8 km and approximately 105 poles. Based on the Distribution Asset Condition Assessment (ACA) Report, 35% of the poles were found to have either some deterioration (fair) to significant deterioration (fair-poor). The age demographics show that 67% of the poles are 40 years or older. Given the large loads served by this subtransmission feeder pole line and the large impact of an outage, the selective replacement over the next five (5) years of 52% of the worst poles (55 poles) will be required to meet its performance requirements.

Total capital and non-capitalized O&M costs (5.4.5.2.A.i)

	Historical Capital Costs				
	2012	2013	2014	2015	2016
Total cost					
Contributions					
Net cost					
O&M expense					

	Future Capital Costs				
	2017	2018	2019	2020	2021
Total cost	$ 170,650	$ 89,933	$ 294,429	$ 203,060	$ 213,214
Contributions	$ -	$ -	$ -	$ -	$ -
Net cost	$ 170,650	$ 89,933	$ 294,429	$ 203,060	$ 213,214
O&M expense	Undetermined				

Customer Attachments and Load (5.4.5.2 A.ii)

Subtransmission feeder pole line serves as the primary feed to three distribution stations (DS) with a total nominal rating of 15 MVA and a peak rating of 9.5 MVA. This subtransmission feeder also serves as the backup feed to another three DS's during the loss of their primary supply for a peak rating of 25 MVA of load.

Project Dates & Expenditure Timing (5.4.5.2.A.iii)

Start Date:	01-Jan-17			
In Service Date:	31-Dec-17			
Expenditure Timing	2017: Q1	2017: Q2	2017: Q3	2017: Q4
	20%	40%	40%	

General Information on Project (5.4.5.2.A)	
	Schedule Risks & Risk Mitigation (5.4.5.2.A.iv)
	For this project the completion schedule depends upon timely design, approvals, obtaining locates and road occupancy permits, arranging field crews and sub-transmission/distribution station loading. The risks are mitigated with alternative supply from Alliston 9M1 / 9M4.
	Comparative Information on Expenditure from Equivalent Projects (5.4.5.2.A.v)
	The estimated material and labour costs and project methodology for this pole line rebuild is from previous like for like pole rebuild projects.
	Total Capital and OM&A costs associated with REG investment (5.4.5.2.A.vi)
	Not Applicable to this Project
	Leave to Construct Approval (5.4.5.2.A.vii)
	Not Applicable to this Project

General Information on Project (5.4.5.2.A)	**Related Project Reference Material i.e. Images, Drawings and or Reference Material**
	

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Project Name: Reliability Rebuild: Subtransmission - Lockhart Road
	Investment Benefits, measured against: Efficiency, Customer Value & Reliability (5.4.5.2.B.1)
	Main Driver (5.4.5.2.B.1.a-1):
	System Renewal
	- Main "Trigger" (5.4.5.2.B.1.a-1.1):
	Assets/asset systems at end of service life due to failure risk
	Secondary Driver (5.4.5.2.B.1.a-2):
	System Service
	- Secondary "Trigger" (5.4.5.2.B.1.a-2.1):
	System efficiency / performance improvement (flexibility to operate subtransmission system)
	Objective or Performance Target to be Achieved (5.4.5.2.B.1.a-3):
	Primary: Efficiency; Secondary: Reliability.
	Additional Co-ordination, Interoperability and Safety
	Background information that ties in with Asset Management Process (5.4.5.2.B.1.a-3):
	Upgrade overhead pole line with wooden cross arms to new armless construction and conductor upgrade from 336.4 kcmil to 556.5 kcmil to accommodate future feeder loading due to load growth for Hewitt Lands in the Barrie South area and for 44 kV back up for future DS Station on Big Bay Point Road - Friday Harbor DS. This project meets the objectives of ensuring public and InnPower personnel safety, maintaining system reliability, and managing costs, which are part of InnPower's Asset Management Process objectives.
	Overview of Investment Prioritization Justification (5.4.5.2.B.1.b)
	This subtransmission feeder supplies critical DS's loads and thus the rebuild of this aged 44 kV pole line is of high priority. This feeder will also provide 44 kV supply for the future Friday Harbour DS and Friday Harbour Development and Future large block developments both East and West of Yonge Street known as the Hewitt Lands.
	Project Identification and Selection (5.4.5.2.B.1.b-1)
	This subtransmission feeder was selected due to its vital role in providing reliable power to InnPower's subtransmission grid, location relative to the proposed load growth / development area in north Innisfil, and for the replacement of old existing assets - poles, cross arms and upgrade of the conductors.
	Project Prioritization (5.4.5.2.B.1.b-2)
	High Priority

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Project Pacing (5.4.5.2.B.1.b-3)
	This project has been paced over a five (5) year period and the work has been carefully selected to address the high risk to InnPower's reliability (if the vital subtransmission system was to sustain a prolonged outage due to pole failures), by choosing poles with the risk of failure.
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)
	- Alternate Considerations - Design (5.4.5.2.B.1.c-1)
	The pole framing for this pole line is selected to accommodate two - 27.6 kV circuits and a 44 kV top circuit.
	- Alternate Considerations - Schedule (5.4.5.2.B.1.c-2)
	The work on this section of pole line will be scheduled when the sub-transmission feeder (Barrie 13M3) can be taken out of service while switching all the load to other subtransmission feeders. This work will be coordinated with Hydro One and the Ontario Grid Control Centre.
	- Alternate Considerations - Funding/Ownership (5.4.5.2.B.1.c-3)
	Project will be funded and owned by InnPower.
	Effect of Investment on System Operation Efficiency and Cost-Effectiveness (5.4.5.2.B.1.c.i)
	This project will upgrade existing pole line to current standards and decrease subtransmission feeder and associated pole line exposure to interruptions due to failure of deteriorated assets. Replacing selected assets and increasing the feeder and pole line resilience to adverse weather will increase system flexibility for system maintenance and outage restoration.
	Net Benefits Accruing to Customers as a Result of the Investment (5.4.5.2.B.1.c.ii)
	Rebuild of this pole line will result in fewer and shorter power interruptions to customers due to improved system reliability and improved system flexibility to restore customers during power outages.
	Impact of the Investment on Reliability Performance including on the Frequency and Duration of Outages (5.4.5.2.B.1.c.iii)
	The rebuild of this pole line will increase system reliability and reduce the duration of outages due to system flexibility to transfer loads on our 44 kV system. This sub-transmission pole line is critical as it serves as the primary feed to three (3) DS's and 2 primary metered customers under normal conditions, and an additional three (3) DS and several more primary meters customers during emergency conditions. Our current Outage Management System (OMS) is not robust enough to report predictions in reliability improvement, hence, the specific improvement to SAIDI and SAIFI have not been presented below. InnPower is looking into enhancing its OMS database and software functionality to include the option to perform such analysis.
	Projected Improvement to SAIFI (System Average Interruption Frequency Index): See Above
	Projected Improvement to SAIDI (System Average Interruption Duration Index): See Above
	Impact of the Driver(s), "Trigger" or other, on the DESIGN of the Project (5.4.5.2.B.1.c-4)
	The framing of the proposed poles are driven by the number of circuits required to accommodate future load. Pole line will be designed for two - 27.6 kV and one - 44 kV primary circuit.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)

Impact of the Driver(s), "Trigger" or other, on the COMPONENT CHARACTERISTICS of the Project (5.4.5.2.B.1.c-5)
The components selected for the project are based on current approved materials list and specific design for the project, which are both reviewed and approved by a professional engineer.
Impact of the Driver(s), "Trigger" or other, on the WORK PLAN of the Project (5.4.5.2.B.1.c-6)
The final design detailing the pole framing, number of circuits, pole sizes will dictate the resources required and the availability of those resources when required. The work plan will be coordinated with the timing of the outage to be taken on the subtransmission line.
Investment Benefits, measured against: Safety (5.4.5.2.B.2)
This project will decrease the probability of power interruption due to failure of deteriorated materials. Minimizing interruptions and outage durations on a holistic basis contributes to community safety by maintain supply to critical electrical distribution infrastructure such as InnPower Distribution Stations and critical Town facilities such as pump stations, streetlights, traffic lights etc.
Investment Benefits, measured against: Cyber-security, Privacy (5.4.5.2.B.3)
N/A
Investment Benefits, measured against: Co-ordination, Interoperability (5.4.5.2.B.4)
This project will be coordinated with various third parties: (1) land developers to ensure future loading needs in the area are served; (2) Hydro One - to ensure the feeder outages are coordinated and that loading issues have been addressed, (3) Ontario Grid Control Center to ensure the timing of the work complies their requirements for feeder outage.
Co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)
Project will be coordinated with telecommunication utilities for 3rd party attachments (Bell and Rogers). Inquiries will be made to the Town of Innisfil to ensure co-ordination with any future proposed projects.
Potential to Enable Future Technological Functionality (5.4.5.2.B.4.b-1)
Rebuild of line allows for installation of equipment with remote / SCADA flexibility.
Potential to Address Future Operational Requirements (5.4.5.2.B.4.b-2)
Decreasing probability of power outages due to failure of deteriorated assets will result in a system that is more flexible to accommodate load switching when required.
Investment Benefits, measured against: Economic Development (5.4.5.2.B.5)
This project will increase system capacity to accommodate anticipated load growth and new local customers / employees which contribute to increased economic development.
Investment Benefits, measured against: Environmental Benefits: (5.4.5.2.B.6)
Not applicable to this project.

Project Name: Reliability Rebuild: Subtransmission - Lockhart Road	
Category-specific requirements for System Renewal Investments (5.4.5.2.C.b)	
Category-Specific Requirements for System Renewal Projects (5.4.5.2.C.b)	**Description of the Characteristics of the Assets Targeted (5.4.5.2.C.b.i)**
	The assets to be replaced include: primary pole line construction. These include poles, wooden cross-arms, conductors, insulators, and attending hardware and equipment.
	- Consequences of Asset Performance Deterioration or Failure
	Deteriorated assets increase the probability of failure and decrease system reliability. This section of line carries a vital subtransmission feeder for InnPower and serves three (3) distribution stations and two (2) primary metered customers on a regular basis and serves as backup feed to another three DS's during the loss of their primary supply for a peak rating of 25 MVA of load. Therefore, a delay in replacing deteriorated poles can result in large scale power outages.
	Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)
	Assets have performed as originally designed and have provided years of service life as expected from these types of assets.
	Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)
	Have achieved or exceeded typical life cycle of the asset.
	- Performance Record of the Assets Targeted (5.4.5.2.C.b.i.2a)
	Assets have performed as originally designed.
	Number of Customers Affected by given Asset Failure (5.4.5.2.C.b.i.3)
	Under emergency conditions this subtransmission line is the supply for up to six (6) DS and 60 percent of InnPower customers.
	Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)
	Varies as to the cause and degree of severity of the outage. As the feeder under emergency conditions is the supply to as many as six (6) DS the quantitative impact is very large when viewed as to the number of customer affected.
	Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)
	Varies as to the cause and degree of severity of the outage. Because the feeder under emergency conditions is the supply to as many as six (6) DS the qualitative impact is also very large due to the percentage of service territory dependent upon this feeder.
	Value of Customer Impact (5.4.5.2.C.b.i.6)
	Depend upon type of customer and duration of outage. Due to the importance of this feeder to InnPower service territory, a large number of our customers both residential and commercial / institutional would be affected.

Category-Specific Requirements for System Renewal Projects (5.4.5.2.C.b)	
	Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)
	Availability of resources and materials. InnPower does not anticipate delays to this project due to the lack of materials or resources.
	Investment Intensity (Asset Replacement Rate; 5.4.5.2.C.b.ii.a):
	Low as typically pole lines achieve or exceed their life as compared to other assets in the field
	Project Priority Relative to Other Projects (5.4.5.2.C.b.ii.b)
	Project has high priority schedule due to the number of DS's that receive their 44 kV supply from this pole line. Schedule for the project is: design for Q1 and construction is in Q2 and Q3 of 2017.
	Impact on System O&M Costs (5.4.5.2.C.b.iii)
	System O&M costs are not expected to be impacted significantly as a result of this project.
	Impact on Reliability Performance and/or Safety Factors (5.4.5.2.C.b.iv)
	Replacing deteriorated assets just-in-time will stabilize system reliability and avoid danger to workers and public associated with falling poles.
	Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)
	The deteriorated poles selected to be replaced are a priority due to the high risk to InnPower's subtransmission grid - the benefit of replacing these assets will contribute to better reliability and system operating capability.
	Like for Like Renewal Analysis, Alternatives Comparison (like-for-like vs. not like-for-like, timing, rate of replacement, etc. (5.4.5.2.C.b.vi)
	Typical installation is like for like replacement to current utility standard.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name **Station Rehab**

Project number: **DO 008** **Budget Year:** 2017

Investment Category: System Renewal

Project Summary:

This program was developed to repair and upgrade InnPower's aging distribution stations. In 2017 InnPower will perform electrical and civil rehabilitation work at two distribution stations, namely Innisfil DS and Sandy Cove DS, as noted in section 5.5 and 5.8 of the Station Asset Condition Assessment report (Appendix F). The rehabilitation work under this program will rectify deficiencies in equipment, foundation, grounding, equipment bonding, site grading, and fencing.

The substation rehabilitation project is a multi-year rehabilitation program that started in 2016, the purpose of this program is to rectify deficiencies identified in the 2015 audit, repair/replace ageing infrastructure to ensure that the life cycle of the substation is extended. By conducting a rehabilitation program InnPower will minimize the need to retire and/or rebuild distribution stations in the short and midterm.

The priority for repair or replacement is defined by a health index score that is determined by evaluating multiple streams of information, i.e. Age, Visual Inspection, Maintenance records, Electrical testing etc. As the program identified similar issues with multiple stations, the repair/replacement is also tied with other capital and maintenance projects planned for the distribution station during that fiscal year. This is done to maximize efficiency and reduce the downtime for each substation undergoing rehabilitation work.

Most of InnPower owned distribution stations are 40-50 years old, these substations have reached their designed life cycle. In 2015 InnPower Corporation performed a complete audit of the distribution station it owns in its service territory. The purpose of the audit was to evaluate the substations from “riser pole to riser pole”.

After developing a methodology to evaluate asset conditions at substations the substation equipment end-of-life and failure rates were defined. A detailed audit of nine InnPower substations was then conducted to provide a reliability and hazard/risk assessment of the station. The assessment included visual inspections, review of available maintenance records, loading and outage information, etc.

Apart from evaluating civil, structural and environmental risks within substations an electric hazard and risk assessment was conducted to review electrical and safety clearances, neutral connections, grounding (ground grid modeling), equipment bonding, equipment sizing (overloading risk) etc.

Total capital and non-capitalized O&M costs (5.4.5.2.A.i)

	Historical Capital Costs				
	2012	2013	2014	2015	2016
Total cost					$199,280
Contributions					$ -
Net cost					$199,280
O&M expense					Undetermined

General Information on Project (5.4.5.2.A)

	Future Capital Costs				
	2017	2018	2019	2020	2021
Total cost	$104,300	$109,853	$115,346	$242,226	$115,680
Contributions	$ -	$ -	$ -	$ -	$ -
Net cost	$104,300	$109,853	$115,346	$242,226	$115,680
O&M expense	Undetermined				

Customer Attachments and Load (5.4.5.2 A.ii)

Varies, the nominal rated load for station is between 5MVA to 20MVA

Project Dates & Expenditure Timing (5.4.5.2.A.iii)

Start Date:	01-Jan-17			
In Service Date:	31-Dec-17			
Expenditure Timing	2017: Q1	2017: Q2	2017: Q3	2017: Q4
	10%	80	10%	0%

Schedule Risks Risk Mitigation (5.4.5.2.A.iv)

Generally station rehabilitation works are dependent on station loading. We need to manage this work around peak load periods. Although this constraint may move the project a few weeks or months, we are confident this project can be completed in 2017.

Comparative Information on Expenditure from Equivalent Projects (5.4.5.2.A.v)

See above table

Total Capital and OM&A costs associated with REG investment (5.4.5.2.A.vi)

There are no specific capital and O&M costs associated with REG investment

Leave to Construct Approval (5.4.5.2.A.vii)

A request for Leave to Construct Approval is not required for this project

General Information on Project (5.4.5.2.A)

Related Project Reference Material i.e. Images, Drawings and or Reference Material

A complete report providing reference project material is available as part of the "Station Asset Condition Assessment" report (Appendix F).

Overall Distribution Station Health Index Score

Summary Assets included in the study:

Transformers,

Tap Changers,

Reclosers (used as circuit breakers),

44kV TransRupter,

Station Fence, and

Ground Grid

Substation Summary Table									
	HI Score								
Substation	Transformer		Tap Changer		Recloser		Fence	Ground Grid	44-kV Transrupter
Big Bay Point DS	22T1	78	22T1-TC	82	All	100	100	60	
Bob Deugo DS	T1	96	TC	100	All	100	100	100	100
Brian Wilson DS	T1	60	T1TC	88	F1-OCR, F2-OCR	77	100	68	
	T2	100	T2TC	100	F3-OCR	100			
					F4-OCR	84			
Cedar Point DS	T1	66	T1-TC	82	All	100	100	76	
Innisfil DS	31T1	70	31T1-TC	50	All	100	60	76	
Lefroy DS	55T1	78	55T1-TC	82	All	100	100	68	
Leonards Beach DS	41T1	70	41T1-TC	82	All	100	100	68	
Sandy Cove DS	A8T1	78	A8T1-TC	82	All	52	100	60	
Stroud DS	50T1	78	50T1-TC	74	All	36	100	52	

The methodology for calculating HI (Health Index) scores is provided in the "Station Asset Condition Assessment" report (Appendix F).

General Information on Project (5.4.5.2.A)

Related Project Reference Material i.e. Images, Drawings and or Reference Material

A complete report providing reference project material is available as part of the "Station Asset Condition Assessment" report (Appendix F).

InnPower Distribution Station – Transformer Demographics (Report prepared in **2015**)

Key information: Transformer Health Index (HI Score) and Year of Manufacture (3 transformers are 45 years or older in **2017**)

Excerpts from the Station Asset Condition Assessment Report are presented below:

Transformer Demographics				
Substation	**Location ID**	**Manufacturer**	**Year of Manufacture**	**HI Score**
Big Bay Point DS	22T1	Ferranti Packard	1971	78
Bob Deugo DS	T1	Northern TX	2006	96
Brian Wilson DS	T1	Federal Pioneer	1991	60
Brian Wilson DS	T2	Virginia TX	2014	100
Cedar Point DS	T1	Federal Pioneer	1976	66
Innisfil DS	31T1	Federal Pioneer	1976	70
Lefroy DS	55T1	Ferranti Packard	1970	78
Leonards Beach DS	41T1	Ferranti Packard	1974	70
Sandy Cove DS	A8T1	Ferranti Packard	1975	78
Stroud DS	50T1	Westinghouse	1969	78

Asset Class	Asset Designation	Asset Age	Health Index	Exceeds TUL?
Substation Transformers TUL: 45 years	Big Bay Point DS-22T1	44	78	N
	Bob Deugo DS-T1	9	96	N
	Brian Wilson DS-T1	24	60	N
	Brian Wilson DS-T2	1	100	N
	Cedar Point DS-T1	39	66	N
	Innisfil DS-31T1	39	70	N
	Lefroy DS-55T1	45	78	**Y**
	Leonards Beach DS-41T1	41	70	N
	Sandy Cove DS-A8T1	40	78	N
	Stroud DS-50T1	46	78	**Y**

General Information on Project (5.4.5.2.A)

Related Project Reference Material i.e. Images, Drawings and or Reference Material

A complete report providing reference project material is available as part of the "Station Asset Condition Assessment" report (Appendix F).

InnPower Distribution Station – Transformer Tap Changer Demographics (Report prepared in **2015**)

Key information: Transformer Tap Changer Health Index (HI Score) and Year of Manufacture (7 transformer tap changers are 30 years or older in **2017**)

Excerpts from the Station Asset Condition Assessment Report are presented below:

Transformer Tap Changer Demographics

Substation	Location ID	Manufacturer	Year of Manufacture	HI Score
Big Bay Point DS	22T1-TC	Ferranti Packard	1971	82
Bob Deugo DS	TC	Northern TX	2006	100
Brian Wilson DS	T1TC	Federal Pioneer	1991	88
Brian Wilson DS	T2TC	Virginia TX	2014	100
Cedar Point DS	T1-TC	Federal Pioneer	1976	82
Innisfil DS	31T1-TC	Federal Pioneer	1976	50
Lefroy DS	55T1-TC	Ferranti Packard	1970	82
Leonards Beach DS	41T1-TC	Ferranti Packard	1974	82
Sandy Cove DS	A8T1-TC	Ferranti Packard	1975	82
Stroud DS	50T1-TC	Westinghouse	1969	74

Asset Class	Asset Designation	Asset Age	Health Index	Exceeds TUL?
Transformer Tap Changers TUL: 30 years	Big Bay Point DS-22T1-TC	44	82	**Y**
	Bob Deugo DS-TC	9	100	N
	Brian Wilson DS-T1TC	24	88	N
	Brian Wilson DS-T2TC	1	100	N
	Cedar Point DS-T1-TC	39	82	**Y**
	Innisfil DS-31T1-TC	39	50	**Y**
	Lefroy DS-55T1-TC	45	82	**Y**
	Leonards Beach DS-41T1-TC	41	82	**Y**
	Sandy Cove DS-A8T1-TC	40	82	**Y**
	Stroud DS-50T1-TC	46	74	**Y**

General Information on Project (5.4.5.2.A)

Related Project Reference Material i.e. Images, Drawings and or Reference Material

A complete report providing reference project material is available as part of the "Asset Condition Assessment" report.

The operating rods and handles are badly rusted.

There is a loop between the neutral cable and the grounding structure.

Oil leakage spotted.

General Information on Project (5.4.5.2.A)

Related Project Reference Material i.e. Images, Drawings and or Reference Material

A complete report providing reference project material is available as part of the "Asset Condition Assessment" report.

Cracked foundation of structural equipment.

There is no gravel outside of the station.

The foundation of transformer has sunk to a very low level.
Transformer has no oil containment; leakage observed.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Project Name: Station Rehab
	Investment Benefits, measured against: Efficiency, Customer Value & Reliability (5.4.5.2.B.1)
	Main Driver (5.4.5.2.B.1.a-1):
	System Renewal
	- Main "Trigger" (5.4.5.2.B.1.a-1.1):
	Assets/asset systems at end of service life due to substandard performance
	Secondary Driver (5.4.5.2.B.1.a-2): None
	- Secondary "Trigger" (5.4.5.2.B.1.a-2.1):
	Assets/asset systems at end of service life due to failure risk
	Objective or Performance Target to be Achieved (5.4.5.2.B.1.a-3):
	Primary: Reliability; Secondary: Efficiency
	Additional: Safety and Environmental Benefits
	Background information that ties in with Asset Management Process (5.4.5.2.B.1.a-3):
	The following planning objectives, which are part of our asset management process, drives the need for this project: Ensuring public and worker safety, maintaining system reliability and customer value, and managing costs and operational efficiency. These items were identified in the Station Condition Assessment study report performed by Metsco Energy Solutions as needing work within the next 10 years. As per section 6 of the report the scope outlined for each year is based on the health index score for each item listed. Ensuring public and worker safety: These legacy stations pose a risk to public and workers due to grounding and equipment bonding: the lack of an insulating layer of crushed stone on the top soil impact "step" and "touch" potential. The vegetation growth at the stations also pose a safety concern as it impacts the ability of the crews to work safely and also poses a threat to the grounding of equipment due to the interference of its root system with the ground grid. Maintaining system reliability and customer value: With water pooling on foundations these structures have a likelihood of failure - given the observations noted during the Asset Condition Assessment study where some foundations were noted to have experienced severe alkali-silica reaction, causing them to crack, and that could impact the mechanical strength of the bus structure, and the failure of the bus structure could results in a major station outage. The addition of an isolated neutral bus creates a single connection to the ground grid; (existing) multiple neutral connections to station ground allow unbalanced load current to enter the grounding system, a duty for which it is not designed for.
	Overview of Investment Prioritization Justification (5.4.5.2.B.1.b)
	This is a required project. Overall station investment takes priority over lines work. These projects pertain directly to station work and therefore are treated with higher priority. The station in which these projects are to be completed range in age from 40 to 50 years old. The specific projects are selected based on the scoring system outlined in our Station Condition Assessment report.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)

Project Identification and Selection (5.4.5.2.B.1.b-1)

Each of the station assets were reviewed during the condition assessment process and checked and assessed for operating condition, compliance to performance specifications, review of maintenance records, infrared scan results, age, oil test results (for transformers), monthly visual inspections, and various other tests that are specific to gauging the condition of the respective assets.

Project Prioritization (5.4.5.2.B.1.b-2)

InnPower uses a "Health Index Score" for prioritizing over project over another. The asset condition assessment methodology was applied for different categories of fixed assets that are employed in InnPower's distribution stations. Computing the Health Index for Tier 1 assets required developing end-of-life criteria for various components associated with each individual asset type. Each criterion represents a factor that is critical in determining
the component's condition relative to potential failure. These components and tests shown in the tables are weighted based on their importance in determining the assets end-of-life.

For the purpose of scoring the condition assessment, the letter condition ratings are assigned the following numbers shown as "factors":
A = 5, B = 4, C = 3, D = 2, E = 1.
These condition rating numbers are multiplied by the assigned weights to compute weighted scores for each component and test. The weighted scores are totaled for each asset. Totaled scores are used in calculating final Health Indices for each asset. For each component, the Health Index calculation involves dividing its total condition score by its maximum condition score, then multiplying by 100. This step normalizes scores by producing a number from 0-100 for each asset. For example, a transformer in perfect condition would have a Health Index of 100 while a completely degraded transformer would have a Health Index of 0.

Project Pacing (5.4.5.2.B.1.b-3)

The Asset Condition Assessment report outlined a prescribed methodology for evaluating the urgency for replacement. This report provided a basis for pacing of the projects. Each major (and some minor) asset's condition was evaluated and rated as: "immediate intervention required", "replace in 2-5 years", and "replace in 5-10 years". As the study was done in 2015 all assets noted in the first two categories would be considered for the current project year.

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

- Alternate Considerations - Design (5.4.5.2.B.1.c-1)

The main investment in the current year (2017) would be for civil works pertaining to foundations, fencing, the top layering on the ground of crushed stones and site grading. We will work with civil consultants to evaluate best options to complete this project and follow most cost effective alternative.

- Alternate Considerations - Schedule (5.4.5.2.B.1.c-2)

The schedule has been determined based on needs assessment as per Condition Assessment report and the scoring of risk. We anticipate station rehabs to conform to the pacing suggested in the Condition Assessment report with all of the assets in "very poor" and "poor" condition repairs or replaced with the stipulated window of 0-5 years.

- Alternate Considerations - Funding/Ownership (5.4.5.2.B.1.c-3)

We have not considered alternate funding and ownership options

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Effect of Investment on System Operation Efficiency and Cost-Effectiveness (5.4.5.2.B.1.c.i)
	This improvement will enable system operating crews to safely access the station equipment and components and also enable easy access to manually operate station controls which will enhance system operating efficiency. Given the large number of customers served by each station such savings in operating times would have a large impact on the overall operating and maintenance efficiency and costs.
	Net Benefits Accruing to Customers as a Result of the Investment (5.4.5.2.B.1.c.ii)
	Firstly, repairing the fences will improve public safety. In addition, the above noted improvements to system operations will enhance overall customer experience.
	Impact of the Investment on Reliability Performance including on the Frequency and Duration of Outages (5.4.5.2.B.1.c.iii)
	Since this project is not driven by reliability we have not specifically analyzed SAIFI and SAIDI improvements. However, as aging infrastructure is replaced outages due to end of life failures will be avoided and therefore having a positive impact on SAIDI and SAIFI
	Projected Improvement to SAIFI (System Average Interruption Frequency Index): Not applicable
	Projected Improvement to SAIDI (System Average Interruption Duration Index): Not applicable
	Impact of the Driver(s), "Trigger" or other, on the DESIGN of the Project (5.4.5.2.B.1.c-4)
	Given that the general life of a station is between 40 to 45 years, and based on the fact that the stations where these projects will be completed are over 40 years old, InnPower has considered the best DESIGN option to optimize cost benefit. Rather than retiring the entire station and rebuild it, InnPower will be strategically improving station design aspects and replace equipment as required to optimize asset life cycle.
	Impact of the Driver(s), "Trigger" or other, on the COMPONENT CHARACTERISTICS of the Project (5.4.5.2.B.1.c-5)
	While evaluating options for station grading material, we have considered the option to install "landscape fabric" at the same time to reduce the risk of vegetation issues. This will result in reduced cost for routine maintenance of the station (re. vegetation management).
	Impact of the Driver(s), "Trigger" or other, on the WORK PLAN of the Project (5.4.5.2.B.1.c-6)
	Given the urgency of the repairs (based on the scheduled proposed in the study) we are scheduling the works in a "just-in-time" manner.
	Investment Benefits, measured against: Safety (5.4.5.2.B.2)
	By addressing "step" and "touch potential" issues at the station we will be increasing public and worker safety. Repairing the fencing will keep the public out of harms way and further contribute to public safety.
	Investment Benefits, measured against: Cyber-security, Privacy (5.4.5.2.B.3)
	The scope included does not apply to cyber-security and privacy

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Investment Benefits, measured against: Co-ordination, Interoperability (5.4.5.2.B.4)
	Co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)
	This project did not require co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry.
	Potential to Enable Future Technological Functionality (5.4.5.2.B.4.b-1)
	Not applicable
	Potential to Address Future Operational Requirements (5.4.5.2.B.4.b-2)
	InnPower designs projects according to the life expectancy of the assets being installed. The use of new technology for immediate system benefit, or enabling the future use of new technology is factored into the project design.
	Investment Benefits, measured against: Economic Development (5.4.5.2.B.5)
	N/A
	Investment Benefits, measured against: Environmental Benefits: (5.4.5.2.B.6)
	Timely repair of equipment containing oil will help prevent oil leaks that could have an impact on the environment.

Project Name: Station Rehab	
Category-specific requirements for System Renewal Investments (5.4.5.2.C.b)	
Category-Specific Requirements for System Renewal Projects (5.4.5.2.C.b)	**Description of the Characteristics of the Assets Targeted (5.4.5.2.C.b.i)**
	All infrastructure within a substation including Electrical, Mechanical, Civil and Environmental that have been annotated in the Distribution Station Asset Condition Assessment report as needing repair or upgrade are targeted by this program.
	- Consequences of Asset Performance Deterioration or Failure
	Further deterioration or failure of the assets would effect InnPower's operational effectiveness, reliability and substation safety.
	Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)
	The project involves investment to repair/replace substation infrastructure required for the continued safe and reliable operation of InnPower's legacy substations.
	Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)
	The assets targeted have all exceeded the typical life cycle.
	- Performance Record of the Assets Targeted (5.4.5.2.C.b.i.2a)
	Inspection, test records are provided in the substation asset condition assessment report. As the project targets all aspects of the substation e.g. Civil, Structural etc. some performance records cannot be quantified
	Number of Customers Affected by given Asset Failure (5.4.5.2.C.b.i.3)
	On an average 1500 customers are connected to each substation, these would be impacted as a consequence of an asset failure
	Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)
	N/A
	Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)
	N/A
	Value of Customer Impact (5.4.5.2.C.b.i.6)
	Medium, the customer will experience an improvement to public safety, and increased reliability
	Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)
	The Asset Condition Assessment report outlined a prescribed methodology for evaluating the urgency for replacement. This report provided a basis for pacing of the projects. Each major (and some minor) asset's condition was evaluated and rated as: "immediate intervention required", "replace in 2-5 years", and "replace in 5-10 years". As the study was done in 2015 all assets noted in the first two categories would be considered for the current project year.

<table>
<tr><td rowspan="18">Category-Specific Requirements for System Renewal Projects (5.4.5.2.C.b)</td><td>Investment Intensity (Asset Replacement Rate; 5.4.5.2.C.b.ii.a):</td></tr>
<tr><td>2 stations will be selected in 2017. On an average 1 to 2 substations will be refurbished in a given year, based on extent of repairs and upgrades required in each, as outlined in the Distribution Asset Condition Assessment report</td></tr>
<tr><td>Project Priority Relative to Other Projects (5.4.5.2.C.b.ii.b)</td></tr>
<tr><td>High, As this project impacts a large number of customers it is given a higher priority than line work</td></tr>
<tr><td>Impact on System O&M Costs (5.4.5.2.C.b.iii)</td></tr>
<tr><td>This project will have no material impact on O&M expenditures, except as noted below for the do-nothing scenario..</td></tr>
<tr><td>- O&M Cost Impact of Not implementing Project</td></tr>
<tr><td>By not implementing this project the O&M cost of the substation are expected to increase, these costs pertain to temporary repairs to fencing, frequent vegetation management, temporary oil leak repairs etc.</td></tr>
<tr><td>Impact on Reliability Performance and/or Safety Factors (5.4.5.2.C.b.iv)</td></tr>
<tr><td>Impact to Safety: By addressing "step" and "touch potential" issues at the station we will be increasing public and worker safety. Repairing the fencing will keep the public out of harms way and further contribute to public safety. Impact to Reliability: As aging infrastructure is replaced outages (momentary and permeant) due to "end of life" failures will be avoided</td></tr>
<tr><td>Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)</td></tr>
<tr><td>The timing of this project is determined by InnPower's substation asset condition assessment study, and its overall asset management process.</td></tr>
<tr><td>Like for Like Renewal Analysis, Alternatives Comparison (like-for-like vs. not like-for-like, timing, rate of replacement, etc. (5.4.5.2.C.b.vi)</td></tr>
<tr><td>Assets renewed in this program are replaced on a like-for-like basis</td></tr>
</table>

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Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name: **Substandard Transformer Rehab**

Project number: DO 002 **Budget Year:** 2017

Investment Category: System Renewal

Project Summary:

This program addresses the aging (end of life) and sub-standard transformer installations that do not conform to Electrical Safety Authority (ESA) Standards where the transformer is installed below the secondary buss. In 2017 InnPower will perform work to upgrade 7 installations of substandard construction.

This method of framing was common practice in earlier years of construction to conserve on pole height. These installations now pose a reliability issue (due to end of life) as well as safety risk (due to clearances) to staff and the public, while working on or in the vicinity of these installations.

There are an estimated 16 remaining installation spread across InnPower's service territory with this type of substandard construction. InnPower plans to pace the replacement of these end of life equipment that pose a safety hazard over the next four years.

Total capital and non-capitalized O&M costs (5.4.5.2.A.i)

	Historical Capital Costs				
	2012	2013	2014	2015	2016
Total cost	$ 27,623	$ 179,665	$ 131,794	$ 103,000	$ 109,505
Contributions	$ -	$ -	$ -	$ -	$ -
Net cost	$ 27,623	$ 179,665	$ 131,794	$ 103,000	$ 109,505
O&M expense	Undetermined	Undetermined	Undetermined	Undetermined	Undetermined

	Future Capital Costs				
	2017	2018	2019	2020	2021
Total cost	$ 85,000	$ 30,000	$ 31,500	$ 33,075	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Net cost	$ 85,000	$ 30,000	$ 31,500	$ 33,075	$ -
O&M expense	Undetermined	Undetermined	Undetermined	Undetermined	Undetermined

Customer Attachments and Load (5.4.5.2 A.ii)

Various.

Project Dates & Expenditure Timing (5.4.5.2.A.iii)

Start Date:	01-Jan-17			
In Service Date:	31-Dec-17			
Expenditure Timing	2017: Q1	2017: Q2	2017: Q3	2017: Q4
	25%	25%	25%	25%

General Information on Project (5.4.5.2.A)	
	Schedule Risks Risk Mitigation (5.4.5.2.A.iv)
	Factors that affect the schedule of this program include equipment lead times, engineering design, field staff availability and third party cooperation (locates, road occupancy, municipal consents and approvals from outside agencies). InnPower mitigates these risks through the planning process which includes close communication with all parties involved, and through schedule risk assessment throughout the project planning and execution phases. InnPower also uses the option to employ contractors for both engineering design and approval, and field labour to meet scheduling requirements.
	Comparative Information on Expenditure from Equivalent Projects (5.4.5.2.A.v)
	Please see table above for this information.
	Total Capital and OM&A costs associated with REG investment (5.4.5.2.A.vi)
	There will be no Capital and OM&A costs associated with REG investment on this project.
	Leave to Construct Approval (5.4.5.2.A.vii)
	Not required for this type of work under Section 92 of the Ontario Energy Board Act 1998
	Related Project Reference Material i.e. Images, Drawings and or Reference Material
	N/A

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Project Name: Substandard Transformer Rehab
	Investment Benefits, measured against: Efficiency, Customer Value & Reliability (5.4.5.2.B.1)
	Main Driver (5.4.5.2.B.1.a-1):
	System Renewal
	- Main "Trigger" (5.4.5.2.B.1.a-1.1):
	Assets/asset systems at end of service life due to failure risk
	Secondary Driver (5.4.5.2.B.1.a-2):
	System Service
	- Secondary "Trigger" (5.4.5.2.B.1.a-2.1):
	Meets system operational objectives: (1) safety and (2) other performance/functionality
	Objective or Performance Target to be Achieved (5.4.5.2.B.1.a-3):
	Primary: Reliability; Secondary: Customer value.
	Additional: Safety
	Background information that ties in with Asset Management Process (5.4.5.2.B.1.a-3):
	This project meets the objectives of ensuring public, worker and third party safety well maintaining system reliability, and managing costs, which are part of InnPower's Asset Management process.
	Overview of Investment Prioritization Justification (5.4.5.2.B.1.b)
	InnPower would prioritize locations based on several factors, these include pole condition, transformer age as well as geographic location, and third party attachments including streetlights.
	Project Identification and Selection (5.4.5.2.B.1.b-1)
	See above.
	Project Prioritization (5.4.5.2.B.1.b-2)
	Projects under this program are prioritize based on risk of failure and risk to safety.
	Project Pacing (5.4.5.2.B.1.b-3)
	InnPower plans to pace the remaining work over 4 years. The work has been scheduled as follows: 2017: 7 installations 2018 - 2020: 3 installation per year.
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)
	- Alternate Considerations - Design (5.4.5.2.B.1.c-1)
	InnPower designs jobs under this project to meet current engineering design standards.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	- Alternate Considerations - Schedule (5.4.5.2.B.1.c-2)
	InnPower collaborates both internally, as well as with third parties, for future road widening, third party attachments or municipal work which may be combined into a single project in order to lower costs.
	- Alternate Considerations - Funding/Ownership (5.4.5.2.B.1.c-3)
	N/A
	Effect of Investment on System Operation Efficiency and Cost-Effectiveness (5.4.5.2.B.1.c.i)
	Pro-active replacement which is routinely performed during regular business hours is often a more cost effective way of upgrading substandard transformers compared to waiting until a failure occurs. By designing systems to the up to date standards, additional connections of pole components are both safer, more accessible, and more reliable.
	Net Benefits Accruing to Customers as a Result of the Investment (5.4.5.2.B.1.c.ii)
	System Reliability and General Safety.
	Impact of the Investment on Reliability Performance including on the Frequency and Duration of Outages (5.4.5.2.B.1.c.iii)
	By designing systems to the current standards and by replacing end of life assets before failure, InnPower will be stabilizing reliability and be better equipped to meet outage duration targets.
	Projected Improvement to SAIFI (System Average Interruption Frequency Index): See Above
	Projected Improvement to SAIDI (System Average Interruption Duration Index):See above
	Impact of the Driver(s), "Trigger" or other, on the DESIGN of the Project (5.4.5.2.B.1.c-4)
	Existing legacy design is upgraded to current standards.
	Impact of the Driver(s), "Trigger" or other, on the COMPONENT CHARACTERISTICS of the Project (5.4.5.2.B.1.c-5)
	Components are selected to meet current InnPower standards and specifications.
	Impact of the Driver(s), "Trigger" or other, on the WORK PLAN of the Project (5.4.5.2.B.1.c-6)
	The work plan, triggered by the need to upgrade to current standards as well as replace end of life assets, is developed and executed in a manner that will minimize cost and risk.
	Investment Benefits, measured against: Safety (5.4.5.2.B.2)
	This project will provide safety benefits to the general public, internal staff as well as third parties. With designs upgraded to meet current clearance specifications, the chance of contact is minimized.
	Investment Benefits, measured against: Cyber-security, Privacy (5.4.5.2.B.3)
	N/A

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Investment Benefits, measured against: Co-ordination, Interoperability (5.4.5.2.B.4)
	Co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)
	Replacement is coordinated with all utilities as well as third parties that may look for future attachment points.
	Potential to Enable Future Technological Functionality (5.4.5.2.B.4.b-1)
	N/A
	Potential to Address Future Operational Requirements (5.4.5.2.B.4.b-2)
	During design consideration is given to future projects which may require larger poles and or transformer.
	Investment Benefits, measured against: Economic Development (5.4.5.2.B.5)
	N/A
	Investment Benefits, measured against: Environmental Benefits: (5.4.5.2.B.6)
	N/A

Project Name: Substandard Transformer Rehab		
Category-specific requirements for System Renewal Investments (5.4.5.2.C.b)		
Category-Specific Requirements for System Renewal Projects (5.4.5.2.C.b)	**Description of the Characteristics of the Assets Targeted (5.4.5.2.C.b.i)**	
	Transformers that are of a substandard design and are reaching an end of typical service life are identified for upgrade under this program.	
	- Consequences of Asset Performance Deterioration or Failure	
	Deterioration or failure will impact customer reliability and outage duration.	
	Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)	
	The substandard transformer project is proactive in nature. If this project does not move forward, it will have a high probability of impacting InnPower's reliability and outage duration targets.	
	Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)	
	The transformers that would be replaced as part of this project are generally 40-50 years of age and nearing end of useful life. Asset condition varies from case to case.	
	- Performance Record of the Assets Targeted (5.4.5.2.C.b.i.2a)	
	The assets targeted have generally performed a full life, providing 40-50 years of service.	
	Number of Customers Affected by given Asset Failure (5.4.5.2.C.b.i.3)	
	Affected customers due to failure may range from 1 to 12 depending on size of transformer being replaced.	
	Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)	
	The quantitative customer impact varies on a case by case basis.	
	Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)	
	The qualitative impact is lowering the outage duration.	
	Value of Customer Impact (5.4.5.2.C.b.i.6)	
	The value of customer impact varies on a case by case basis.	
	Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)	
	Once a location is selected the factors affecting timing are primarily engineering approvals for the design and coordinating pole and component delivery, and crew coordination. Third party cooperation needs to be arranged to complete projects in a timely manner. These include: hydro vacuuming services, locating services, road occupancy permits, and municipal or other approval agencyconsents.	
	Investment Intensity (Asset Replacement Rate; 5.4.5.2.C.b.ii.a):	
	With an estimated 16 locations remaining within the service area, InnPower will budget based on previous years to have all locations replaced within the next 4 years.	

Category-Specific Requirements for System Renewal Projects (5.4.5.2.C.b)	
	Project Priority Relative to Other Projects (5.4.5.2.C.b.ii.b)
	Due to the substandard nature of the remaining 16 locations, priority will be given to locations with the most customer impact.
	Impact on System O&M Costs (5.4.5.2.C.b.iii)
	These projects do not materially impact system O&M costs.
	- O&M Cost Impact of Not implementing Project
	N/A
	Impact on Reliability Performance and/or Safety Factors (5.4.5.2.C.b.iv)
	This project will help provide better reliability and safety as older assets will be replaced. Benefits contributing to safety for third party attachments are gained through a greater clearance from the electrical assets as well as more clearances for new connections.
	Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)
	Replacement is based mainly by age of asset, location and risk, which are then scheduled for the budget year.
	Like for Like Renewal Analysis, Alternatives Comparison (like-for-like vs. not like-for-like, timing, rate of replacement, etc. (5.4.5.2.C.b.vi)
	Project is based on replacement of substandard design, all locations are brought to current standards.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name **Transformers**

Project number: DO 010 **Budget Year:** 2017

Investment Category: System Renewal

Project Summary

This is a program consisting of individual projects and investments related to the upgrade and replacement of distribution transformers in InnPower's distribution system. Work within this section covers the replacement of faulty overhead and underground transformers with new units, replacing overloaded overhead and underground transformers with higher capacity units and recovering value from scrapping defective unrepairable transformers. The overall capital requirements for this project is an estimate based on past spending levels (given typical annual failure rates and typical overloading rates for transformers), and the recommendation contained within the Transformer Asset Condition Assessment. Detailed planning is not available for this program.

Total capital and non-capitalized O&M costs (5.4.5.2.A.i)

	Historical Capital Costs				
	2012	2013	2014	2015	2016
Total cost					$ 120,000
Contributions					$ -
Net cost					$ 120,000
O&M expense					undetermined

	Future Capital Costs				
	2017	2018	2019	2020	2021
Total cost	$ 100,000	$ 110,000	$ 121,000	$ 133,100	$ 146,410
Contributions	$ -	$ -	$ -	$ -	$ -
Net cost	$ 100,000	$ 110,000	$ 121,000	$ 133,100	$ 146,410
O&M expense	undetermined	undetermined	undetermined	undetermined	undetermined

Customer Attachments and Load (5.4.5.2 A.ii)

Customer attachments and load varies.

Project Dates & Expenditure Timing (5.4.5.2.A.iii)

Start Date:	01-Jan-17			
In Service Date:	31-Dec-17			
Expenditure Timing	2017: Q1	2017: Q2	2017: Q3	2017: Q4
	15%	30%	40%	15%

General Information on Project (5.4.5.2.A)	
	Schedule Risks & Risk Mitigation (5.4.5.2.A.iv)
	Transformer upgrade projects are partially driven by customer requests. InnPower, therefore has very limited control over the scope and timing of these projects. InnPower reviews customer upgrade requests on a regular basis such that transformer upgrades are identified in a timely manner to accommodate all customer needs. Each request for new or upgraded service connection is reviewed both by a Technician and an Engineer to determine proper sizing of transformer. If the rating for the existing unit is too low then the decision is made to upgrade the unit with a larger size at the time of connection. InnPower will work with customers to control timing of these projects such that customer expectations are met. Transformer replacement projects are driven by asset health. InnPower performs inspections and maintenance work to prolong asset life and to identify assets that are at risk for failure, in order to plan requirements for replacement.
	Comparative Information on Expenditure from Equivalent Projects (5.4.5.2.A.v)
	InnPower is currently working on implementing new procedures to better track transformer costs. Transformer upgrade and replacement project/activities do not have a direct comparator.
	Total Capital and OM&A costs associated with REG investment (5.4.5.2.A.vi)
	There are no REG investments associated with this work.
	Leave to Construct Approval (5.4.5.2.A.vii)
	Leave to Construct approval is not required.

General Information on Project (5.4.5.2.A)

Related Project Reference Material i.e. Images, Drawings and or Reference Material

Transformers are provided in accordance with InnPower's Conditions of Service. Connection details vary widely within that standard. Transformer replacement forecasts are based on InnPower's Distribution Asset Condition Assessment and Asset Management Plan, however, this project considers only transformers that are replaced or upgraded as stand-alone projects.

Supplemental Information Based on Distribution Asset Condition Assessment Report

Asset Replacement Plan 2017-2021*					
Asset Class	**2017**	**2018**	**2019**	**2020**	**2021**
Padmounted Transformers	9	9	9	8	8
Polemounted Transformers	50	50	50	50	50
Total	59	59	59	58	58

Summary of Asset Condition Results						
		Condition Results				
Asset Class	**Quantity**	**Very Good**	**Good**	**Fair**	**Poor**	**Very Poor**
		%	**%**	**%**	**%**	**%**
Padmount Transformers	1,128	39.70%	53.70%	6.60%	0.00%	0.00%
Polemount Transformers	2,146	11.70%	37.90%	38.80%	10.70%	1.00%

Distribution Transformer Health Index					
Asset Class	**Very Good**	**Good**	**Fair**	**Poor**	**Very Poor**
Padmount	433	620	75	0	0
Polemount	250	813	833	229	21
Total	**683**	**1433**	**908**	**229**	**21**

Distribution Transformer Age Profile						
Asset Class	**1-10 years**	**11-20 years**	**21-30 years**	**31-40 years**	**41-50 years**	**>50 years**
Padmount	341	368	312	52	41	2
Polemount	233	181	663	517	375	119
Platform	0	0	0	3	0	0
Unknown	1	1	1	7	7	0
Total	575	550	976	579	423	121

*** The above replacement plan was recommended by Metsco, the consultant on the Distribution Asset Condition Assessment study. However, due to the high cost of replacing the number of transformers noted above, InnPower will continue to monitor the need and manage the replacement program within the allotted budget.**

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Project Name Transformers
	Investment Benefits, measured against: Efficiency, Customer Value & Reliability (5.4.5.2.B.1)
	The main driver for this project is "System Renewal" which ties into the asset management objective "Maintaining System Reliability and Customer Value". Transformers are inspected regularly 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. Additionally, overloaded transformers are identified for replacement using InnPower's metering data, as presented in the Appendix of the Asset Condition Assessment report. Overloaded transformers are upgraded in a paced/controlled fashion, to avoid unnecessary and unplanned interruptions to customers.
	Main Driver (5.4.5.2.B.1.a-1):
	System Renewal
	- Main "Trigger" (5.4.5.2.B.1.a-1.1):
	Assets/asset systems at end of service life due to: failure
	Secondary Driver (5.4.5.2.B.1.a-2):
	System Access
	- Secondary "Trigger" (5.4.5.2.B.1.a-2.1):
	Assets/asset systems at end of service life due to failure risk (System Renewal) Customer connection request – if an upgrade to the transformer size is required (System Access)
	Objective or Performance Target to be Achieved (5.4.5.2.B.1.a-3):
	The objective of this program is to ensure reliable service to customers and meet existing and future demand levels.
	Primary: Reliability; Secondary: Customer value
	Additional: Safety and Environmental Benefits
	Background information that ties in with Asset Management Process (5.4.5.2.B.1.a-3.i):
	The secondary driver is the asset management objective "Maintaining System Reliability and Customer Value". Upgrading overloaded transformers, and transformers serving customers who request upgrades beyond the existing transformer capacity, ensures that service is maintained to customers during periods of higher loading. Additionally, changes to capacity in the transformer enable customers to upgrade their service size without affecting service reliability. InnPower also creates customer value by recovering salvage value from scrapping defective transformers.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Overview of Investment Prioritization Justification (5.4.5.2.B.1.b)
	This program is of high priority relative to other material investments as it directly affects InnPower's ability to supply electricity to its customers. Additionally, part of its allocation is the replacement of transformers that have failed unexpectedly and have resulted in an interruption to the customers' services until they are replaced and therefore cannot be deferred. Project planning will be coordinated with other projects/programs of the same priority level.
	Project Identification and Selection (5.4.5.2.B.1.b-1)
	Reactive transformer replacement: Failed transformers are replaced immediately. Proactive transformer replacement: These are identified through InnPower's visual inspection programs and the Asset Loading database for transformers. Proactive replacement criteria include: • Transformers that have visibly deteriorated and have a high risk of imminent failure; • Transformers that have visible oil leaks; and • Transformers that have been flagged for consistent overloading.
	Project Prioritization (5.4.5.2.B.1.b-2)
	Reactive transformer replacement receive highest priority to reduce customer outage duration. Proactive transformer replacements are identified through InnPower's visual inspection programs and Asset Loading database for transformers and are prioritized based on the Asset Management Process.
	Project Pacing (5.4.5.2.B.1.b-3)
	Through its asset inspection program and transformer loading analysis InnPower is able to plan proactive replacement jobs in a manner that enables a well paced schedule of replacement.
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)
	- Alternate Considerations - Design (5.4.5.2.B.1.c-1)
	Typically pole construction design changes are not required, except when safety issues are identified in the field. In such instances the job is engineered and constructed to current standards. In every instance, however, when a load is increased on a pole the design is reviewed and pole calculation / stress analysis is performed.
	- Alternate Considerations - Schedule (5.4.5.2.B.1.c-2)
	Reactive replacement: The schedule is determined by the rate of failure. Proactive replacement: The schedule for replacement will be determined through the prioritization process performed according to the Asset Management process.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	- Alternate Considerations - Funding/Ownership (5.4.5.2.B.1.c-3)
	The replacement of transformers follows InnPower's Conditions of Service. Where ownership and funding opportunities exist i.e. due to the size of a customer's service or where the upgraded transformer would exceed the capacity provided for in the Conditions of Service, alternate arrangements for ownership/customer contribution will be made. In general, where options are available with respect to design, scheduling, funding or ownership, the most effective overall alternative will be selected.
	Effect of Investment on System Operation Efficiency and Cost-Effectiveness (5.4.5.2.B.1.c.i)
	Overloaded transformers are replaced with transformers of appropriate capacity, which avoids interruptions due to the transformer protective device operating from extreme overloadingconditions.
	Net Benefits Accruing to Customers as a Result of the Investment (5.4.5.2.B.1.c.ii)
	Although this program is not intended for system access improvements, it is expected to have a positive impact on InnPower's ability to process customer service upgrade requests and new connections.
	Impact of the Investment on Reliability Performance including on the Frequency and Duration of Outages (5.4.5.2.B.1.c.iii)
	This program decreases the frequency and duration of outages by seeking to replace transformers which are in very poor condition in a controlled manner. Although this project is intended to stabilize, if not improve, reliability a detailed calculation has not been performed to ascertain SAIDI and SAIFI impact
	Projected Improvement to SAIFI (System Average Interruption Frequency Index): see comments above.
	Projected Improvement to SAIDI (System Average Interruption Duration Index): see comments above.
	Impact of the Driver(s), "Trigger" or other, on the DESIGN of the Project (5.4.5.2.B.1.c-4)
	Transformer design complies with InnPower's approved transformer specification. A job requiring pole design is approved by a professional engineer to ensure compliance with InnPower's design standards.
	Impact of the Driver(s), "Trigger" or other, on the COMPONENT CHARACTERISTICS of the Project (5.4.5.2.B.1.c-5)
	The configuration of the transformer characteristics will comply with InnPower's approved transformer specification.
	Impact of the Driver(s), "Trigger" or other, on the WORK PLAN of the Project (5.4.5.2.B.1.c-6)
	The work plan for each job is arranged to meet customer requirements and is coordinated with equipment suppliers and InnPower's Operations Department and/or contractor to ensure cost efficiency.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Investment Benefits, measured against: Safety (5.4.5.2.B.2)
	This program helps to mitigate potential safety risks associated with events such as transformer oil leaking, transformer fires and internal equipment faults. New units will be constructed and installed in accordance to current safety standards. This program will have no adverse effects on health and safety protection and performance.
	Investment Benefits, measured against: Cyber-security, Privacy (5.4.5.2.B.3)
	Not applicable.
	Investment Benefits, measured against: Co-ordination, Interoperability (5.4.5.2.B.4)
	Transformer replacements at this level do not impact inter-utility coordination or regional planning activities. Coordination with customers and electricians is part of every project. Authorization from the Electrical Safety Authority may be required prior to reconnection of services if activities are being coordinated with a change to the customer's service and is handled through an established process.
	Co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)
	InnPower coordinates the work with 3rd party pole attachment companies (Bell, Rogers) on an as needed basis. Should the pole require redesign with the transformer installation or replacement; coordination with 3rd party pole attachment companies will be conducted.
	Potential to Enable Future Technological Functionality (5.4.5.2.B.4.b-1)
	Transformers that meet the current standards will be installed, which include modern internal protective devices (Internal Fault Detector-IFD), disconnect switches, pressure relief devices and internal fault identifying devices.
	Potential to Address Future Operational Requirements (5.4.5.2.B.4.b-2)
	Transformers are sized to the latest standards for operational needs, which could include available capacity for future load increases.
	Investment Benefits, measured against: Economic Development (5.4.5.2.B.5)
	This program is not designed to directly enable economic development, however the additional capacity provided through transformer upgrades may have a positive effect on enabling economic development on a small scale. InnPower ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Investment Benefits, measured against: Environmental Benefits: (5.4.5.2.B.6)
	N/A

<table>
<tr><td colspan="2">Project Name Transformers</td></tr>
<tr><td colspan="2">Category-specific requirements for System Renewal Investments (5.4.5.2.C.b)</td></tr>
<tr><td rowspan="10">Category-Specific Requirements for System Renewal Projects (5.4.5.2.C.b)</td><td>Description of the Characteristics of the Assets Targeted (5.4.5.2.C.b.i)</td></tr>
<tr><td>Transformers to be replaced; will be those that have been deemed unfit by a competent and qualified person (as defined in InnPower's Construction Verification Program). These usually include units that have: failed due to internal faults or have incurred damage due to external influences such as lightning, exterior tank rusting, and component damage or failure.

The methodology used to address the cause for the need for transformer replacement includes:
(1) Analysis of failure;
(2) Review of opportunity for load balancing (for overloaded transformers) among adjacent transformers in a cost effective manner; and
(3) Analysis of current and future loading of a transformer for new installations and upgrades.</td></tr>
<tr><td>- Consequences of Asset Performance Deterioration or Failure</td></tr>
<tr><td>This project fulfills InnPower's goals of meeting its reliability targets by contributing to stabilize, if not improve, SAIDI, SAIFI, and other customer specific reliability indices. This project also supports safety targets by creating a safer work environment through the removal of transformers in poor condition.

Finally, this project supports InnPower's customer centric focus and service quality targets by removing the risk of lengthy and unplanned outages from unexpectedly failed or overloaded distribution transformers.</td></tr>
<tr><td>Asset Performance Target and Asset Lifecycle Optimization (5.4.5.2.C.b.i.1)</td></tr>
<tr><td>The transformers selected for proactive replacement represent a level of risk to InnPower. This project provides risk mitigation consistent with two of InnPower's asset management objectives: maintaining system reliability and mitigating environmental risk.</td></tr>
<tr><td>Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.i.2)</td></tr>
<tr><td>The asset condition of these transformers relative to their typical lifecycle varies from transformer to transformer.

In InnPower's past experience most transformers have failed towards the end of their life cycle, except when caused by external influences including lightning strike, or damage to components due to falling tree branches.

The transformers that are overloaded are not immediately disposed/scrapped, as they are not always at the end of their life; they are brought back to InnPower's warehouse for review by a competent and qualified person, as defined in InnPower's Construction Verification Program (CVP), for condition assessment.

Transformers selected for proactive replacement present a level of risk to InnPower either through imminent failure of the transformer or through the need to address environmental risk associated with transformers that have visible oil leaks.</td></tr>
</table>

Category-Specific Requirements for System Renewal Projects (5.4.5.2.C.b)	
	- Performance Record of the Assets Targeted (5.4.5.2.C.b.i.2a)
	InnPower has recently improved its record keeping process for transformers, which include: load tracking and analysis, improved asset registry, asset tracking and costing, and asset inventory management.
	Number of Customers Affected by given Asset Failure (5.4.5.2.C.b.i.3)
	Varies per project.
	Quantitative Customer Impact and Risk (5.4.5.2.C.b.i.4)
	At this time InnPower 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 the failed transformers, and the configuration and/or location of the transformers (ease of replacement). Additionally, the number of customers potentially impacted by overloaded transformer will depend on load increases throughout the year and the number of transformers and associated customers affected. The number of customers affected by requests that trigger transformer upgrades will depend on customer demand for service upgrades.
	Qualitative Customer Impact and Risk (5.4.5.2.C.b.i.5)
	The completion of this program will ensure that InnPower's system reliability is not negatively impacted by excessive transformer failures. Replacement of overloaded transformers with appropriately sized units will also reduce the risk of overload related service interruptions in the future. These improvements will enhance overall customer satisfaction. Additionally, customers will benefit from the upgrading of overloaded transformers through the enabling of potential service upgrades.
	Value of Customer Impact (5.4.5.2.C.b.i.6)
	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. Where conflicting demands prevent all transformers falling within this program from being completed, the most critical units (those affecting the largest number of customers, and those having the largest cost of failure) will be prioritized over others.
	Other Factors Affecting Project Timing (5.4.5.2.C.b.ii)
	This program is comprised of multiple projects. The timing and priority of these projects vary. Timing is directed by incidents of failure, when overloading is detected or when an asset becomes flagged for replacement after investigating its condition data. Units which have failed and are out of service have the highest priority and must be replaced immediately to restore power to customers. Units which are overloaded or in poor condition will be prioritized based on the potential impact to connected customers and the ability to perform the work.
	Investment Intensity (Asset Replacement Rate; 5.4.5.2.C.b.ii.a):
	The intensity of InnPower's investment is levelized through systematic inspection, loading review, and planning.

Category-Specific Requirements for System Renewal Projects (5.4.5.2.C.b)	**Project Priority Relative to Other Projects (5.4.5.2.C.b.ii.b)**
	Failed transformers receive high priority. The proactive replacement process considers the following parameters for work prioritization: (1) rating of Asset Condition Assessment, and risk of failure / risk to the environment, and (2) level of overloading; transformers overloaded to higher percentages (i.e. >250%) of rated load receive a higher priority compared to those with lower overload readings (i.e. 100%-250%).
	Impact on System O&M Costs (5.4.5.2.C.b.iii)
	These projects do not materially impact system O&M costs.
	- O&M Cost Impact of Not implementing Project
	These projects do not materially impact system O&M costs.
	Impact on Reliability Performance and/or Safety Factors (5.4.5.2.C.b.iv)
	The impact this project will have on reliability performance and safety is as follows: - InnPower's current standards for new transformers include internal protective devices (Internal Fault Detector-IFD), disconnect switches, pressure relief devices and internal fault identifying devices, which help isolate faults and reduce area outages. In some cases it will minimize the extent of danger to public safety during a failure event. - Reliability is improved by removing assets with very low health from the system prior to an uncontrolled failure, upgrading overloaded transformers prior to an overcurrent related failure and coordinating construction activities to minimize service interruptions.
	Analysis of Project Benefits and Timing (5.4.5.2.C.b.v)
	InnPower identifies and selects projects through processing of customer requests, inspection, and data analysis. The Asset Condition Assessment includes estimated numbers of transformers which will require replacement either through this program or through line reconstruction work. The estimated timing of asset replacement investments is levelized on the long term. InnPower uses this information to determine the expected project timing. Completing this annual program will stabilize, if not improve, overall reliability and improve public and employee safety. The timing of this project could be affected by the availability of materials and the unknown timing of sudden asset failures, or shifts in load causing overloaded conditions. Mitigation plans are in place for these possibilities including spare stock management, load forecasting and monitoring and Asset Condition Assessments, which seek to predict replacement timing and needs, and ensure appropriate resources are in place. Costs of the project may be affected by the actual rates of failures and overloading, as well as the capacities and configurations of the transformers affected. While there is some uncertainty in the cost and timing of the project, delaying portions of this project beyond the forecast period may cause the risk of failure to increase dramatically and will reduce some of the project benefits, such as the reduction of risk and outages. More transformers will likely need replacement at a later date (after failure), which will result in longer unplanned outages and a decrease in customer satisfaction.

Category-Specific Requirements for System Renewal Projects (5.4.5.2.C.b)	**Like for Like Renewal Analysis, Alternatives Comparison (like-for-like vs. not like-for-like, timing, rate of replacement, etc. (5.4.5.2.C.b.vi)**
	Like for like construction will be utilized where practical, particularly for failed assets or assets at the end of their life, if such transformers meet the current safety standards, a similar unit will be installed in the same location and fashion. Where transformers are being upgraded, like for like construction is not an option due to the need to install larger capacity units, which may involve upgrading other accessory devices to match the higher capacity. The rate of replacement is determined by InnPower's Asset Condition Assessment results, customer requests for new service and service upgrades, failure, and loading changes.

Capital Project Summary

to meet
Ontario Energy Board
Filing Requirements
for
Electricity
Transmission
and
Distribution
Applications

Chapter 5
Section 4.5.2

Material Investments

2017 System Service Projects

innpower

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name **Repoling: 5 SR - McKay Road to Salem Road**

Project number: DO 013 **Budget Year:** 2017

Investment Category: System Service

Project Summary:

This investment in 2017 will repole approximately 11 poles with sub transmission and distribution feeders on 5th Side Road between McKay Road and Salem Road by adding one (1) subtransmission circuit and two (2) distribution circuits to serve new load in the Salem development area.

Over the next 15 years the addition of new loads up to 80MW is planned for the "green field" area development in South Barrie (also known as the Barrie annexed lands).
These lands are serviced by InnPower, and the new loads which will be phased in will need to be serviced by InnPower starting in the 2017/2018 timeframe.

The annexed lands are divided into two development sections namely "Hewitt development" and "Salem development" for a total planned load increase of 80MW. The purpose of this project is to service the new load growth in the Salem area developments (up to 40MW).

InnPower currently has a single phase of a 8.32kV circuit (4.8kV) and a 44kV subtransmission circuit which can not meet the projected load requirement. The purpose of this project is to convert the pole line to accommodate one more 44kV and two 3-phase 27.6kV distribution circuits. This repoling work will include a total of 26 poles. InnPower will do this project in two phases. The first phase will be completed later in 2016 with 15 poles, and the 11 remaining poles will be replaced in 2017.

Total capital and non-capitalized O&M costs (5.4.5.2.A.i)

	Historical Capital Costs				
	2012	2013	2014	2015	2016
Total cost					$ 362,573
Contributions					$ -
Net cost					$ 362,573
O&M expense					Undetermined

	Future Capital Costs				
	2017	2018	2019	2020	2021
Total cost	$ 273,427	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Net cost	$ 273,427	$ -	$ -	$ -	$ -
O&M expense	Undetermined				

Customer Attachments and Load (5.4.5.2 A.ii)

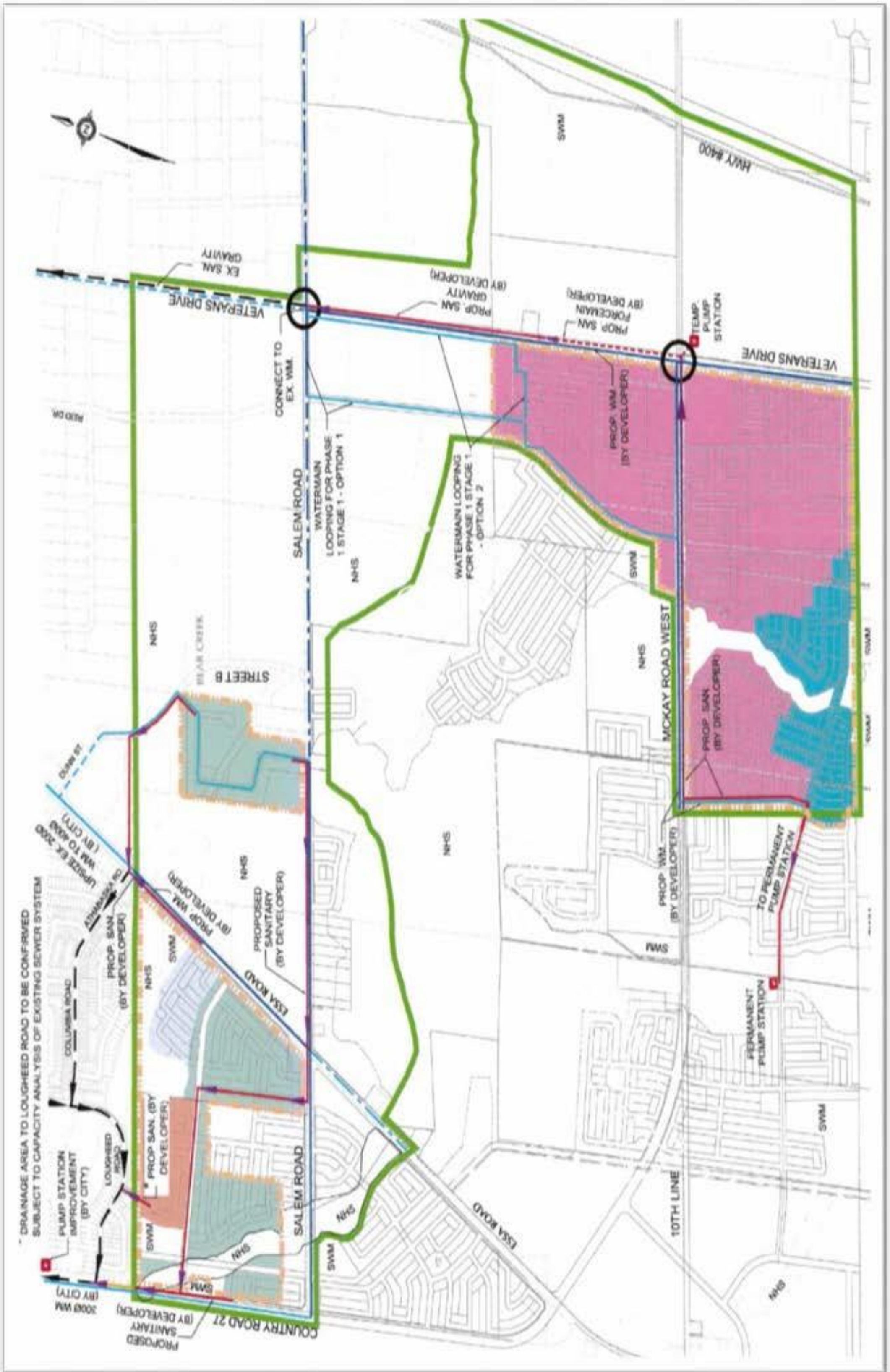
2,852 Customers in total for PH1 of the development; i.e. 10.8MVA

General Information on Project (5.4.5.2.A)					
	Project Dates & Expenditure Timing (5.4.5.2.A.iii)				
	Start Date:	01-Jan-17			
	In Service Date:	31-Dec-17			
	Expenditure Timing	2017: Q1	2017: Q2	2017: Q3	2017: Q4
		5%	20%	65%	10%
	Schedule Risks & Risk Mitigation (5.4.5.2.A.iv)				
	The schedule of this project is dependent on the following: (a) Developers Plans and Environmental Assessment (EA) approvals, (b) Approval from 3rd party agencies, and (c) Municipal Consent. To mitigate the risks in schedule InnPower is working with the developers, land owner groups and the City of Barrie on a quarterly basis. Effective collaboration with all parties through frequent meetings enables InnPower to closely monitor the progress of the development and plan its line repoling work accordingly.				
	Comparative Information on Expenditure from Equivalent Projects (5.4.5.2.A.v)				
	The expenditure for this project has been derived using the historical per pole/span cost of a circuit built with the same configuration. This cost has been adjusted to reflect changes in labour rates and material price increases.				
	Total Capital and OM&A costs associated with REG investment (5.4.5.2.A.vi)				
	For this project there are no Capital and OM&A costs associated with REG investment.				
	Leave to Construct Approval (5.4.5.2.A.vii)				
	This project does not require “Leave to Construct” under Section 92 of the Ontario Energy Board Act 1998.				

General Information on Project (5.4.5.2.A)

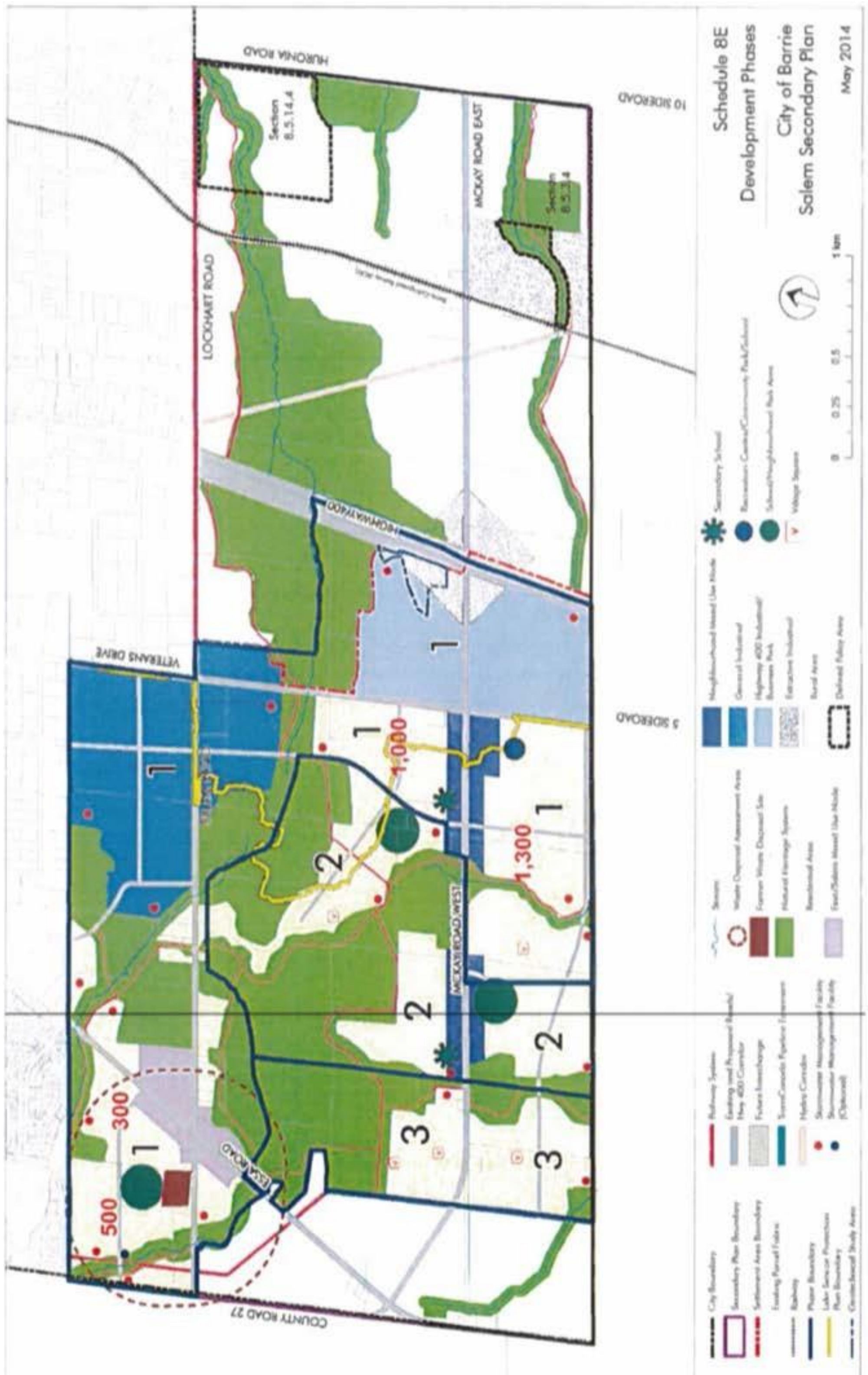
Related Project Reference Material i.e. Images, Drawings and or Reference Material

Salem Land Development Map - Phase 1



General Information on Project (5.4.5.2.A)

Salem Land Development - Phase 1 with estimated customer increase



Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Project Name Repoling: 5 SR - McKay Road to Salem Road
	Investment Benefits, measured against: Efficiency, Customer Value & Reliability (5.4.5.2.B.1)
	Main Driver (5.4.5.2.B.1.a-1):
	System Service
	- Main "Trigger" (5.4.5.2.B.1.a-1.1):
	Changes in load that will constrain the ability of the system to provide consistent service delivery.
	Secondary Driver (5.4.5.2.B.1.a-2):
	System Access
	- Secondary "Trigger" (5.4.5.2.B.1.a-2.1):
	Customer service requests for connections (both new and modification to existing)
	Objective or Performance Target to be Achieved (5.4.5.2.B.1.a-3):
	Primary: Customer value
	Additional: Co-ordination, Interoperability, and Economic Development
	Background information that ties in with Asset Management Process (5.4.5.2.B.1.a-3.i):
	The asset management process has identified the circuit planned to be re-built and extended as one that cannot meet the new load growth requirements.
	Overview of Investment Prioritization Justification (5.4.5.2.B.1.b)
	The project has been prioritized based on the plans and schedules provided by the City of Barrie and the developers for the Salem Lands. InnPower employs a "Just in time" investment strategy, and therefore the project aligns with the projected dates for building permits issuance from the City of Barrie.
	Project Identification and Selection (5.4.5.2.B.1.b-1)
	The project was identified based on the requirements for new loads connecting on to InnPower's distribution system. The selection criteria was based on a "just in time" construction and investment strategy.
	Project Prioritization (5.4.5.2.B.1.b-2)
	For these types of projects "just in time" investment and construction strategy, projects are prioritized based on the needs of developers (new customers) and construction schedules of new subdivisions. The timing and/or priority of this project was based upon the construction permits and schedules of the new sub-divisions.
	Project Pacing (5.4.5.2.B.1.b-3)
	InnPower intends to conduct preliminary designs in 2016, with construction drawings planned for completion in Q1 2017. Construction for the project with commence (continue from earlier phase) and complete in Q3.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)
	- Alternate Considerations - Design (5.4.5.2.B.1.c-1)
	Alternative design considerations included the possibility of adding a distribution station in the Salem Lands in the near term. This option was not cost effective.
	- Alternate Considerations - Schedule (5.4.5.2.B.1.c-2)
	Alternate considerations for schedule included completing the full scope of the project in a single phase. This was however not selected as it would put burden on resource and budget allocation for the particular year.
	- Alternate Considerations - Funding/Ownership (5.4.5.2.B.1.c-3)
	InnPower will be solely funding the project. Alternative funding options are not applicable.
	Effect of Investment on System Operation Efficiency and Cost-Effectiveness (5.4.5.2.B.1.c.i)
	The investment would provide InnPower with better circuit tie capability on the 27.6kV distribution network. By having more tie points within a distribution network the overall system effectiveness and operation efficiency is increased.
	Net Benefits Accruing to Customers as a Result of the Investment (5.4.5.2.B.1.c.ii)
	The investment will provide service to new and existing customers.
	Impact of the Investment on Reliability Performance including on the Frequency and Duration of Outages (5.4.5.2.B.1.c.iii)
	Even though the primary driver for this project is not reliability, the investment will provide InnPower with additional circuit ties which would then provide better restoration capability during an outage. The new pole line for the 44kV sub-transmission network would also increase the reliability of the circuit.
	Projected Improvement to SAIFI (System Average Interruption Frequency Index): *N/A*
	Projected Improvement to SAIDI (System Average Interruption Duration Index): *N/A*
	Impact of the Driver(s), "Trigger" or other, on the DESIGN of the Project (5.4.5.2.B.1.c-4)
	The circuit design was based on "System service", the circuit will be designed to meet the new load criteria.
	Impact of the Driver(s), "Trigger" or other, on the COMPONENT CHARACTERISTICS of the Project (5.4.5.2.B.1.c-5)
	The components of the project are mainly pole, wire, service transformer, arrestors and insulators. Each of these components are selected based on InnPower's current engineering standards.
	Impact of the Driver(s), "Trigger" or other, on the WORK PLAN of the Project (5.4.5.2.B.1.c-6)
	The work plan is based upon the schedule of the developers. InnPower will develop the work plan based on the optimum use of outside contractors, these contractors are selected based on a competitive bidding process.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Investment Benefits, measured against: Safety (5.4.5.2.B.2)
	The project is not intended to address safety concerns with the distribution system.
	Investment Benefits, measured against: Cyber-security, Privacy (5.4.5.2.B.3)
	The project is not intended to address Cyber-Security, Privacy concerns with the distribution system.
	Investment Benefits, measured against: Co-ordination, Interoperability (5.4.5.2.B.4)
	Co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)
	InnPower participates in regional planning, both at an infrastructure level with the local municipalities and the county, and in the Integrated Regional Resource Planning (IRRP) group along with representatives from the Independent Electricity System Operator (IESO), Hydro One Networks Inc. (HONI), and PowerStream.
	Potential to Enable Future Technological Functionality (5.4.5.2.B.4.b-1)
	Not Applicable.
	Potential to Address Future Operational Requirements (5.4.5.2.B.4.b-2)
	Based on the numbers made available to us from the Salem land owner groups and the City of Barrie. The circuit design will accommodate all anticipated load requirements.
	Investment Benefits, measured against: Economic Development (5.4.5.2.B.5)
	As the sole purpose of this project is to service new loads, an increase in population within the area would trigger economic development as new businesses would be attracted.
	Investment Benefits, measured against: Environmental Benefits: (5.4.5.2.B.6)
	Not applicable.

Project Name: Repoling: 5 SR - McKay Road to Salem Road	
Category-specific requirements for System Service Investments (5.4.5.2.C.c)	
Category-specific requirements for System Service Investments (5.4.5.2.C.c)	**Benefits to Customers versus Cost Impact (5.4.5.2.C.c.i)**
	This investment will provide new customers in the Salem development area with safe and reliable access to power. With addition of new customers the investments will be levelized and therefore as new customers get added to our system the electricity rates will decrease in the future.
	Regional Electricity Infrastructure Requirements (5.4.5.2.C.c.ii)
	InnPower participates in regional planning, both at an infrastructure level with the local municipalities and the county, and in the Integrated Regional Resource Planning (IRRP) group along with representatives from the Independent Electricity System Operator (IESO), Hydro One Networks Inc. (HONI), and PowerStream.
	Integration of Advance Technology (5.4.5.2.C.c.iii)
	Not Applicable.
	Integration of Interoperability (5.4.5.2.C.c.iii-1)
	All new projects are constructed using approved construction standards in compliance with ESA Regulation 22/04. During sub-division developments InnPower attends frequent utility coordination site meetings, which allows for the coordination and planning of investment with other utilities.
	Integration of Cybersecurity (5.4.5.2.C.c.iii-2)
	The project is not intended to address Cyber-Security, Privacy concerns with the distribution System.
	System Benefits to Reliability (5.4.5.2.C.c.iv-1)
	Even though the primary driver for this project is not reliability, the investment will provide InnPower will additional circuit ties which would then provide better restoration capability during an outage. The new pole line for the 44kV sub-transmission network would also increase the reliability of the circuit.
	System Benefits to Efficiency (5.4.5.2.C.c.iv-2)
	The investment would provide InnPower with better circuit tie capability on the 27.6kV distribution network. By having more tie points within a distribution network the overall system effectiveness and operation efficiency is increased.
	System Benefits to Safety (5.4.5.2.C.c.iv-3)
	The project is not intended to address safety concerns with the distribution system.
	Factors Affecting Implementation Timing (5.4.5.2.C.c.v-1)
	The schedule of this project is dependent on the following: (a) Developers Plans and Environmental Assessment (EA) approvals, (b) Approval from 3rd party agencies, and (c) Municipal Consent.

Category-specific requirements for System Service Investments (5.4.5.2.C.c)	
	Factors Affecting Implementation Priority (5.4.5.2.C.c.v-2)
	For these types of projects "just in time" investment and construction strategy, projects are prioritized based on the needs of developers (new customers) and construction schedules of new subdivisions. The timing and/or priority of this project was based upon the construction permits and schedules of the new sub-divisions.
	Summary of Options Analysis (5.4.5.2.C.c.vi)
	The option to construct this line by converting the overhead lines to underground lines was considered but not selected as it was cost prohibitive.
	Analysis of project benefits and costs i.e. "Do Nothing" (5.4.5.2.C.c.vi-1)
	A "Do Nothing" scenario is not feasible for this project.
	Analysis of project benefits and costs i.e. "Technically feasible alternatives" (5.4.5.2.C.c.vi-2)
	All other technically feasible options were cost prohibitive these included all underground construction which is several times in magnitude of overhead construction and construction of a distribution substation in Salem lands in the near term. Typically the construction costs of a 10MVA two feeder 44kV/27.6kV distribution station are approx. $2.8million (this does not include land acquisition). As Salem area begins to expand further InnPower will need to construct a Distribution Station, however, this investment will not only postpone the need for it but will improve system efficiency and performance when the distribution station does get built in the future.
	Significant Benefits and Costs - the Value of which cannot readily be Quantified (5.4.5.2.C.c.-A)
	N/A

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name: **Repoling: Big Bay Point Road - Friday Harbour DS to Friday Harbour Development (North)**

Project number: DO 022 **Budget Year:** 2017

Investment Category: System Service

Project Summary

This project will re-pole the section of line from the proposed site of the new Friday Harbour distribution station to the north entrance of Friday Harbour development. The pole line is approximately 2,200 meters in length. Currently InnPower has a single 3-phase feeder on this section that is fed from its Big Bay Point station, rated at 8,320 volts.

The purpose of this project is to accommodate the anticipated load growth due to development at Friday Harbour. Based on the current load growth projections, while taking into consideration a conservative absorption rate, InnPower will run out of capacity at the existing Big Bay Point station in 2018 and will need to build the new Friday Harbour station in or before 2018 - we have currently budgeted for the station in 2018. In an effort to pace the work and in preparation to serve Friday Harbour residents in a timely manner, InnPower will re-pole this line of overhead circuitry in 2017.

The new poles will be framed for two (2) 3-phase distribution feeders; i.e. one new feeder and one existing feeder. The existing feeder that is rated at 8,320 volts will continue to serve existing customers; while the second (new) feeder will be rated at 27,600 volts and will serve Friday Harbour loads from the new Friday Harbour station.

Total capital and non-capitalized O&M costs (5.4.5.2.A.i)

	Historical Capital Costs				
	2012	2013	2014	2015	2016
Total cost					
Contributions					
Net cost					
O&M expense					

	Future Capital Costs				
	2017	2018	2019	2020	2021
Total cost	$ 362,570				
Contributions	$ -				
Net cost	$ 362,570				
O&M expense	Undetermined				

Customer Attachments and Load (5.4.5.2 A.ii)

Total anticipated customer count for Friday Harbour Development is 1,600 with an anticipated residential load of 5.13 MVA of residential load, plus commercial load for retail, boat docks, recreational area, golf course, pumping station, street lights, marina village, and hotel(s) and convention centre. The marina village, and hotel and convention centre loading was not known at the time of the preparation of this report.

General Information on Project (5.4.5.2.A)					
	Project Dates & Expenditure Timing (5.4.5.2.A.iii)				
	Start Date:	01-Jan-17			
	In Service Date:	31-Dec-17			
	Expenditure Timing	2017: Q1	2017: Q2	2017: Q3	2017: Q4
		10%	25%	60%	5%
	Schedule Risks & Risk Mitigation (5.4.5.2.A.iv)				
	The schedule of this project is dependent on the following: a) Developers Plans b)Town of Innisfil Draft Plan Approval of Development and c) signoff from other approval agencies - Region, MOE, Lake Simcoe Conservation Authority, Utilities. To mitigate the risks in schedule InnPower is working and meeting with the developer and the Town of Innisfil on a quarterly basis regarding progress and timing of the project. By meeting frequently InnPower is aware of the progress of the development and the Town of Innisfil is aware of InnPower's plans to serve the new load. Design approval process with 3rd party agency is already underway.				
	Comparative Information on Expenditure from Equivalent Projects (5.4.5.2.A.v)				
	The expenditure for this project has been derived using the historical per pole/span cost of a circuit built with the same configuration. This cost has been adjusted to reflect changes in labour rates and material price increases.				
	Total Capital and OM&A costs associated with REG investment (5.4.5.2.A.vi)				
	For this project there are no Capital and OM&A costs associated with REG investment.				
	Leave to Construct Approval (5.4.5.2.A.vii)				
	Leave to Construct Approval is not required for this project.				

General Information on Project (5.4.5.2.A)

Related Project Reference Material i.e. Images, Drawings and or Reference Material

Map of Friday Harbour Development

General Information on Project (5.4.5.2.A)

Related Project Reference Material i.e. Images, Drawings and or Reference Material

Friday Harbour Development – Energization of Phase 1 units in 2017

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)		
	Project Name	Repoling: Big Bay Point Road - Friday Harbour DS to Friday Harbour Development (North)
	Investment Benefits, measured against: Efficiency, Customer Value & Reliability (5.4.5.2.B.1)	
	Main Driver (5.4.5.2.B.1.a-1):	
	System Service	
	- Main "Trigger" (5.4.5.2.B.1.a-1.1):	
	Changes in load that will constrain the ability of the system to provide consistent service delivery	
	Secondary Driver (5.4.5.2.B.1.a-2):	
	System Access	
	- Secondary "Trigger" (5.4.5.2.B.1.a-2.1):	
	Customer service requests for connections (both new and modification to existing)	
	Objective or Performance Target to be Achieved (5.4.5.2.B.1.a-3):	
	Primary:	Customer value
	Additional	Co-ordination, Interoperability, and Economic Development
	Background information that ties in with Asset Management Process (5.4.5.2.B.1.a-3):	
	The asset management process has identified that circuits planned to be re-built and extended are one that cannot meet the new load growth requirements and manage shifting of anticipated load during system outages or interruptions in this area.	
	Overview of Investment Prioritization Justification (5.4.5.2.B.1.b)	
	The project has been prioritized based on the plans and schedules provided by the TOI and the developers for the Friday Harbour Lands. InnPower employs a "Just in time" investment strategy, and therefore the project aligns with the projected dates for site servicing by the developers. Review of designs by 3rd party is underway with servicing to commence in Q3 / Q4 of 2017.	
	Project Identification and Selection (5.4.5.2.B.1.b-1)	
	The project was identified based on the requirements for new loads connecting on to InnPower's distribution system. The selection criteria was based on a "just in time" construction and investment strategy.	
	Project Prioritization (5.4.5.2.B.1.b-2)	
	For these types of projects "just in time" investment and construction strategy is employed, projects are prioritized based on the needs of developers (new customers) and construction schedules of new subdivisions. The timing and/or priority of this project was based upon the site servicing schedules of the new development.	

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Project Pacing (5.4.5.2.B.1.b-3)
	InnPower intends to begin to conduct preliminary designs in 2016, with construction in mid to late 2017. Given the need to supply the new load in 2018 this project cannot be spread over several years.
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)
	- Alternate Considerations - Design (5.4.5.2.B.1.c-1)
	Design is based on the anticipated loads and the number of circuits required to service the future anticipated load.
	- Alternate Considerations - Schedule (5.4.5.2.B.1.c-2)
	As the development is commencing construction in 2017, alternative schedules are not considered.
	- Alternate Considerations - Funding/Ownership (5.4.5.2.B.1.c-3)
	InnPower will be solely funding the project.
	Effect of Investment on System Operation Efficiency and Cost-Effectiveness (5.4.5.2.B.1.c.i)
	The investment would provide InnPower with better circuit tie capability on the 27.6kV distribution network between Line 13 and Big Bay Point Road. By having more tie points within a distribution network the overall system effectiveness and operation efficiency is increased and outage duration are minimized.
	Net Benefits Accruing to Customers as a Result of the Investment (5.4.5.2.B.1.c.ii)
	The investment will provide service to new and existing customers.
	Impact of the Investment on Reliability Performance including on the Frequency and Duration of Outages (5.4.5.2.B.1.c.iii)
	Even though the primary driver for this project is not reliability, the investment will provide InnPower with additional circuit ties which would then provide better restoration capabilities during an outage. Renewing of the assets on the existing 3-phase 8,320 volt circuitry will enable more reliable operation. Specific performance improvement to SAIDI and SAIFI were not performed.
	Projected Improvement to SAIFI (System Average Interruption Frequency Index): *N/A*
	Projected Improvement to SAIDI (System Average Interruption Duration Index): *N/A*
	Impact of the Driver(s), "Trigger" or other, on the DESIGN of the Project (5.4.5.2.B.1.c-4)
	The circuit design was based on "System service", the circuit will be designed to meet the new load criteria.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Impact of the Driver(s), "Trigger" or other, on the COMPONENT CHARACTERISTICS of the Project (5.4.5.2.B.1.c-5)
	The components of the project are mainly pole, wire, service transformer, arrestors and insulators. Each of these components are selected based on InnPower's current engineeringstandards.
	Impact of the Driver(s), "Trigger" or other, on the WORK PLAN of the Project (5.4.5.2.B.1.c-6)
	The work plan is based upon the schedule of the developers. InnPower will develop the work plan based on the optimum use of outside contractors, these contractors are selected based on a competitive bidding process.
	Investment Benefits, measured against: Safety (5.4.5.2.B.2)
	The project is not intended to address safety concerns with the distribution system.
	Investment Benefits, measured against: Cyber-security, Privacy (5.4.5.2.B.3)
	The project is not intended to address Cyber-Security, Privacy concerns with the distributionsystem.
	Investment Benefits, measured against: Co-ordination, Interoperability (5.4.5.2.B.4)
	Co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)
	InnPower coordinates work with 3rd parties including pole attachment companies (Rogers, Bell). This project does not require coordination with members of the Integrated Regional Resource Plan (IRRP) process, or neighboring utilities. On all such project, however, InnPower works closely with the representatives of the developers' groups, Town of Innisfil, and other approval agencies - Region, MOE, and Lake Simcoe Conservation Authority.
	Potential to Enable Future Technological Functionality (5.4.5.2.B.4.b-1)
	Not Applicable
	Potential to Address Future Operational Requirements (5.4.5.2.B.4.b-2)
	Based on the numbers made available to us from the Developer and the Town of Innisfil. The circuit design will accommodate all anticipated load requirements.
	Investment Benefits, measured against: Economic Development (5.4.5.2.B.5)
	As the sole purpose of this project is to service new loads, an increase in population within the area and large sized single detached residential / recreational infill development would trigger economic development, as both new infill residential construction and businesses would be attracted and existing businesses would prosper.
	Investment Benefits, measured against: Environmental Benefits: (5.4.5.2.B.6)
	The project is not intended to protect against any environmental impacts.

<table>
<tr><td colspan="2">Project Name Repoling: Big Bay Point Road - Friday Harbour DS to Friday Harbour Development (North)</td></tr>
<tr><td colspan="2">Category-specific requirements for System Service Investments (5.4.5.2.C.c)</td></tr>
<tr><td rowspan="12">Category-specific requirements for System Service Investments (5.4.5.2.C.c)</td><td>Benefits to Customers versus Cost Impact (5.4.5.2.C.c.i)</td></tr>
<tr><td>This investment will provide new customers in the Friday Harbour development with safe and reliable access to power. With addition of new customers the investments will be levelized and therefore as new customers get added to our system the electricity rates will decrease in the future.</td></tr>
<tr><td>Regional Electricity Infrastructure Requirements (5.4.5.2.C.c.ii)</td></tr>
<tr><td>This project was not impacted by Regional Electricity Infrastructure requirements: InnPower participates in regional planning, both at an infrastructure level with the local municipalities and the county, and in the Integrated Regional Resource Planning (IRRP) group along with representatives from the Independent Electricity System Operator (IESO), Hydro One Networks Inc. (HONI), and PowerStream.</td></tr>
<tr><td>Integration of Advance Technology (5.4.5.2.C.c.iii)</td></tr>
<tr><td>Not Applicable</td></tr>
<tr><td>Integration of Interoperability (5.4.5.2.C.c.iii-1)</td></tr>
<tr><td>All new projects are constructed using approved construction standards in compliance with ESA Regulation 22/04.

For this development InnPower attends design meetings for both the Mid-rise podium developer and the low rise and common facilities developer which allows for better coordination and planning of investment.

Expansion of distribution system allows for flexibility in system operation both under normal and emergency situations.</td></tr>
<tr><td>Integration of Cybersecurity (5.4.5.2.C.c.iii-2)</td></tr>
<tr><td>Not Applicable</td></tr>
<tr><td>System Benefits to Reliability (5.4.5.2.C.c.iv-1)</td></tr>
<tr><td>The circuitry planned for this section of line will be configured to tie in with another feeder from the same station creating a loop/backup feed. This will provide the option to improve restoration when one of the feeders are out of service.

Renewing of the assets on the existing 3-phase 8,320 volt circuitry will enable more reliable operation.</td></tr>
</table>

Category-specific requirements for System Service Investments (5.4.5.2.C.c)	
	System Benefits to Efficiency (5.4.5.2.C.c.iv-2)
	The expansion of the distribution system, particularly with the planned circuit tie inside the Friday Harbour development, will result in overall system effectiveness and operational efficiency.
	System Benefits to Safety (5.4.5.2.C.c.iv-3)
	Upgrading of the aged assets prior to failure (existing 8,320 volt circuitry) will have a positive impact on the overall safety of the distribution system for both InnPower personnel and also the public.
	Factors Affecting Implementation Timing (5.4.5.2.C.c.v-1)
	The schedule of this project is dependent on the following: a) Developers Plan and Schedule. Town of Innisfil Draft Plan Approval of Development and signoff from other approval agencies - Region, MOE, Lake Simcoe Conservation Authority Utilities has been granted. To mitigate the risks in schedule InnPower is working and meeting with the developers (Geranium Corporation, Saddlebrook Management Consultants, SCS Consulting Group Limited and their contractors), and the Town of Innisfil as often as needed regarding progress and timing of the project. By meeting frequently InnPower is aware of the progress of the development and the Town of Innisfil is aware of InnPower's plans to service the new load.
	Factors Affecting Implementation Priority (5.4.5.2.C.c.v-2)
	The project has been prioritized based on the plans and schedules provided by all the stakeholders, including developers and the Town of Innisfil. InnPower employs a "Just in time" investment strategy, and therefore the project aligns with the projected dates for site servicing by the developers.
	Summary of Options Analysis (5.4.5.2.C.c.vi)
	Although the option to underground this section of feeder is a possibility, the cost for this work will be multiple time higher than the plan proposed herein, and the return for the increased investment cannot be justified using InnPower's business model.
	Analysis of project benefits and costs i.e. "Do Nothing" (5.4.5.2.C.c.vi-1)
	The intent of this project is to service new loads; a "Do Nothing" scenario (with existing circuitry) will not be sufficient to meet customer load requirements starting in 2018.
	Analysis of project benefits and costs i.e. "Technically feasible alternatives" (5.4.5.2.C.c.vi-2)
	While an underground construction is more reliable, typically underground costs are higher by several magnitudes (varies per job condition). These costs make the project cost prohibitive even though it is technically feasible.

Category-specific requirements for System Service Investments (5.4.5.2.C.c)	**Significant Benefits and Costs - the Value of which cannot readily be Quantified (5.4.5.2.C.c.-A)**
	The ability of InnPower to service new developments conveys the message to the development industry that InnPower and Town of Innisfil are capable of handling the growth which benefits the economic development of the Town and associated communities and community services.

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Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name: Repoling: Lockhart Road – Huronia Road to Stroud DS

Project number: DO 014 & DO 017 **Budget Year:** 2017

Investment Category: System Service

Project Summary:

This investment in 2017 will replace 36 poles on Lockhart Road between Huronia Road and InnPower's Stroud distribution station which currently have a sub transmission feeder and a distribution feeder. The newly configured pole in will have a larger conductor (556kcmil) on the subtransmission line with two distribution feeders to feed the new load to be added in the Hewitt development area in South Barrie.

Over the next 15 years the addition of new loads up to 80MW is planned for the "green field" area development in South Barrie (also known as the Barrie annexed lands). These lands are serviced by InnPower, and the new loads which will be phased in will need to be serviced by InnPower starting in the 2017/2018 timeframe.

The annexed lands are divided into two development sections namely "Hewitt development" and "Salem development" for a total planned load increase of 80MW. The purpose of this project is to service the new load growth in the Salem area developments (up to 40MW).

InnPower currently has a single phase of a 8.32kV circuit (4.8kV) and a 44kV subtransmission circuit which can not meet the projected load requirement. The purpose of this project is to convert the pole line to accommodate two 3-phase distribution circuits, and increase the 44kV circuit conductor size. This repoling work will include a total of 52 poles. InnPower started the work in 2015 and will complete it in 2017.

Total capital and non-capitalized O&M costs (5.4.5.2.A.i)

	Historical Capital Costs				
	2012	2013	2014	2015	2016
Total cost				$ 260,000	$ 15,200
Contributions				$ -	$ -
Net cost				$ 260,000	$ 15,200
O&M expense				Undetermined	Undetermined

	Future Capital Costs				
	2017	2018	2019	2020	2021
Total cost	$ 618,932				
Contributions	$ -				
Net cost	$ 618,932				
O&M expense	Undetermined				

Customer Attachments and Load (5.4.5.2 A.ii)

1550 Future Lots for Phase 1 Hewitt (West of Yonge Street) Lands between Lockhart Road and Mapleview Road; Anticipated Load - 5.89 MVA of load. The subtransmission line will support the overall Hewitt area loads which will have 2,852 Customers in total for PH1 of the development; i.e. 10.8 MVA

General Information on Project (5.4.5.2.A)					
	Project Dates & Expenditure Timing (5.4.5.2.A.iii)				
	Start Date:	01-Jan-17			
	In Service Date:	31-Dec-17			
	Expenditure Timing	2017: Q1	2017: Q2	2017: Q3	2017: Q4
		10%	60%	30%	
	Schedule Risks & Risk Mitigation (5.4.5.2.A.iv)				
	The schedule of this project is dependent on the following: a) Developers Plans b) City of Barrie Draft Plan Approval of Development and c) signoff from other approval agencies - Lake Simcoe Conservation Authority, Region, MOE, Utilities. To mitigate the risks in schedule InnPower is working and meeting with the developers, land owner groups and the City of Barrie on a quarterly basis regarding progress and timing of the project. By meeting frequently InnPower is aware of the progress of the development and the City of Barrie is aware of InnPower's plans to service the new load.				
	Comparative Information on Expenditure from Equivalent Projects (5.4.5.2.A.v)				
	The expenditure for this project has been derived using the historical per pole/span cost of a circuit built with the same configuration. This cost has been adjusted to reflect changes in labour rates and material price increases.				
	Total Capital and OM&A costs associated with REG investment (5.4.5.2.A.vi)				
	For this project there are no Capital and OM&A costs associated with REG investment				
	Leave to Construct Approval (5.4.5.2.A.vii)				
	Leave to Construct Approval is not required for this project				

General Information on Project (5.4.5.2.A)

Related Project Reference Material i.e. Images, Drawings and or Reference Material

Development Map of Hewitt Lands

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Project Name: Repoling: Lockhart Road - Huronia Road to Stroud DS
	Investment Benefits, measured against: Efficiency, Customer Value & Reliability (5.4.5.2.B.1)
	Main Driver (5.4.5.2.B.1.a-1):
	System Service
	- Main "Trigger" (5.4.5.2.B.1.a-1.1):
	Changes in load that will constrain the ability of the system to provide consistent service delivery
	Secondary Driver (5.4.5.2.B.1.a-2):
	System Access
	- Secondary "Trigger" (5.4.5.2.B.1.a-2.1):
	Customer service requests for connections (both new and modification to existing)
	Objective or Performance Target to be Achieved (5.4.5.2.B.1.a-3):
	Primary: Customer value; Secondary: Reliability
	Additional Co-ordination, Interoperability, and Economic Development
	Background information that ties in with Asset Management Process (5.4.5.2.B.1.a-3):
	The asset management process has identified that the current circuitry cannot meet the new load growth requirements. Therefore requiring these circuits modifications.
	Overview of Investment Prioritization Justification (5.4.5.2.B.1.b)
	This project is justified based on InnPower's commitment to serve new customers, as stated in tis conditions of service. The project has been prioritized based on the plans and schedules provided by the City of Barrie and the developers for the Hewitt Lands. InnPower employs a "Just in time" investment strategy, and therefore the project aligns with the projected dates for site servicing by the developers.
	Project Identification and Selection (5.4.5.2.B.1.b-1)
	The project was identified based on the requirements for new loads connecting on to InnPower's distribution system. The selection criteria was based on a "just in time" construction and investment strategy
	Project Prioritization (5.4.5.2.B.1.b-2)
	High. The need to service new loads gives this project a high priority. For these types of projects "just in time" investment and construction strategy, projects are prioritized based on the needs of developers (new customers) and construction schedules of new subdivisions. The timing and/or priority of this project was based upon the site servicing schedules of the new subdivisions.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Project Pacing (5.4.5.2.B.1.b-3)
	This project was started in 2015 and will be completed in 2017 - it was paced over this period to reduce the rate impact to customers.
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)
	- Alternate Considerations - Design (5.4.5.2.B.1.c-1)
	Design is based on the anticipated loads and the number of circuits required to service the future anticipated load.
	- Alternate Considerations - Schedule (5.4.5.2.B.1.c-2)
	As the development is commencing construction in 2017, alternative schedules for the work to be pushed further are not considered.
	- Alternate Considerations - Funding/Ownership (5.4.5.2.B.1.c-3)
	InnPower will be solely funding the project.
	Effect of Investment on System Operation Efficiency and Cost-Effectiveness (5.4.5.2.B.1.c.i)
	The investment would provide InnPower with better circuit tie capability on the 27.6kV distribution system between Mapleview and Lockhart Road (North and South boundaries of the development). By having more tie points within a distribution network the overall system effectiveness and operation efficiency is increased and outage durations are minimized.
	Net Benefits Accruing to Customers as a Result of the Investment (5.4.5.2.B.1.c.ii)
	The investment will provide service to new and existing customers.
	Impact of the Investment on Reliability Performance including on the Frequency and Duration of Outages (5.4.5.2.B.1.c.iii)
	Even though the primary driver for this project is not reliability, the investment will provide InnPower with additional circuit ties which would then provide better restoration capabilities during an outage.
	Projected Improvement to SAIFI (System Average Interruption Frequency Index): N/A
	Projected Improvement to SAIDI (System Average Interruption Duration Index): N/A
	Impact of the Driver(s), "Trigger" or other, on the DESIGN of the Project (5.4.5.2.B.1.c-4)
	The circuitry, based on the trigger to serve new loads, will be designed to meet the new load criteria for two new distribution feeders. InnPower will be using USF standards for the design with a triangular configuration for the 44kV circuit and a vertical configuration for the two distribution circuits.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Impact of the Driver(s), "Trigger" or other, on the COMPONENT CHARACTERISTICS of the Project (5.4.5.2.B.1.c-5)
	The components of the project are mainly poles, overhead conductor, service transformers, arrestors and insulators. Each of these components are selected based on InnPower's current engineering standards.
	Impact of the Driver(s), "Trigger" or other, on the WORK PLAN of the Project (5.4.5.2.B.1.c-6)
	The work plan is based upon the schedule of the developers. InnPower will develop the work plan based on the optimum use of outside contractors, these contractors are selected based on a competitive bidding process.
	Investment Benefits, measured against: Safety (5.4.5.2.B.2)
	The project is not intended to address safety concerns with the distribution system
	Investment Benefits, measured against: Cyber-security, Privacy (5.4.5.2.B.3)
	The project is not intended to address Cyber-Security, Privacy concerns with the distribution system
	Investment Benefits, measured against: Co-ordination, Interoperability (5.4.5.2.B.4)
	Co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)
	InnPower is also working hand in hand with developers, City of Barrie and other 3rd party agencies for coordination in schedules and 3rd party approvals.
	Potential to Enable Future Technological Functionality (5.4.5.2.B.4.b-1)
	Not Applicable
	Potential to Address Future Operational Requirements (5.4.5.2.B.4.b-2)
	Based on the numbers made available to us from the Hewitt land owner groups and the City of Barrie the circuit design will accommodate all anticipated load requirements.
	Investment Benefits, measured against: Economic Development (5.4.5.2.B.5)
	As the sole purpose of this project is to service new loads, an increase in population within the area would trigger economic development as new businesses would be attracted and older business would prosper.
	Investment Benefits, measured against: Environmental Benefits: (5.4.5.2.B.6)
	The project is not intended to protect against any environmental impacts.

Project Name: Repoling: Lockhart Road - Huronia Road to Stroud DS

Category-specific requirements for System Service Investments (5.4.5.2.C.c)	
Category-specific requirements for System Service Investments (5.4.5.2.C.c)	**Benefits to Customers versus Cost Impact (5.4.5.2.C.c.i)**
	This investment will provide new customers in the Hewitt development area with safe and reliable access to power. With addition of new customers the investments will be levelized and therefore as new customers get added to our system the electricity rates will decrease in the future.
	Regional Electricity Infrastructure Requirements (5.4.5.2.C.c.ii)
	InnPower participates in regional planning, both at an infrastructure level with the local municipalities and the county, and in the Integrated Regional Resource Planning (IRRP) group along with representatives from the Independent Electricity System Operator (IESO), Hydro One Networks Inc. (HONI), and PowerStream. InnPower has actively participated (often initiating communication) with the members of the Barrie Lands development group.
	Integration of Advance Technology (5.4.5.2.C.c.iii)
	Not Applicable
	Integration of Interoperability (5.4.5.2.C.c.iii-1)
	All new projects are constructed using approved construction standards in compliance with ESA Regulation 22/04. During sub-division developments InnPower attends frequent utility coordination site meetings, which allows for the coordination and planning of investment with other utilities.
	Integration of Cybersecurity (5.4.5.2.C.c.iii-2)
	Not Applicable
	System Benefits to Reliability (5.4.5.2.C.c.iv-1)
	Even though the primary driver for this project is not reliability, the investment will provide InnPower with additional circuit ties which would then provide better restoration capability during an outage. Existing resident will receive more reliable service as the infrastructure is renewed.
	System Benefits to Efficiency (5.4.5.2.C.c.iv-2)
	The investment would provide InnPower with better circuit tie capability on the 27.6kV distribution network. Additional tie points within a distribution network will improve overall system effectiveness and operational efficiency.

Category-specific requirements for System Service Investments (5.4.5.2.C.c)	
	System Benefits to Safety (5.4.5.2.C.c.iv-3)
	By upgrading aged assets prior to failure will result in an overall safer distribution system for both InnPower personnel and also the public.
	Factors Affecting Implementation Timing (5.4.5.2.C.c.v-1)
	The schedule of this project is dependent on the following: a) Developers Plans b) City of Barrie Draft Plan Approval of Development and c) signoff from other approval agencies - Lake Simcoe Conservation Authority, Region, MOE, Utilities. To mitigate the risks in schedule InnPower is working and meeting with the developers, land owner groups and the City of Barrie on a quarterly basis regarding progress and timing of the project. By meeting frequently InnPower is aware of the progress of the development and the City of Barrie is aware of InnPower's plans to serve the new load.
	Factors Affecting Implementation Priority (5.4.5.2.C.c.v-2)
	The project has been prioritized based on the plans and schedules provided by the City of Barrie and the developers for the Hewitt Lands. InnPower employs a "Just in time" investment strategy, and therefore the project aligns with the projected dates for site servicing by the developers.
	Summary of Options Analysis (5.4.5.2.C.c.vi)
	Although the option to underground this section of feeder is a possibility, the cost for this work will be multiple time higher than the plan proposed herein, and the return for the increased investment cannot be justified using InnPower's business model.
	Analysis of project benefits and costs i.e. "Do Nothing" (5.4.5.2.C.c.vi-1)
	The intent of this project is to service new loads; a "Do Nothing" scenario (with existing single phase circuitry) will impact InnPower's ability to serve new loads.
	Analysis of project benefits and costs i.e. "Technically feasible alternatives" (5.4.5.2.C.c.vi-2)
	While an underground construction is more reliable typically underground costs are higher by several magnitudes. These costs make the project cost prohibitive even though it is technically feasible.
	Significant Benefits and Costs - the Value of which cannot readily be Quantified (5.4.5.2.C.c.-A)
	The ability of InnPower to service new developments conveys the message to the development industry that InnPower is capable of handling the growth which benefit the economic development in the immediate area and the associated communities and communityservices.

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name: Repoling: Mapleview Drive - Prince William Way to Seline Crescent

Project number: DO 016 & DO 021 **Budget Year:** 2017

Investment Category: System Service

Project Summary

This project will repole approximately 2.7km of overhead circuitry and add 300m of underground circuitry to meet capacity requirements for load growth in the Hewitt Lands in South Barrie
.
Over the next 15 years the addition of new loads up to 80MW is planned for the "green field" area development in South Barrie (also known as the Barrie annexed lands). These lands are serviced by InnPower, and the new loads which will be phased in will need to be serviced by InnPower starting in the 2017/2018 timeframe.

The annexed lands are divided into two developments sections namely "Hewitt development" and "Salem development" for a total planned load increase of 80MW. The purpose of this project is to service the new load growth in the Hewitt area developments (40MW).

InnPower currently has a single phase 4.8kV circuit, which does not meet the projected load requirement. The purpose of this project is to upgrade the single phase 4.8kV circuit to the following: (1) Prince William Way to Yonge Street: a three-phase circuit at 27.6kV, with provisions for a second three-phase circuit 27.6kV in the future. The repoling project will include approximately 300m of underground circuitry and 28 poles of overhead circuit; (2) Yonge Street to Seline Crescent: a three-phase circuit at 27.6kV, with provision for a second three-phase circuit in the future. This repoling project will include approximately 26 poles of overhead circuit.

Total capital and non-capitalized O&M costs (5.4.5.2.A.i)

	Historical Capital Costs				
	2012	2013	2014	2015	2016
Total cost					
Contributions					
Net cost					
O&M expense					
	Future Capital Costs				
	2017	2018	2019	2020	2021
Total cost	$837,831				
Contributions	$ -				
Net cost	$837,831				
O&M expense	Undetermined				

Customer Attachments and Load (5.4.5.2 A.ii)

Phase 1: 3,150 Customers and 11.89MVA of load. Total load planned: 40MW.

Project Dates & Expenditure Timing (5.4.5.2.A.iii)

Start Date:	01-Jan-17			
In Service Date:	31-Dec-17			
Expenditure Timing	2017: Q1	2017: Q2	2017: Q3	2017: Q4
	5%	20%	65%	10%

General Information on Project (5.4.5.2.A)	
	Schedule Risks & Risk Mitigation (5.4.5.2.A.iv)
	The schedule of this project is dependent on the following: (a) Developers Plans and Environmental Assessment (EA) approvals, (b) Approval from 3rd party agencies, i.e. Metrolinx, and (c) Municipal Consent. To mitigate the risks in schedule InnPower is working with the developers, land owner groups and the City of Barrie on a quarterly basis. Effective collaboration with all parties through frequent meetings enables InnPower to closely monitor the progress of the development and plan its line repoling work accordingly.
	Comparative Information on Expenditure from Equivalent Projects (5.4.5.2.A.v)
	The expenditure for this project has been derived using the historical per pole/span cost of a circuit built with the same configuration. This cost has been adjusted to reflect changes in labour rates and material price increases.
	Total Capital and OM&A costs associated with REG investment (5.4.5.2.A.vi)
	For this project there are no Capital and OM&A costs associated with REG investment
	Leave to Construct Approval (5.4.5.2.A.vii)
	This project does not require “Leave to Construct” under Section 92 of the Ontario Energy Board Act 1998.

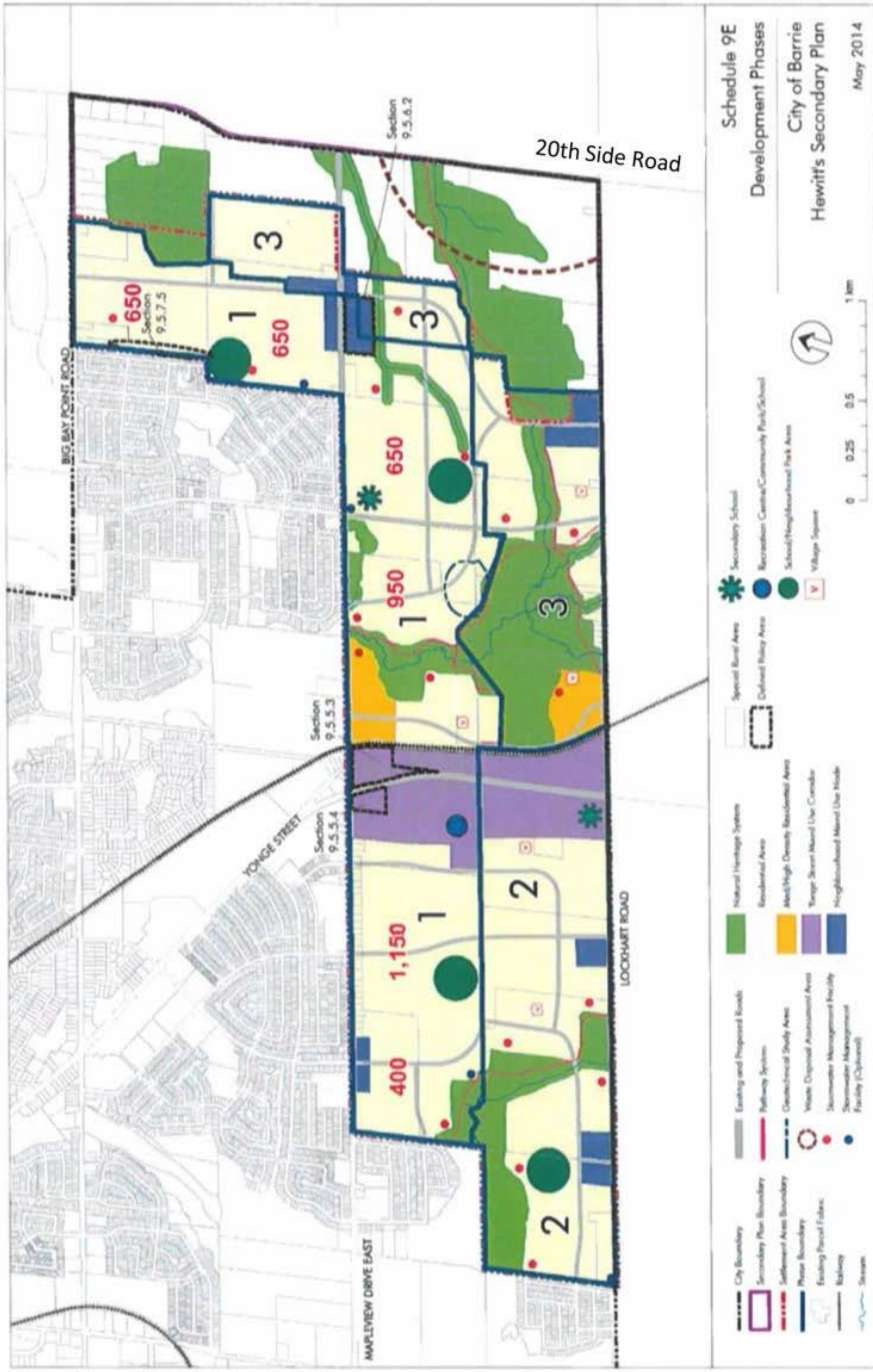
General Information on Project (5.4.5.2.A)

Related Project Reference Material i.e. Images, Drawings and or Reference Material

Hewitt Area Development Map

General Information on Project (5.4.5.2.A)

Hewitt Area Development Map with Phase 1 residential unit count



Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Project Name Repoling: Mapleview Drive - Prince William Way to Seline Crescent
	Investment Benefits, measured against: Efficiency, Customer Value & Reliability (5.4.5.2.B.1)
	Main Driver (5.4.5.2.B.1.a-1):
	System Service
	- Main "Trigger" (5.4.5.2.B.1.a-1.1):
	Changes in load that will constrain the ability of the system to provide consistent service delivery
	Secondary Driver (5.4.5.2.B.1.a-2):
	System Access
	- Secondary "Trigger" (5.4.5.2.B.1.a-2.1):
	Customer service requests for connections (both new and modification to existing)
	Objective or Performance Target to be Achieved (5.4.5.2.B.1.a-3):
	Primary: Customer value; Secondary: Reliability.
	Additional Co-ordination, Interoperability and Economic Development
	Background information that ties in with Asset Management Process (5.4.5.2.B.1.a-3):
	The asset management process, including the system planning process, has analyzed the servicing requirements of the new load, and has determined that the existing single phase circuitry cannot serve the new loads. The repoling project meets the Asset Management objective of "accommodating load growth and customer needs"
	Overview of Investment Prioritization Justification (5.4.5.2.B.1.b)
	The project has been prioritized based on the plans and schedules provided by the City of Barrie and the developers for the Hewitt Lands. InnPower employs a "just-in-time" investment strategy, and therefore the project aligns with the projected dates for building permits issuance from the City of Barrie.
	Project Identification and Selection (5.4.5.2.B.1.b-1)
	The project was identified based on the requirements for new loads connecting on to InnPower's distribution system. The selection criteria was based on a "just-in-time" construction and investment strategy.
	Project Prioritization (5.4.5.2.B.1.b-2)
	For these types of projects a "just-in-time" investment and construction strategy is employed, projects are prioritized based on the needs of developers (new customers) and construction schedules of new subdivisions. The timing and/or priority of this project was based upon the construction permits and schedules of the new sub-divisions.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Project Pacing (5.4.5.2.B.1.b-3)
	InnPower intends to conduct preliminary designs in Q4 2016, with construction drawings planned for completion in Q1 2017. Construction for the project with commence and complete in Q3 2017. Based on the information available at the time of the preparation of this report. The overall project cannot be spread over multiple years as the construction work is scheduled to begin in 2017 and the new load is scheduled to be energized in early 2018.
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)
	- Alternate Considerations - Design (5.4.5.2.B.1.c-1)
	InnPower considered a joint-use with PowerStream the neighboring utility in Barrie; this was however not possible as the number of circuits required by both utilities did not result in a technically feasible pole design.
	- Alternate Considerations - Schedule (5.4.5.2.B.1.c-2)
	As the development is commencing construction in 2017, alternative schedules are not considered.
	- Alternate Considerations - Funding/Ownership (5.4.5.2.B.1.c-3)
	As collaborations with the neighboring utility was not technically feasible (as noted above), InnPower will be solely funding the project.
	Effect of Investment on System Operation Efficiency and Cost-Effectiveness (5.4.5.2.B.1.c.i)
	The investment would provide InnPower with better circuit tie capability on the 27.6kV distribution network. Additional tie points within a distribution network will improve overall system effectiveness and operational efficiency.
	Net Benefits Accruing to Customers as a Result of the Investment (5.4.5.2.B.1.c.ii)
	The investment will provide service to new and existing customers.
	Impact of the Investment on Reliability Performance including on the Frequency and Duration of Outages (5.4.5.2.B.1.c.iii)
	Even though the primary driver for this project is not reliability, the investment will provide InnPower with additional circuit ties which would then provide better restoration capability during an outage. Existing residents will receive more reliable service as the infrastructure is renewed.
	Projected Improvement to SAIFI (System Average Interruption Frequency Index): N/A
	Projected Improvement to SAIDI (System Average Interruption Duration Index): N/A
	Impact of the Driver(s), "Trigger" or other, on the DESIGN of the Project (5.4.5.2.B.1.c-4)
	Based on the trigger InnPower will, through the implementation of this project eliminate constrains that hinder the system to provide consistent service delivery. This is accomplished by designing the new poleline and circuitry to supply the immediate and future needs of the area's power demand.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Impact of the Driver(s), "Trigger" or other, on the COMPONENT CHARACTERISTICS of the Project (5.4.5.2.B.1.c-5)
	The components of the project are mainly pole, wire, service transformer, arrestors and insulators. Each of these components are selected based on InnPower's current engineering standards.
	Impact of the Driver(s), "Trigger" or other, on the WORK PLAN of the Project (5.4.5.2.B.1.c-6)
	The work plan is based upon the schedule of the developers. InnPower will develop the work plan based on the optimum use of outside contractors, these contractors are selected based on a competitive bidding process.
	Investment Benefits, measured against: Safety (5.4.5.2.B.2)
	The project is not intended to address safety concerns with the distribution system.
	Investment Benefits, measured against: Cyber-security, Privacy (5.4.5.2.B.3)
	The project is not intended to address Cyber-Security, or privacy concerns with the distribution system.
	Investment Benefits, measured against: Co-ordination, Interoperability (5.4.5.2.B.4)
	Co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)
	InnPower has reached out to the neighboring utility i.e. PowerStream for joint use. It was determined by both utilities that a joint use scenario would not be technically feasible due to the number of circuit requirements of each utility. InnPower is also working hand in hand with developers, City of Barrie and other 3rd party agencies for coordination in schedules and 3rd party approvals.
	Potential to Enable Future Technological Functionality (5.4.5.2.B.4.b-1)
	Not Applicable
	Potential to Address Future Operational Requirements (5.4.5.2.B.4.b-2)
	The circuit design will accommodate all anticipated load requirements (based on the numbers made available to us from the Hewitt land owner groups and the City of Barrie). The circuitry will be configured to enable switching capabilities to maintain, if not improve, system operational needs. On a separate budget SCADA switches have been planned to enable automation and improve system operations capabilities.

Evaluation criteria and information requirements for each project/activity	**Investment Benefits, measured against: Economic Development (5.4.5.2.B.5)**
	As the sole purpose of this project is to service new loads, an increase in population within the area would trigger economic development as new businesses would be attracted.
	Investment Benefits, measured against: Environmental Benefits: (5.4.5.2.B.6)
	The project is not intended to protect against any environmental impacts to the distribution system.

Project Name Repoling: Mapleview Drive - Prince William Way to Seline Crescent		
Category-specific requirements for System Service Investments (5.4.5.2.C.c)		
Category-specific requirements for System Service Investments (5.4.5.2.C.c)	**Benefits to Customers versus Cost Impact (5.4.5.2.C.c.i)**	
	This investment will provide new customers in the Hewitt development area with safe and reliable access to power. With addition of new customers the investments will be levelized and therefore as new customers get added to our system the electricity rates will decrease in the future.	
	Regional Electricity Infrastructure Requirements (5.4.5.2.C.c.ii)	
	InnPower participates in regional planning, both at an infrastructure level with the local municipalities and the county, and in the Integrated Regional Resource Planning (IRRP) group along with representatives from the Independent Electricity System Operator (IESO), Hydro One Networks Inc. (HONI), and PowerStream.	
	Integration of Advance Technology (5.4.5.2.C.c.iii)	
	Not Applicable	
	Integration of Interoperability (5.4.5.2.C.c.iii-1)	
	All new projects are constructed using approved construction standards in compliance with ESA Regulation 22/04. During sub-division developments InnPower attends frequent utility coordination site meetings, which allows for the coordination and planning of investment with other utilities.	
	Integration of Cybersecurity (5.4.5.2.C.c.iii-2)	
	Not Applicable	
	System Benefits to Reliability (5.4.5.2.C.c.iv-1)	
	Even though the primary driver for this project is not reliability, the investment will provide InnPower with additional circuit ties which would then provide better restoration capability during an outage. Existing resident will receive more reliable service as the infrastructure is renewed.	
	System Benefits to Efficiency (5.4.5.2.C.c.iv-2)	
	The investment would provide InnPower with better circuit tie capability on the 27.6kV distribution network. Additional tie points within a distribution network will improve overall system effectiveness and operational efficiency.	
	System Benefits to Safety (5.4.5.2.C.c.iv-3)	
	The project is not intended to address safety concerns with the distribution system.	
	Factors Affecting Implementation Timing (5.4.5.2.C.c.v-1)	
	The schedule of this project is dependent on the following: (a) Developers Plans and Environmental Assessment (EA) approvals, (b) Approval from 3rd party agencies, i.e. Metrolinx, and (c) Municipal Consent.	

Category-specific requirements for System Service Investments (5.4.5.2.C.c)	
	Factors Affecting Implementation Priority (5.4.5.2.C.c.v-2)
	The project has been prioritized based on the plans and schedules provided by the City of Barrie and the developers for the Hewitt Lands. InnPower employs a "Just in time" investment strategy, and therefore the project aligns with the projected dates for building permits issuance from the City of Barrie.
	Summary of Options Analysis (5.4.5.2.C.c.vi)
	(A) Joint use of pole line with PowerStream is not technically feasible; (B) All overhead design is also not technically feasible; (C) All underground design is cost prohibitive; and (D) Combination of Overhead and Underground Circuits - this option met all technical and commercial requirements.
	Analysis of project benefits and costs i.e. "Do Nothing" (5.4.5.2.C.c.vi-1)
	The intent of this project is to service new loads, a "Do Nothing" scenario (with existing single phase circuitry) will not be sufficient to meet customer load requirements starting in 2018.
	Analysis of project benefits and costs i.e. "Technically feasible alternatives" (5.4.5.2.C.c.vi-2)
	While an underground construction is more reliable typically underground costs are higher by several magnitudes (varies per job condition). These costs make the project cost prohibitive even though it is technically feasible. The segment on the west side was chosen to be underground as the overhead circuit was congested by a neighboring utility's substation egress feeders.
	Significant Benefits and Costs - the Value of which cannot readily be Quantified (5.4.5.2.C.c.-A)
	N/A

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Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name: Sandy Cove DS automation

Project number: DO-015 **Budget Year:** 2017

Investment Category: System Service

Project Summary:

This project will upgrade the oil reclosers (used as station circuit breakers) at the Sandy Cove DS to the new maintenance-free vacuum type electronic reclosers for two (2) feeders. The average age of these oil type reclosers is 52 years, installed between 1957 and 1968.

The reclosers at Sandy Cove DS were identified in the substation asset condition assessment study as equipment that need immediate intervention.

InnPower Corporation commenced a Substation automation program in 2011, as part of this program oil type reclosers (used as station circuit breakers) were replaced with maintenance-free vacuum type reclosers with microprocessor controlled relays and radio communication.

Prior to 2017 all legacy substations would have the new type of reclosers, except for Sandy Cove DS. As part of the project InnPower will make modifications to the substation structures, add new protection relays that are SCADA capable with monitoring and control functionality.

Total capital and non-capitalized O&M costs (5.4.5.2.A.i)

	Historical Capital Costs				
	2012	2013	2014	2015	2016
Total cost					
Contributions					
Net cost					
O&M expense					

	Future Capital Costs				
	2017	2018	2019	2020	2021
Total cost	$125,000				
Contributions	$ -				
Net cost	$125,000				
O&M expense	Undetermined				

Customer Attachments and Load (5.4.5.2 A.ii)

700 customers; 5MVA

Project Dates & Expenditure Timing (5.4.5.2.A.iii)

Start Date:	**01-Jan-17**			
In Service Date:	31-Dec-17			
Expenditure Timing	2017: Q1	2017: Q2	2017: Q3	2017: Q4
	5%	20%	65%	10%

General Information on Project (5.4.5.2.A)

Schedule Risks & Risk Mitigation (5.4.5.2.A.iv)

InnPower has successfully completed several recloser replacement projects at substations. Oil reclosers at all stations apart from Sandy Cove DS will be completed prior to 2017. The biggest risks in meeting the schedule are recloser lead times and metal fabrication/galvanization lead times. As standard designs have been developed and equipment layouts have been prepared for similar work the risk in schedule will be mitigated by ordering equipment and metal structures in Q1. This would allow adequate lead-time for installation and commissioning in Q3

Comparative Information on Expenditure from Equivalent Projects (5.4.5.2.A.v)

Prior to this project InnPower has completed similar automation (recloser replacement) projects at 6 legacy distribution stations. These costs are presented below for comparison. The expenditure for this project has been derived from past experience on similar projects, with contingency for inflation and fluctuation in USD exchange rate.

The table below provides the cost for similar type of work performed in the past 5 years in upgrading oil type reclosers in our legacy distribution station.

2012	2013	2014	2015	2016
$33,443	$ 169,828	$214,679	$152,900	$164,590
(completing 2011 works at Leonard's Beach DS	Innisfil DS	Cedar Point DS, Big Bay Point DS	Lefroy DS	Stroud DS

Total Capital and OM&A costs associated with REG investment (5.4.5.2.A.vi)

While the primary driver for this project is system service, addition of automation at substation will allow further REG investment in our service territory. Microprocessor controlled reclosers allow coordination with renewable generators for transfer trip schemes. Automation at substation also allows InnPower to tweak feeder protection as required and monitor loads and voltages. Such information helps with Connection Impact Assessment (CIA) for new generators.

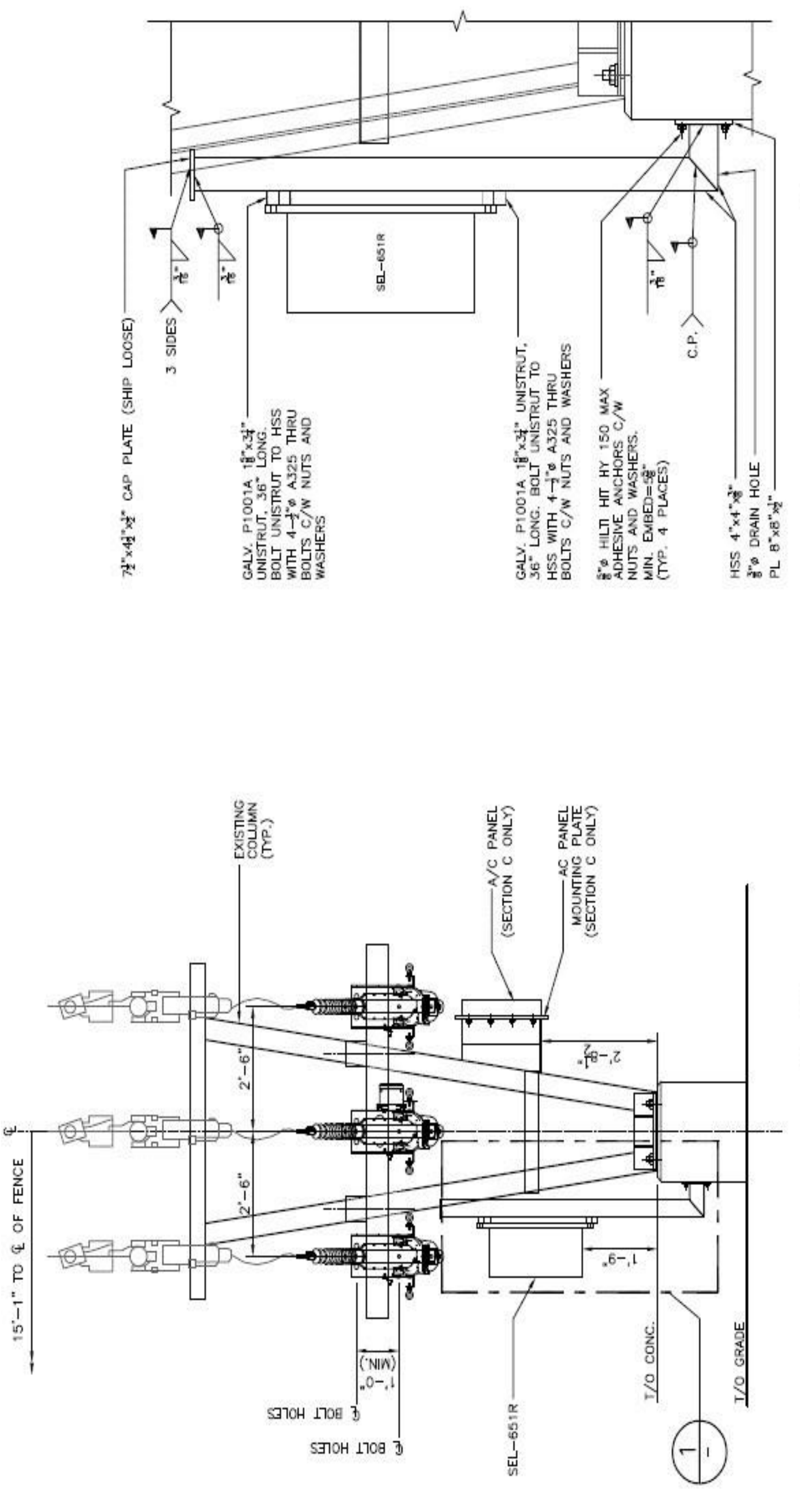
Leave to Construct Approval (5.4.5.2.A.vii)

Leave to Construct Approval is not required for this project

General Information on Project (5.4.5.2.A)

Related Project Reference Material i.e. Images, Drawings and or Reference Material

InnPower follows a standard design for this type of substation project, a sample is shown below



Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Project Name: Sandy Cove DS automation
	Investment Benefits, measured against: Efficiency, Customer Value & Reliability (5.4.5.2.B.1)
	Main Driver (5.4.5.2.B.1.a-1):
	System Service
	- Main "Trigger" (5.4.5.2.B.1.a-1.1):
	Meets system operational objectives: reliability, and system efficiency.
	Secondary Driver (5.4.5.2.B.1.a-2):
	System Renewal
	- Secondary "Trigger" (5.4.5.2.B.1.a-2.1):
	Assets/asset systems at end of service life due to failure risk
	Objective or Performance Target to be Achieved (5.4.5.2.B.1.a-3):
	Primary: Reliability; Secondary: Customer value;
	Additional Co-ordination, Interoperability and Cyber-security, Privacy
	Background information that ties in with Asset Management Process (5.4.5.2.B.1.a-3):
	The replacement of substation reclosers at Sandy Cove DS was identified in the substation asset condition assessment study as equipment that need immediate intervention. The substation asset condition assessment was completed with InnPower's assets management process methodology and meets two (2) specific objectives, namely: (1) managing costs, and operation efficiency, and (2) maintaining system reliability and customer value. Substation automation programs have been in place at InnPower for more than 5 years and Sandy Cove DS automation is the last station planned to undergo substation automation.
	Overview of Investment Prioritization Justification (5.4.5.2.B.1.b)
	The existing recloser at Sandy Cove DS are at the end of its designed lifecycle i.e. more than 35 years old. As distribution station supply power to a large number of customers, equipment replacement within substation take high priority. InnPower uses reclosers within substation as breakers, therefore they are the primary protection equipment for feeder and equipment. The Sandy Cove DS reclosers were identified in the substation condition assessment study as items that need immediate intervention.
	Project Identification and Selection (5.4.5.2.B.1.b-1)
	This project is part of a substation automation project, prior to 2017 InnPower will complete replacing reclosers at all substations and Sandy Cove DS will be the only legacy station remaining that would require an upgrade.
	Project Prioritization (5.4.5.2.B.1.b-2)
	High. Substations were prioritized based on recloser refurbishment schedules to save costs, and the Sandy Cove substation recloser regular refurbishment was scheduled for 2017. By replacing these in 2017 InnPower will avoid refurbishment costs for the reclosers.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	**Project Pacing (5.4.5.2.B.1.b-3)**
	The overall substation automation project for legacy distribution stations was paced over 7 years. This project is the last station in a series of seven (7).
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)
	- Alternate Considerations - Design (5.4.5.2.B.1.c-1)
	Design alternatives were considered at the start of the substation automation project, as designs have been standardized for each substation type no design alternative was considered specifically for Sandy Cove DS Automation.
	- Alternate Considerations - Schedule (5.4.5.2.B.1.c-2)
	As the Sandy Cove recloser coincides with the asset replacement schedule and InnPower's "just in time" replacement methodology, alternative schedules were not considered.
	- Alternate Considerations - Funding/Ownership (5.4.5.2.B.1.c-3)
	Alternate Funding/Ownership is not applicable for this project.
	Effect of Investment on System Operation Efficiency and Cost-Effectiveness (5.4.5.2.B.1.c.i)
	By replacing oil-reclosers with microprocessor controlled reclosers InnPower will be able to monitor substation feeders and would be able to operate breakers remotely via SCADA. With this additional capability InnPower will be able to monitor feeder level outages (momentary and permanent) and minimize the need to dispatch crews to close a breaker or get hold-offs during work on distribution feeders. This would have a positive impact on O&M costs and substantially increase the system operation efficiency.
	Net Benefits Accruing to Customers as a Result of the Investment (5.4.5.2.B.1.c.ii)
	As a result of this investment customers will see an overall decrease in restoration times during outages. In conjunction with other feeder level automation schemes, InnPower will also be able to implement Distribution Automation schemes for fault detection, isolation and restoration. By monitoring feeder voltages and currents, customers will see an increase in power quality.
	Impact of the Investment on Reliability Performance including on the Frequency and Duration of Outages (5.4.5.2.B.1.c.iii)
	Adding automated reclosers to substations will improve outage response / restoration times. Automated reclosers will also allow InnPower to monitor momentary outages; and by monitoring and tracking momentary outages InnPower will be able to proactively avoid some permanent outages. A single 30 minute outage, if avoided through this project, will improve SAIFI by .04 and SAIDI by .02. However, overall system impact on SAIDI and SAFI has not been projected for this work.
	Projected Improvement to SAIFI (System Average Interruption Frequency Index): see comments above
	Projected Improvement to SAIDI (System Average Interruption Duration Index): see comments above.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Impact of the Driver(s), "Trigger" or other, on the DESIGN of the Project (5.4.5.2.B.1.c-4)
	The objective of this program is to ensure reliable service to customers through quick system restoration and meet existing and future flexibility needs on the distribution system, in order to efficiently operate the system. The primary investment objective is the asset management objective "Reliability" and the secondary investment objective is the asset management objective "Operational Efficiency".
	Impact of the Driver(s), "Trigger" or other, on the COMPONENT CHARACTERISTICS of the Project (5.4.5.2.B.1.c-5)
	Component characteristics for the project has been chosen based on standardized design already approved by InnPower for similar work.
	Impact of the Driver(s), "Trigger" or other, on the WORK PLAN of the Project (5.4.5.2.B.1.c-6)
	The work plan will be arranged to save costs by using in-house crews where possible, and with timely collaboration with all the team members (designers, fabricators, approval parties, internal and external technical and field personnel).
	Investment Benefits, measured against: Safety (5.4.5.2.B.2)
	Automated reclosers allow precise protection function of distribution features (TCC curves can be customized per feeder), they also detect end of line ground faults which enhances safety. By allowing a central control room for remote operations and hold off's, physical access to substations is limited, thus limiting staff exposure.
	Investment Benefits, measured against: Cyber-security, Privacy (5.4.5.2.B.3)
	Automated devices use 128 AES encryption for communication over a private communication network, all devices have multiple access passwords and unused ports are blocked to enhance cyber-security and grid protection.
	Investment Benefits, measured against: Co-ordination, Interoperability (5.4.5.2.B.4)
	Co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)
	Coordination with other utilities, regional planning etc. is not required for this project.
	Potential to Enable Future Technological Functionality (5.4.5.2.B.4.b-1)
	By installing automated reclosers at substations, InnPower opens up the capability of future technological functionality; e.g. feeder automation schemes, transfer trip, and substation monitoring and control.
	Potential to Address Future Operational Requirements (5.4.5.2.B.4.b-2)
	InnPower's standard for substation communication is DNP3, however IEC-61850 communications is enabled for all substation devices to allow fast substation communications in the future for substation automation.

<table>
<tr><td rowspan="4">Evaluation criteria and information requirements for each project/activity</td><td>Investment Benefits, measured against: Economic Development (5.4.5.2.B.5)</td></tr>
<tr><td>The addition of Substation Automation does not directly impact economic development, however some installations have the added indirect benefit of supporting economic development through quicker restoration times and, in some cases, automatic source transfer. These benefits can lower the operational costs of large customers connected downstream of the recloser by improving service reliability, which may impact further development of their business activities in the area.</td></tr>
<tr><td>Investment Benefits, measured against: Environmental Benefits: (5.4.5.2.B.6)</td></tr>
<tr><td>Automation allows reclosers to be operated from InnPower's control room. This reduces crew dispatching and travel which has a minor environmental benefit.</td></tr>
</table>

Project Name: Sandy Cove DS automation	
Category-specific requirements for System Service Investments (5.4.5.2.C.c)	
Category-specific requirements for System Service Investments (5.4.5.2.C.c)	**Benefits to Customers versus Cost Impact (5.4.5.2.C.c.i)**
	By implementing substation automation projects the end customer benefits in the following ways: a) Faster fault detection during an outage, b) Faster restoration times, c) Replacement of aging infrastructure helps avoid device failure due to end of life, and d) Feeder monitoring allows the utility to have a better control over power quality.
	Regional Electricity Infrastructure Requirements (5.4.5.2.C.c.ii)
	Regional Electricity Infrastructure Requirements are not applicable to this project.
	Integration of Advance Technology (5.4.5.2.C.c.iii)
	Substation automation use advanced technologies i.e. Microprocessor controlled relays and Intelligent Electronic Devices (IED's). The project will incorporate these intelligent devices to control reclosers and for monitoring and control at the substation level.
	Integration of Interoperability (5.4.5.2.C.c.iii-1)
	N/A
	Integration of Cybersecurity (5.4.5.2.C.c.iii-2)
	Automated devices use 128 AES encryption for communication over a private communication network, all devices have multiple access passwords and unused ports are blocked to enhance cyber-security and grid protection.
	System Benefits to Reliability (5.4.5.2.C.c.iv-1)
	Adding automated reclosers to substations will improve outage response / restoration times. Automated reclosers will also allow InnPower to monitor momentary outages; and by monitoring and tracking momentary outages, InnPower will be able to proactively avoid some permanent outages. A single 30 minute outage, if avoided through this project, will improve SAIFI by .04 and SAIDI by .02. However, overall system impact on SAIDI and SAFI has not been projected for this work.
	System Benefits to Efficiency (5.4.5.2.C.c.iv-2)
	By replacing oil-reclosers with microprocessor controlled reclosers InnPower will be able to monitor substation feeders and would be able to operate breakers remotely via SCADA. With this additional capability InnPower will be able to monitor feeder level outages (momentary and permanent) and minimize the need to dispatch crews to close a breaker or get hold-offs during work on distribution feeders. This would have a positive impact on O&M costs and substantially increase the system operation efficiency.

Category-specific requirements for System Service Investments (5.4.5.2.C.c)	
	System Benefits to Safety (5.4.5.2.C.c.iv-3)
	Automated reclosers allow precise protection function of distribution features (TCC curves can be customized per feeder), they also detect end of line ground faults which enhances safety. By allowing a central control room for remote operations and hold off's, physical access to substations is limited, thus limiting staff exposure.
	Factors Affecting Implementation Timing (5.4.5.2.C.c.v-1)
	This asset has been identified in the DS Condition assessment as one that needs immediate intervention.
	Factors Affecting Implementation Priority (5.4.5.2.C.c.v-2)
	This asset has been identified in the DS Condition assessment as one that needs immediate intervention.
	Summary of Options Analysis (5.4.5.2.C.c.vi)
	N/A; InnPower will be using design and methodology developed for this type of work to ensure consistency and standardization.
	Analysis of project benefits and costs i.e. "Do Nothing" (5.4.5.2.C.c.vi-1)
	If InnPower adopts "Do Nothing" strategy the existing oil recloser will have to be sent for refurbishment. A refurbishment on a device that is passed its useful life would only make the unit fit for service for the short term.
	Analysis of project benefits and costs i.e. "Technically feasible alternatives" (5.4.5.2.C.c.vi-2)
	N/A
	Significant Benefits and Costs - the Value of which cannot readily be Quantified (5.4.5.2.
	N/A

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name	Distribution SCADA controlled load interrupting gang switch
Project number: DO 020	**Budget Year: 2017**
Investment Category: System Service	

Project Summary

This program will install one (1) SCADA controlled load interrupting gang switch on InnPower's distribution grid every year for the next 5 years.

A feeder automation plan for the distribution grid was commenced in 2011. The plan identified a priority project to enhance feeder automation capability on the 27.6kV distribution grid, this project was completed in 2012. Subsequently a detailed distribution automation plan was completed in 2013 which reviewed existing infrastructure, high risk feeders, feeders serving the most number of customers and other factors to determine ideal locations for SCADA controlled switches. These switches help reduce crew dispatch times and enable effective isolation and restoration of feeder sections during a fault and/or outage directly from the control room. The SCADA controlled switches also provide visibility, and therefore voltage/current readings and digital inputs can be monitored remotely.

In 2017 InnPower will be installing one (1) three-phase vacuum recloser on its 27.6kV distribution grid. The scope includes the upgrading of poles, and the installation and commissioning of the recloser, its radio communication module, programing of the electronic controls, and SCADA system modification. Often the two (2) adjacent poles require replacement if the new standard mandates the switch pole to be taller by 10 feet or more. The new recloser would tie in with the other automated devices on the 27.6kV gird, i.e. Substation reclosers and switches; and become part of a de-centralized feeder detection, isolation and restoration scheme.

Total capital and non-capitalized O&M costs (5.4.5.2.A.i)

	Historical Capital Costs				
	2012	2013	2014	2015	2016
Total cost	$ 124,767	$ 13,384	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Net cost	$124,767	$ 13,384	$ -	$ -	$ -
O&M expense	*undetermined*	*undetermined*	*undetermined*	*undetermined*	*undetermined*

	Future Capital Costs				
	2017	2018	2019	2020	2021
Total cost	$ 75,000	$ 78,750	$ 82,688	$ 86,821	$ 91,162
Contributions	$ -	$ -	$ -	$ -	$ -
Net cost	$ 75,000	$ 78,750	$ 82,688	$ 86,821	$ 91,162
O&M expense	*undetermined*	*undetermined*	*undetermined*	*undetermined*	*undetermined*

Customer Attachments and Load (5.4.5.2 A.ii)

Switches are installed as disconnect switches in series with primary lines of feeders, or as tie-switches connected between two feeders, and therefore typically each affect 100's to 1000's of customers from 1 or 2kVA to 10's of MVA.

	Project Dates & Expenditure Timing (5.4.5.2.A.iii)				
	Start Date:	01-Jan-17			
	In Service Date:	31-Dec-17			
	Expenditure Timing	2017: Q1	2017: Q2	2017: Q3	2017: Q4
		2%	18%	70%	10%
General Information on Project (5.4.5.2.A)	**Schedule Risks Risk Mitigation (5.4.5.2.A.iv)**				
	Similar projects have been successfully completed by InnPower in the past, the biggest risk to schedule is equipment lead-times usually 16-20 weeks. As this type of equipment is standard to InnPower's distribution system, this risk will be mitigated by ordering the equipment required for this project in Q1.				
	Comparative Information on Expenditure from Equivalent Projects (5.4.5.2.A.v)				
	Prior to this project InnPower has completed similar projects. The expenditure for this project has been derived from past experience on similar projects, with contingency for inflation and fluctuation in USD exchange rate.				
	Total Capital and OM&A costs associated with REG investment (5.4.5.2.A.vi)				
	Capital and OM&A costs associated with REG investment is not applicable to this project				
	Leave to Construct Approval (5.4.5.2.A.vii)				
	Leave to Construct Approval is not required for this project.				
	Related Project Reference Material i.e. Images, Drawings and or Reference Material				
	SCADA switches are installed in accordance with InnPower's construction standards. Construction details vary widely within that standard.				

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)

Project Name	Distribution SCADA controlled load interrupting gang switch

Investment Benefits, measured against: Efficiency, Customer Value & Reliability (5.4.5.2.B.1)

Main Driver (5.4.5.2.B.1.a-1):

System Service

- Main "Trigger" (5.4.5.2.B.1.a-1.1):

Meets system operational objectives: system efficiency

Secondary Driver (5.4.5.2.B.1.a-2):

System Renewal

- Secondary "Trigger" (5.4.5.2.B.1.a-2.1):

Assets/asset systems at end of service life due to functional obsolescence

Objective or Performance Target to be Achieved (5.4.5.2.B.1.a-3):

Primary: Efficiency; Secondary: Reliability; This program will install one (1) SCADA controlled load interrupting gang switch on InnPower's distribution grid every year for the next 5 years.

Additional Safety, and Co-ordination, Interoperability

Background information that ties in with Asset Management Process (5.4.5.2.B.1.a-3):

InnPower's distribution automation plan has identified "critical" locations within its distribution network for the installation of automated switches. These locations are based on the number of customers served, risk due to vegetation, attached load, number of critical customers, and existing infrastructure.

Overview of Investment Prioritization Justification (5.4.5.2.B.1.b)

SCADA controlled switches enable automation. Automation provides the ability to decrease the duration of service interruptions to offset the impact on the customer of an increasing volume of interruptions, due to equipment failure associated with the declining health of the distribution system. Distributed automation will also mitigate the impact of service interruptions resulting from significant weather events (e.g. high volume of outages resulting from wind and ice storms). InnPower "high risk" feeders with the largest number of customers are the highest priority for automation.

Project Identification and Selection (5.4.5.2.B.1.b-1)

The project was identified as part of InnPower's distributed automation plan completed in 2013.

Project Prioritization (5.4.5.2.B.1.b-2)

Medium priority.

This is an annual program. Timing of the projects within the program are spaced throughout the year and coordinated with the ability to obtain outages in order to install SCADA switches, as well as resource availability. The timing of the projects is such that it enables InnPower to install the target number of SCADA switches each year with the goal of continual improvement to system operational efficiency and reliability.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Project Pacing (5.4.5.2.B.1.b-3)
	During the next five years InnPower plans to install one automated switches per year on its distribution feeders
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)
	- Alternate Considerations - Design (5.4.5.2.B.1.c-1)
	Designs are planned in accordance with InnPower's analysis of its Distribution Automation Plan, past switching orders, switch operation database and line loading database, as well as the opinion of system control operators.
	- Alternate Considerations - Schedule (5.4.5.2.B.1.c-2)
	Scheduling of the work is based on available resources, past investment levels and the desire to enable advanced technology on the distribution system.
	- Alternate Considerations - Funding/Ownership (5.4.5.2.B.1.c-3)
	Alternate Funding/Ownership is not applicable for this project.
	Effect of Investment on System Operation Efficiency and Cost-Effectiveness (5.4.5.2.B.1.c.i)
	The various SCADA technologies enabled by InnPower's SCADA switches allow for efficient system operation by allowing system control operators to monitor and control the distribution system, including responding to line loading and faults. SCADA switches also allows the time and costs related to dispatching line crews to make changes to the distribution system to be reduced by allowing remotely operated switches to be controlled from the control room .
	Net Benefits Accruing to Customers as a Result of the Investment (5.4.5.2.B.1.c.ii)
	Automation provides the ability to decrease the duration of service interruptions to offset the impact on the customer of service interruptions, due to equipment failure. Distribution automation will also mitigate the impact of service interruptions resulting from significant weather events (e.g. high volume of outages resulting from wind and ice storms). InnPower "high risk" feeders with the largest number of customers are the highest priority for automation
	Impact of the Investment on Reliability Performance including on the Frequency and Duration of Outages (5.4.5.2.B.1.c.iii)
	Even though reliability is not the primary driver for this project, adding automated switches will improve outage response and restoration times.
	Projected Improvement to SAIFI (System Average Interruption Frequency Index): *N/A*
	Projected Improvement to SAIDI (System Average Interruption Duration Index): *N/A*

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Impact of the Driver(s), "Trigger" or other, on the DESIGN of the Project (5.4.5.2.B.1.c-4)
	The main driver for this project is the asset management objective "managing costs and operational efficiency". Disconnect and tie switches are used on InnPower's distribution system to control line loading by moving line segments between feeders, to restore power by rerouting line flows after an interruption has occurred, and to isolate work zones to allow for the safe construction of distribution projects. Due to the nature and configuration of the system, some switches are operated more frequently than others. SCADA and remotely operable switches allow efficient system operation by enabling switches to be operated from the control room through a SCADA system. This reduces time and costs related to dispatching line crews to the affected switches and for manual switch operation. Additionally, SCADA switches allow insight into line current flows, which enables system control operators to effectively reconfigure the system to a more efficient configuration, while respecting loading limits of equipment and regulatory operational limits of the distribution system. Finally, SCADA systems allow for advanced technology such as fault locating through supervisory functions and automated "self-healing" technology, such as smart source transfer systems. By installing SCADA switches in targeted locations, InnPower can greatly improve the operational efficiency of its distribution system.
	Impact of the Driver(s), "Trigger" or other, on the COMPONENT CHARACTERISTICS of the Project (5.4.5.2.B.1.c-5)
	InnPower has developed internal standards for the characteristics of such switches
	Impact of the Driver(s), "Trigger" or other, on the WORK PLAN of the Project (5.4.5.2.B.1.c-6)
	The work plan will be developed and coordinated with internal crews and outside contractors / 3rd parties to meet committed schedule. Opportunities for costs savings are considered by using internal crews where possible. Work plan will also identify other lines work scheduled for the area to collaborate the schedule to save costs.
	Investment Benefits, measured against: Safety (5.4.5.2.B.2)
	These projects are not intended to address safety concerns in the distribution system.
	Investment Benefits, measured against: Cyber-security, Privacy (5.4.5.2.B.3)
	Automated devices use 128 AES encryption for communication over a private communication network, all devices have multiple access passwords and unused ports are blocked to enhance cyber-security and grid protection.
	Investment Benefits, measured against: Co-ordination, Interoperability (5.4.5.2.B.4)
	The radio frequency used by the built in radios of these switches use the frequency band dedicated to electric utilities by Industry Canada, which is commonly used by other LDC's in the area.
	Co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)
	Coordination with other utilities, regional planning etc. is not required for this project, except when the pole needs to be replaced InnPower will work with 3rd party attachment companies to coordinate the work as needed.

<table>
<tr><td rowspan="10">Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)</td><td>Potential to Enable Future Technological Functionality (5.4.5.2.B.4.b-1)</td></tr>
<tr><td>By installing automated switches, InnPower opens up the capability of future technological functionality e.g. feeder automation schemes, transfer trip, and monitoring and control.</td></tr>
<tr><td>Potential to Address Future Operational Requirements (5.4.5.2.B.4.b-2)</td></tr>
<tr><td>SCADA systems are a technologically advanced feature of distribution systems. The installation of SCADA switches on InnPower's distribution system allows insight into line loading, advanced fault detection capabilities and the possibility of self-healing grids. The installation of SCADA switches also expands the SCADA communication network, which enables future additions of equipment using similar communications technology. InnPower selects its preferred SCADA technology based on robustness, features, expandability and the ability to seamlessly integrate into the existing network. Future line load increases and system flexibility needs are assessed when determining the optimal location and configuration of each switch.</td></tr>
<tr><td>Investment Benefits, measured against: Economic Development (5.4.5.2.B.5)</td></tr>
<tr><td>The installation of remotely operated switches does not directly impact economic development, however some installations have the added indirect benefit of supporting economic development through quicker restoration times and, in some cases, automatic source transfer. These benefits can lower the operational costs of commercial customers connected downstream of the switch by improving service reliability, which may impact further development of their business activities in the area.</td></tr>
<tr><td>Investment Benefits, measured against: Environmental Benefits: (5.4.5.2.B.6)</td></tr>
<tr><td>Remotely operated switches allow switches to be operated from InnPower's SCADA. This reduces crew dispatching and travel which has a minor environmental benefit.</td></tr>
</table>

Project Name Distribution SCADA controlled load interrupting gang switch		
Category-specific requirements for System Service Investments (5.4.5.2.C.c)		
Category-specific requirements for System Service Investments (5.4.5.2.C.c)	**Benefits to Customers versus Cost Impact (5.4.5.2.C.c.i)**	
	Automation provides the ability to decrease the duration of service interruptions to offset the impact on the number of service interruptions, due to equipment failure. Distribution automation will also mitigate the impact of service interruptions resulting from significant weather events (e.g. high volume of outages resulting from wind and ice storms). InnPower "high risk" feeders with the largest number of customers are the highest priority for automation.	
	Regional Electricity Infrastructure Requirements (5.4.5.2.C.c.ii)	
	Regional Electricity Infrastructure Requirements are not applicable to this project.	
	Integration of Advance Technology (5.4.5.2.C.c.iii)	
	By installing automated switches, InnPower opens up the capability of future technological functionality e.g. feeder automation schemes, transfer trip, and monitoring and control.	
	Integration of Interoperability (5.4.5.2.C.c.iii-1)	
	Switch replacements at this level do not impact inter-utility coordination.	
	Integration of Cybersecurity (5.4.5.2.C.c.iii-2)	
	Automated devices use 128 AES encryption for communication over a private communication network, all devices have multiple access passwords and unused ports are blocked to enhance cyber-security and grid protection.	
	System Benefits to Reliability (5.4.5.2.C.c.iv-1)	
	This project will enhance system reliability, efficiency and safety of the InnPower system when compared to the "do nothing" option. Other alternatives provide less functionality and do not provide the same benefits to system reliability and operational efficiency. Reliability: SCADA switches allow for the quick rerouting of line flows through remote operation of the switches. Additionally, SCADA switches have supervisory functions that alert system control operators to fault conditions downstream. The combination of these technologies allows for quicker restoration times, which reduced the duration of outages on the distribution system.	
	System Benefits to Efficiency (5.4.5.2.C.c.iv-2)	
	The various SCADA technologies enabled by InnPower's SCADA switches allows for efficient system operation by allowing system control operators to monitor and control the distribution system, including responding to line loading and faults. SCADA switches also reduces the time and costs related to dispatching line crews to make changes to the distribution system by allowing remotely operated switches to be controlled from the control room .	

Category-specific requirements for System Service Investments (5.4.5.2.C.c)	
	System Benefits to Safety (5.4.5.2.C.c.iv-3)
	This program has the benefit of allowing system control operators insight into system conditions, which allows for action to mitigate safety concerns due to system loading levels. Informed decisions can be made regarding line switching to avoid overload conditions. Additionally, the use of SCADA switches benefits employee safety because switches can be operated from a distance, minimizing employee exposure to flash-over or arcing that may occur if the switch being operated is defective, or if line current exceeds the interrupting capability of the switch.
	Factors Affecting Implementation Timing (5.4.5.2.C.c.v-1)
	This is an annual program. Timing of the projects within the program are spaced throughout the year and coordinated with the ability to obtain outages in order to install these switches, as well as resource availability. The timing of the projects is such that it enables InnPower to install the target number of SCADA switches each year with the goal of continuous improvement to system operational efficiency and reliability.
	Factors Affecting Implementation Priority (5.4.5.2.C.c.v-2)
	InnPower "high risk" feeders with the largest number of customers are the highest priority for automation.
	Summary of Options Analysis (5.4.5.2.C.c.vi)
	Analysis of project benefits and costs i.e. "Do Nothing" (5.4.5.2.C.c.vi-1)
	This program has been compared to the options of "Do Nothing". The SCADA switch program has the following benefits and costs relative to this option: - A "Do Nothing" alternative would result in leaving frequently operated manual switches as i s and by not installing switches where additional system flexibility is required. This alternative does not benefit system reliability and/or operational efficiency and in the case of system flexibility, may pose an additional cost to system operational efficiency due to load changes within the system.
	Analysis of project benefits and costs i.e. "Technically feasible alternatives" (5.4.5.2.C.c.vi-2)
	The "Technically feasible alternative" to this project that was considered is the installation of manual switches where needed to benefit system flexibility. This option has a lower initial capital cost but would require additional travel and operational time with each switch operation. Additionally, manual load-interrupting switches have exposed swinging blade systems which require additional maintenance, due to alignment and animal contact issues, above and beyond the requirements of SCADA Switch systems (which utilize encapsulated current shunting and interrupting switches). Manual switches would not have the benefit of enabling advanced technology or system awareness and may have an overall higher life-cycle cost, depending on the frequency of operation.
	Significant Benefits and Costs - the Value of which cannot readily be Quantified (5.4.5.2.C.c.-A)
	N/A

Capital Project Summary

to meet
Ontario Energy Board
Filing Requirements
for
Electricity
Transmission
and
Distribution
Applications

Chapter 5
Section 4.5.2

Material Investments

2017 General Plant Projects

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name **Engineering IT**

Project number: GO001 **Budget Year** 2017

Investment Category: General Plant

Project Summary

The engineering IT budget targets operational efficiency by upgrading and incorporating new enterprise engineering software that optimize the day to day functions of both the engineering and operations departments at InnPower. For the current planning period the major projects include GIS enhancements, asset data integration, work management, control room hardware and software, SCADA enhancements, and Circuit Simulation/Power Flow software (CYME) enhancements.

In 2017 InnPower will be incorporating asset spatial and maintenance information into the GIS, this would be done by tying various enterprise software such as North Star, Great Plains, CYME, Savage etc. This would make the GIS a comprehensive asset management software. Other initiatives include incorporating AMI information to CYME (engineering analysis software), this would allow InnPower to perform real-time system loading and optimization studies. Dashboards and historians are planned to be added to the SCADA software for internal and external customer engagement.

Total capital and non-capitalized O&M costs (5.4.5.2.A.i)

	Historical Capital Costs				
	2012	2013	2014	2015	2016
Total cost	$11,947	$28,828	$61,388	$84,471	$121,500
Contributions	$-	$-	$-	$-	$-
Net cost	$11,947	$28,828	$61,388	$84,471	$121,500
O&M expense	Undetermined	Undetermined	Undetermine	Undetermined	Undetermined

	Future Capital Costs				
	2017	2018	2019	2020	2021
Total cost	$ 167,325	$ 145,516	$ 119,000	$ 100,000	$ 105,000
Contributions	$-	$-	$-	$-	$-
Net cost	$167,325	$145,516	$119,000	$100,000	$105,000
O&M expense	Undetermined	Undetermined	Undetermine	Undetermined	Undetermined

Customer Attachments and Load (5.4.5.2 A.ii)

N/A

Project Dates & Expenditure Timing (5.4.5.2.A.iii)

Start Date:	01-Jan-17			
In Service Date:	31-Dec-17			
Expenditure Timing	2017: Q1	2017: Q2	2017: Q3	2017: Q4
	10%	35%	35%	20%

General Information on Project (5.4.5.2.A)	
	Schedule Risks & Risk Mitigation (5.4.5.2.A.iv)
	Project implementation is phased throughout the year as shown above in "expenditure timing", and as required to meet specific project requirements. Schedule risks include vendor availability and internal resourcing. Risk mitigation involves planning and communication with suppliers.
	Comparative Information on Expenditure from Equivalent Projects (5.4.5.2.A.v)
	N/A
	Total Capital and OM&A costs associated with REG investment (5.4.5.2.A.vi)
	N/A
	Leave to Construct Approval (5.4.5.2.A.vii)
	N/A
	Related Project Reference Material i.e. Images, Drawings and or Reference Material
	N/A

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)

Project Name Engineering IT

Investment Benefits, measured against: Efficiency, Customer Value & Reliability (5.4.5.2.B.1)

Main Driver (5.4.5.2.B.1.a-1):

General Plant

- Main "Trigger" (5.4.5.2.B.1.a-1.1):

Need for business operations efficiency

Secondary Driver (5.4.5.2.B.1.a-2):

General Plant

- Secondary "Trigger" (5.4.5.2.B.1.a-2.1):

Need for system capital investment support

Objective or Performance Target to be Achieved (5.4.5.2.B.1.a-3):

Primary: Efficiency; Secondary: Customer value

Additional: Cyber-security, Privacy

Background information that ties in with Asset Management Process (5.4.5.2.B.1.a-3):

The investment in hardware and software systems that support engineering and operations contribute directly in achieving InnPower's Asset Management goals.

A stated objective in InnPower's Asset Management process is to accommodate load growth. The IT investment in circuit simulation/power flow systems would enable InnPower to implement reliable design of its infrastructure expansion or upgrade projects.

Gradual investment in a work management system will result in business efficiencies that will help manage both capital and O&M costs.

Investment in enhancing our SCADA and OMS system will result in better system operating capabilities, and outage restoration efforts that will enable InnPower to improve system reliability.

Enhancing the GIS system by expanding its database so that it could serve as InnPower's asset data warehouse, by adding asset data including maintenance and performance information/outage statistics, will enable InnPower to perform better data analytics, this will in turn lead to better asset replacement decisions.

As a further enhancement to its operating procedures, InnPower is planning to equip its mobile workforce with handheld devices loaded with mobile-GIS functionality. This is included in the 5 year plan.

Overview of Investment Prioritization Justification (5.4.5.2.B.1.b)

Medium priority - projects included in this program receive a medium priority as it enables several aspects of our Asset Management program to be completed as planned, as noted above in section 5.4.5.2.B.1.a-3.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Project Identification and Selection (5.4.5.2.B.1.b-1)
	The process for project identification and selection includes a needs assessment of both our current and future needs. These needs are ascertained based on InnPower's deliverables to comply with its Asset Management process. InnPower has obtained assistance from an outside industry expert in GIS systems to map its development path. It has also engaged the software manufacturer of its circuit simulation/power flow software - CYME - to develop a program to enable implementation and use of its software. A value based assessment completed the selection process.
	Project Prioritization (5.4.5.2.B.1.b-2)
	Medium
	Project Pacing (5.4.5.2.B.1.b-3)
	Work will be spread out 5 years, with initial focus on verifying and integrating asset specification, maintenance and performance data, and load data into the enterprise software. InnPower will implement a graduated investment plan to incrementally improve its Engineering IT system capabilities.
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)
	- Alternate Considerations - Design (5.4.5.2.B.1.c-1)
	N/A
	- Alternate Considerations - Schedule (5.4.5.2.B.1.c-2)
	N/A
	- Alternate Considerations - Funding/Ownership (5.4.5.2.B.1.c-3)
	N/A
	Effect of Investment on System Operation Efficiency and Cost-Effectiveness (5.4.5.2.B.1.c.i)
	System operating efficiency will be enhanced through the implementation of betterments to its GIS and SCADA system. Additionally, the collection and storage of accurate asset data will improve InnPower's asset management process, and the implementation of intelligent data harvesting methods will enable better decision making during the budgeting processes, and help improve system performance.
	Net Benefits Accruing to Customers as a Result of the Investment (5.4.5.2.B.1.c.ii)
	The improvement in system operation efficiency will results in better overall service to customers including high reliability. The enhancements to our GIS and SCADA systems will enable InnPower customers to obtain more timely and accurate information during outages, through web maps and social media integrations.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Impact of the Investment on Reliability Performance including on the Frequency and Duration of Outages (5.4.5.2.B.1.c.iii)
	Although this is not a reliability driven program, the enhancements made to our asset database and the GIS and SCADA system, with improved mobile capability of our line crews and technicians, will improve overall system operating efficiency, and will likely result in fewer outages and quicker restoration times. Investment in circuit simulation/power flow software will enable InnPower to build a more flexible and robust system that will have a positive impact on power system performance.
	Projected Improvement to SAIFI (System Average Interruption Frequency Index): N/A
	Projected Improvement to SAIDI (System Average Interruption Duration Index): N/A
	N/A
	Impact of the Driver(s), "Trigger" or other, on the DESIGN of the Project (5.4.5.2.B.1.c-4)
	N/A
	Impact of the Driver(s), "Trigger" or other, on the COMPONENT CHARACTERISTICS of the Project (5.4.5.2.B.1.c-5)
	N/A
	Impact of the Driver(s), "Trigger" or other, on the WORK PLAN of the Project (5.4.5.2.B.1.c-6)
	N/A
	Investment Benefits, measured against: Safety (5.4.5.2.B.2)
	N/A
	Investment Benefits, measured against: Cyber-security, Privacy (5.4.5.2.B.3)
	InnPower conducts several cyber-security and privacy audits during a year to conform to best practices and industry standards.
	Investment Benefits, measured against: Co-ordination, Interoperability (5.4.5.2.B.4)
	InnPower has worked toward collaborating with outside parties, and minimizing costs by sharing resources with the Town of Innisfil who is InnPower's sole shareholder, and Simcoe County.
	Co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)
	InnPower is collaborating with the Town of Innisfil and Simcoe County for GIS functions including shared land-base information, and working towards a common infrastructure that could be shared among ourselves. InnPower currently shares its SCADA radio communication system with the Town of Innisfil, and future investments in the radio system’s IT enhancement and/or upkeep will be done in collaboration and with cost sharing with the Town of Innisfil. As of the filing of this DSP cost sharing plans have not been finalized.

Evaluation criteria and information requirements for each project/activity	
	Potential to Enable Future Technological Functionality (5.4.5.2.B.4.b-1)
	InnPower believes strongly in industry wide standardization, all software procured will be " multi-speak" compatible and/or CIM compliant and therefore would allow seamless integration with other compliant software in the future
	Potential to Address Future Operational Requirements (5.4.5.2.B.4.b-2)
	All software are scalable and would meet current and future operational requirements by changes to licensing.
	Investment Benefits, measured against: Economic Development (5.4.5.2.B.5)
	N/A
	Investment Benefits, measured against: Environmental Benefits: (5.4.5.2.B.6)
	N/A

Project Name	Engineering IT
Category-specific requirements for General Plant Investments (5.4.5.2.C.d)	

Category-specific requirements for General Plant Investments (5.4.5.2.C.d)	
	Summary of Qualitative Analysis (5.4.5.2.C.d.i-1)
	N/A
	Summary of Quantitative Analysis (5.4.5.2.C.d.i-2)
	N/A
	Assessments of Financially Feasible Options (5.4.5.2.C.d.i-3)
	New system implementation projects follow company policy with regards to obtaining competitive pricing (tendering, etc.). This provides the basis for assessing other financially feasible options. The process is overseen by senior management, vetted by legal counsel, and approved by the Board of Directors. Other financial options considered by InnPower include: (1) Reducing life cycle costs through sharing software licensing costs and services with third parties. As a result of such consideration InnPower has developed a relationship with both the Town of Innisfil and Simcoe County. (2) InnPower has invested in training in-house personnel to reduce the cost of hiring outside integrators for system development. This has helped develop in- house expertise; resulting in increased efficiency, faster implementation, easier de-bugging, and quicker resolution to system issues. InnPower has worked with the software developer of its SCADA systems to enhance their software capabilities; this has resulted in InnPower receiving credit for some of this work through the Scientific Research and Experimental Development Tax Incentive program.

Category-specific requirements for General Plant Investments (5.4.5.2.C.d)	**- Analysis of "Do Nothing" Scenario (5.4.5.2.C.d.i-4)**
	In a "Do Nothing" scenario, InnPower asset information will be fragmented in different software applications and paper files. This would not allow InnPower to effectively manage and/or track its assets. InnPower will continue to use quasi-manual systems for work management. The Control Room software, SCADA, and GIS systems will remain at current levels/software release versions, lacking routine system updates and enhancements which will likely impair its operational capabilities, and result in incompatibilities with operating systems. InnPower's Asset Management process will be negatively impacted if asset information consolidation efforts and data accuracy verification is not completed. Efficiency improvements to be achieved through the development of relational databases between the various enterprise software systems will be lost. InnPower will continue its dependence on outside contractors to perform circuit simulation/power flow studies, resulting in higher costs, and possible work delays.
	Net Benefit of Investment (5.4.5.2.C.d.i-5)
	Meet Asset Management objectives, improve quality of engineering work, enhance efficiency and improve outage restoration.
	Business Case Justification / Documentation (5.4.5.2.C.d.ii)
	This investment supports InnPower achieving the Asset Management goals listed below: Better design reliability: Software implementations will improve design reliability of InnPower's infrastructure expansion and/or upgrade projects. Enhanced Efficiency: Investment in a work management system will result in business efficiencies that will help manage both capital and O&M costs. Operational benefits: Investment in enhancing our SCADA and OMS system will result in better system operating capabilities, and enhance outage restoration efforts. This will in turn enable InnPower to improve the overall system reliability. Better asset replacement decisions: Enhancing the GIS system by ensuring that it serves as InnPower's asset data warehouse, and by adding asset data (including maintenance and performance information/outage statistics), InnPower will be able to perform better data analytics that will lead to informed asset replacement decisions.
	- Alternatives Considered (5.4.5.2.C.d.ii-1)
	Alternative were considered as described above in 5.4.5.2.C.d.i-3 and 5.4.5.2.C.d.i-4

Category-specific requirements for General Plant Investments (5.4.5.2.C.d)	
	- Benefits to Customers - Short Term (5.4.5.2.C.d.ii-2a)
	The improvement in system operation efficiency will results in better overall service to customers including high reliability. The enhancements to our GIS and SCADA systems will enable InnPower customers to obtain more timely and accurate information during outages.
	- Benefits to Customers - Long Term (5.4.5.2.C.d.ii-2b)
	Same as noted above for short term benefits (5.4.5.2.C.d.ii-2a)
	- Impact on Distributor Costs - Short Term (5.4.5.2.C.d.ii-3a)
	The implementation of new or upgraded system will result in slightly higher costs for system maintenance and upkeep, however, InnPower expects to see some improvement in efficiency to offset some or all of the extra costs.
	- Impact on Distributor Costs - Long Term (5.4.5.2.C.d.ii-3b)
	Same as noted above for Short Term benefits (5.4.5.2.C.d.ii-3a)

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name **Finance IT**

Project number: GF 001 Budget Year: 2017

Investment Category: General Plant

Project Summary

This capital project is comprised of an ongoing business requirement to upgrade and enhance existing financial and regulatory software. InnPower Corporation's primary focus is on enhancements to the budgeting software as well as upgrades to the existing financial software. Dashboard software has been budgeted in order to aggregate multiple data sources into a common platform for analytics and decision making.

Total capital and non-capitalized O&M costs (5.4.5.2.A.i)

	Historical Capital Costs				
	2012	2013	2014	2015	2016
Total cost	$ 27,917	$ 31,588	$ 48,849	$ 94,356	$122,000
Contributions	$ -	$ -	$ -	$ -	$ -
Net cost	$ 27,917	$ 31,588	$ 48,849	$ 94,356	$122,000
O&M expense	Undetermined				

	Future Capital Costs				
	2017	2018	2019	2020	2021
Total cost	$ 77,000	$ 50,000	$ 60,000	$ 50,000	$ 50,000
Contributions	$ -	$ -	$ -	$ -	$ -
Net cost	$ 77,000	$ 50,000	$ 60,000	$ 50,000	$ 50,000
O&M expense	Undetermined				

Customer Attachments and Load (5.4.5.2 A.ii)

N/A

Project Dates & Expenditure Timing (5.4.5.2.A.iii)

Start Date:	01-Jan-17			
In Service Date:	31-Dec-17			
Expenditure Timing	2017: Q1	2017: Q2	2017: Q3	2017: Q4
	25%	25%	25%	25%

Schedule Risks & Risk Mitigation (5.4.5.2.A.iv)

Project implementation is phased throughout the year and as required to meet specific projects or new additions. Project risks may include vendor availability and internal resourcing. Risk mitigation involves planning and communication with vendors.

Comparative Information on Expenditure from Equivalent Projects (5.4.5.2.A.v)

Historical costs are reflected in table above 5.4.5.2.A.i

General Information on Project (5.4.5.2.A)	
	Total Capital and OM&A costs associated with REG investment (5.4.5.2.A.vi)
	N/A
	Leave to Construct Approval (5.4.5.2.A.vii)
	N/A
	Related Project Reference Material i.e. Images, Drawings and or Reference Material
	N/A

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Project Name Finance IT
	Investment Benefits, measured against: Efficiency, Customer Value & Reliability (5.4.5.2.B.1)
	Main Driver (5.4.5.2.B.1.a-1):
	General Plant
	- Main "Trigger" (5.4.5.2.B.1.a-1.1):
	Need for business operations efficiency
	Secondary Driver (5.4.5.2.B.1.a-2): None
	- Secondary "Trigger" (5.4.5.2.B.1.a-2.1): None
	Objective or Performance Target to be Achieved (5.4.5.2.B.1.a-3):
	Primary: Efficiency
	Background information that ties in with Asset Management Process (5.4.5.2.B.1.a-4):
	N/A
	Overview of Investment Prioritization Justification (5.4.5.2.B.1.b)
	High Priority - Software is treated as a strategic asset. Enhancements and upgrades are required to maintain productivity and to benefit from new software capabilities. Automation software is implemented to streamline existing and new processes allowing better productivity and timely reporting.
	Project Identification and Selection (5.4.5.2.B.1.b-1)
	N/A
	Project Prioritization (5.4.5.2.B.1.b-2)
	N/A
	Project Pacing (5.4.5.2.B.1.b-3)
	The project is paced depending on software versions and individual project timelines. Software projects are paced depending on the need and prioritized accordingly. Internal resourcing is also a factor in project pacing.
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)
	- Alternate Considerations - Design (5.4.5.2.B.1.c-1)
	N/A
	- Alternate Considerations - Schedule (5.4.5.2.B.1.c-2)
	N/A

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	- Alternate Considerations - Funding/Ownership (5.4.5.2.B.1.c-3)
	N/A
	Effect of Investment on System Operation Efficiency and Cost-Effectiveness (5.4.5.2.B.1.c.i)
	N/A
	Net Benefits Accruing to Customers as a Result of the Investment (5.4.5.2.B.1.c.ii)
	N/A
	Impact of the Investment on Reliability Performance including on the Frequency and Duration of Outages (5.4.5.2.B.1.c.iii)
	N/A
	Projected Improvement to SAIFI (System Average Interruption Frequency Index): N/A
	Projected Improvement to SAIDI (System Average Interruption Duration Index): N/A
	Impact of the Driver(s), "Trigger" or other, on the DESIGN of the Project (5.4.5.2.B.1.c-4)
	N/A
	Impact of the Driver(s), "Trigger" or other, on the COMPONENT CHARACTERISTICS of the Project (5.4.5.2.B.1.c-5)
	N/A
	Impact of the Driver(s), "Trigger" or other, on the WORK PLAN of the Project (5.4.5.2.B.1.c-6)
	N/A
	Investment Benefits, measured against: Safety (5.4.5.2.B.2)
	N/A
	Investment Benefits, measured against: Cyber-security, Privacy (5.4.5.2.B.3)
	N/A
	Investment Benefits, measured against: Co-ordination, Interoperability (5.4.5.2.B.4)
	N/A
	Co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)
	N/A
	Potential to Enable Future Technological Functionality (5.4.5.2.B.4.b-1)
	Suppliers of enterprise systems such as financial and budgeting applications are constantly upgrading their products to deliver new processes and functionality. As new versions are released, upgrades are necessary to maintain vendor support for the systems. Vendor upgrades to existing software are required for security, reliability and to realize benefits of additions and improvements.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Potential to Address Future Operational Requirements (5.4.5.2.B.4.b-2)
	N/A
	Investment Benefits, measured against: Economic Development (5.4.5.2.B.5)
	N/A
	Investment Benefits, measured against: Environmental Benefits: (5.4.5.2.B.6)
	N/A

Project Name	Finance IT
Category-specific requirements for General Plant Investments (5.4.5.2.C.d)	
Category-specific requirements for General Plant Investments (5.4.5.2.C.d)	**Summary of Qualitative Analysis (5.4.5.2.C.d.i-1)**
	N/A
	Summary of Quantitative Analysis (5.4.5.2.C.d.i-2)
	N/A
	Assessments of Financially Feasible Options (5.4.5.2.C.d.i-3)
	N/A
	- Analysis of "Do Nothing" Scenario (5.4.5.2.C.d.i-4)
	By not continuing investment in financial systems software, the ability to maintain support from vendors is diminished. An outdated software version would therefore not include applicable tax updates, payroll changes and other required modifications. Efficiencies that are typically accomplished by the addition of new features and/or widgets during a software upgrade would not be gained in a “Do Nothing” scenario.
	Net Benefit of Investment (5.4.5.2.C.d.i-5)
	Maintaining software at current levels maintains staff productivity; periodic investments in new software allows InnPower Corporation to migrate to these new and/or upgraded applications without the need to make large one-time investments in software that meet the minimum operating requirements. Regulatory reporting requirement can also be met from software upgrades and enhancements.
	Business Case Justification Documentation (5.4.5.2.C.d.ii)
	InnPower Corporation's financial and regulatory department provide monthly, quarterly and year end reporting to support the regulatory, government and internal reporting requirements. Software systems require regular maintenance and upgrades to remain current to meet minimum operating requirements. Dashboard software will enable management to analyze data and assist in the decision making process.
	- Alternatives Considered (5.4.5.2.C.d.ii-1)
	N/A
	- Benefits to Customers - Short Term (5.4.5.2.C.d.ii-2a)
	N/A

Category-specific requirements for General Plant Investments (5.4.5.2.C.d)	**- Benefits to Customers - Long Term (5.4.5.2.C.d.ii-2b)**
	N/A
	- Impact on Distributor Costs - Short Term (5.4.5.2.C.d.ii-3a)
	N/A
	- Impact on Distributor Costs - Long Term (5.4.5.2.C.d.ii-3b)
	N/A

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Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name: **IT Hardware**

Project number: GB 001 **Budget Year:** 2017

Investment Category: General Plant

Project Summary

This capital project is comprised of an ongoing business requirement to replace end user computers and network infrastructure. InnPower utilizes a 5 year lifecycle for IT hardware. Network infrastructure includes additional storage and replacement, security enhancements and backup /disaster recovery strategies.

Total capital and non-capitalized O&M costs (5.4.5.2.A.i)

	Historical Capital Costs				
	2012	2013	2014	2015	2016
Total cost	$ 73,117	$ 53,604	$ 79,344	$ 148,675	$ 130,000
Contributions	$ -	$ -	$ -	$ -	$ -
Net cost	$ 73,117	$ 53,604	$ 79,344	$ 148,675	$ 130,000
O&M expense	Undetermined				

	Future Capital Costs				
	2017	2018	2019	2020	2021
Total cost	$ 165,000	$ 150,000	$ 150,000	$ 150,000	$ 150,000
Contributions	$ -	$ -	$ -	$ -	$ -
Net cost	$ 165,000	$ 150,000	$ 150,000	$ 150,000	$ 150,000
O&M expense	Undetermined				

Customer Attachments and Load (5.4.5.2 A.ii)

N/A

Project Dates & Expenditure Timing (5.4.5.2.A.iii)

Start Date:	01-Jan-17			
In Service Date:	31-Dec-17			
Expenditure Timing	2017: Q1	2017: Q2	2017: Q3	2017: Q4
	25%	25%	25%	25%

Schedule Risks & Risk Mitigation (5.4.5.2.A.iv)

Project implementation is phased throughout the year and as required to meet specific projects or new additions. Project risks may include vendor availability and internal resourcing. Risk mitigation involves planning and communication with suppliers.

Comparative Information on Expenditure from Equivalent Projects (5.4.5.2.A.v)

Historical costs are reflected in table above 5.4.5.2.A.i.

General Information on Project (5.4.5.2.A)	
	Total Capital and OM&A costs associated with REG investment (5.4.5.2.A.vi)
	N/A
	Leave to Construct Approval (5.4.5.2.A.vii)
	N/A
	Related Project Reference Material i.e. Images, Drawings and or Reference Material
	N/A

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Project Name: IT Hardware
	Investment Benefits, measured against: Efficiency, Customer Value & Reliability (5.4.5.2.B.1)
	Main Driver (5.4.5.2.B.1.a-1):
	General Plant
	- Main "Trigger" (5.4.5.2.B.1.a-1.1):
	Need for business operations efficiency
	Secondary Driver (5.4.5.2.B.1.a-2): None
	- Secondary "Trigger" (5.4.5.2.B.1.a-2.1): None
	Objective or Performance Target to be Achieved (5.4.5.2.B.1.a-3):
	Primary: Efficiency
	Background information that ties in with Asset Management Process (5.4.5.2.B.1.a-4):
	The criteria used for this project complies with InnPower's standard for given asset replacement: 5 year lifecycle for IT hardware.
	Overview of Investment Prioritization Justification (5.4.5.2.B.1.b)
	High Priority – Personal computers are treated as a strategic asset. They are InnPower Corporation's primary staff productivity tool. They are used to: maintain and deliver services to customers; improve staff productivity; cost-effectively manage total cost of PC ownership; and support investments in new applications, infrastructure and business capabilities.
	Project Identification and Selection (5.4.5.2.B.1.b-1)
	Assets to be added, replaced, or upgraded under this project are identified and selected based on consideration to specific project deliverable requirements or employee requirements to complete routine tasks assigned to each individual.
	Project Prioritization (5.4.5.2.B.1.b-2)
	Prioritization for the selection of assets are based on specific business needs for each project or to meet the needs of each individual employee.
	Project Pacing (5.4.5.2.B.1.b-3)
	Project pacing is achieved through maintaining consistent PC lifecycle refresh programs, this allows InnPower to migrate to new applications without a need to make a large one-time investment in PCs that meet the minimum operating requirements of these new applications. IT hardware that needs to meet enterprise/system expansion requirements are paced through long term planning.
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)
	- Alternate Considerations - Design (5.4.5.2.B.1.c-1)
	N/A

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	- Alternate Considerations - Schedule (5.4.5.2.B.1.c-2)
	N/A: The schedule for this work is determined by IT policy, and the evolving needs of the corporation.
	- Alternate Considerations - Funding/Ownership (5.4.5.2.B.1.c-3)
	N/A
	Effect of Investment on System Operation Efficiency and Cost-Effectiveness (5.4.5.2.B.1.c.i)
	N/A
	Net Benefits Accruing to Customers as a Result of the Investment (5.4.5.2.B.1.c.ii)
	N/A
	Impact of the Investment on Reliability Performance including on the Frequency and Duration of Outages (5.4.5.2.B.1.c.iii)
	Maintaining robust IT systems will contribute to reliability. Capital spending for Outage Management and SCADA systems will assist with the identification of outages and improve restoration.
	Projected Improvement to SAIFI (System Average Interruption Frequency Index): *N/A*
	Projected Improvement to SAIDI (System Average Interruption Duration Index): *N/A*
	Impact of the Driver(s), "Trigger" or other, on the DESIGN of the Project (5.4.5.2.B.1.c-4)
	N/A
	Impact of the Driver(s), "Trigger" or other, on the COMPONENT CHARACTERISTICS of the Project (5.4.5.2.B.1.c-5)
	N/A
	Impact of the Driver(s), "Trigger" or other, on the WORK PLAN of the Project (5.4.5.2.B.1.c-6)
	N/A
	Investment Benefits, measured against: Safety (5.4.5.2.B.2)
	N/A
	Investment Benefits, measured against: Cyber-security, Privacy (5.4.5.2.B.3)
	Hardware replacement is required to address end of vendor support (i.e. Windows XP)
	Investment Benefits, measured against: Co-ordination, Interoperability (5.4.5.2.B.4)
	N/A
	Co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)
	N/A

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Potential to Enable Future Technological Functionality (5.4.5.2.B.4.b-1)
	Suppliers of enterprise systems such as: GIS; OMS; SCADA; AMI; and IFS ERP, are constantly upgrading their products to deliver new processes and functionality. As new versions are released, up-to-date hardware is required in order to perform necessary upgrades to maintain vendor support for these systems.
	Potential to Address Future Operational Requirements (5.4.5.2.B.4.b-2)
	N/A
	Investment Benefits, measured against: Economic Development (5.4.5.2.B.5)
	N/A
	Investment Benefits, measured against: Environmental Benefits: (5.4.5.2.B.6)
	N/A

Project Name: IT Hardware	
Category-specific requirements for General Plant Investments (5.4.5.2.C.d)	
Category-specific requirements for General Plant Investments (5.4.5.2.C.d)	**Summary of Qualitative Analysis (5.4.5.2.C.d.i-1)**
	N/A
	Summary of Quantitative Analysis (5.4.5.2.C.d.i-2)
	N/A
	Assessments of Financially Feasible Options (5.4.5.2.C.d.i-3)
	N/A
	- Analysis of "Do Nothing" Scenario (5.4.5.2.C.d.i-4)
	PCs are the primary productivity tool used by InnPower staff. If InnPower follows the "do-nothing" option, it will result in unreliable and slow PCs which would negatively impact productivity and customer service.
	Net Benefit of Investment (5.4.5.2.C.d.i-5)
	By minimizing the number of supported devices, the IT support effort required to manage, order, configure, and deploy PCs is reduced. This in turn reduces the total cost of ownership for PCs.
	Business Case Justification Documentation (5.4.5.2.C.d.ii)
	InnPower Corporation PCs are treated as a strategic asset, because they are the primary staff productivity tool. InnPower maintains its PC lifecycle management processes utilizing a PC refresh cycle to a maximum of 5 years, in order to: deliver, maintain and improve services to customers; to improve staff productivity; to effectively manage total cost of PC ownership; and to support investments in new applications, infrastructure and business capabilities. Maintaining consistent PC lifecycle refresh program allows InnPower to migrate to new applications without a need to make large one-time investments in PCs that is required to meet the minimum operating requirements of new applications.
	- Alternatives Considered (5.4.5.2.C.d.ii-1)
	N/A
	- Benefits to Customers - Short Term (5.4.5.2.C.d.ii-2a)
	PCs are the primary productivity tool used by InnPower staff. Reliable and faster PCs have a positive impact on productivity, customer service and reliability.
	- Benefits to Customers - Long Term (5.4.5.2.C.d.ii-2b)
	Same benefits as stated above under Short Term benefits (5.4.5.2.C.d.ii-2a)

Category-specific requirements for General Plant Investments (5.4.5.2.C.d)	**- Impact on Distributor Costs - Short Term (5.4.5.2.C.d.ii-3a)**
	N/A
	- Impact on Distributor Costs - Long Term (5.4.5.2.C.d.ii-3b)
	N/A

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Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name **IT Software**

Project number: GB 002 **Budget Year:** 2017

Investment Category: General Plant

Project Summary

This capital project is comprised of an ongoing business requirement to upgrade and enhance existing software. InnPower Corporation's primary focus for this project is the Customer Information System (CIS), network security and miscellaneous client software.

Total capital and non-capitalized O&M costs (5.4.5.2.A.i)

	Historical Capital Costs				
	2012	2013	2014	2015	2016
Total cost	$ 18,090	$ 20,672	$ 88,347	$ 56,990	$115,000
Contributions	$ -	$ -	$ -	$ -	$ -
Net cost	$ 18,090	$ 20,672	$ 88,347	$ 56,990	$115,000
O&M expense	Undetermined				

	Future Capital Costs				
	2017	2018	2019	2020	2021
Total cost	$ 95,000	$ 95,000	$ 95,000	$ 95,000	$ 95,000
Contributions	$ -	$ -	$ -	$ -	$ -
Net cost	$ 95,000	$ 95,000	$ 95,000	$ 95,000	$ 95,000
O&M expense	Undetermined				

Customer Attachments and Load (5.4.5.2 A.ii)

N/A

Project Dates & Expenditure Timing (5.4.5.2.A.iii)

Start Date:	01-Jan-17			
In Service Date:	31-Dec-17			
Expenditure Timing	2017: Q1	2017: Q2	2017: Q3	2017: Q4
	25%	25%	25%	25%

Schedule Risks & Risk Mitigation (5.4.5.2.A.iv)

Project implementation is phased throughout the year and as required to meet specific projects or new additions. Project risks may include vendor availability and internal resourcing. Risk mitigation involves planning and communication with vendors.

Comparative Information on Expenditure from Equivalent Projects (5.4.5.2.A.v)

Historical costs are reflected in table above 5.4.5.2.A.i.

General Information on Project (5.4.5.2.A)	
	Total Capital and OM&A costs associated with REG investment (5.4.5.2.A.vi)
	N/A
	Leave to Construct Approval (5.4.5.2.A.vii)
	N/A
	Related Project Reference Material i.e. Images, Drawings and or Reference Material
	N/A

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)

Project Name: IT Software

Investment Benefits, measured against: Efficiency, Customer Value & Reliability (5.4.5.2.B.1)

Main Driver (5.4.5.2.B.1.a-1):

General Plant

- Main "Trigger" (5.4.5.2.B.1.a-1.1):

Need for business operations efficiency

Secondary Driver (5.4.5.2.B.1.a-2): None

- Secondary "Trigger" (5.4.5.2.B.1.a-2.1): None

Objective or Performance Target to be Achieved (5.4.5.2.B.1.a-3):

Primary: Efficiency

Background information that ties in with Asset Management Process (5.4.5.2.B.1.a-3):

N/A

Overview of Investment Prioritization Justification (5.4.5.2.B.1.b)

High Priority - Software is treated as a strategic asset. The CIS software is the backbone of all customer data and is used for billing electricity. Enhancements and upgrades are required to maintain productivity and to benefit from new software capabilities. Automation software is implemented to streamline existing and new processes allowing better productivity and customer service. Network security is also a high priority; software upgrades and additions play an important role in maintaining data integrity and privacy.

Project Identification and Selection (5.4.5.2.B.1.b-1)

N/A

Project Prioritization (5.4.5.2.B.1.b-2)

N/A

Project Pacing (5.4.5.2.B.1.b-3)

The project is paced depending on software versions and individual project timelines. Software projects are paced depending on the need and prioritized accordingly. Internal resourcing is also a factor.

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

- Alternate Considerations - Design (5.4.5.2.B.1.c-1)

N/A

- Alternate Considerations - Schedule (5.4.5.2.B.1.c-2)

N/A

- Alternate Considerations - Funding/Ownership (5.4.5.2.B.1.c-3)

N/A

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Effect of Investment on System Operation Efficiency and Cost-Effectiveness (5.4.5.2.B.1.c.i)
	N/A
	Net Benefits Accruing to Customers as a Result of the Investment (5.4.5.2.B.1.c.ii)
	The upkeep of our customer information service portal will enable customer service personnel to better serve our customers in a timely and efficient manner.
	Impact of the Investment on Reliability Performance including on the Frequency and Duration of Outages (5.4.5.2.B.1.c.iii)
	This project is not intended to impact reliability. However, the Outage Management System is heavily reliant on the CIS System as it obtains customer information while processing outage records, and to log customer specific outage information. A CIS system that operates smoothly, particularly during storms can assist with making customer contact and therefore assist with the overall restoration efforts.
	Projected Improvement to SAIFI (System Average Interruption Frequency Index): *N/A*
	Projected Improvement to SAIDI (System Average Interruption Duration Index): *N/A*
	Impact of the Driver(s), "Trigger" or other, on the DESIGN of the Project (5.4.5.2.B.1.c-4)
	N/A
	Impact of the Driver(s), "Trigger" or other, on the COMPONENT CHARACTERISTICS of the Project (5.4.5.2.B.1.c-5)
	N/A
	Impact of the Driver(s), "Trigger" or other, on the WORK PLAN of the Project (5.4.5.2.B.1.c-6)
	N/A
	Investment Benefits, measured against: Safety (5.4.5.2.B.2)
	N/A
	Investment Benefits, measured against: Cyber-security, Privacy (5.4.5.2.B.3)
	Maintaining software that supports security is a vital part of preventing cyber security risks and addressing privacy concerns.
	Investment Benefits, measured against: Co-ordination, Interoperability (5.4.5.2.B.4)
	N/A
	Co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)
	N/A

Evaluation criteria and information requirements for each project/activity	
	Potential to Enable Future Technological Functionality (5.4.5.2.B.4.b-1)
	Suppliers of enterprise systems such as CIS and security applications are constantly upgrading their products to deliver new processes and functionality. As new versions are released, upgrades are necessary to maintain vendor support for the systems. Vendor upgrades to existing software are also required for security, reliability and to realize benefits of additions and improvements.
	Potential to Address Future Operational Requirements (5.4.5.2.B.4.b-2)
	N/A
	Investment Benefits, measured against: Economic Development (5.4.5.2.B.5)
	N/A
	Investment Benefits, measured against: Environmental Benefits: (5.4.5.2.B.6)
	N/A

Project Name IT Software		
Category-specific requirements for General Plant Investments (5.4.5.2.C.d)		
Category-specific requirements for General Plant Investments (5.4.5.2.C.d)	**Summary of Qualitative Analysis (5.4.5.2.C.d.i-1)**	
	N/A	
	Summary of Quantitative Analysis (5.4.5.2.C.d.i-2)	
	N/A	
	Assessments of Financially Feasible Options (5.4.5.2.C.d.i-3)	
	N/A	
	- Analysis of "Do Nothing" Scenario (5.4.5.2.C.d.i-4)	
	By not investing in CIS upgrades and IT security applications, there will be negative impacts to Customer Service and productivity. Other impacts could include privacy breaches, and computing viruses. Reporting requirements are a big part of InnPower's business and software are required for reporting, planning and resourcing.	
	Net Benefit of Investment (5.4.5.2.C.d.i-5)	
	Maintaining software at current levels and investing in new software allows InnPower Corporation to migrate to these new or upgraded applications without a need to make large one-time investments in software that meet the minimum operating requirements.	
	Business Case Justification Documentation (5.4.5.2.C.d.ii)	
	InnPower Corporation's Customer Information System is responsible for customer data and billing of services. Regulatory requirements impact modifications to CIS systems. Customer engagement tools are also connected directly to the CIS and software add-ons are required to support these opportunities. Cyber security and privacy are extremely important in maintaining data integrity and personal information. Software vendors also have to stay current with ever changing operating systems and hardware. By maintaining current CIS software, the need for a large one time software investment is not required.	
	- Alternatives Considered (5.4.5.2.C.d.ii-1)	
	N/A	

Category-specific requirements for General Plant Investments (5.4.5.2.C.d)	
	- Benefits to Customers - Short Term (5.4.5.2.C.d.ii-2a)
	CIS software is used by a large portion of InnPower staff. The majority of customer service related questions and process are managed by the CIS and add-on applications. Add-on software allow customers to see their data and make decisions accordingly. Effective current CIS software allow customer service representatives the ability to deal with customer queries in an effective and timely manner. This increases overall productivity and the customer experience. Security software upgrades protect customer's data and provide the privacy required.
	- Benefits to Customers - Long Term (5.4.5.2.C.d.ii-2b)
	Same as the benefits stated above for short term benefits((5.4.5.2.C.d.ii-2a).
	- Impact on Distributor Costs - Short Term (5.4.5.2.C.d.ii-3a)
	N/A
	- Impact on Distributor Costs - Long Term (5.4.5.2.C.d.ii-3b)
	N/A

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Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name **Locator Vehicle Mini-van (x2)**

Project number: GO 010-a **Budget Year:** 2017

Investment Category: General Plant

Project Summary

Purchase of two (2) additional small vehicles, to complement the additional staffing requirements for performing locating services.

Total capital and non-capitalized O&M costs (5.4.5.2.A.i)

	Historical Capital Costs					
	2012	2013	2014	2015	2016	
Total cost						
Contributions						
Net cost						
O&M expense						

	Future Capital Costs					
	2017	2018	2019	2020	2021	
Total cost	$ 63,000					
Contributions	$ -					
Net cost	$ 63,000					
O&M expense	Undetermined					

Customer Attachments and Load (5.4.5.2 A.ii)

N/A

Project Dates & Expenditure Timing (5.4.5.2.A.iii)

Start Date:	01-Jan-17				
In Service Date:	31-Dec-17				
Expenditure Timing	2017: Q1	2017: Q2	2017: Q3	2017: Q4	
		100%			

Schedule Risks & Risk Mitigation (5.4.5.2.A.iv)

In order to ensure delivery in Project year, InnPower will have tenders sent in late 2016 with expected delivery in Q1/Q2 of 2017

Comparative Information on Expenditure from Equivalent Projects (5.4.5.2.A.v)

InnPower has purchased new small vehicles, we will use these previous purchases as a guide to stay within the projected budget.

Total Capital and OM&A costs associated with REG investment (5.4.5.2.A.vi)

N/A

Leave to Construct Approval (5.4.5.2.A.vii)

Not required

Related Project Reference Material i.e. Images, Drawings and or Reference Material

InnPower's overall vehicular investment program is provided below for reference. The basis for investment ties in with InnPower's vehicle replacement policy and to the personnel additions stated in the Human Resources plan.

Future Capital Costs ($ '000)				
2017	2018	2019	2020	2021
$ 818,500	$ 752,025	$ 295,917	$ 101,079	$ 114,337
Replacement Double Bucket Truck - 1993 Altec ($373.5k)	Tech Vehicle - Ford Escape 2008 Replacement (#85): ($45,675)	Tech Vehicle - Ford Escape 2009 & 2010 Replacement (#88 & 95): ($95,917)	Fleet vehicle replacement 2005 1/2 ton (#87): ($51,750)	Fleet vehicle replacement 2011- 1/2 ton (#96): ($54,337)
Fleet vehicle replacement 1-2006 Ford 1/2 ton ($45k)	Meter Tech Vehicle - NEW ($45,675)	Tension Machines ($200k)	Tech Vehicle - Ford Escape 2008 Rep (#92): ($49,329)	Fleet vehicle replacement 2011- 1 ton (#101): ($60k)
Locator Vehicles (x2): ($63k) - New Hire	Inspector vehicle - NEW ($45,675)			
RBD - new Crew: ($250k)	65' Double Bucket-new crew ($400k)			
New Technologist Vehicle ($43.5) - New Hire	1 Ton Pickup Truck-new crew: ($45k)			
New Inspector Vehicle ($43.5) - New Hire	Tooling for Bucket & RBD ($150k)			
	Additional Spider system ($20k)			

At the time of filing this application InnPower observed the possible requirement to lump all 2017 new hire vehicles together to prepare the Material Write up for the total of $150k. InnPower will have the revised write up available upon request.

YEAR	VEHICLE	TRUCK #	PLATE #
1993	GMC BUCKET TRUCK MODEL WG64	301	359 1YH
2000	GMC PICK-UP WITH DUMP BOX	94	1339XV
2005	DODGE RAM PICK-UP	87	AF 78557
2006	FORD F150	93	1185RZ
2008	FORD ESCAPE (HYBRID)	92	BDBA902
2008	FORD ESCAPE (HYBRID)	85	ACMR852
2009	FORD ESCAPE (HYBRID)	88	AEME615
2009	FORD ESCAPE (HYBRID)	89	AEME616
2010	POSI PLUSSINGLE BUCKET MODEL FM2	302	185 9ZB
2010	FORD ESCAPE (HYBRID)	95	BJWA 824
2010	REEL TRAILER	402	H6112Y
2010	PORTABLE TRAFFIC SIGNALERS (2)	404	NO PLATES
2011	CHEVY SILVERADO HYBRID	96	AA52433
2011	FORD SRW F350 PICK UP	101	3809ZJ
2011	FLOAT TRAILER	403	H6607W
2011	POLE TRAILER	401	H6113Y
2011	FREIGHTLINER RBD	201	554 8ZR
2014	HONDA CRV	97	BSST 522
2014	HONDA CRV	98	BSST 523
2015	KIA SOUL - Electric	601	GVAF582

General Information on Project (5.4.5.2.A)

Related Project Reference Material i.e. Images, Drawings and or Reference Material

InnPower's overall vehicular investment program is provided below for reference. The basis for investment ties in with InnPower's vehicle replacement policy and to the personnel additions stated in the Human Resources plan.

Human Resources Five Year Plan

	Forecast	Projection				
	2015	2016	2017	2018	2019	2020
Customer Growth	470	744	374	1,233	1,246	1,032
Customer Growth %	3.0%	4.6%	2.2%	7.1%	6.7%	5.2%
Total Customers Y/E	16,245	16,989	17,363	18,595	19,841	20,873
Employees	41.0	44.0	50.5	59.5	60.5	60.5
Customer to employee	396	386	344	313	328	345

	Forecast	Projection				
	2015	2016	2017	2018	2019	2020
President & CEO	1	1	1	1	1	1
Executive Assistant	0	0	1	1	1	1
HR Manager	1	1	1	1	1	1
HR/Admin. Assistant	0.5	0.5	1	1	2	2
CFO	1	1	1	1	1	1
Accounting Manager	1	1	1	1	1	1
Accounting Clerk	2	2	3	3	3	3
Financial Analyst	1	1	1	1	1	1
Business Analyst	0	1	1	1	1	1
P/T Finance Support	0.5	0.5	0	0	0	0
Regulatory/Consv Mgr	1	1	1	1	1	1
CDM Rep.	1	1	1	1	1	1
Regulatory Assistant	0.5	0.5	1	1	1	1
VP, Corp Services	1	1	1	1	1	1
Metering/IT Manager	0	0	0	1	1	1
Meter Technician	1	1	1	2	2	2
Network Administrator	1	1	2	2	2	2
IS Analyst	1	1	1	1	1	1
Customer Service Mgr	1	1	1	1	1	1
Customer Accounts Rep.	2.5	2.5	2.5	2.5	2.5	2.5
Customer Service Rep.	6	6	6	7	7	7
VP, Eng. & Opers.	1	1	1	1	1	1
Eng. & Ops. Assistant	1	1	1	2	2	2
Engineering Mgr	1	1	1	1	1	1
Smart Grid	1	1	1	1	1	1
Engineering Supervisor	0	0	0	0	0	0
SCADA/Meter Tech.	0	1	1	1	1	1
Engineering Technologist	1	1	2	2	2	2
Engineering Technician	2	2	2	2	2	2
GIS Technician	1	1	1	1	1	1
Inspector	1	1	1	2	2	2
Dispatcher	0	1	1	1	1	1
Locator	0	0	2	2	2	2
Operations Manager	1	1	1	1	1	1
Operations Supervisor	0	0	0	0	0	0
Sub Foreman	1	1	1	2	2	2
Line Crew	4	4	4	6	6	6
Stockkeeper	2	2	2	2	2	2
Purchaser	0	0	0	1	1	1
Total	41	44	50.5	59.5	60.5	60.5
Change		3	6.5	9	1	0

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)

Project Name	Locator Vehicle Mini-van (x2)

Investment Benefits, measured against: Efficiency, Customer Value & Reliability (5.4.5.2.B.1)

Main Driver (5.4.5.2.B.1.a-1):

General Plant

- Main "Trigger" (5.4.5.2.B.1.a-1.1):

Need for business operations efficiency

Secondary Driver (5.4.5.2.B.1.a-2): None

- Secondary "Trigger" (5.4.5.2.B.1.a-2.1): None

Objective or Performance Target to be Achieved (5.4.5.2.B.1.a-3):

Primary: Reliability; Secondary: None / Additional: Safety

Background information that ties in with Asset Management Process (5.4.5.2.B.1.a-3i):

InnPower plans to expand its internal staffing in 2017, with the added manpower there will be a need for additional vehicles.

Overview of Investment Prioritization Justification (5.4.5.2.B.1.b)

This investment is required to support the travel needs of the locating staff. A majority of the time spent by the locating staff is off-site as they respond to locating requests sent to Ontario-One-Call by those looking to perform excavation.

Project Identification and Selection (5.4.5.2.B.1.b-1)

These small vehicles were selected based on the minimum specifications required for the locators to perform their work.

Project Prioritization (5.4.5.2.B.1.b-2)

These two vehicles had a high priority as it is a mandatory accessory for the personnel to perform their work - the type of work mandated by the OEB.

Project Pacing (5.4.5.2.B.1.b-3)

The purchase of these two vehicles will be done on a "just-in-time" basis to coincide with the hire of the personnel.

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

- Alternate Considerations - Design (5.4.5.2.B.1.c-1)

Not applicable; the specifications for the vehicles are based on the minimum required for the locators to perform their work.

- Alternate Considerations - Schedule (5.4.5.2.B.1.c-2)

Alternate consideration for the purchase of the vehicles were considered, and the "just-in-time" purchase was chosen.

- Alternate Considerations - Funding/Ownership (5.4.5.2.B.1.c-3)

Not applicable.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Effect of Investment on System Operation Efficiency and Cost-Effectiveness (5.4.5.2.B.1.c.i)
	The timely completion of locating underground assets in the work area will enable InnPower's works that require excavation to be completed without delay due to late locates.
	Net Benefits Accruing to Customers as a Result of the Investment (5.4.5.2.B.1.c.ii)
	Customers who have requested for locating services will receive timely service.
	Impact of the Investment on Reliability Performance including on the Frequency and Duration of Outages (5.4.5.2.B.1.c.iii)
	Not applicable.
	Projected Improvement to SAIFI (System Average Interruption Frequency Index): N/A
	Projected Improvement to SAIDI (System Average Interruption Duration Index): N/A
	Impact of the Driver(s), "Trigger" or other, on the DESIGN of the Project (5.4.5.2.B.1.c-4)
	Not applicable; design specifications for the vehicles will be chosen based on standard options made available by the manufacturer of the vehicles, and are based on the minimum required for the locators to perform their work.
	Impact of the Driver(s), "Trigger" or other, on the COMPONENT CHARACTERISTICS of the Project (5.4.5.2.B.1.c-5)
	The component characteristics of the vehicles will be selected based on the requirements of the locators to perform their work. These characteristics will be noted in the tender document.
	Impact of the Driver(s), "Trigger" or other, on the WORK PLAN of the Project (5.4.5.2.B.1.c-6)
	Not applicable.
	Investment Benefits, measured against: Safety (5.4.5.2.B.2)
	These vehicles will be equipped with safety equipment/fixtures as per InnPower's standard practice for fleet vehicles. These include safety equipment such as strobe lights/flashers, reversing camera, radios (helps with emergency communication), and fleet trackers (with "panic button") to ensure safety.
	Investment Benefits, measured against: Cyber-security, Privacy (5.4.5.2.B.3)
	Not applicable.
	Investment Benefits, measured against: Co-ordination, Interoperability (5.4.5.2.B.4)
	Not applicable.
	Co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)
	Not applicable.
	Potential to Enable Future Technological Functionality (5.4.5.2.B.4.b-1)
	Not applicable.
	Potential to Address Future Operational Requirements (5.4.5.2.B.4.b-2)
	Not applicable.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Investment Benefits, measured against: Economic Development (5.4.5.2.B.5)
	The completion of locate requests in a timely manner will help with any job that requires excavation to be completed on schedule, helping to save costs due to project delays.
	Investment Benefits, measured against: Environmental Benefits: (5.4.5.2.B.6)
	InnPower's preference is to purchase electric/hybrid vehicles to help reduce emissions.

Project Name Locator Vehicle Mini-van (x2)	
Category-specific requirements for General Plant Investments (5.4.5.2.C.d)	
Category-specific requirements for General Plant Investments (5.4.5.2.C.d)	**Summary of Qualitative Analysis (5.4.5.2.C.d.i-1)**
	InnPower will be switching locating personnel from contract crews to internal staff to keep pace with customer demand and lessen the need for external contracting staff.
	Summary of Quantitative Analysis (5.4.5.2.C.d.i-2)
	InnPower follows a tendering policy for all vehicle purchases. The quantity of vehicles listed under this project corresponds to the number of locators to be hired in 2017, for whom a vehicle will be an essential accessory to perform their daily work.
	Assessments of Financially Feasible Options (5.4.5.2.C.d.i-3)
	In making the decision to purchase a mini-van various other options were considered, including options for other types of vehicles (cars, pick-up trucks, cross-over type vehicles, and SUV's). The vehicle type selected (mini-van) was the most financially feasible vehicle that also meets the daily needs of locators. The remaining financial options were to either rent or lease these vehicles. These options were considered and the preferred option was to purchase the vehicles.
	- Analysis of "Do Nothing" Scenario (5.4.5.2.C.d.i-4)
	Without the purchase of two additional small vehicles, InnPower would not have the equipment required for additional staff. This would lead to either looking to rent or lease equipment or continue to use an external contracting firm for day to day work.
	Net Benefit of Investment (5.4.5.2.C.d.i-5)
	Ability to perform vital job function needed for InnPower to meet its obligation to its customers and the OEB. Ensure locates are completed on time for projects requiring excavation. InnPower will be able to meet requirements stated in Bill 8, Ontario Underground Infrastructure Notification System Act, 2012 Enables InnPower to comply with Section 3 of Electrical Safety Authority's Guideline for Excavation in the Vicinity of Utility Lines
	Business Case Justification Documentation (5.4.5.2.C.d.ii)
	InnPower is looking to ensure that its fleet is reliable and safe for all departments. During the next several years InnPower will be looking to purchase additional vehicles to complement new staff. This investment is planned to be spread out the vehicle purchases over multiple years to avoid a big jump in the budget in any given year.

Category-specific requirements for General Plant Investments (5.4.5.2.C.d)	
	- Alternatives Considered (5.4.5.2.C.d.ii-1)
	The alternatives to purchasing a mini-van for each locator are: (1) not purchasing such vehicles and stay with hiring outside contractors to perform the work, (2) rent or lease the vehicles, and (3) purchase a different type of vehicles other than a mini-van. Based on due consideration of cost versus benefit, the option to purchase mini- vans was chosen.
	- Benefits to Customers - Short Term (5.4.5.2.C.d.ii-2a)
	Completion of locate requests received from customers in a timely manner, Completion of excavation work required to meet customer request for connection or other work requiring excavation (i.e. asset relocation) in a timely manner.
	- Benefits to Customers - Long Term (5.4.5.2.C.d.ii-2b)
	- Same as outlined above for short term customer benefits in section 5.4.5.2.C.d.ii-2a
	- Impact on Distributor Costs - Short Term (5.4.5.2.C.d.ii-3a)
	The addition of two vehicles to InnPower's fleet will impact the O&M budget as the vehicles will require routine maintenance and repair work.
	- Impact on Distributor Costs - Long Term (5.4.5.2.C.d.ii-3b)
	In the long term it is anticipated that the overall cost of internalizing the locating crews (switching from outside contract crews) will lower total O&M costs.

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Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name: **RBD - new Crew**

Project number: GO 011 **Budget Year:** 2017

Investment Category: General Plant

Project Summary:

Purchase of an additional Radial Boom Digger (RBD) truck to complement the additional line crew staffing requirements.

Total capital and non-capitalized O&M costs (5.4.5.2.A.i)

	Historical Capital Costs					
	2012	2013	2014	2015	2016	
Total cost						
Contributions						
Net cost						
O&M expense						

	Future Capital Costs					
	2017	2018	2019	2020	2021	
Total cost	$250,000					
Contributions	$ -					
Net cost	$250,000					
O&M expense	See Note 1 on Page 235					

Customer Attachments and Load (5.4.5.2 A.ii)

Not applicable.

Project Dates & Expenditure Timing (5.4.5.2.A.iii)

Start Date:	01-Jan-17				
In Service Date:	31-Dec-17				
Expenditure Timing	2017: Q1	2017: Q2	2017: Q3	2017: Q4	
			50%	50%	

Schedule Risks & Risk Mitigation (5.4.5.2.A.iv)

In order to ensure delivery in Project year, IPC will have Tenders sent in early 2017 with expected delivery by Q4.

Comparative Information on Expenditure from Equivalent Projects (5.4.5.2.A.v)

IPC purchased a new RBD in 2011, we will use this previous purchase as a guide to stay within the projected budget monies.

Total Capital and OM&A costs associated with REG investment (5.4.5.2.A.vi)

Not applicable.

General Information on Project (5.4.5.2.A)	**Leave to Construct Approval (5.4.5.2.A.vii)**
	Not applicable.
	Related Project Reference Material i.e. Images, Drawings and or Reference Material
	Not applicable.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)

Project Name: RBD - new Crew

Investment Benefits, measured against: Efficiency, Customer Value & Reliability (5.4.5.2.B.1)

Main Driver (5.4.5.2.B.1.a-1):

General Plant

- Main "Trigger" (5.4.5.2.B.1.a-1.1):

Need for business operations efficiency

Secondary Driver (5.4.5.2.B.1.a-2): None

- Secondary "Trigger" (5.4.5.2.B.1.a-2.1): None

Objective or Performance Target to be Achieved (5.4.5.2.B.1.a-3):

Primary: Reliability; Secondary: None

Additional: Safety

Background information that ties in with Asset Management Process (5.4.5.2.B.1.a-4):

IPC plans to expand its internal Line staff in 2018, with the added man power the need for additional equipment will be needed. To avoid large investments in coming years, IPC looks to level out spending and purchase vehicles over several years lessening "rate shock" to customers.

Overview of Investment Prioritization Justification (5.4.5.2.B.1.b)

The addition of a line crew in 2018 will require a Radial Boom Digger truck to meet their fleet vehicle requirements. This vehicle will be required for the crew to complete their routine work assignments requiring bore holes, pole setting, anchor installation, transformer installation and removal.

Project Identification and Selection (5.4.5.2.B.1.b-1)

This project was identified based on our current work practices that proved the need for an RBD truck to be assigned to the new line crew. Based on the current usage of the existing RBD truck, if it was to be shared with this new crew, will likely negatively impact IPC's ability to complete work requiring an RBD in a timely manner.

The type of RBD truck was selected based on finding the closest match between our needs and the trucks available in the market.

Project Prioritization (5.4.5.2.B.1.b-2)

A needs assessment was performed to determine the purchase of this truck in the given year. Based on the result of the needs assessment it was deemed to be a required investment.

Project Pacing (5.4.5.2.B.1.b-3)

The timing of this project was based on an effort on IPC's part to pace the overall investment required to support the addition of a new line crew. Most of the remaining expenses have been scheduled in 2018, however, to reduce rate shock this investment has been scheduled in 2017.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)
	- Alternate Considerations - Design (5.4.5.2.B.1.c-1)
	Not applicable
	- Alternate Considerations - Schedule (5.4.5.2.B.1.c-2)
	This is a one time investment, and the timing of this investment has been determined based on operations needs - InnPower did consider the option to differ this project until 2018 when the new crew will be added, however, in an effort to keep the overall budget levelized (where possible) over the forecast period this investment was scheduled in 2017.
	- Alternate Considerations - Funding/Ownership (5.4.5.2.B.1.c-3)
	Not applicable.
	Effect of Investment on System Operation Efficiency and Cost-Effectiveness (5.4.5.2.B.1.c.i)
	This investment will enable line crews to perform their work without hindrance - which could otherwise be caused by the lack of timely hole digging, pole setting, anchor installations, transformer install and removal.
	Net Benefits Accruing to Customers as a Result of the Investment (5.4.5.2.B.1.c.ii)
	The RBD truck will enable customer connection needs that require work pertaining to bore holes, and pole removal/relocation requests from customers to be completed in a timely manner.
	Impact of the Investment on Reliability Performance including on the Frequency and Duration of Outages (5.4.5.2.B.1.c.iii)
	The intent of this investment does not improve reliability, however, since this project will enable some types of field works to be formed with greater efficiency, InnPower will likely see a margin of improvement in customer outage duration.
	Projected Improvement to SAIFI (System Average Interruption Frequency Index): N/A
	Projected Improvement to SAIDI (System Average Interruption Duration Index): N/A
	Impact of the Driver(s), "Trigger" or other, on the DESIGN of the Project (5.4.5.2.B.1.c-4)
	The specifications for the truck and the options to be added are based on the need of the trigger: business operations efficiency
	Impact of the Driver(s), "Trigger" or other, on the COMPONENT CHARACTERISTICS of the Project (5.4.5.2.B.1.c-5)
	As noted above in answer to 5.4.5.2.B.1.c-4, the components to be chosen as "options" will be based on the needs to meet our business operations efficiency.
	Impact of the Driver(s), "Trigger" or other, on the WORK PLAN of the Project (5.4.5.2.B.1.c-6)
	Not applicable.
	Investment Benefits, measured against: Safety (5.4.5.2.B.2)
	Not applicable.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Investment Benefits, measured against: Cyber-security, Privacy (5.4.5.2.B.3)
	Not applicable.
	Investment Benefits, measured against: Co-ordination, Interoperability (5.4.5.2.B.4)
	Not applicable.
	Co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)
	Not applicable.
	Potential to Enable Future Technological Functionality (5.4.5.2.B.4.b-1)
	Not applicable.
	Potential to Address Future Operational Requirements (5.4.5.2.B.4.b-2)
	The specifications for the truck and the options to be added are based on the need to meet future operational requirements for height and functionality.
	Investment Benefits, measured against: Economic Development (5.4.5.2.B.5)
	InnPower ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Investment Benefits, measured against: Environmental Benefits: (5.4.5.2.B.6)
	Not applicable.
	Note 1:
	It is anticipated that the purchase of the new Radial Boom Digger truck will result in an incremental increase to O&M costs based on usage and age, which will vary year to year.

Project Name RBD - new Crew	
Category-specific requirements for General Plant Investments (5.4.5.2.C.d)	
Category-specific requirements for General Plant Investments (5.4.5.2.C.d)	**Summary of Qualitative Analysis (5.4.5.2.C.d.i-1)**
	IPC will be expanding internal Line staff in order to complete Projects with internal staff rather than out source to Contract staffing at an additional cost. With the additional staff, the need to purchase additional vehicles is required.
	Summary of Quantitative Analysis (5.4.5.2.C.d.i-2)
	The number of vehicles needed was based on our needs assessment. For the addition of one line crew a single RBD will be required. IPC follows a tendering policy for large vehicle purchases.
	Assessments of Financially Feasible Options (5.4.5.2.C.d.i-3)
	The options that will impact the finances of the organization range from purchasing a new vehicle as noted herein, leasing a new vehicle, leasing a used vehicle, postponing the purchase, or "do nothing". These options were reviewed and considered and the most favourable option was to invest in a new Radial Boom Digger (RBD) truck with the specification selected by IPC to meet its operational needs.
	- Analysis of "Do Nothing" Scenario (5.4.5.2.C.d.i-4)
	Without the purchase of an additional RBD, IPC would not have the equipment required for additional staff. This would lead to either looking to rent equipment or continue to use an external contracting firm for day to day work.
	Net Benefit of Investment (5.4.5.2.C.d.i-5)
	This investment will result in the timely completion of routine jobs that require bore holes, pole setting, anchor installation, transformer installation and removal.
	Business Case Justification Documentation (5.4.5.2.C.d.ii)
	IPC is looking to ensure that the fleet is reliable and safe for all departments. During the next several years IPC will be looking to purchase additional vehicles to complement new staff, it is planned to spread out (pace) the large vehicle purchases to avoid a big jump in budget (rate shock) in one year.
	- Alternatives Considered (5.4.5.2.C.d.ii-1)
	As noted above in 5.4.5.2.C.d.i-3 various other options were considered and the most viable option, both operationally and financially, was to purchase a new RBD truck as noted herein.
	- Benefits to Customers - Short Term (5.4.5.2.C.d.ii-2a)
	Timely job completion. Timely outage restoration. With the addition to the fleet, IPC would lessen the need for external resources, helping to lower O&M costs.

Category-specific requirements for General Plant Investments (5.4.5.2.C.d)	**- Benefits to Customers - Long Term (5.4.5.2.C.d.ii-2b)**
	- Same as stated in the question above for short term benefits (5.4.5.2.C.d.ii-2a)
	- Impact on Distributor Costs - Short Term (5.4.5.2.C.d.ii-3a)
	Lower job costs due to lesser down time; marginal increase in O&M costs for vehicle maintenance and upkeep.
	- Impact on Distributor Costs - Long Term (5.4.5.2.C.d.ii-3b)
	- Same as stated in the question above for short term benefits (5.4.5.2.C.d.ii-3a)

Capital Project Summary

General Information on Project (5.4.5.2.A)

Project Name **Replacement Double Bucket Truck – 1993 Altec**

Project number: GO 006 **Budget Year:** 2017

Investment Category: General Plant

Project Summary

This project is for the replacement of IPC's existing 1993 68' Altec Double Bucket Truck. This unit was purchased in 2010 and is reaching end of life expectancy. With cost for repair work, down time and the difficulty in finding parts for an aging vehicle, IPC would replace this unit with a new Double Bucket improving reliability as well as lower repair costs and vehicle down time.

Total capital and non-capitalized O&M costs (5.4.5.2.A.i)

	Historical Capital Costs				
	2012	2013	2014	2015	2016
Total cost					
Contributions					
Net cost					
O&M expense	$ 23,083	$ 13,030	$ 13,403	$ 11,791	$ 13,300
	Future Capital Costs				
	2017	2018	2019	2020	2021
Total cost	$ 373,500	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Net cost	$ 373,500	$ -	$ -	$ -	$ -
O&M expense	$ 2,000	$ 4,500	$ 4,500	$ 4,500	$ 4,500

Customer Attachments and Load (5.4.5.2 A.ii)

N/A

Project Dates & Expenditure Timing (5.4.5.2.A.iii)

Start Date:	01-Jan-17			
In Service Date:	31-Dec-17			
Expenditure Timing	2017: Q1	2017: Q2	2017: Q3	2017: Q4
	50%	50%	0%	0%

Schedule Risks & Risk Mitigation (5.4.5.2.A.iv)

In order to ensure delivery in Project year, IPC will have Tenders sent in early 2017 with expected delivery by end of Q2.

Comparative Information on Expenditure from Equivalent Projects (5.4.5.2.A.v)

This vehicle purchase will be the first Double Bucket that IPC has purchased new. IPC will confer with other parties that have purchased similar units to ensure that pricing is with in industry standards.

General Information on Project (5.4.5.2.A)	
	Total Capital and OM&A costs associated with REG investment (5.4.5.2.A.vi)
	N/A
	Leave to Construct Approval (5.4.5.2.A.vii)
	N/A
	Related Project Reference Material i.e. Images, Drawings and or Reference Material (5.4.5.2.A.viii)
	N/A

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)

Project Name	Replacement Double Bucket Truck – 1993 Altec

Investment Benefits, measured against: Efficiency, Customer Value & Reliability (5.4.5.2.B.1)

Main Driver (5.4.5.2.B.1.a-1):

General Plant

- Main "Trigger" (5.4.5.2.B.1.a-1.1):

Need for business operations efficiency. Additional height requirements due to the increase in pole height.

Secondary Driver (5.4.5.2.B.1.a-2): None

- Secondary "Trigger" (5.4.5.2.B.1.a-2.1): None

Objective or Performance Target to be Achieved (5.4.5.2.B.1.a-3):

Primary: Reliability; Secondary: None

Additional: Safety

Background information that ties in with Asset Management Process (5.4.5.2.B.1.a-4):

IPC purchased unit# 301, a 1993 model Altec 68′ Double Bucket, in 2010 from a local LDC. This unit is reaching its end of life, IPC generally uses a 200,000km/10 years policy which this unit has reached on both levels.

Overview of Investment Prioritization Justification (5.4.5.2.B.1.b)

This project was justified based on our fleet replacement policy.

Project Identification and Selection (5.4.5.2.B.1.b-1)

This project was identified based on criteria outlined in our fleet replacement policy. The selection of the truck type and other specifications such as height and operational features were decided based on specific needs of line crew to fulfill operational requirements.

Project Prioritization (5.4.5.2.B.1.b-2)

This project was chosen as a priority based on both vehicle replacement criteria and on- going maintenance costs of the vehicle that will be replaced.

Project Pacing (5.4.5.2.B.1.b-3)

This is a one time investment, and the timing of this investment has been determined based on operational needs for a reliable bucket truck and based on investment optimization consideration.

Analysis of Project and Project Alternatives (5.4.5.2.B.1.c)

- Alternate Considerations - Design (5.4.5.2.B.1.c-1)

N/A, except that the options to be added to the truck have been considered based on current and future needs of line crew to perform job requirements.

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	**- Alternate Considerations - Schedule (5.4.5.2.B.1.c-2)**
	This is a one time investment, and the timing of this investment has been determined based on operational needs for a reliable bucket truck and based on investment optimization consideration.
	- Alternate Considerations - Funding/Ownership (5.4.5.2.B.1.c-3)
	N/A
	Effect of Investment on System Operation Efficiency and Cost-Effectiveness (5.4.5.2.B.1.c.i)
	This investment will result in an increase in vehicle availability for use by line crews to get to the job site and to perform pole top work promptly - which will result in operational efficiency. For the first several years there will be a marked decrease in vehicle maintenance costs.
	Net Benefits Accruing to Customers as a Result of the Investment (5.4.5.2.B.1.c.ii)
	Improved outage response time; improved work completion for customer connections.
	Impact of the Investment on Reliability Performance including the Frequency and Duration of Outages (5.4.5.2.B.1.c.iii)
	Although this project is not meant to address customer outage reliability performance, improved response time will have a slightly positive impact on outage duration.
	Projected Improvement to SAIFI (System Average Interruption Frequency Index): N/A
	Projected Improvement to SAIDI (System Average Interruption Duration Index): N/A
	Impact of the Driver(s), "Trigger" or other, on the DESIGN of the Project (5.4.5.2.B.1.c-4)
	The specifications for the truck and the options to be added are based on the need of the trigger: for business operations efficiency
	Impact of the Driver(s), "Trigger" or other, on the COMPONENT CHARACTERISTICS of the Project (5.4.5.2.B.1.c-5)
	As noted above in answer to 5.4.5.2.B.1.c-4, the components to be chosen as "options" will be based on the need to meet our business operations efficiency.
	Impact of the Driver(s), "Trigger" or other, on the WORK PLAN of the Project (5.4.5.2.B.1.c-6)
	N/A
	Investment Benefits, measured against: Safety (5.4.5.2.B.2)
	The new vehicle will be built to higher safety standards than the older 23 years old vehicle it will be replacing.
	Investment Benefits, measured against: Cyber-security, Privacy (5.4.5.2.B.3)
	This project is not intended to address cyber-security or privacy
	Investment Benefits, measured against: Co-ordination, Interoperability (5.4.5.2.B.4)
	Co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)
	N/A

Evaluation criteria and information requirements for each project/activity (5.4.5.2.B)	
	Potential to Enable Future Technological Functionality (5.4.5.2.B.4.b-1)
	N/A
	Potential to Address Future Operational Requirements (5.4.5.2.B.4.b-2)
	The specifications for the truck and the options to be added are based on the need to meet future operational requirements for height and functionality.
	Investment Benefits, measured against: Economic Development (5.4.5.2.B.5)
	InnPower ensures that policies and practices do not unnecessarily create barriers to economic development which are primarily focused within its communities.
	Investment Benefits, measured against: Environmental Benefits: (5.4.5.2.B.6)
	N/A

Project Name Replacement Double Bucket Truck – 1993 Altec		
Category-specific requirements for General Plant Investments (5.4.5.2.C.d)		
Category-specific requirements for General Plant Investments (5.4.5.2.C.d)	**Summary of Qualitative Analysis (5.4.5.2.C.d.i-1)**	
	With the purchase of a new Double Bucket vehicle, IPC will see less down time for vehicle repair, less maintenance/repair costs as well as a more reliable vehicle. With new technology available IPC will have lower fuel consumption costs. IPC has determined that replacement in this Project year will help to provide efficient service to new and existing plant.	
	Summary of Quantitative Analysis (5.4.5.2.C.d.i-2)	
	IPC follows a tendering policy for large vehicle purchases.	
	Assessments of Financially Feasible Options (5.4.5.2.C.d.i-3)	
	The options that will impact the finances of the organization range from purchasing a new vehicle as noted herein, leasing a new vehicle, leasing a used vehicle, postponing the purchase, or "do nothing". These option were reviewed and considered and the most favourable option was to replace the 1993 model truck with a new Double Bucket Truck with the specification selected by IPC to meet their operational needs.	
	- Analysis of "Do Nothing" Scenario (5.4.5.2.C.d.i-4)	
	If IPC was to continue with its existing 1993 unit, the risk of having the unit out for repair for an extended period of time may delay the completion of other projects due to unavailable equipment.	
	Net Benefit of Investment (5.4.5.2.C.d.i-5)	
	The net benefit of investing in this new truck includes improved operational functionality (jobs completed on time, reliability, less crew down time), customer satisfaction (when jobs are completed on time, including customer connections and outage restoration), and reduced O&M costs for the first several years.	
	Business Case Justification Documentation (5.4.5.2.C.d.ii)	
	IPC is looking to ensure that the fleet is reliable and safe for all departments. IPC vehicles are assessed on an annual basis based on a company replacement policy. With this unit reaching its end of life, it is critical to be replaced to avoid vehicle down time and negative impacts to customer requests, outage restoration efforts, and productivity.	
	- Alternatives Considered (5.4.5.2.C.d.ii-1)	
	As noted above in 5.4.5.2.C.d.i-3 various other options were considered and the most viable option, both operationally and financially, was to purchase a new vehicle as noted herein.	

Category-specific requirements for General Plant Investments (5.4.5.2.C.d)	**- Benefits to Customers - Short Term (5.4.5.2.C.d.ii-2a)**
	Timely job completion. Timely outage restoration. Benefits of the company. lowering O&M costs.
	- Benefits to Customers - Long Term (5.4.5.2.C.d.ii-2b)
	- Same as stated in the question above for short term benefits (5.4.5.2.C.d.ii-2a).
	- Impact on Distributor Costs - Short Term (5.4.5.2.C.d.ii-3a)
	Lower job costs due to a decrease in down time; reduced O&M costs.
	- Impact on Distributor Costs - Long Term (5.4.5.2.C.d.ii-3b)
	- Same as stated in the question above for short term benefits (5.4.5.2.C.d.ii-3a).

Appendix B: South Georgian Bay/Muskoka Region Needs Assessment Report

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

NEEDS ASSESSMENT REPORT

Region: South Georgian Bay/Muskoka

Revision: Final
Date: March 3, 2015

Prepared by: South Georgian Bay/Muskoka Region Study Team

South Georgian Bay/Muskoka Region Study Team	
Organization	**Name**
Hydro One Networks Inc. (Lead Transmitter)	Sacha Constantinescu Aleksandar Todic
Independent Electricity System Operator	Phillip Woo Nicole Hopper Bernice Chan
Hydro One Networks Inc. (Distribution)	Richard Shannon Ashley Lebel Charlie Lee
PowerStream Inc.	Michael Swift
Innisfil Hydro Distribution Systems Ltd.	Brenda Pinke
Orangeville Hydro Ltd.	Rob Koekkoek
Veridian Connections Inc.	Craig Smith

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the South Georgian Bay/Muskoka Region and to assess whether those needs require further coordinated regional planning. The potential needs that have been identified through this Needs Assessment Report may be studied further through subsequent regional planning processes and may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Needs Assessment Report are based on the information and assumptions provided by study team participants.

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 Needs Assessment 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 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"), 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 Needs Assessment Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

NEEDS ASSESSMENT EXECUTIVE SUMMARY

REGION	South Georgian Bay/Muskoka Region		
LEAD	Hydro One Networks Inc.		
START DATE	January 2, 2015	**END DATE**	March 3, 2015

1. INTRODUCTION

The purpose of this Needs Assessment report is to undertake an assessment of the South Georgian Bay/Muskoka Region ("the Region") and determine if there are regional needs that require coordinated regional planning. Where regional coordination is not required, and a "localized" wires solution is necessary, such needs will be addressed between relevant Local Distribution Companies (LDCs) and Hydro One Networks Inc. (HONI) and other parties as required.

For needs that require further regional planning and coordination, the Independent Electricity System Operator (IESO) will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or whether both are required.

2. REGIONAL ISSUE/TRIGGER

The Needs Assessment for the South Georgian Bay/Muskoka Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The Needs Assessment for Group 1 Regions is complete and has been initiated for Group 2 Regions. The South Georgian Bay/Muskoka Region belongs to Group 2 and the Needs Assessment for this Region was triggered on January 2, 2015 and was completed on March 3, 2015.

3. SCOPE OF NEEDS ASSESSMENT

The scope of the Needs Assessment study was limited to the next 10 years as per the recommendations of the Planning Process Working Group (PPWG) Report to the Board. As such, relevant data and information was collected up to the year 2023.

Needs emerging over the next 10 years and requiring coordinated regional planning may be further assessed as part of the IESO-led SA process, which will determine the appropriate regional planning approach: IRRP, RIP, and/or local planning.

This Needs Assessment included a study of transmission system and connection facilities capability, which covers station and line loading, thermal and voltage analysis as well as a review of system reliability, operational issues such as load restoration, and assets approaching end-of-useful-life.

4. INPUTS/DATA

Study team participants, including representatives from LDCs, the IESO and HONI transmission provided information for the Region. The information included historical load, load forecast, Conservation and Demand Management (CDM) and Distributed Generation (DG) information, load restoration data, and performance information including major equipment approaching end-of-useful-life. See Section 4 of the report for further details.

5. ASSESSMENT METHODOLOGY

The assessment's primary objective was to identify the electrical infrastructure needs in the Region over the study period (2014 to 2023). The assessment reviewed available information and load forecasts, and included single contingency analysis to confirm needs, if and when required. See Section 5 of the report for further details.

6. RESULTS

Transmission Capacity Needs

A. 115/230kV Transmission Lines and Auto-Transformers

- With the 230/115kV auto-transformer T1 or T2 at Essa TS out-of-service, the companion transformer is expected to exceed its summer 10-Day Limited Time Rating (LTR) during the study period based on gross summer demand forecast. T1 is expected to exceed its summer 10-Day LTR in the near-term and T2 in the medium-term. The net summer demand forecast is not expected to significantly defer the need due to the high growth rate at Barrie TS.
- With one element out of service, the 115 kV circuit E3B is expected to exceed its summer Long-Term Emergency (LTE) rating in the near-term based on gross summer demand forecast. The net summer demand forecast is not expected to significantly defer the need due to the high growth rate at Barrie TS.

B. 115/230kV Transmission Stations

- Barrie TS is a summer peaking station and currently exceeds its normal supply capacity based on both gross and net summer demand forecast.
- Muskoka TS is a winter peaking station and will exceed its normal supply capacity in near-term based on both gross and net winter demand forecast.
- Parry Sound TS is a winter peaking station and currently exceeds its normal supply capacity based on both gross and net winter demand forecast.
- Midhurst TS T1/T2 DESN may exceed its normal supply capacity in the medium-term based on gross and net summer demand forecast if potential new commercial operations in the city of Barrie materialize.

System Reliability, Operation and Restoration Needs

Based on the gross and net coincident demand forecast, the loss of one element will not result in load interruption greater than the limit of 150MW. The loss of two elements will not result in load interruption greater than the limit of 600MW.

For the loss of two elements, based on gross and net region-coincident demand forecast the load interrupted by configuration may exceed 150MW and 250MW. The loss of 230kV circuits M6E+M7E may require some load to be restored within 4 hours and 30 minutes; the loss of 230kV circuits M80B+M81B may require some load to be restored within 4 hours; and the loss of 230kV circuits E8V+E9V may require some load to be restored within 4 hours during the study period. 230kV circuit M6E+M7E may not meet the 30 minutes restoration criteria. Further assessment is required.

Due to the increase generation within the Bruce Area, 115kV circuit S2S and Stayner T1 auto-transformer may be overloaded under pre-contingency conditions during high flow eastward from the Bruce Area. One possible solution would be to operate S2S open loop. This issue was identified by IESO as part of this assessment. Further assessment is required.

With Essa TS 500/230kV auto-transformer T3 or T4 out of service, the loss of the remaining 500/230kV Essa TS auto-transformer, may result in excessive post-contingency voltage declines under high loads conditions within the Essa area. This issue was identified by IESO as part of this assessment. Further assessment is required.

Aging Infrastructure / Replacement Plan

- Replacement of 115-44kV transformers (T1 and T2) at Barrie TS is scheduled for 2018.
- Replacement of 230-44kV transformers (T1 and T2) and possible rebuild of low voltage switchyard at Minden TS is scheduled for 2019.
- Replacement of dual windings 230-44/27.6kV transformers (T1 and T2) and associated low voltage equipment at Orangeville TS is scheduled for 2017.
- Ground clearance on several sections of the 230kV circuits M6E and M7E are planned to be increased in 2015. This may increase the current thermal rating of the lines.

7. RECOMMENDATIONS

Based on the findings of this Needs Assessment, the study team's recommendations are as follows.

Study team recommends that a Scoping Assessment should be undertaken to address the near-term transmission and system reliability, operation and restoration needs as listed in Section 6, taking into consideration where appropriate the aging infrastructure/replacement plans identified.

These near-term needs require coordinated regional planning and development of a regional and/or sub-regional plan as soon as possible. The Scoping Assessment will determine whether the IESO-led IRRP process and/or the transmitter-led RIP process (for wires solutions) should be further undertaken for one or more of these needs. The assessment may also recommend that local planning of wires only option between the transmitter and affected LDCs may be undertaken to address certain needs.

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LIST OF FIGURES AND TABLES

1 INTRODUCTION

This Needs Assessment report provides a summary of needs that are emerging in the South Georgian Bay/Muskoka Region ("the Region") over the ten-year period from 2014 to 2023. The development of the Needs Assessment report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements, and the Planning Process Working Group (PPWG) Report to the Board.

The purpose of this Needs Assessment report is to undertake an assessment of the South Georgian Bay/Muskoka Region to identify any near-term and/or emerging needs in the area and determine if these needs require a "localized" wires only solution(s) in the near-term and/or a coordinated regional planning assessment. Where a local wires only solution is necessary to address the needs, Hydro One Networks Inc. (HONI), as transmitter, with Local Distribution Companies (LDCs) or other connecting customer(s), will further undertake planning assessments to develop options and recommend a solution(s). For needs that require further regional planning and coordination, the Independent Electricity System Operator (IESO) will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or both are required. The SA may also recommend that local planning between the transmitter and affected LDCs be undertaken to address certain needs.

This report was prepared by the South Georgian Bay/Muskoka Region Needs Assessment study team (Table 1) and led by the transmitter, HONI. The report captures the results of the assessment based on information provided by LDCs, the OPA and the Independent Electricity System Operator (IESO).

Table 1: Study Team Participants for South Georgian Bay/Muskoka Region

No.	Company
1.	Hydro One Networks Inc. (Lead Transmitter)
2.	Independent Electricity System Operator
3.	Hydro One Networks Inc. (Distribution)
4.	PowerStream Inc.
5.	Innisfil Hydro Distribution Systems Ltd.
6.	Orangeville Hydro Ltd.
7.	Veridian Connections Inc.

2 REGIONAL ISSUE/TRIGGER

The Needs Assessment for the South Georgian Bay/Muskoka Region was triggered in response to the OEB's RIP process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The Needs Assessment for Group 1 Regions is complete and has been initiated for Group 2 Regions. The South Georgian Bay/Muskoka Region belongs to Group 2. The Needs Assessment for this Region was triggered on January 2, 2015 and was completed on March 3, 2015.

3 SCOPE OF NEEDS ASSESSMENT

This Needs Assessment covers the South Georgian Bay/Muskoka Region over an assessment period of 2014 to 2023. The scope of the Needs Assessment includes a review of transmission system connection facility capability which covers transformer station capacity, thermal capacity, and voltage performance. System reliability, operational issues such as load restoration, and asset replacement plans were also briefly reviewed as part of this Needs Assessment.

3.1 South Georgian Bay/Muskoka Region Description and Connection Configuration

The South Georgian Bay/Muskoka Region is the area roughly bordered by West Nipissing to the northwest, Algonquin Provincial Park to the northeast, Peterborough County and Hastings County to the southeast, Lake Scugog, York and Peel Regions to the south, Wellington County to the southwest and Grey Highlands to the west. The boundaries of the Region are shown in Figure 1 below.

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

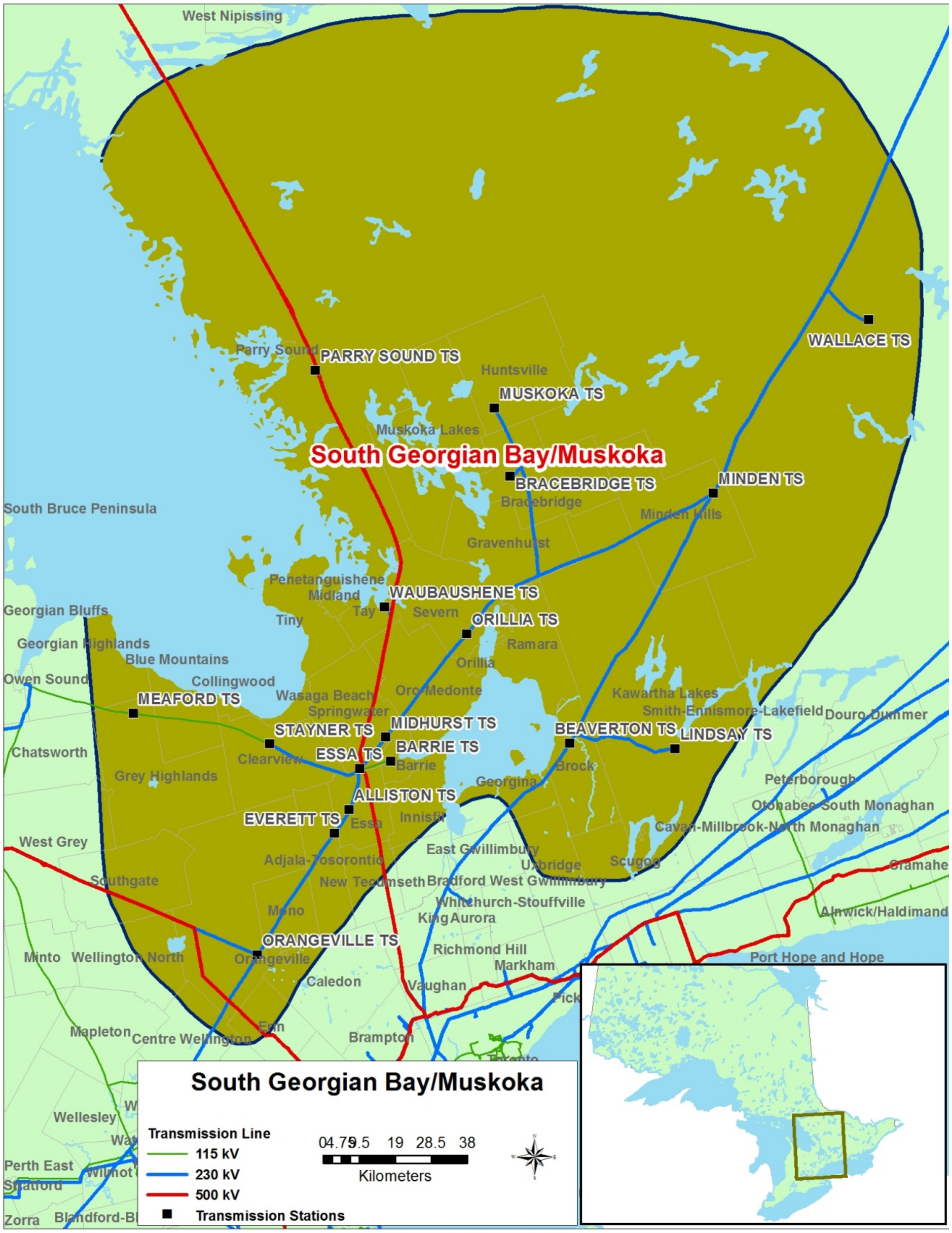


Figure 1: South Georgian Bay/Muskoka Region Map

The following circuits are not included in the South Georgian Bay/Muskoka Region:

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

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

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 Assessment:

- Essa TS is the major transmission station that connects the 500kV network to the 230kV system via two 500/230kV auto-transformers. Essa TS also supplies the 115kV system towards Barrie TS via two 230/115kV auto-transformers.

- Eleven step-down transformer stations supply load to the north and east areas of the Region (north and east of Essa TS): Barrie TS, Beaverton TS, Bracebridge TS, Lindsay TS, Midhurst TS, Minden TS, Muskoka TS, Orillia TS, Parry Sound TS, Wallace TS, and Waubashene TS.

- Five step-down transformer stations supply load to the south and west areas of the Region (south and west of Essa TS): Alliston TS, Everett TS, Meaford TS, Orangeville TS, and Stayner TS.

- Eight 230kV circuits (E8V, E9V, E20S, E21S, E26, E27, M6E, and M7E) radiating outward from Essa TS provide local supply to the Region. These circuits are essential to the Region and will be included in the study to ensure long-term reliability. Four 230kV circuits (D1M, D2M, D3M, and D4M) entering the region from the east are also a major supply path for the Region and will be analyzed in this study.

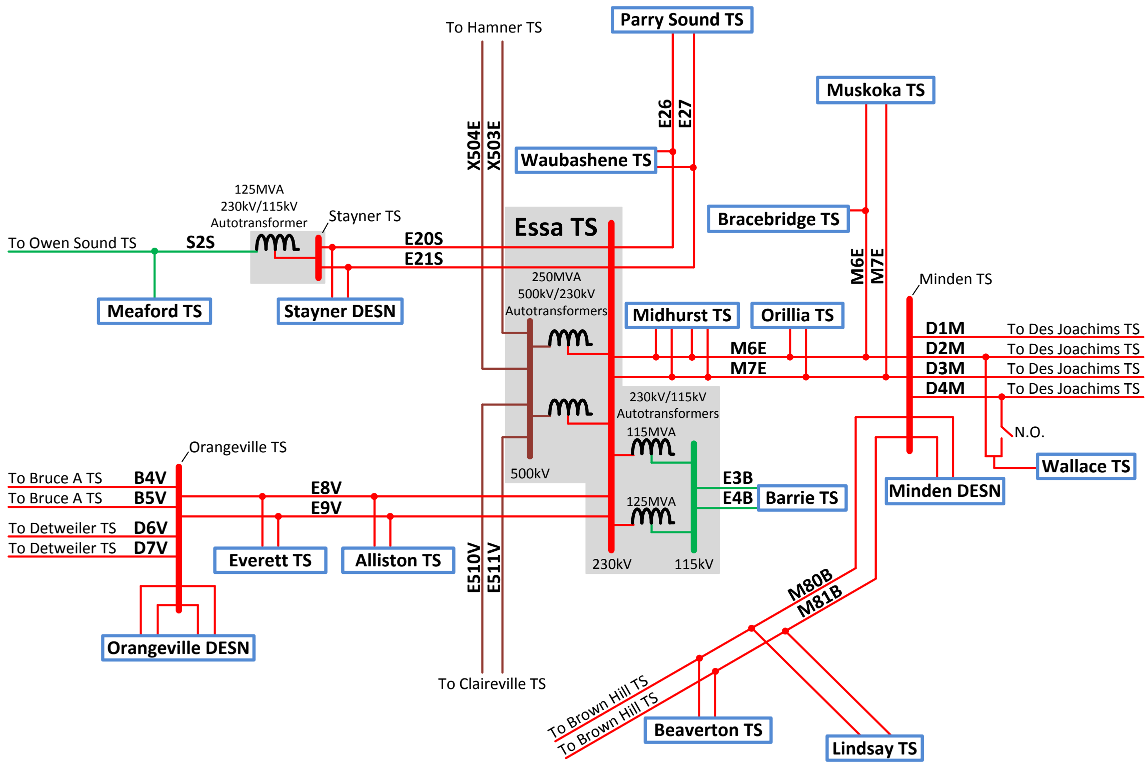


Figure 2: Single Line Diagram – South Georgian Bay/Muskoka Region

Table 2 below provides a list of LDCs in the South Georgian Bay/Muskoka Region.

Table 2: List of LDCs in the South Georgian Bay/Muskoka Region

Local Distribution Companies (LDCs)
Hydro One Networks Inc. (Distribution)
Powerstream Inc.
COLLUS PowerStream Corp.
InnPower Corp.
Lakeland Power Distribution Ltd.
Midland Power Utility Corp.
Orangeville Hydro Ltd.
Orillia Power Distribution Corp.
Parry Sound Power Corp.
Newmarket-Tay Power Distribution Ltd.
Veridian Connections Inc.
Wasaga Distribution Inc.

4 INPUTS AND DATA

In order to conduct this Needs Assessment, study team participants provided the following information and data to HONI:

- IESO provided:
    i. Historical 2013 regional coincident peak load and station non-coincident peak load
    ii. List of existing reliability and operational issues
    iii. Conservation and Demand Management (CDM) and Distributed Generation (DG) data
- LDCs provided historical (2011-2013) net load and gross load forecast (2014-2023)
- HONI (Transmission) provided transformer, station, and circuit ratings
- Any relevant planning information, including planned transmission and distribution investments provided by the transmitter and LDCs, etc.

4.1 Load Forecast

As per the data provided by the study team, the load in the South Georgian Bay/Muskoka Region is expected to grow at an average gross rate of approximately 2% annually from 2014-2018 and 1.8% annually from 2019-2023.

Most of the load growth is attributed to the southern portion of the region, with the highest approximate annual growth rate occurring at the following stations: Barrie TS (4.1% from 2014-2018 and 5.9% from 2019-2023); Alliston TS (4.7% from 2014-2018 and 3.3% from 2019-2023); Midhurst TS (3.5% from 2014-2018 and 2.9% from 2019-2023) and Everett TS (3.2% from 2014-2018 and 2.9% from 2019-2023).

5 ASSESSMENT METHODOLOGY

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

1. The Region is winter peaking, however five out of sixteen stations in the Region are summer peaking (Alliston TS, Barrie TS, Everett TS, Midhurst TS and Orangeville TS T1/T2 DESN). Therefore, this assessment is based on both winter and summer peak loads, as appropriate.

2. Forecast winter/summer loads are provided by the Region's LDCs. There are no customer loads within this region.

3. The LDC's load forecast is translated into load growth rates and is applied onto the 2013 winter/summer peak load as a reference point.

4. The 2013 winter/summer peak loads are adjusted for extreme weather conditions according to HONI's methodology.

5. Accounting for (2), (3), (4) above, the gross load forecast and a net load forecast were developed. The gross demand forecast is used to develop a worst case scenario to identify needs. Where there are issues, the net load forecast, which accounts for CDM and DG, is analyzed to determine if needs can be deferred.

   A gross and net non-coincident peak load forecast was produced for both winter and summer and were used to perform the analysis for Section 6.1.2 of this report.

   A coincident region peak load forecast was used to perform the analysis for sections 6.1.1 of this report. A gross and net-region coincident peak load forecast was developed for winter conditions. As for summer conditions, only a gross coincident forecast was developed for conservatism but also due to the high load growth relative to CDM and DG in the summer peaking portion of the region. The gross summer coincident peak load forecast was developed based on projected percentages of the winter historical loading.

6. Review impact of any on-going and/or planned development projects in the Region during the study period.

7. Review and assess impact of any critical/major elements planned/identified to be replaced at the end-of-their-useful-life such as auto-transformers, cables, and stations.

8. 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 or the historical low voltage power factor, whichever is more conservative. For stations having low-voltage capacitor banks, a 95% lagging power factor was assumed or the historical low-voltage power factor, whichever is more conservative. Normal planning supply capacity for transformer stations in this Region is determined by the summer/winter 10-Day Limited Time Rating (LTR).

9. To identify emerging needs in the Region and determine whether or not further coordinated regional planning should be undertaken, the study was performed observing all elements in service and only one element out of service.

10. Transmission adequacy assessment considers, but is not limited to, the following criteria:
    - Region-coincident peak load forecast is used.
    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range.
    - With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their Long-Term Emergency (LTE) ratings and transformers within their summer/winter 10-Day LTR.
    - All voltages must be within pre and post contingency ranges as per Ontario Resource and Transmission Assessment Criteria (ORTAC).
    - With one element out of service, no more than 150MW of load is lost by configuration. With two elements out of service, no more than 600MW of load is lost by configuration.
    - With two elements out of service, the system is capable of meeting the load restoration time limits as per ORTAC.

6 RESULTS

This section summarizes the results of the Needs Assessment in the South Georgian Bay/Muskoka Region.

6.1 Transmission Capacity Needs

6.1.1 115/230kV Transmission Lines and Auto-Transformers

The 115/230kV transmission line and auto-transformer needs identified during the study period include, but may not be limited to the following:

- With the 230/115kV auto-transformer T1 or T2 at Essa TS out of service, the companion auto-transformer at Essa TS is expected to exceed its summer 10-Day LTR in the near-term based on gross summer demand forecast. T1 is expected to exceed its summer 10-Day LTR in the near-term (approximately 104% and 142% of summer 10-Day LTR by 2018 and 2023 respectively) and T2 in the medium-term (approximately 106% and 113% of summer 10-Day LTR by 2022 and 2023 respectively). The net summer demand forecast is not expected to significantly defer the need due to the high growth rate at Barrie TS.
- With one element out of service, the 115kV circuit E3B is expected to exceed its summer LTE rating in the near-term based on gross summer demand forecast (approximately 106% and 137% of summer LTE rating by 2019 and 2023

respectively). The net summer demand forecast is not expected to significantly defer the need due to the high growth rate at Barrie TS.

- With one element out of service, the voltage after tap-changer action at the Muskoka TS 230kV bus drops slightly below minimum continuous voltage limit in the medium-term based on gross winter demand forecast. With net winter demand forecast, the voltage remains within acceptable limits. This will be monitored and reassessed in the next regional planning cycle.
- With one element out of service, the voltage declines immediately following a contingency at Muskoka TS 44kV exceeds the limit of 10% after 2020 based on gross winter demand forecast. With the net winter demand forecast, the voltage remains within acceptable limits. This will be monitored and reassessed in the next regional planning cycle.

6.1.2 115/230kV Transformer Stations

The connection capacity needs identified during the study period include, but may not be limited to the following:

Barrie TS T1/T2 DESN (115-44kV):

- Barrie TS is a summer peaking station and currently exceeds its normal supply capacity based on both gross and net summer demand forecast (approximately 103% and 150% of summer 10-Day LTR in 2014 and 2023 respectively).

Everett TS T1/T2 DESN (230-44kV):

- Everett TS is a summer peaking station and will exceed its normal supply capacity at the end of the study period based on the gross summer demand forecast. With the net summer demand forecast, the station remains below its normal supply capacity. This will be monitored and reassessed in the next regional planning cycle.

Minden TS T1/T2 DESN (230-44kV):

- Minden TS is a winter peaking station and will exceed its normal supply capacity in the near-term based on the gross winter demand forecast. With the net winter demand forecast, the station remains below its normal supply capacity until the end of the study period. This will be monitored and reassessed in the next regional planning cycle.

Muskoka TS T1/T2 DESN (230-44kV):

- Muskoka TS is a winter peaking station and will exceed its normal supply capacity in near-term based on both gross and net winter demand forecast (approximately 100% and 103% of winter 10-Day LTR in 2016 and 2023 respectively). The station capacity is currently limited by the low voltage current transformers (CTs). If this limitation is non-existent, the power transformer winter LTR would remain above the gross winter demand forecast for the study period.

Parry Sound TS T1/T2 DESN (230-44kV)

- Parry Sound TS is a winter peaking station and currently exceeds its normal supply capacity based on both gross and net winter demand forecast (approximately 117% and 119% of winter 10-Day LTR in 2014 and 2023 respectively). Using a historically more reasonable winter power factor of 0.95, the station still exceeds its normal supply capacity (approximately 111% and 113% of winter 10-Day LTR in 2014 and 2023 respectively).

Waubaushene TS T5/T6 DESN (230-44kV)

- Waubaushene TS is a winter peaking station and will exceed its normal supply capacity at the end of the study period based on the gross winter demand forecast. With the net winter demand forecast, the station remains below its normal supply capacity. This will be monitored and reassessed in the next regional planning cycle.

Several load customers are planning new commercial operations in the City of Barrie during the study period. The forecast used for capacity assessment is the ‘median’ load growth projection for the City of Barrie, which reflects the historical load growth. Using the ‘high growth scenario’, where new commercial operations may materialize and achieve their projected loading by 2018, the following additional capacity needs emerge:

Midhurst TS

- Both T1/T2 and T3/T4 DESN stations at Midhurst TS are summer peaking and remain within their normal supply capacity based on gross ‘median’ summer demand forecast.
- T1/T2 DESN may exceed its normal supply capacity in the medium-term based on both net and gross ‘high growth scenario’ summer demand forecast (approximately 102% and 104% of summer 10-Day LTR in 2021 and 2023 respectively).
- T3/T4 DESN may exceed its normal supply capacity in the medium-term based on gross ‘high growth scenario’ summer demand forecast. With the net forecast, the station remains within its normal supply capacity until the end of the study period. This will be monitored and reassessed in the next regional planning cycle.

6.2 System Reliability, Operation and Restoration Review

Based on the gross and net coincident demand forecast, the maximum load interrupted by configuration due to the loss of one element is below the load loss limit of 150MW. The maximum load interrupted by configuration due to the loss of two elements is below the load loss limit of 600MW.

For the loss of two elements, the load interrupted by configuration may exceed 150MW and 250MW based on gross and net coincident demand forecast. The loss of 230kV circuits M6E+M7E may require some load to be restored within 4 hours and 30 minutes; the loss of 230kV circuits M80B+M81B may require some load to be restored within 4 hours; the loss of 230kV circuits E8V +E9V may require some load to be restored within 4 hours during the study period. 230kV circuit M6E+M7E may not meet the 30 minutes restoration criteria. Further assessment is required.

Due to the increase generation within the Bruce Area, 115kV circuit S2S and Stayner T1 auto-transformer may be overloaded under pre-contingency conditions during high flow eastward from the Bruce Area. One possible solution would be to operate S2S open loop. This issue was identified by IESO as part of this assessment. Further assessment is required.

With an Essa TS 500/230kV auto-transformer T3 or T4 out of service, the loss of the remaining 500/230kV Essa TS auto-transformer, may result in excessive post-contingency voltage declines under high load conditions within the Essa area. This issue was identified by IESO as part of this assessment. Further assessment is required.

6.3 Aging Infrastructure and Replacement Plan of Major Equipment

HONI reviewed the sustainment initiatives that are currently planned for the replacement of any auto-transformers, power transformers and high-voltage cables.

During the study period:

- Replacement of 115-44kV transformers (T1 and T2) at Barrie TS is scheduled for 2018.
- Replacement of 230-44kV transformers (T1 and T2) and possible rebuild of low voltage switchyard at Minden TS is scheduled for 2019.
- Replacement of dual windings 230-44/27.6kV transformers (T1 and T2) and associated low voltage equipment at Orangeville TS is scheduled for 2017.
- Ground clearance on several sections of the 230kV circuits M6E and M7E are planned to be increased in 2015. This may increase the current thermal rating of the lines.

7 RECOMMENDATIONS

Based on the findings of the Needs Assessment, the study team's recommendations are as follows.

Study team recommends that a Scoping Assessment should be undertaken to address the following needs:

- Barrie TS 115kV transmission and transformation capacity – this includes the 230/115kV auto-transformer needs at Essa TS, the 115kV circuit E3B supplying Barrie TS (first three points of section 6.1.1) and the transformation capacity need at Barrie TS (first point of section 6.1.2). Coordination is also required with the existing sustainment initiative at Barrie TS.
- Muskoka TS T1/T2 DESN transformation capacity (fourth point of section 6.1.2).
- Parry Sound TS transformation capacity (fifth point of section 6.1.2).
- Midhurst TS T1/T2 DESN potential transformation capacity need based on 'high growth scenario'.
- System reliability, operation and restoration needs (section 6.2).

These near-term needs require coordinated regional planning and development of a regional and/or sub-regional plan as soon as possible. The Scoping Assessment (SA) will determine whether the IESO-led IRRP process and/or the transmitter-led RIP process (for wires solutions) should be further undertaken for one or more of these needs. The assessment may also recommend that local planning of wires only option between the transmitter and affected LDCs may be undertaken to address certain needs.

8 NEXT STEPS

IESO will initiate a SA process for the region as soon as possible for the needs identified in the region.

9 REFERENCES

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013
ii) IESO 18-Month Outlook: March 2014 – August 2015
iii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0
iv) IESO System Impact Assessment Report for Dufferin Wind Farm (CAA ID: 2010-396)
v) South Simcoe Area Study: Adequacy of Transmission Facilities and Transmission Plan 2010-2024
vi) Minden, Essa and Parry Sound Area Supply Study (2010)

10 ACRONYMS

BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long-Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NA	Needs Assessment
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 Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

Appendix C: South Georgian Bay/Muskoka Region Scoping Assessment Outcome Report

SOUTH GEORGIAN BAY/ MUSKOKA REGION
SCOPING ASSESSMENT OUTCOME REPORT

June 22, 2015

ieso
Independent Electricity System Operator

Contents

South Georgian Bay/Muskoka Study Team

Company
Independent Electricity System Operator
Hydro One Networks Inc. (Transmission)
Hydro One Networks Inc. (Distribution)
InnPower
Lakeland Power
Midland PUC
Newmarket-Tay Power
Orangeville Hydro
Orillia Power
PowerStream
PowerStream COLLUS
Veridian Connections
Wasaga Distribution

1 South Georgian Bay/Muskoka Scoping Assessment Outcome

Scoping Assessment Outcome Report Summary			
Region:	South Georgian Bay/Muskoka		
Start Date	March 23, 2015	**End Date**	June 22, 2015

1. Introduction

This Scoping Assessment Outcome Report is part of the Ontario Energy Board's ("OEB" or "Board") Regional Planning process. The Board endorsed the Planning Process Working Group's Report to the Board in May 2013 and formalized the process timelines through changes to the Transmission System Code and Distribution System Code in August 2013.

The first stage in the regional planning process, the Needs Assessment, was carried out by Hydro One Networks Inc. ("Hydro One") for the South Georgian Bay/Muskoka region. The purpose of the Needs Assessment is to identify if there are any electricity needs in the region requiring regional coordination. The final Needs Assessment report[1] was issued on March 3, 2015 and concluded that some needs in the region may require regional coordination, and these needs should be reviewed further under the IESO-led Scoping Assessment process, which is the second stage in the regional planning process.

The IESO, in collaboration with the Regional Participants, further reviewed the needs identified, in combination with information collected as part of the Needs Screening, and information on potential wires and non-wires alternatives, to assess and determine the best planning approach for the whole or parts of the region: an integrated regional resource plan ("IRRP"), a regional infrastructure plan ("RIP") or that regional coordination is not required and the planning can simply be done between the Transmitter and its customers.

This Scoping Assessment report:

- Defines the sub-regions for needs requiring regional coordination as identified in the Needs Screening report;
- Determines the appropriate regional planning approach and scope for each sub-region with identified needs requiring regional coordination;
- Establishes a Terms of Reference in the case where an IRRP is the recommended approach for the sub-region(s);
- Establishes a working group for each sub-region recommended for an IRRP or a RIP.

2. Team

The Scoping Assessment was carried out with the following Regional Participants:

- Independent Electricity System Operator ("IESO")
- Hydro One Networks Inc. ("Hydro One Transmission")

[1] The Needs Assessment report for the Southern Georgian Bay/Muskoka Region can be found at http://www.hydroone.com/RegionalPlanning/SGB-Muskoka/Pages/default.aspx

- Hydro One Networks Inc. (“Hydro One Distribution”)
- InnPower
- Lakeland Power
- Midland PUC
- Newmarket-Tay Power
- Orangeville Hydro
- Orillia Power
- PowerStream
- PowerStream COLLUS
- Veridian Connections
- Wasaga Distribution

3. Categories of Needs, Analysis and Results

I. Overview of the Region

The South Georgian Bay/ Muskoka region is located in central Ontario and includes all or part of the following Counties and Districts: the County of Simcoe County, County of Dufferin, District of Muskoka, District of Parry Sound and County of Grey. For electricity planning purposes, the planning region is defined by electricity infrastructure boundaries, not municipal boundaries.

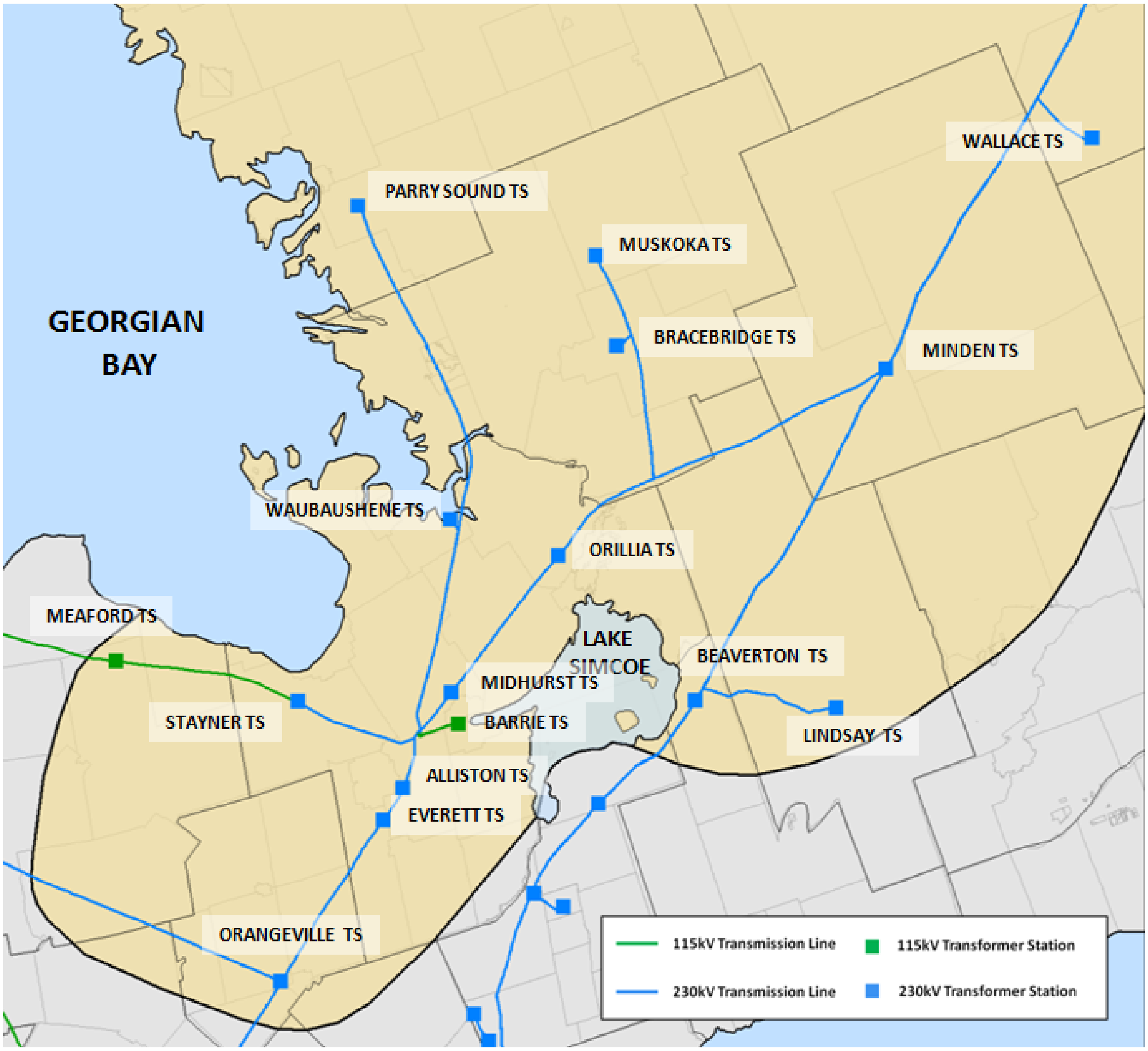
The region also includes the following First Nations:

- Henvey Inlet
- Magnetawan
- Shawanaga
- Wasauksing
- Moose Deer Point
- Beausoleil
- Wahta Mohawks
- Chippewas of Rama
- Chippewas of Georgina Island
- Mississaugas of Scugog

The electricity infrastructure supplying the South Georgian Bay/Muskoka region is shown in Figure 1. The region is supplied from 115 kV and 230 kV transmission lines and stations that connect at the Essa transformer station (“TS”). The 500/230 kV auto-transformers at Essa TS provide the major source of supply to the area.

The southern portion of this region is summer-peaking (i.e., electricity demand is highest during the summer months), and is characterized by strong forecast growth, particularly in the Barrie and Innisfil areas. The northern part of the region is winter peaking (i.e., electricity demand is highest during the winter months), and growth is forecast to be more gradual.

Figure 1. South Georgian Bay/Muskoka Region Electricity Infrastructure



NOTE: Region is defined by electricity infrastructure; geographical boundaries are approximate.

II. <u>Needs Identified</u>

Hydro One's Needs Assessment report identified the following needs in the South Georgian Bay Muskoka Region, based on a 10-year demand forecast.

115 kV and 230 kV Lines and Auto-Transformers

- The 230/115 kV auto-transformers at Essa TS are expected to exceed their 10-day Long Term Rating (LTR) upon loss of the companion auto-transformer. This need is forecast to arise in the near term for the T1 auto-transformer, and the medium term for T2.
- The 115 kV circuit E3B, which supplies Barrie TS radially from Essa TS, is expected to exceed its Long Term Emergency (LTE) rating upon loss of the companion circuit in the near-term.

115 kV and 230 kV Transmission Stations

The following stations are expected to exceed their normal supply capacity:

Station	Timing of Peak Demand	Timing of Need
Barrie TS	Summer	Today
Muskoka TS	Winter	Near-term
Parry Sound TS	Winter	Today
Midhurst TS	Summer	Medium term, if potential new commercial operations materialize
Minden	Winter	Long term*
Waubaushene	Winter	Long term*

*In the Needs Assessment report, no needs were identified for the Minden and Waubaushene stations based on the 10-year net demand forecast, which includes conservation and demand management ("CDM") and distributed generation ("DG"). Based on the gross load forecast, which does not include CDM or DG, needs were identified within the 10-year horizon. These needs can therefore be expected to appear in the long term (after 10 years) based on net load.

Load Restoration Needs

Potential needs related to restoring loads after a major outage were identified in the Needs Assessment report. This analysis was further developed through the Scoping Assessment Process. Based on this assessment, the following restoration needs were identified:

Circuits	Load Restoration Criterion not met
M6E+M7E	30 min and 4 hours
E8V+E9V	4 hours

In addition, loading on M80/81B and E26/27 is currently around 150 MW. Based on current load transfer capability, load restoration criteria can be met in the near term. However, with load growth, restoration needs may emerge in the longer term. The IESO will monitor growth in the affected areas, and potential future needs will be re-assessed in the next regional planning cycle.

Bulk System Needs

The following needs were identified for the bulk system supplying the Region:

- Excessive post-contingency voltage declines may occur upon losing one of the 500/230 kV auto-transformers at Essa TS when the other is out of service.
- Overloads of 115 kV circuit S2S and the Stayner T1 auto-transformer may results from increased generation in the Bruce area.

Aging Infrastructure / Replacement Plans

The following infrastructure is expected to reach its end-of-life or is the subject of sustainment activities within the study period.

Equipment	Date
Barrie TS—115/44 kV transformers	2018-2020*
Minden TS—230/44 kV transformers and possible rebuild of low-voltage switchyard	2019
Orangeville TS—230-44/27.6 kV transformers and associated low-voltage equipment	2017
M6/7E—ground clearance on several sections to be increased. This may increase the thermal	2015

capability of this line.	
E3/4B	These circuits are about 50-60 years old. Hydro One expects to undertake sustainment work on these facilities within the next 20 years.
Essa TS - 230/115kV Autotransformer (T1)	~2020

* Hydro One identified this need to be addressed by 2018 in the Needs Assessment report. This need may be pushed out to and managed until 2020 to accommodate the lead time of alternatives to address it.

Reliability Needs
Regional Participants identified reliability needs that they would like to see included in the regional planning process. Two types of reliability needs were identified: distribution system reliability concerns related to long 44kV feeders in the northern part of the Region; and a lack of supply redundancy. To the extent that these needs can be coordinated with other regional needs, the Regional Participants agreed to address them as part of the regional planning process.

III. Analysis of Needs and Identification of Sub-Regions

The Regional Participants have discussed the needs in the South Georgian Bay/ Muskoka area and have identified two sub-regions for further study through the regional planning process. The two sub-regions, "Barrie/Innisfil" and "Parry Sound/Muskoka", are shown in Figure 2.

Barrie/Innisfil Sub-Region
Strong electricity demand growth is forecast for the Barrie/Innisfil area, consistent with the provincial *Growth Plan for the Greater Golden Horseshoe, 2006*. This sub-region is summer-peaking, and includes the following infrastructure:

- Stations—Midhurst TS, Barrie TS, Everett TS, Alliston TS
- Transmission circuits—E8/9V, E3/4B, M6/7E (Essa-Midhurst section)
- 230/115 kV auto-transformers at Essa TS

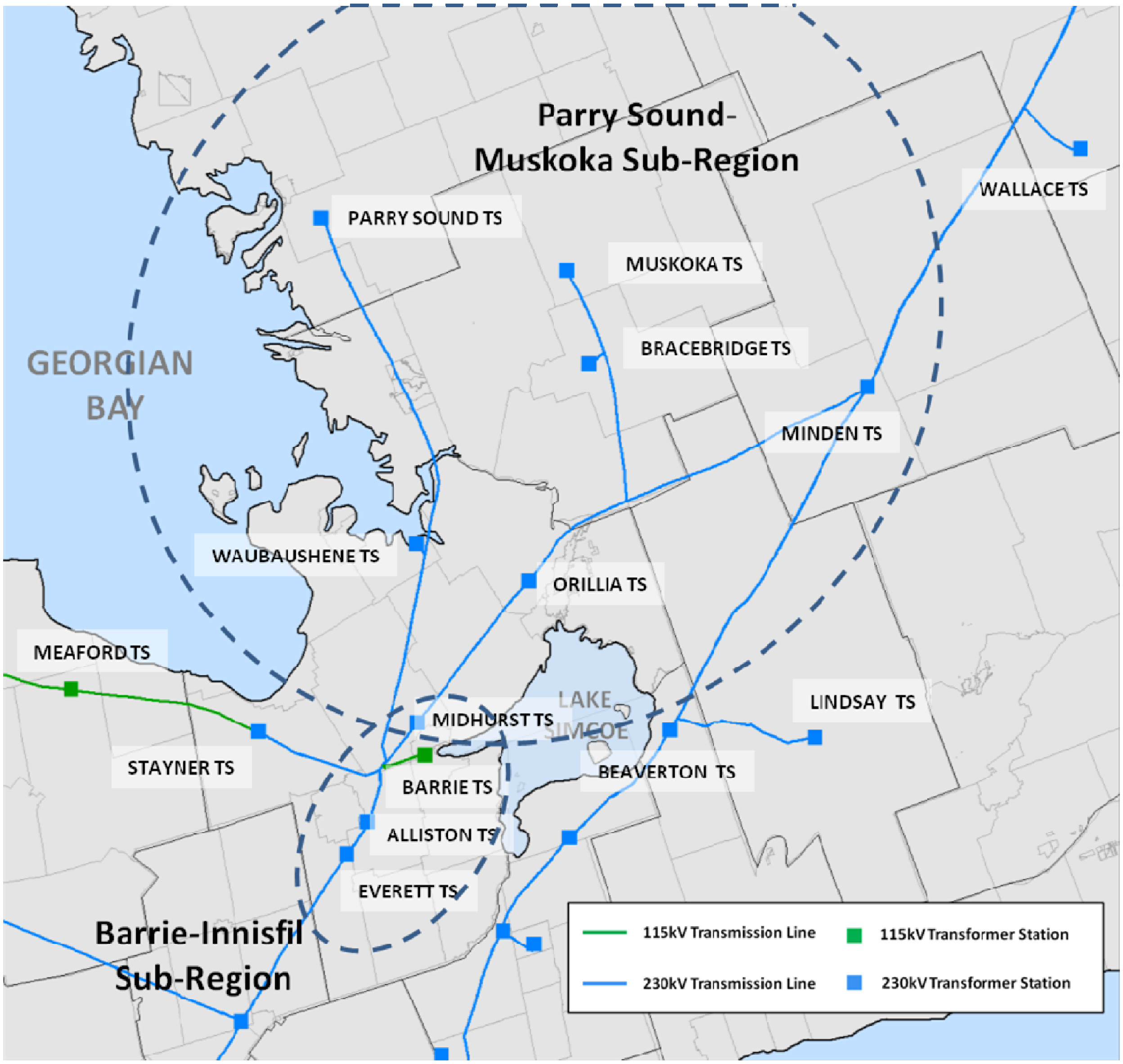
Customers in this sub-region are supplied by PowerStream, InnPower and Hydro One Distribution.

The needs in this sub-region include addressing growth (expressed in the Needs Assessment as overloaded infrastructure at Barrie TS, the E3B circuit, and the Essa 230/115 kV auto-transformers), and meeting load restoration criteria (E8/9V). In addition, with the Barrie TS transformers nearing their end-of-life, the plan for their replacement needs to be coordinated with the above growth-related needs. Options include maintaining Barrie TS as a 115 kV station (like-for-like replacement) or upgrading it to 230 kV, thereby increasing its capacity. The upstream infrastructure supplying the station—the Essa 230/115 kV auto-transformers and the E3/4B transmission line—will also be impacted by this decision and the associated costs and impacts must be considered.

While it is recognized that, with the need to replace Barrie TS equipment, a wires solution will necessarily be part of the plan for this sub-region, the growth-related needs in the area may be met by a combination of wires and non-wires solutions. In addition, the decisions made in this area will have broad impacts, involving multiple local distribution companies ("LDCs") and provincial ratepayers. Therefore, the Regional Participants propose that this sub-region be studied through the IRRP process.

The Barrie TS infrastructure is currently scheduled for replacement in 2018, however the existing equipment can be managed until 2020 if required. Nonetheless, a decision needs to be made as soon as possible in order to allow enough lead time to plan and bring new equipment into service. Therefore, rather than wait for the outcome of the IRRP (which typically takes 18 months), the Terms of Reference for the Barrie/Innisfil IRRP specifies that a decision on the wires component of the integrated solution will be made early in the IRRP process. At that time, wires planning would be initiated through a hand-off letter to the Transmitter.

Figure 2. South Georgian Bay/Muskoka Sub-Regions



NOTE: Region and sub-regions are defined by electricity infrastructure; geographical boundaries are approximate.

Parry Sound/Muskoka Sub-Region

This sub-region is winter-peaking, and is characterized by relatively slow growth. It includes the following infrastructure:

- Stations—Parry Sound TS, Waubaushene TS, Orillia TS, Bracebridge TS, Muskoka TS, Minden TS
- Transmission circuits—M6/7E, E26/27

Customers in this sub-region are supplied by Hydro One Distribution, Lakeland Power, Midland PUC, Newmarket-Tay Power, Orillia Power, and Veridian Connections.

The needs in this sub-region include:

- Addressing capacity needs at several stations
- Enabling loads to be restored within the timeframes laid out in the ORTAC criteria in the event of a major outage on M6/7E
- Coordinating asset replacement plans at Minden TS with regional needs, as appropriate
- Coordinating solutions to address distribution reliability concerns due to long feeder lengths with regional capacity needs, as appropriate
- Addressing reliability concerns related to a lack of supply redundancy.

With the relatively slow electricity demand growth forecast for this sub-region, the Regional Participants agreed that there may be opportunities for non-wires solutions to defer major capital investment. Therefore, it is proposed that this sub-region be studied through the IRRP process.

Needs to be Addressed through Bulk System Planning

The Essa TS 500/230 kV auto-transformers are bulk system assets that provide the major source of supply to the whole South Georgian Bay/Muskoka Region. Therefore, the Regional Participants agreed that the need associated with these assets be studied by the IESO as part of bulk system planning. Given the importance of this infrastructure to the Region, it was suggested that this planning be conducted in parallel with the IRRPs, and that the IESO involve the Regional Participants in the planning process.

The IESO will also undertake study of the S2S/Stayner auto-transformer issue arising due to increased generation in the Bruce area through the bulk planning process.

Needs to be Addressed through Local Planning

The Regional Participants agreed that the replacement of the Orangeville TS transformer and associated low-voltage equipment does not require regional coordination and can be addressed through local planning involving the transmitter and affected LDC.

4. Conclusion

The Scoping Assessment concludes that:

- An IRRP be undertaken to address the needs in the Barrie/Innisfil sub-region
- An IRRP be undertaken to address the needs in the Parry Sound/Muskoka sub-region
- Additional needs identified in the Needs Assessment will be addressed through other processes as follows:
    - Essa 500/230 kV autotransformers—bulk system planning (IESO), with regular updates

to/ input from the Regional Planning Participants

- S2S/Stayner auto-transformer issue—bulk system planning (IESO)
- Orangeville TS transformer replacement—local planning by transmitter and LDC

The draft Terms of Reference for the Barrie/Innisfil and the Parry Sound/Muskoka IRRPs are attached.

2 Barrie/Innisfil IRRP Terms of Reference

1. Introduction and Background

These Terms of Reference establish the objectives, scope, key assumptions, roles and responsibilities, activities, deliverables and timelines for an Integrated Regional Resource Plan ("IRRP") of the Barrie/Innisfil sub-region.

Based on the potential for demand growth within this sub-region, limits on the capability of the transmission capacity supplying the area, and opportunities for coordinating demand and supply options, an integrated regional resource planning approach is recommended.

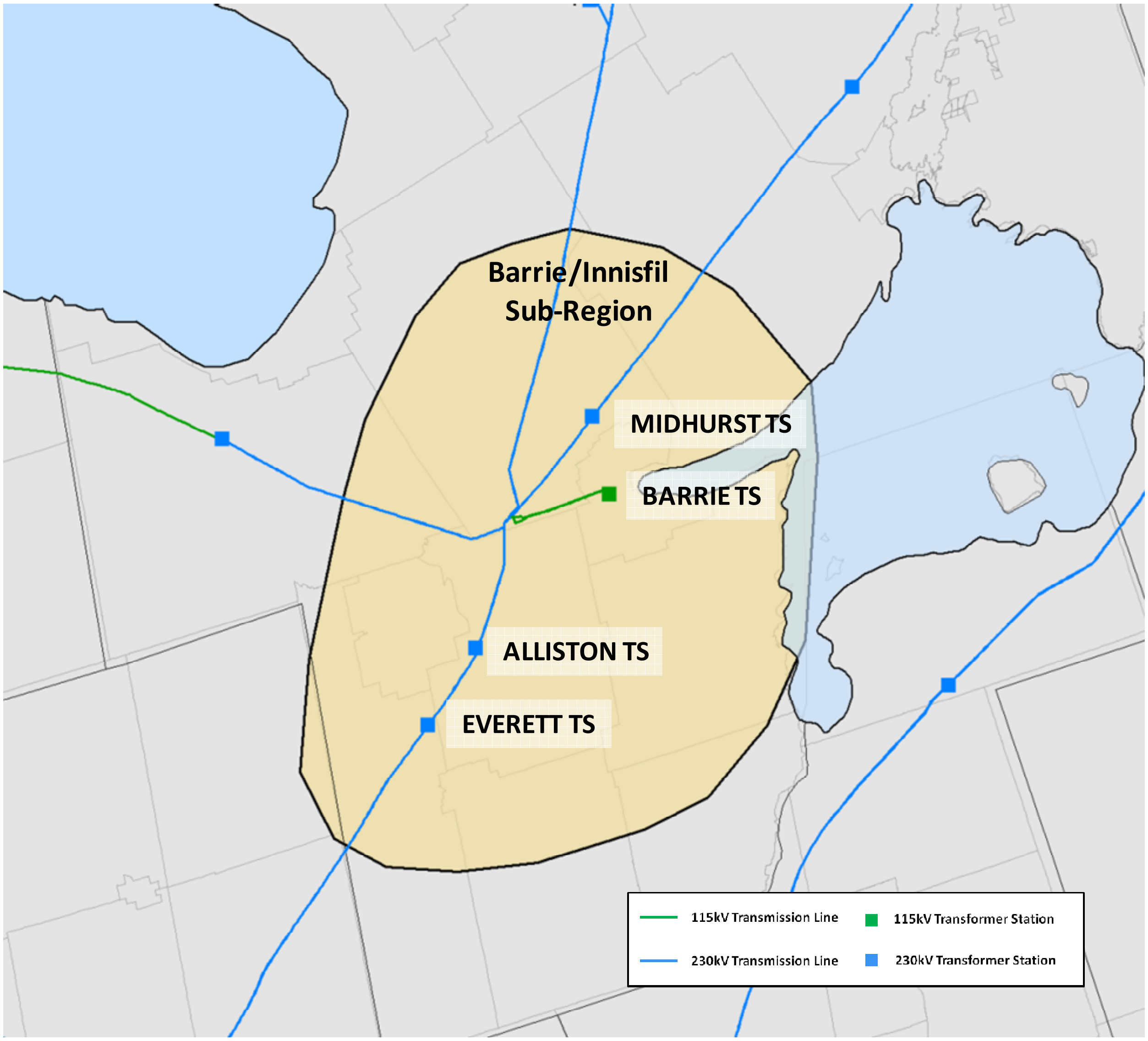
Barrie/Innisfil sub-region

The Barrie/Innisfil sub-region is a summer-peaking region that includes the City of Barrie, the Town of Innisfil, and customers in surrounding municipalities supplied from the Barrie, Midhurst, Everett and Alliston transformer stations (TS). The approximate geographical boundaries of the sub-region are shown in Figure 3.

The sub-region includes all or part of the following municipalities:

- City of Barrie
- Town of Innisfil
- Township of Essa
- Township of Springwater
- Township of Clearview
- Township of Mulmur
- Township of Adjala-Tosorontio
- Town of New Tecumseth
- Town of Bradford West Gwillimbury

Figure 3. Barrie/Innisfil Sub-Region



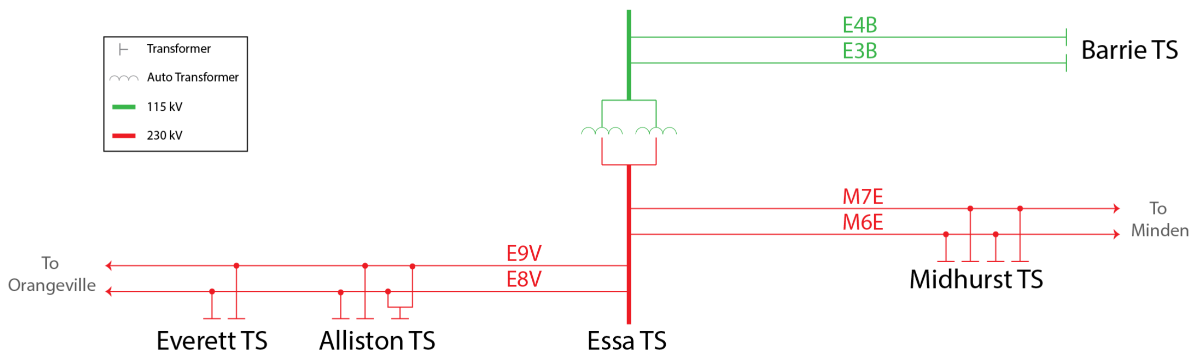
Source: IESO

NOTE: The sub-region is defined by electricity infrastructure; geographical boundaries are approximate.

Barrie/Innisfil Electricity System

The electricity system supplying the Barrie/Innisfil sub-region is shown in Figure 4.

Figure 4. Barrie/Innisfil Electricity System



Source: IESO

Background

Two planning studies have been conducted in the South Simcoe area in the last 12 years.

In November of 2003, a joint utility planning study was initiated between six LDCs in Simcoe County, one large industrial customer and Hydro One Transmission to assess the supply and reliability needs of Simcoe County. The study recommended the implementation of two transmission projects to supply forecast growth in the Meaford/Collingwood and South Simcoe areas: the addition of Everett TS, which came into service in 2007 and the Southern Georgian Bay Transmission Reinforcement, which involved upgrading the Essa-to-Stayner line to 230 kV and installing a 230/115 kV auto-transformer at Stayner TS, came into service in 2009.

In 2010, Hydro One Transmission initiated a regional supply planning study of the South Simcoe area. Together with the Ontario Power Authority (now the Independent Electricity System Operator), PowerStream, Innisfil Power, and Hydro One Distribution, a study report was prepared in 2011 that recommended the installation of low voltage capacitors at Midhurst TS, which was completed in 2012 and for Innisfil Hydro to make a formal request to Hydro One for additional transformation capacity.

2. Objectives

1. To assess the adequacy of electricity supply to customers in the Barrie/Innisfil sub-region over the next 20 years.
2. To coordinate customer-driven electricity needs with major asset renewal needs, and develop a flexible, comprehensive, integrated electricity plan for the Barrie/Innisfil sub-region.
3. To develop an implementation plan, while maintaining flexibility in order to accommodate changes in key assumptions over time.

3. Scope

This IRRP will develop and recommend an integrated plan to meet the needs of the Barrie/Innisfil sub-region. The plan is a joint initiative involving PowerStream, InnPower, Hydro One Distribution, Hydro

One Transmission, and the IESO, and will incorporate input from community engagement. The plan will integrate forecast electricity demand growth, conservation and demand management ("CDM") in the area with transmission and distribution system capability, end-of-life of major facilities in the area, relevant community plans, other bulk system developments, and Feed-in Tariff ("FIT") and other generation uptake through province-wide programs, and will develop an integrated plan to address needs.

This IRRP will address regional needs in the Barrie/Innisfil area. Specifically, the following existing infrastructure is included in the scope of this study:

- 230/115 kV auto-transformers at Essa TS
- Stations—Midhurst TS, Barrie TS, Everett TS, Alliston TS
- Transmission circuits—E8/9V, E3/4B, M6/7E (Essa-Midhurst section)

The adequacy of the bulk system supplying the area (i.e., the 500/230 kV auto-transformers at Essa TS) is being assessed by the IESO in parallel with this study through a separate bulk system planning process. Results of that study will be shared with the Working Group as they become available.

The Barrie/Innisfil IRRP will:

- Prepare a 20-year electricity demand forecast and establish needs over this timeframe.
- Examine the Load Meeting Capability and reliability of the existing transmission system supplying the Barrie/Innisfil sub-region, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices.
- Establish feasible integrated alternatives to address remaining needs, including a mix of CDM, generation, transmission and distribution facilities, and other electricity system initiatives in order to address the needs of the Barrie/Innisfil sub-region.
- Assess end-of-life needs in the context of longer-term capacity needs and impacts on other connection and network facilities in the area, and hand off the wires component of the integrated solution early in the IRRP process in order to allow enough lead time to address the end-of-life of the Barrie TS transformers
- Evaluate options using decision-making criteria including but not limited to: technical feasibility, economics, reliability performance, environmental and social factors.

4. Data and Assumptions

The plan will consider the following data and assumptions:

- Demand Data
    - Historical coincident peak demand information for the sub-region
    - Historical weather correction, median and extreme conditions
    - Gross peak demand forecast scenarios by sub-region, TS, etc.
    - Coincident peak demand data including transmission-connected customers
    - Identified potential future load customers

- Conservation and Demand Management
    - LDC CDM plans
    - Incorporation of verified LDC results and progression towards OEB targets, and any other CDM programs/opportunities in the area
    - Long-term conservation forecast for LDC customers, based on sub-region's share of the 2013 Long-Term Energy Plan target
    - Conservation potential studies, if available
    - Potential for CDM at transmission-connected customers' facilities

- Local resources
    - Existing local generation, including distributed generation ("DG"), district energy, customer-based generation, Non-Utility Generators and hydroelectric facilities as applicable
    - Existing or committed renewable generation from Feed-in-Tariff ("FIT") and non-FIT procurements
    - Future district energy plans, combined heat and power, energy storage, or other generation proposals

- Relevant local plans, as applicable
    - LDC Distribution System Plans
    - Community Energy Plans and Municipal Energy Plans
    - Municipal Growth Plans

- Criteria, codes and other requirements
    - Ontario Resource and Transmission Assessment Criteria ("ORTAC")
        - Supply capability
        - Load security
        - Load restoration requirements
    - NERC and NPCC reliability criteria, as applicable
    - OEB Transmission System Code
    - OEB Distribution System Code
    - Reliability considerations, such as the frequency and duration of interruptions to customers
    - Other applicable requirements

- Existing system capability
    - Transmission line ratings as per transmitter records
    - System capability as per current IESO PSS/E base cases
    - Transformer station ratings (10-day LTR) as per asset owner
    - Load transfer capability
    - Technical and operating characteristics of local generation

- Bulk System considerations to be applied to the existing area network
    - Essa 500/230 kV auto-transformer capability
    - North-South Tie flow assumptions

- End-of-life asset considerations/sustainment plans
    - Transmission assets, in particular Barrie TS transformers
    - Distribution assets

- Other considerations, as applicable

5. Working Group

The core Working Group will consist of planning representative/s from the following organizations:

- Independent Electricity System Operator *(Team Lead for IRRP)*
- Hydro One Transmission
- PowerStream
- InnPower
- Hydro One Distribution

<u>Authority and Funding</u>

Each entity involved in the study will be responsible for complying with regulatory requirements as applicable to the actions/tasks assigned to that entity under the implementation plan resulting from this IRRP. For the duration of the study process, each participant is responsible for their own funding.

5. Engagement

Integrating early and sustained engagement with communities and stakeholders in the planning process was recommended to and adopted by the provincial government to enhance the regional planning and siting processes in 2013. These recommendations were subsequently referenced in the 2013 Long Term Energy Plan. As such, the Working Group is committed to conducting plan-level engagement throughout the development of the Barrie/Innisfil IRRP.

The first step in engagement will consist of meetings with municipalities and First Nation communities within the planning area, First Nation communities who may have an interest in the planning area and the Métis Nation of Ontario to discuss regional planning, the development of the Barrie/Innisfil plan, and integrated solutions.

This will be followed by the establishment of a Local Advisory Committee for local community members to provide input and recommendations throughout the planning process, including information on local priorities and ideas on the design of community engagement strategies. Broad community engagement will be conducted to obtain public input in the development of the plan.

6. Activities, Timeline and Primary Accountability

	Activity	Lead Responsibility	Deliverable(s)	Timeframe
1	**Prepare Terms of Reference considering stakeholder input**	*IESO*	- Finalized Terms of Reference	Q2 2015
2	**Develop the Planning Forecast for the sub-**		- Long-term planning	Q3 2015

	region		forecast scenarios	
	- Establish historical coincident peak demand information	*IESO*		
	- Establish historical weather correction, median and extreme conditions	*IESO*		
	- Establish gross peak demand forecast	*LDCs*		
	- Establish existing, committed and potential DG	*LDCs*		
	- Establish near- and long-term conservation forecasts based on LDC CDM plans and LTEP CDM targets	*IESO*		
	- Develop planning forecast scenarios - including the impacts of CDM, DG and extreme weather conditions	*IESO*		
3	**Provide information on load transfer capabilities under normal and emergency conditions**	*LDCs*	- Load transfer capabilities under normal and emergency conditions	Q3 2015
4	**Provide and review relevant community plans, if applicable**	*LDCs and IESO*	- Relevant community plans	Q3 2015
5	**Complete system studies to identify needs over a twenty-year period** - Obtain PSS/E base case Include bulk system assumptions as identified in Key Assumptions - Apply reliability criteria as defined in ORTAC to demand forecast scenarios - Confirm and refine the need(s) and timing/load levels	*IESO, Hydro One Transmission*	- Summary of needs based on demand forecast scenarios for the 20-year planning horizon	Q3-Q4 2015
6	**Develop Options and Alternatives**		- Develop flexible planning options for forecast scenarios	Q3-Q4 2015
	Develop conservation options	*IESO and LDCs*		
	Develop local generation options	*IESO and LDCs*		
	Develop transmission (see Action 7 below) and distribution options	*Hydro One Transmission, and LDCs*		
	Develop options involving other electricity initiatives (e.g., smart grid, storage)	*IESO/ LDCs with support as needed*		
	Develop portfolios of integrated alternatives	*All*		
	Technical comparison and evaluation	*All*		
7	**Early Wires Planning**		- Cost, feasibility and reliability performance of potential wires options - Detailed option development	Q3-Q4 2015
	Identify potential wires options to address Barrie TS end-of-life and local capacity needs	*Hydro One Transmission*		
	Provide information on cost, feasibility and reliability performance of identified wires options for the purpose of developing integrated solutions			

	Conduct detailed studies of wires options to ensure in-service date for Barrie TS transformer replacement can be met			
8	**Plan and Undertake Community & Stakeholder Engagement**		- Community and Stakeholder Engagement Plan - Input from local communities	
	- Establish engagement subcommittee of the Working Group (if required)	*All*		Q3 2015
	- Early engagement with local municipalities and First Nation communities within study area, First Nation communities who may have an interest in the study area, and the Métis Nation of Ontario	*All*		Q3-Q4 2015
	- Establish Local Advisory Committee and develop broader community engagement plan with LAC input	*All*		Q3-Q4 2015
	- Develop communications materials	*All*		Q1-Q2 2016
	- Undertake community and stakeholder engagement	*All*		
	- Summarize input and incorporate feedback	*All*		
9	**Hand off Wires Component of Integrated Solution**	*IESO*	- Hand-off letter to Hydro One	Q4 2015
10	**Develop long-term recommendations and implementation plan based on community and stakeholder input**	*IESO*	- Implementation plan - Monitoring activities and identification of decision triggers - Hand-off letters - Procedures for annual review	Q3 2016
11	**Prepare the IRRP report detailing the recommended near, medium and long-term plan for approval by all parties**	*IESO*	- IRRP report	Q4 2016

3 Parry Sound/Muskoka IRRP Terms of Reference

1. Introduction and Background

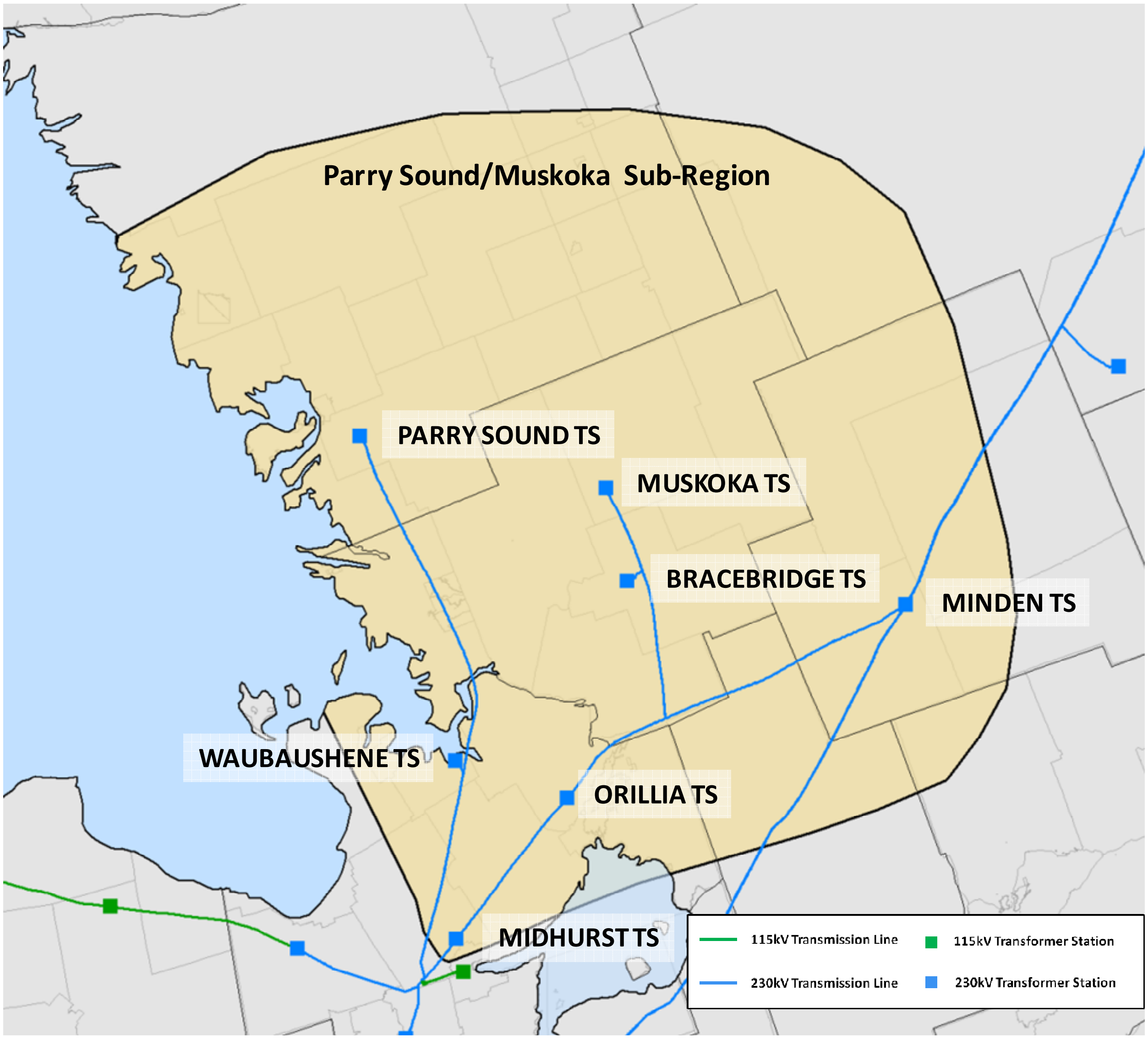
These Terms of Reference establish the objectives, scope, key assumptions, roles and responsibilities, activities, deliverables and timelines for an Integrated Regional Resource Plan ("IRRP") of the Parry Sound/Muskoka sub-region.

Based on the potential for demand growth within this sub-region, limits on the capability of the transmission capacity supplying the area, and opportunities for coordinating demand and supply options, an integrated regional resource planning approach is recommended.

Parry Sound/Muskoka sub-region

The Parry Sound/Muskoka sub-region is a winter-peaking region and it roughly encompasses the Districts of Muskoka and Parry Sound. The approximate geographical boundaries of the sub-region are shown in Figure 5.

Figure 5. Parry Sound/Muskoka Sub-Region



Source: IESO

NOTES: (1) The sub-region is defined by electricity infrastructure; geographical boundaries are approximate. (2) Midhurst TS is included in the scope of the Parry Sound/Muskoka IRRP for the purpose of evaluating restoration needs on the Essa-to-Minden transmission line (M6/7E). Supply and transformer station capacity at Midhurst TS are being addressed through the Barrie/Innisfil IRRP, are thus is not in scope for the Parry Sound/Muskoka IRRP.

The sub-region includes all or part of the following municipalities:

- City of Orillia
- Municipality of Highlands East
- Municipality of Magnetawan

- Municipality of McDougall
- Municipality of Whitestone
- Town of Bracebridge
- Town of Gravenhurst
- Town of Huntsville
- Town of Kearney
- Town of Midland
- Town of Parry Sound
- Town of Penetanguishene
- Township of Algonquin Highlands
- Township of Armour
- Township of Carling
- Township of Georgian Bay
- Township of Joly
- Township of Lake of Bays
- Township of McKellar
- Township of McMurrich-Monteith
- Township of Minden Hills
- Township of Muskoka Lakes
- Township of Oro-Medonte
- Township of Perry
- Township of Ramara
- Township of Ryerson
- Township of Seguin
- Township of Severn
- Township of Strong
- Township of Tay
- Township of the Archipelago
- Township of Tiny
- United Townships of Dysart, Dudley, Harcourt, Guilford, Harburn, Bruton, Havelock, Eyre and Clyde
- Village of Burk's Falls
- Village of Sundridge

The Parry Sound/Muskoka sub-region also includes the following First Nations:

- Henvey Inlet
- Magnetawan
- Shawanaga
- Wasauksing

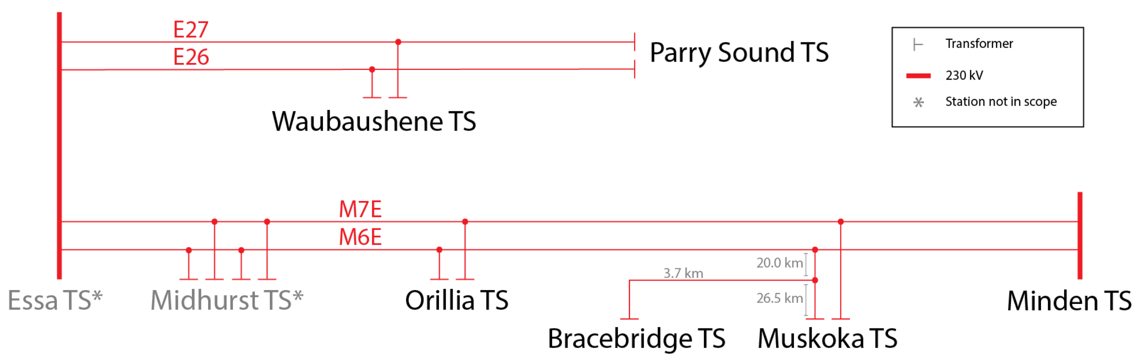
- Moose Deer Point
- Beausoleil
- Wahta Mohawks
- Chippewas of Rama

Engagement on this regional plan may be extended to include additional communities outside of the IRRP area boundaries.

Parry Sound/Muskoka Electricity System

The electricity system supplying the Parry Sound/Muskoka sub-region is shown in Figure 6.

Figure 6. Parry Sound/Muskoka Electricity System



Source: IESO

2. Objectives

1. To assess the adequacy of electricity supply to customers in the Parry Sound/Muskoka sub-region over the next 20 years.
2. To develop a flexible, comprehensive, integrated electricity plan for the Parry Sound/Muskoka sub-region.
3. To develop an implementation plan, while maintaining flexibility in order to accommodate changes in key assumptions over time.

3. Scope

This IRRP will develop and recommend an integrated plan to meet the needs of the Parry Sound/Muskoka sub-region. The plan is a joint initiative involving Lakeland Power, Midland PUC, Newmarket-Tay Power, Orillia Power, PowerStream, Veridian Connections, Hydro One Distribution, Hydro One Transmission, and the IESO, and will incorporate input from community engagement. The plan will integrate forecast electricity demand growth, conservation and demand management ("CDM") in the area with transmission and distribution system capability, end-of-life of major facilities in the area, relevant community plans, other bulk system developments, and Feed-in Tariff ("FIT") and other generation uptake through province-wide programs, and will develop an integrated plan to address needs.

This IRRP will address regional needs in the Parry Sound/Muskoka area. Specifically, the following existing infrastructure is included in the scope of this study:

- Stations—Parry Sound TS, Waubaushene TS, Orillia TS, Bracebridge TS, Muskoka TS, Minden TS
- Transmission circuits—M6/7E, E26/27

The adequacy of the bulk system supplying the area (i.e., the 500/230 kV auto-transformers at Essa TS) is being assessed by the IESO in parallel with this study through a separate bulk system planning process. Results of that study will be shared with the Working Group as they become available.

The Parry Sound/Muskoka IRRP will:

- Prepare a 20-year electricity demand forecast and establish needs over this timeframe
- Examine the Load Meeting Capability and reliability of the existing transmission system supplying the Parry Sound/Muskoka sub-region, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices
- Establish feasible integrated alternatives including a mix of CDM, generation, transmission and distribution facilities, and other electricity system initiatives in order to address the needs of the Parry Sound/Muskoka sub-region
- Evaluate options using decision-making criteria including but not limited to: technical feasibility, economics, reliability performance, environmental and social factors

4. Data and Assumptions

The plan will consider the following data and assumptions:

- Demand Data
  - Historical coincident peak demand information for the sub-region
  - Historical weather correction, median and extreme conditions
  - Gross peak demand forecast scenarios by sub-region, TS, etc.
  - Coincident peak demand data including transmission-connected customers
  - Identified potential future load customers

- Conservation and Demand Management
  - LDC CDM plans
  - Incorporation of verified LDC results and progression towards OEB targets, and any other CDM programs/opportunities in the area
  - Long-term conservation forecast for LDC customers, based on sub-region’s share of the 2013 Long-Term Energy Plan target
  - Conservation potential studies, if available
  - Potential for CDM at transmission-connected customers’ facilities

- Local resources
    - Existing local generation, including distributed generation ("DG"), district energy, customer-based generation, Non-Utility Generators and hydroelectric facilities as applicable
    - Existing or committed renewable generation from Feed-in-Tariff ("FIT") and non-FIT procurements
    - Future district energy plans, combined heat and power, energy storage, or other generation proposals

- Relevant local plans, as applicable
    - LDC Distribution System Plans
    - Community Energy Plans and Municipal Energy Plans
    - Municipal Growth Plans

- Criteria, codes and other requirements
    - Ontario Resource and Transmission Assessment Criteria ("ORTAC")
        - Supply capability
        - Load security
        - Load restoration requirements
    - NERC and NPCC reliability criteria, as applicable
    - OEB Transmission System Code
    - OEB Distribution System Code
    - Reliability considerations, such as the frequency and duration of interruptions to customers
    - Other applicable requirements

- Existing system capability
    - Transmission line ratings as per transmitter records
    - System capability as per current IESO PSS/E base cases
    - Transformer station ratings (10-day LTR) as per asset owner
    - Load transfer capability
    - Technical and operating characteristics of local generation

- Bulk System considerations to be applied to the existing area network
    - Essa 500/230 kV auto-transformer capability
    - North-South Tie flow assumptions

- End-of-life asset considerations/sustainment plans
    - Transmission assets
    - Distribution assets

- Other considerations, as applicable

5. Working Group

The core Working Group will consist of planning representative/s from the following organizations:

- Independent Electricity System Operator *(Team Lead for IRRP)*
- Hydro One Transmission
- Hydro One Distribution
- Lakeland Power
- Midland PUC
- Newmarket-Tay Power
- Orillia Power
- PowerStream
- Veridian Connections

Authority and Funding

Each entity involved in the study will be responsible for complying with regulatory requirements as applicable to the actions/tasks assigned to that entity under the implementation plan resulting from this IRRP. For the duration of the study process, each participant is responsible for their own funding.

5. Engagement

Integrating early and sustained engagement with communities and stakeholders in the planning process was recommended to and adopted by the provincial government to enhance the regional planning and siting processes in 2013. These recommendations were subsequently referenced in the 2013 Long Term Energy Plan. As such, the Working Group is committed to conducting plan-level engagement throughout the development of the Parry Sound/Muskoka IRRP.

The first step in engagement will consist of meetings with municipalities and First Nation communities within the planning area, First Nation communities who may have an interest in the planning area and the Métis Nation of Ontario to discuss regional planning, the development of the Parry Sound/Muskoka plan, and integrated solutions.

This will be followed by the establishment of a Local Advisory Committee for local community members to provide input and recommendations throughout the planning process, including information on local priorities and ideas on the design of community engagement strategies. Broad community engagement will be conducted to obtain public input in the development of the plan.

6. Activities, Timeline and Primary Accountability

	Activity	Lead Responsibility	Deliverable(s)	Timeframe
1	**Prepare Terms of Reference considering stakeholder input**	*IESO*	- Finalized Terms of Reference	Q2 2015
2	**Develop the Planning Forecast for the sub-region**		- Long-term planning forecast scenarios	Q3 2015
	- Establish historical coincident peak demand information	*IESO*		
	- Establish historical weather correction, median and extreme conditions	*IESO*		

	- Establish gross peak demand forecast for LDC service areas	*LDCs*		
	- Establish existing, committed and potential DG	*LDCs*		
	- Establish near- and long-term conservation forecast based on LDC CDM plans and LTEP target	*IESO*		
	- Develop planning forecast scenarios - including the impacts of CDM, DG and extreme weather conditions	*IESO*		
3	**Provide information on load transfer capabilities under normal and emergency conditions**	*LDCs*	- Load transfer capabilities under normal and emergency conditions	Q3 2015
4	**Provide and review relevant community plans, if applicable**	*LDCs, First Nations and IESO*	- Relevant community plans	Q3 2015
5	**Complete system studies to identify needs** - Obtain PSS/E base case - Include bulk system assumptions as identified in Key Assumptions - Apply reliability criteria as defined in ORTAC to demand forecast scenarios - Confirm and refine the need(s) and timing/load levels	*IESO, Hydro One Transmission*	- Summary of needs based on demand forecast scenarios for the 20-year planning horizon	Q4 2015
6	**Develop Options and Alternatives**		- Develop flexible planning options for forecast scenarios	Q1 2016
	- Identify solutions requiring immediate implementation and prepare hand-off letters to responsible parties (if applicable)	*IESO*		
	- Develop conservation options	*IESO and LDCs*		
	- Develop local generation options	*IESO and LDCs*		
	- Develop transmission and/or distribution options including maximizing existing infrastructure capability	*IESO, Hydro One Transmission and LDCs*		
	- Develop options involving other electricity initiatives (e.g., smart grid, storage)	*IESO/ LDCs with support as needed*		
	- Develop portfolios of integrated alternatives	*All*		
	- Technical comparison and evaluation	*All*		
7	**Plan and Undertake Community & Stakeholder Engagement**		- Community and Stakeholder Engagement Plan - Input from local communities, First Nation communities, and Métis Nation of Ontario	
	- Establish engagement subcommittee of the Working Group (if required)	*All*		Q3 2015
	- Early engagement with local municipalities and First Nation communities within study area, First Nation communities who may have an interest in the study area, and the	*All*		Q3-Q4 2015

	Métis Nation of Ontario			
	- Establish Local Advisory Committee and First Nations Local Advisory Committee and develop broader community engagement plan with LAC input	*All*		Q4 2015
	- Develop communications materials	*All*		Q1-Q2 2016
	- Undertake community and stakeholder engagement	*All*		
	- Summarize input and incorporate feedback	*All*		
8	**Develop long-term recommendations and implementation plan based on community and stakeholder input**	*IESO*	- Implementation plan - Monitoring activities and identification of decision triggers - Hand-off letters - Procedures for annual review	Q3 2016
9	**Prepare the IRRP report detailing the recommended near, medium and long-term plan for approval by all parties**	*IESO*	- IRRP report	Q4 2016

4 List of Acronyms

CDM	Conservation and Demand Management
DG	Distributed Generation
FIT	Feed-in-Tariff
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	kilovolt
LAC	Local Advisory Committee
LDC	Local Distribution Company
MW	Megawatt
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
RPP	Regional Planning Process
TS	Transformer Station

Appendix D: Barrie/Innisfil Working Group IESO Hand-off Letter

Connecting Today.
Powering Tomorrow.

Independent Electricity System Operator

1600-120 Adelaide Street West
Toronto, ON M5H 1T1
t 416.967.7474

www.ieso.ca

December 7, 2015

Bing Young
Director, System Planning
Hydro One Networks, Inc.
483 Bay Street
Toronto, ON M5G 2P5

Dear Bing:

Re: Initiating a Near-term Transmission Project identified through the Barrie/Innisfil Integrated Regional Resource Planning ("IRRP") process

The purpose of this letter is to:

- Hand off a near-term transmission project to Hydro One that is required to address urgent needs to replace infrastructure nearing its end of life and provide supply capacity in the Barrie/Innisfil sub-region; and
- Request that Hydro One begin development of a project to replace the existing Barrie transformer station ("Barrie TS") and the E3/4B transmission line with new 230 kV infrastructure.

Since a wires option has been determined to be the only feasible means to address these urgent needs, the hand off of this transmission project to Hydro One is consistent with the regional planning process endorsed by the Ontario Energy Board ("OEB") as part of its Renewed Regulatory Framework for Electricity.

The Barrie/Innisfil Working Group ("the Working Group"), consisting of staff from the IESO, Hydro One, PowerStream and InnPower, is conducting an IRRP process for the Barrie/Innisfil sub-region. The Terms of Reference for the Barrie/Innisfil IRRP established a phased planning process to ensure that near-term needs could be met in a timely fashion. The Working Group has completed the first phase of the IRRP, including reviewing options to address near-term needs with consideration of future needs, meeting with municipalities in the sub-region, and meeting with First Nation communities in the broader South Georgian Bay/Muskoka region. Due to the nature and the timing of the needs, which include replacing existing infrastructure that is approaching its end of life, and providing additional capacity to supply growth in the City of Barrie and Town of Innisfil in the near and medium term, the Working Group has concluded that non-wires alternatives are not viable options and recommends development of this near-term transmission project. The objectives and scope of this project are provided in Attachment 1.

At this time, the Working Group recommends that Hydro One proceed immediately with development of the transmission project, including pursuing the required environmental and regulatory approvals. The Working Group will continue to develop the medium- and long-term plan for the Barrie/Innisfil sub-region in parallel, and will benefit from updated information from Hydro One through the development of this project.

To facilitate development of this project, the IESO will provide Hydro One with the following information on request:

- Demand forecasts
- Conservation and distributed generation forecasts
- Any other relevant information

We look forward to ongoing exchange of information, results and deliverables from the Barrie/Innisfil near-term transmission project as part of the Barrie/Innisfil Working Group activities, and to continuing to work with and provide support to Hydro One in the implementation of this project.

Yours truly,

Bob Chow
Director, Transmission Integration

Cc: Barrie/Innisfil IRRP Working Group Members:

PowerStream
Irv Klajman
Michael Swift
Riaz Shaikh

InnPower
Wade Morris
Ali Syed

Hydro One Distribution
Paul Brown
Richard Shannon
Charlie Lee
Mark Van Tol
Matthew Bell
Gaurav Behal

Hydro One Networks
Michael Penstone
Ibrahim El-Nahas
Alexander Constantinescu
Kirpal Bahra
Ajay Garg
Harneet Panesar

IESO
Michael Lyle
Nicole Hopper
Megan Lund
Nancy Marconi
Julia McNally
Luisa da Rocha
Amanda Flude
Tabatha Bull
Mark Wilson
Leonard Kula
Ahmed Maria
Phillip Woo

Attachment 1 – Project Objectives and Scope

Project Objectives:

- To address the "end of life" of the Barrie transformer station ("Barrie TS") and the infrastructure that supplies it: the E3/4B transmission line; and the 230/115 kV autotransformers at the Essa transformer station ("Essa TS"). Various elements of this infrastructure range from 40 to 67 years old and have been identified for replacement as early as 2018 by Hydro One's sustainment program. These assets are indentified in Figure 1.
- To provide capacity to supply growth in the southern portion of the City of Barrie and in the Town of Innisfil. Currently, Barrie TS is the primary source of supply for this area. Based on current forecasts (net of conservation and distributed generation), this station will reach its capacity around 2017. Distribution system enhancements currently planned by PowerStream will enable this need to be deferred until around 2020, at which point additional supply capability will be required.

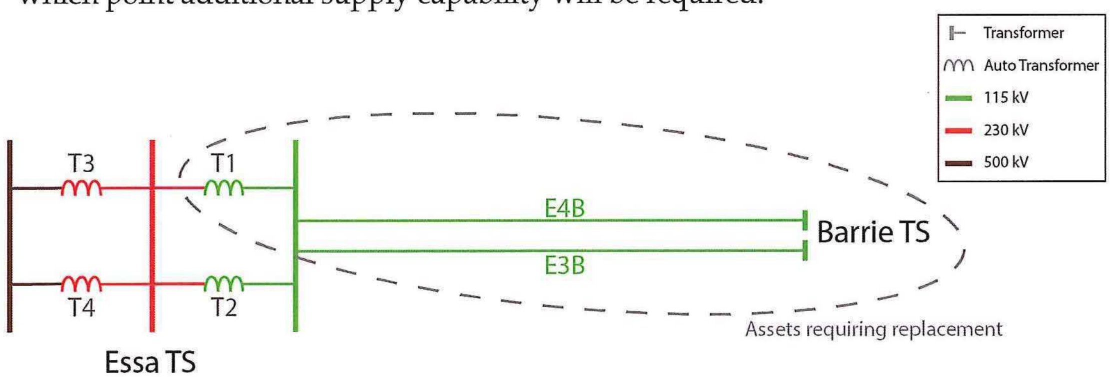


Figure 1 - Single line diagram detailing existing supply of Barrie TS and assets requiring replacement

Project Scope:

The Working Group has considered various alternatives for meeting the above objectives, including non-wires alternatives and various wires options:

- Non-wires solutions were determined to be infeasible by the Working Group on the basis that over 100 MW of existing customer load in southern Barrie and the Town of Innisfil that is currently supplied by Barrie TS would be left without electricity supply if the infrastructure is not replaced when it reaches end of life.
- An option to replace the existing 115 kV line, station and autotransformer with like-for-like equipment (i.e., maintaining its voltage at 115 kV) was also ruled out on the basis that it would not address the growth requirements in the area. Any additional capacity needed to supply growth would then require development of new, greenfield station site(s) and rights-of-way, which would be inconsistent with the 2014 Provincial Policy Statement.[1]

---

[1] Section 1.6.3 of the 2014 Provincial Policy Statement states that: "Before consideration is given to developing new *infrastructure* and *public service facilities*: a) the use of existing *infrastructure* and *public*

Based on the above considerations, the Working Group recommends that Hydro One proceed with a project consisting of:

- Rebuilding Barrie TS and the E3/4B transmission line and upgrading the voltage of these facilities from 115 kV to 230 kV;
- Upgrading the transformers at Barrie TS from 55/92 MVA units to 75/125 MVA units; and
- Retiring the two 230/115 kV auto-transformers at Essa TS (T1 and T2).

These measures address the near-term need to refurbish Barrie TS, allowing it to continue supplying the existing load in southern Barrie and the Town of Innisfil. At the same time, upgrading the station and line to 230 kV allows for the additional load growth forecast in this area to be supplied for the near and medium term using the existing station site and transmission right-of-way. Upgrading the transmission line to 230 kV also provides increased capability that allows for future development of the system. Additionally, savings are incurred from removing the 230/115 kV auto-transformers at Essa TS that are currently maintained solely to supply Barrie TS.

Due to the timing of the needs, and considering typical development timelines for transmission refurbishment/upgrade projects, Hydro One should work toward a targeted in-service date of 2020. It is the Working Group's understanding that a Class Environmental Assessment process will be required for this project, as well as Leave to Construct approval from the OEB for the line replacement portion of this project. The IESO will endeavor to provide support to Hydro One in these activities.

The Working Group will continue to review the medium- and long-term needs in the Barrie/Innisfil sub-region and will develop an IRRP addressing needs over a 20-year period for publication at the end of 2016.

---

service facilities should be optimized; and b) opportunities for adaptive re-use should be considered, wherever feasible."

Appendix E: Distribution Asset Condition Assessment

METSCO
Energy Solutions

InnPower Corporation
Distribution Asset Condition Assessment

METSCO Project P-15-141-005

May 17, 2016

LICENSED PROFESSIONAL ENGINEER
5/16/16
D. F. THOMPSON
PROVINCE OF ONTARIO

Prepared By:

Daryn Thompson P.Eng.

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1 Introduction

This report summarizes the results of an Asset Condition Assessment study carried out by METSCO on behalf of InnPower, with the objective of establishing the health and condition of fixed assets employed in the distribution systems.

The assets covered in the report include the following fixed assets:

- Overhead Pole Line Assets
  - Wood Poles
  - Overhead Conductors
- Underground Distribution System
  - Underground Cables
- Distribution Transformers
- Distribution Devices
  - Padmount Switchgear
  - Motorized 44-kV Switches
  - SCADA-Mate Switches
  - Line Reclosers
  - Capacitors
  - Voltage Regulators

The report is organized into five (5) sections including this introductory section:

Section 2 lists the summarized results from section 4 and 5, providing an overview on the condition of InnPower’s distribution assets.

Section 3 describes the background information and the methodology for implementing asset condition assessment.

Section 4 provides the results of asset condition assessment on InnPower’s major distribution assets.

Section 5 includes the asset management philosophy as well as a recommended replacement plan

2 Summary of Results

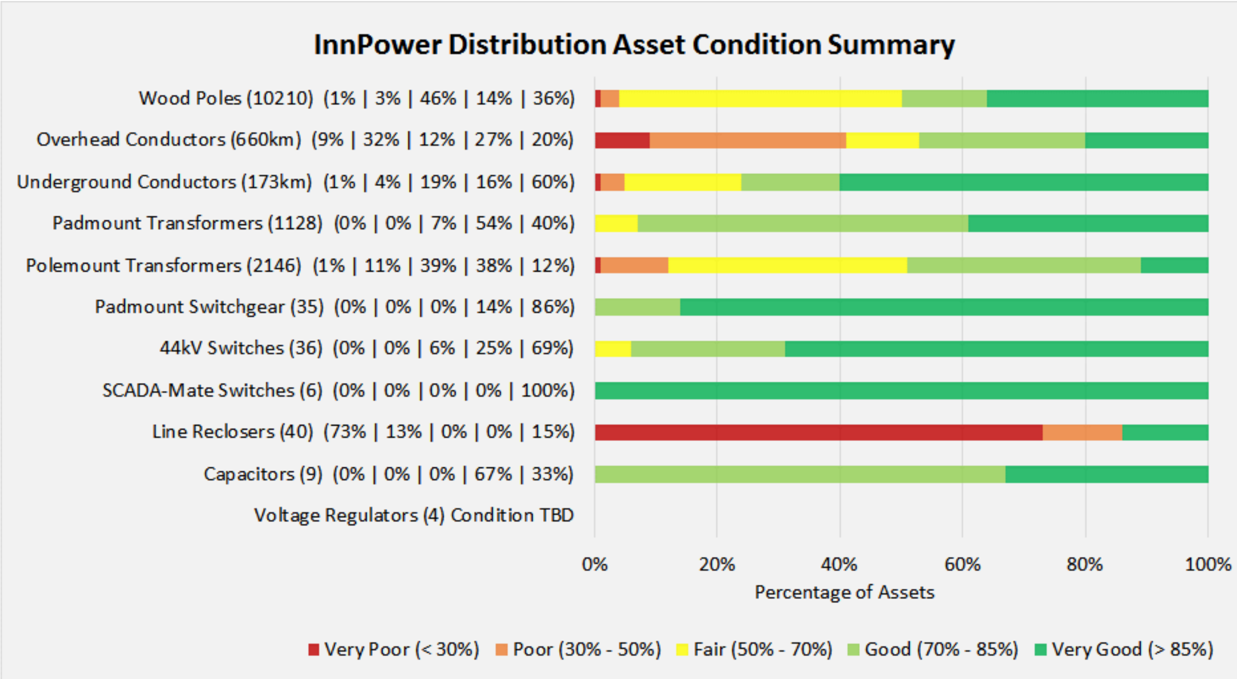


Figure 1 Distribution Asset Condition Summary

Table 1 Summary of Asset Condition Results

		Condition Results				
Asset Class	**Quantity**	**Very Good**	**Good**	**Fair**	**Poor**	**Very Poor**
		%	**%**	**%**	**%**	**%**
Distribution Wood Poles	10,210	35.91%	13.63%	46.21%	3.21%	1.04%
Overhead Conductors (km)	660	20.4%	26.7%	11.8%	31.9%	9.3%
Underground Conductors (km)	173	59.5%	16.3%	19.0%	4.1%	1.0%
Padmount Transformers	1,128	39.7%	53.7%	6.6%	0.0%	0.0%
Polemount Transformers	2,146	11.7%	37.9%	38.8%	10.7%	1.0%
Padmounted Switchgear	35	85.7%	14.3%	0.0%	0.0%	0.0%
Motorized 44-kV Switches	36	69.4%	25.0%	5.6%	0.0%	0.0%
SCADA-Mate Switches	6	100.0%	0.0%	0.0%	0.0%	0.0%
Line Reclosers	40	15.0%	0.0%	0.0%	12.5%	72.5%
Capacitors	9	33.3%	66.7%	0.0%	0.0%	0.0%
Voltage Regulators	4	Condition to be determined				

Table 2 Asset Replacement Plan 2017-2021

Asset	ACA Figure Reference	2017	2018	2019	2020	2021
Distribution Wood Poles	Figure 6	434	304	304	304	304
Overhead Conductors (km)	Figure 8	22.75	22.75	22.75	22.75	22.75
Underground Conductors (km)	Figure 10	1.06	1.06	1.06	1.06	1.06
Padmounted Transformers	Figure 12	9	9	9	8	8
Polemounted Transformers	Figure 12	50	50	50	50	50
Padmounted Switchgear	Figure 14	0	0	0	0	0
Motorized 44-kV Switches	Figure 14	0	0	0	0	0
SCADA-Mate Switches	Figure 14	0	0	0	0	0
Line Reclosers	Figure 14	11	6	6	6	6
Capacitors	Figure 14	0	0	0	0	0
Voltage Regulators	Condition TBD	0	0	0	0	0

3 Asset Condition Assessment Methodology

3.1 List of Distribution Assets

- Overhead Pole Line Assets
  - Wood Poles
  - Overhead Conductors
- Underground Distribution System
  - Underground Cables
- Distribution Transformers
  - Padmount Transformers
  - Polemount Transformers
- Distribution Devices
  - Padmount Switchgear
  - Motorized 44kV Switches
  - SCADA-Mate Switches
  - Line Reclosers
  - Capacitors
  - Voltage Regulators

3.2 Methodology

The Asset Condition Assessment methodology was applied for different categories of fixed assets that are employed on InnPower's distribution system. Adoption of this methodology would require periodic asset inspections and recording of their condition to identify the assets most at risk, requiring focused investments into risk mitigation.

Computing the Health Index for distribution assets requires developing end-of-life criteria for various components associated with each individual asset type. Each criterion represents a factor that is critical in determining the component's condition relative to potential failure. These components and tests shown in the tables are weighted based on their importance in determining the assets end-of-life.

For the purpose of scoring the condition assessment, the letter condition ratings are assigned the following numbers shown as "factors":

- A = 4
- B = 3
- C = 2
- D = 1
- E = 0

These condition rating numbers (i.e., A = 4, B = 3, etc.) are multiplied by the assigned weights to compute weighted scores for each component and test. The weighted scores are totaled for each asset.

Totaled scores are used in calculating final Health Indices for each asset. For each component, the Health Index calculation involves dividing its total condition score by its maximum condition score, then multiplying by 100. This step normalizes scores by producing a number from 0-100 for each asset. For example, a transformer in perfect condition would have a Health Index of 100 while a completely degraded transformer would have a Health Index of 0.

3.2.1 **Overhead Pole Line Assets**

Condition assessment methodologies for the following components employed on overhead lines are discussed below:

- Wood Poles
- Overhead Conductors

3.2.1.1 Wood Poles

As wood is a natural material, its degradation processes 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 effects of weather. Fungi attack both external surfaces and the internal heartwood of wood poles. The process of fungal decay requires the presence of fungus spores in the presence of water and oxygen. For this reason, the area of the pole most susceptible to fungal decay is at and around the ground line, although pole rot is also known to begin at the top of the pole. To prevent the decay of wood poles, utilities treat them with preservatives before installation. Wood preservatives have two basic functions:

- keep out moisture that supports fungi by sealing the surfaces; and
- kill off the fungal spores.

Most power companies install only fully treated wood poles these days, however this was not always the case and the lines constructed over 40 years ago may not have been constructed with fully treated poles but only butt treated poles may have been used. Typically, fully treated poles are expected to provide a longer service life in relation to butt treated poles.

The following factors represent some of the more critical factors affecting wood pole strength as poles age:

- Original type and class of wood pole;
- Original defects in wood (e.g. knots, cracks or rot);
- Rate of decay in service life which depends on type of treatment and environmental conditions;
- Pole damage by woodpeckers, insects, and other wildlife; and
- Wood burns.

Several types of damage can also deform bolt holes in poles. Generally, such deformities do not present immediate problems. However, in some cases deformed holes can result in both failure of the structure and failure of other components attached to the pole. Bolts also can become loose, elongated, bent, cracked, sheared/broken and lost.

Visual inspection can detect the following types of wood pole damage readily:

- Fibre damage that may occur when wind hits a wood pole with force beyond the pole's bearing capacity;
- Partial damage that may result when objects hit wood poles and reduce effective pole circumference. If the damage affects only part of a pole's cross-section the utility may keep the pole in service with a reduced factor of safety.
- Wood splits from various causes that may accelerate the end of a pole's life, depending upon the extent of the split damage;
- Disorientation 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 that may damage wood poles, wooden support cross-braces and timber, reducing the ability of these structures to withstand mechanical stress changes or causing their complete loss through fire; and
- Wood cracks that may hold moisture and cause decay or weaken the structures through freeze/thaw forces during winter.

Utilities have sought objective and accurate means to assess pole condition and remaining life, as a result of which, a wide range of wood pole assessment and diagnostic tools and techniques has developed. These include techniques designed to apply traditional probing and hammer tests in more controlled, repeatable and objective ways. Indirect and non-destructive techniques such as ultrasonic, X-rays, and electrical resistance are also used.

The condition assessment process for wood poles includes scoring based on multiple parameter criteria as described below:

Table 3 Wood Poles – Age Condition Grading

Condition Rating	Age
A	0 to 10 years
B	10 to 30 years
C	30 to 40 years
D	40 to 50 years
E	50 years or older

Table 4 Wood Poles – Crossarm Condition Grading

Condition Rating	Corresponding Condition
A	Unknown; No crossarm; Good; normal; no problem
C	Fair; some deterioration
E	Bad; schedule for replacement

Table 5 Wood Poles – Insect Infestation Condition Grading

Condition Rating	Corresponding Condition
A	No/Unknown
C	Yes

Table 6 Wood Poles – Pole Top Condition Grading

Condition Rating	Corresponding Condition
A	Unknown; Good; normal; no problem
C	Fair; some deterioration
E	Bad; significant deterioration

Table 7 Wood Poles – Pole Shell Condition Grading

Condition Rating	Corresponding Condition
A	Unknown; Good; normal; no problem
C	Fair; some deterioration
E	Bad; significant deterioration

Table 8 Wood Poles – Wood Pecker Damage Condition Grading

Condition Rating	Corresponding Condition
A	Unknown; Good; none visible or minor surface damage
C	Fair; moderate repairable damage
E	Bad; severe damage

Table 9 Wood Poles – Remaining Strength Condition Grading

Condition Rating	Corresponding Condition
A	91% to 100%
B	82% to 90 %
C	73% to 81%
D	65% to 72%
E	Less than 65%

Table 10 Wood Poles – Pole Treatment Condition Grading

Condition Rating	Corresponding Condition
A	Fully treated
C	Butt treated
E	No treatment

Table 11 provides a summarized health index formulation for wood poles:

Table 11 Wood Poles – Health Index

Asset Class	Condition		Weight		Ranking	Max Grade	
	Best Practice	Aggregated	Best Practice	Aggregated		Best Practice	Aggregated
Wood Poles	Age	Age	15	15	A,B,C,D,E	60	60
	Crossarm Condition	Overall Pole Condition	1	5	A,C,E	4	20
	Insect Infestation		1		A,C	4	
	Pole Top Condition		1		A,C,E	4	
	Shell Condition		1		A,C,E	4	
	Wood Pecker Damage		1		A,C,E	4	
	Remaining Strength	Remaining Strength	20	20	A,B,C,D,E	80	80
	Pole Treatment	Pole Treatment	5	5	A,C,E	20	20
Total Score						**180**	**180**

In order to utilize InnPower's inspection data for calculation, criteria listed in **Table 4** through **Table 8** were aggregated into one overall pole condition, based upon visual inspection, which carries the total weight of all 5 health index parameters. As seen in **Table 11** , this adjustment will not affect the max grade of the original formulation. The revised health index formulation for wood poles is also described in **Table 12** and **Table 13** as follows.

Table 12 Wood Poles – Overall Pole Condition Grading

Condition Rating	Corresponding Condition
A	Good; no problem
B	Normal aging
C	Fair; some deterioration
D	Fair-poor; significant deterioration
E	Bad; critical damage; remediation required

Table 13 Wood Poles – Revised Health Index

Asset Class	Condition	Weight	Ranking	Max Grade
Wood Poles	Age	15	A,B,C,D,E	60
	Overall Pole Condition	5	A,B,C,D,E	20
	Remaining Strength	20	A,B,C,D,E	80
	Pole Treatment	5	A,C,E	20
Total Score				**180**

3.2.1.2 Overhead Conductors

Conductors allow flow of current through them facilitating the movement of power from substations to customers' premises. Overhead line conductors are typically supported on wood pole structures to which they are attached by insulators suitable for the voltage at which the lines operate. The conductors on a line are sized by taking into account the amount of current to be carried. The maximum current carrying capacity of conductors is determined by their thermal rating. However distribution line conductors are commonly sized to provide the right balance between energy loss in conductors and the capital cost of conductors. As a result the distribution lines often operate under loads significantly below the thermal rating of the conductors.

Overhead line conductors must have adequate tensile strength, enabling them to be stretched between poles. Distribution lines typically have span length of 40 m to 60 m. Three different types of conductors are commonly used on distribution lines:

- Aluminium Conductors Steel Reinforced (ACSR),
- All Aluminium Conductors (Al or ASC),
- Aluminium Alloy Conductors (AAC).

Steel reinforced aluminium conductors have galvanized steel core strands that supply most of their tensile strength. The steel core has both tensile and ductile properties, allowing the core to withstand both longitudinal forces and bending movements without failure. AAC conductors cost less in relation to ACSR conductors, but their tensile strength is significantly lower than those of the ACSR conductors. Both the price and tensile strength of AAC conductors lie in between those of ASC and ACSR conductors.

Because of the relatively short span lengths employed on distribution lines in relation to transmission lines, the tensile strength of conductors on distribution lines is not as critical as it is on transmission lines. Most distribution utilities these days, therefore, employ all aluminium conductors on distribution lines. Aluminium alloy conductors are sometimes used on distribution lines with longer span lengths.

As current passes through the conductors, the resistance causes its temperature to rise, the temperature change is proportional to the square of the load current passing through the conductor. The rise in temperature causes the conductor to lengthen and sag between points of support, reducing the height of the conductor above ground. Although it seldom happens on distribution lines, line operation at loads beyond conductors' thermal rating of approximately 90° C may lead to annealing of conductors, resulting in permanent loss of its tensile strength.

To provide their intended functions on distribution lines, conductors must retain both their conductive properties and mechanical (i.e., tensile) strength. Aluminium conductors have three primary modes of degradation, corrosion, fatigue and creep. The rate of each degradation mode depends on several factors, including the size and construction of the conductor as well as environmental and operating conditions.

Generally, corrosion represents the most critical life-limiting factor for ACSR conductors. Environmental conditions affect degradation rates from corrosion. Both aluminium and zinc-coated steel core conductors are susceptible to corrosion from chlorine-based pollutants, even in low concentrations, but the rate of corrosion of steel core is significantly greater than that of aluminium. While fatigue degradation is a serious concern for transmission lines that are strung with significantly higher tension, it is commonly not a serious issue for distribution lines.

Overloaded lines operating beyond their thermal capacity can suffer from a loss of tensile strength due to annealing at elevated operating temperatures. Each elevated temperature event adds cumulative damage to the conductors. After loss of 10% of a conductor's rated tensile strength, significant sag occurs, requiring either re-sagging or replacement of the conductor. ACSR conductors can withstand greater annealing degradation compared to ASC.

Phase to phase power arcs can result from conductor galloping during severe storm events. This can cause localized burning and melting of a conductor's aluminium strands, reducing strength at those sites and potentially leading to conductor failures.

Other forms of conductor damage include:

- Broken strands (i.e., outer and inners)
- Strand abrasion
- Elongation (i.e., change in sags and tensions)
- Burn damage (i.e., power arc/clashing)
- Bird-caging.

Although laboratory tests are available to determine the degree of corrosion and assess the tensile strength and remaining useful life of conductors, distribution line conductors rarely require testing. Conductors on distribution lines often outlive the poles and are not usually on the critical path to determine 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 sub optimal system operation due to high line loss.

Computing the Health Index for overhead line conductors requires developing end-of-life criteria for conductors. The condition assessment process includes scoring based on the following parameter:

Table 14 Overhead Conductors – Age Condition Grading

Condition Rating	Age
A	0 to 10 years
B	11 to 30 years
C	31 to 50 years
D	51 to 70 years
E	Over 70 years

In order to tailor to the format of InnPower's asset data, the condition for age rating is slightly modified, as specified in the table below.

Table 15 Overhead Conductors – (InnPower Adjusted) Age Condition Grading

Condition Rating	Age
A	0 to 15 years
B	16 to 35 years
C	36 to 45 years
D	46 to 65 years
E	Over 65 years

Usually, the asset health for overhead conductors is primarily based on service age if no other data (e.g. failure rate) is available.

Table 16 provides a summarized health index formulation for overhead conductors:

Table 16 Overhead Conductors – Health Index

Asset Class	Condition	Weight	Ranking	Max Grade
Overhead Conductors	Service Age	5	A,B,C,D,E	20
Total Score				**20**

3.2.2 Underground Distribution System

The major assets employed on underground distribution systems can be grouped into the following categories:

- Cables
- Splices and Terminations

3.2.2.1 Cables

Safety, reliability, aesthetics and operating costs govern the design and construction standards for underground distribution lines. Underground cables can be constructed in a number of configurations, including direct buried cables, cables installed in direct buried conduits and cables installed in a concrete encased ducts. Medium voltage underground cables have the following key components:

- Cables
- Cable Splices
- Cable Terminations

Medium voltage cables may employ either copper or aluminium conductors. They may be constructed in either single phase or three phase configurations. Two major types of cables are in common use in Canada: paper insulated lead covered (PILC) and cross linked polyethylene (XLPE).

Polymer insulations for cables were introduced as an economic alternative to PILC cables in 1970's. The insulation system in these cables consists of a semi-conducting sheath over the conductor, the insulation, another semi-conducting layer over the insulation, a metallic shield tape or concentric neutral and a jacket. For the early generation of these cables, manufactured in the 1970's, two unexpected factors entered into the failure mechanism: presence of impurities in the insulation system and ingress of moisture that made these cables susceptible to premature failures due to water treeing. Corrosion of concentric neutral conductors is another potential mode of failure. Water treeing is the most significant degradation process for polymeric cables. The original design of cables with polymeric sheaths allowed water to penetrate and come into contact with the insulation. In the presence of electric fields water migration can result in treeing and ultimately breakdown. The rate of growth of water trees is dependent on the quality of the polymeric insulation and the manufacturing process. Any contamination voids or discontinuities will accelerate degradation. This has been the reason for poor reliability and relatively short lifetimes of early polymeric cables.

As manufacturing processes have improved the performance and ultimate life of this type of cable has also improved. In addition to manufacturing improvements, development of tree retardant TRXLPE cables and designs to incorporate metal foil barriers and water migration control have further reduced the rate of deterioration due to treeing.

Distribution underground cables are one of the more challenging assets on electricity systems from a condition assessment and asset management viewpoint. Although a number of test techniques, such as partial discharge (PD) testing have become available over the recent years, it is still very difficult and expensive to obtain accurate condition information for buried cables. The standard approach to managing cable systems has been monitoring of cable failure rates and the impacts of in-service failures on reliability and operating costs and when the costs associated with in-service failures, including the cost of repeated emergency repairs and customer outage costs become higher than the annualized cost of cable replacement, the cables are replaced.

3.2.2.2 Cable Splices and Terminations

Cable splices and terminations are subject to the same type of insulation degradation and aging as the cables themselves. Improperly made splices may be susceptible to moisture ingress and as a result may experience higher failure rates compared to cables.

Computing the Health Index for an underground cable section requires developing end-of-life criteria for its various components. The condition assessment process includes scoring based on multiple parameter criteria as described below:

Table 17 Underground Cables – Age Condition Grading

Condition Rating	Age
A	0 to 10 years
B	10 to 20 years
C	20 to 30 years
D	30 to 40 years
E	> 40 years

In order to tailor to the format of InnPower's asset data, the condition for age rating is slightly modified, as specified in the table below.

Table 18 Underground Cables – (InnPower Adjusted) Age Condition Grading

Condition Rating	Age
A	0 to 15 years
B	16 to 25 years
C	26 to 35 years
D	36 to 45 years
E	> 45 years

Table 19 Underground Cables – Design Related Condition Grading

Condition Rating	Type of Design
A	PILC Cables
B	Tree Retardant XLPE
E	Earlier vintages of XLPE

Table 20 Underground Cables – Loading Condition Grading

Condition Rating	Loading Condition
A	Circuit loaded less than 25% of its rating
B	Circuit loading of 25% to 50% of its rating
C	Circuit loading of 50% to 75% of its rating
D	Circuit loading of 75% to 100% of its rating
E	Circuit loading of greater than 100% of its rating

Table 21 Underground Cables – Failure Rate Condition Grading

Condition Rating	Failure Rates
A	Less than 0.5 Failures per 10 km in the last 5 years
B	0.5 to 1.0 Failures 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 2.5 Failures per 10 km in the last 5 years
E	2.5 or more Failures per 10 km in the last 5 years

Table 22 Underground Cables – Splice or Stress Cone Condition Grading

Condition Rating	Splice or Stress Cone Condition
A	Splice or Stress Cone appears in good condition, no indication of moisture ingress
C	Normal wear, no apparent damage, no evidence of moisture ingress
E	Poor condition, potential moisture ingress or IR indicates hot spot

Table 23 provides a summarized health index formulation for underground cables:

Table 23 Underground Cables – Health Index

Asset Class	Condition	Weight	Ranking	Max Grade
Underground Cables	Age of Cable Circuit	3	A,B,C,D,E	12
	Type/Design of Cable	3	A,B,C,D,E	12
	Loading of Cable Circuit	5	A,B,C,D,E	20
	Historic Failure rates	8	A,B,C,D,E	32
	Visual inspection of splices or stress cones	1	A,B,C,D,E	4
Total Score				**80**

3.2.3 Distribution Transformers

Three main types of distribution transformers are employed on InnPower's distribution system:

- Pole mounted transformer
- Pad mounted transformer
- Platform transformer

Aside from the different design and construction standards employed in their manufacture and installation, each type of transformer serves the same functions and the same asset management strategy can be employed for these assets as described below:

Distribution transformers step down to the medium voltage distribution power to final utilization voltage of either: 120/240V, 120/208V, 240/416 V or 347/600 V. Both single phase and three phase transformers are in use. In pole top applications, three single phase transformers are commonly employed to create a three phase bank, however for pad mounted applications, three phase transformers are used for three phase applications.

The key components of a distribution transformer are:

- primary and secondary coils, made of copper or aluminium conductors
- magnetic core made of iron laminations
- insulation system, commonly consisting of paper and mineral oil
- sealed transformer tank
- primary and secondary bushings or bushing wells to accommodate elbows
- auxiliary devices

The most critical component in transformer aging consideration is the insulation system, consisting of mineral oil and paper. Transformer oil consists of hydrocarbon compounds that degrade with time due to oxidation, resulting in formation of moisture, organic acids and sludge. The oil oxidation rate is a function of operating temperature. Increased acidity and moisture content in insulating oil causes accelerated degradation of insulation paper. Formation of sludge adversely impacts the cooling efficiency of the transformer, resulting in higher operating temperatures and further increasing the rate of oxidation of both the oil and the paper. Distribution transformers commonly fail when the age weakened insulation system is subjected to a voltage surge during lightning.

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. With the exception of rust proofing and 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.

Computing the Health Index for a distribution transformer 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 condition assessment process includes scoring based on multiple parameter criteria as described below:

Table 24 Distribution Transformers – Age Condition Grading

Condition Rating	Distribution Transformer Age
A	0 to 10 years
B	10 to 20 years
C	20 to 30 years
D	30 to 40 years
E	40 years or older

Table 25 Distribution Transformers – Peak Loading Condition Grading

Condition Rating	Peak Loading 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 26 Distribution Transformers – Infrared Scan Condition Grading

Condition Rating	Corresponding condition
A	No Hotspots detected
B	Minor Hotspots detected (temperature difference from ambient of 1-10°C)
C	Minor Hotspots detected (temperature difference from ambient of 10-20°C)
D	Major Hotspots detected (temperature difference from ambient of 20-40°C)
E	Major Hotspots detected (temperature difference from ambient >40°C)

Table 27 provides a summarized health index formulation for distribution transformers:

Table 27 Distribution Transformers – Health Index

Asset Class	Condition	Weight	Rankings	Max Grade
Distribution Transformers	Age of transformer	6	A,B,C,D,E	24
	Peak loading	6	A,B,C,D,E	24
	IR Scan	8	A,B,C,D,E	32
Total Score				**80**

3.2.4 Distribution Devices

This asset class includes the following distribution devices employed on InnPower's distribution system:

- Padmount Switchgear
- Motorized 44-kV Switches
- SCADA-Mate Switches
- Line Reclosers
- Capacitors
- Voltage Regulators

3.2.4.1 Distribution Switches

Disconnect switches provide means of load disconnect and isolation for equipment, such as underground laterals or distribution transformers. The key components of a distribution switch are:

- Switch blades
- Operating handle and mechanism
- Insulator bushings
- Grounding and bonding conductors

Padmounted disconnects have the following additional components:

- Padmounted metal enclosure
- Inter-phase glass polyester barriers
- Padlocks

The most critical components in the disconnect switch are the switch blades and operating mechanism. Misaligned or poorly surfaced contacts can result in excessive arcing during switch opening or closing, resulting in further deterioration of the blades. Corrosion may cause rusting of the links and pins in the operating mechanism reducing the blade movement speed. Broken grounds or damaged insulators are some other defects that may appear with age.

Padmounted disconnect switch enclosures are vulnerable to corrosion due to road salt spray. Non-functioning padlocks or broken inter-phase barriers are other serious defects that may develop with aging.

Computing the Health Index for a distribution switches and switchgear 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 condition assessment process includes scoring based on multiple parameter criteria as described below:

Table 28 Padmount Switchgear – Age Condition Grading

Condition Rating	Age of Switchgear
A	Under 15 years
B	15 to 20 years
C	21 to 25 years
D	26 to 30 years
E	30 years or older

Table 29 44kV and SCADE-Mates – Age Condition Grading

Condition Rating	Age of Switch
A	0 to 10 years
B	10 to 20 years
C	20 to 30 years
D	30 to 40 years
E	40 years or older

Table 30 Distribution Switches – Infrared Scan Condition Grading

Condition Rating	Corresponding condition
A	No Hotspots detected
B	Minor Hotspots detected (temperature difference from ambient of 1-10°C)
C	Minor Hotspots detected (temperature difference from ambient of 10-20°C)
D	Major Hotspots detected (temperature difference from ambient of 20-40°C)
E	Major Hotspots detected (temperature difference from ambient >40°C)

Table 31 provides a summarized health index formulation for distribution switches:

Table 31 Distribution Switches – Health Index

Asset Class	Condition	Weight	Rankings	Max Grade
Distribution Switches and Switchgear	Age	10	A,B,C,D,E	40
	IR Scan	10	A,B,C,D,E	40
Total Score				**80**

3.2.4.2 Line Reclosers

The condition assessment process for line reclosers includes scoring based on multiple parameter criteria as described below:

Table 32 Line Reclosers – Age Condition Grading

Condition Rating	Age of Line Recloser
A	0 to 7 years
B	8 to 15 years
C	16 to 24 years
D	25 to 32 years
E	33 years or older

Table 33 Line Reclosers – Infrared Scan Condition Grading

Condition Rating	Corresponding condition
A	No Hotspots detected
B	Minor Hotspots detected (temperature difference from ambient of 1-10°C)
C	Minor Hotspots detected (temperature difference from ambient of 10-20°C)
D	Major Hotspots detected (temperature difference from ambient of 20-40°C)
E	Major Hotspots detected (temperature difference from ambient >40°C)

Table 34 provides a summarized health index formulation for line reclosers:

Table 34 Line Reclosers – Health Index

Asset Class	Condition	Weight	Rankings	Max Grade
Line Reclosers	Age	10	A,B,C,D,E	40
	IR Scan	10	A,B,C,D,E	40
Total Score				**80**

3.2.4.3 Polemounted Capacitors

The condition assessment process for capacitor banks includes scoring based on multiple parameter criteria as described below:

Table 35 Capacitor Banks – Capacitor Unit Condition Grading

Condition Rating	Corresponding Condition
A	No indication of any capacitor failures through bulging of cans or oil leaks. No signs of external deterioration of gaskets/ weld seam on cans. No external corrosion or rust on cans
B	Less than 1% of capacitor cans indicate failure through bulged tanks or oil leaks. Minor signs of external deterioration of gaskets/ weld seams and minor rust on remaining healthy capacitor cans.
C	1% to 3% of capacitor cans indicate failure through bulged tanks or leaking oil. Significant signs of external deterioration of gaskets/ weld seams and/or rusting of remaining healthy capacitor cans. Minor signs of oil leaks or oil stains on capacitor cans. Requires corrective maintenance within the next several months.
D	3% to 5% of capacitor cans indicate failure through bulging of tanks or oil leaks. Major signs of external deterioration of gaskets/ weld seams on cans. Signs of significant oil leaks or oil stains on healthy cans. Extensive external corrosion or rust on cans. Requires corrective action within the next few weeks.
E	More than 5% of capacitor cans indicate failure through bulged tanks and oil leaks. Capacitor bank unable to provide intended function and has degraded beyond repairs.

Table 36 Capacitor Banks – Insulator Condition Grading

Condition Rating	Corresponding Condition
A	Support Insulators (rack and inter-rack) are not damaged and are free of contamination, chips, radial cracks, flashover burns, copper splash and copper wash. Cementing and fasteners are secure.
B	Support Insulators (rack and inter-rack) are not damaged, however minor contamination, chips and cracks are visible. Cementing and fasteners are secure.
C	Support Insulators (rack and inter-rack) are not damaged, however major contamination, chips, and some flashover burns and copper splash are visible. Cementing and fasteners are secure.
D	Support Insulators (rack and inter-rack) are damaged or cementing and fasteners are not secure.
E	Support Insulators (rack and inter-rack), or cementing and fasteners are damaged beyond repair.

Table 37 Capacitor Banks – Infrared Scan Condition Grading

Condition Rating	Corresponding Condition
A	No hot spots detected
B	Minor hot spots detected
C	Noticeable hot spots detected, but they do not jeopardize safe on-going operation
D	Serious hot spots detected
E	Very Serious hot spots detected

Table 38 Capacitor Banks – Overall Condition Grading

Condition Rating	Corresponding Condition
A	Capacitor Bank is externally clean, and corrosion free. All primary and secondary connections are in good condition. No external evidence of overheating or any other abnormality. Appears to have been well maintained
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
E	Shunt capacitor is defective, damaged or degraded beyond repairs

Table 39 provides a summarized health index formulation for capacitor banks:

Table 39 Capacitor Banks – Health Index

Asset Class	Condition	Weight	Ranking	Max Grade
Capacitor Banks	Condition of Capacitor Units	5	A,B,C,D,E	20
	Condition of Insulators	2	A,B,C,D,E	8
	IR Scan	3	A,B,C,D,E	12
	Overall Condition of the Bank	4	A,B,C,D,E	16
Total Score				**56**

4 Asset Demographics and Condition Assessment

4.1 Overhead Pole Line Assets

4.1.1 Distribution Wood Poles

4.1.1.1 Demographics

There are approximately 10,210 wood poles (and 2 concrete poles) employed on InnPower's electricity distribution system. A sample of 5,321 poles were tested between 2013 and 2015. Demographic information on the tested wood poles is presented in **Figure 2**. Approximately 15% of the tested poles have been in service for over 40 years (shown in yellow) and about 33% (shown in red) are now older than their typical service life of 50 years. Together, almost half of the tested poles have reached 40 years of service life. The summary of the total installed quantity of wood poles is shown in **Table 40**.

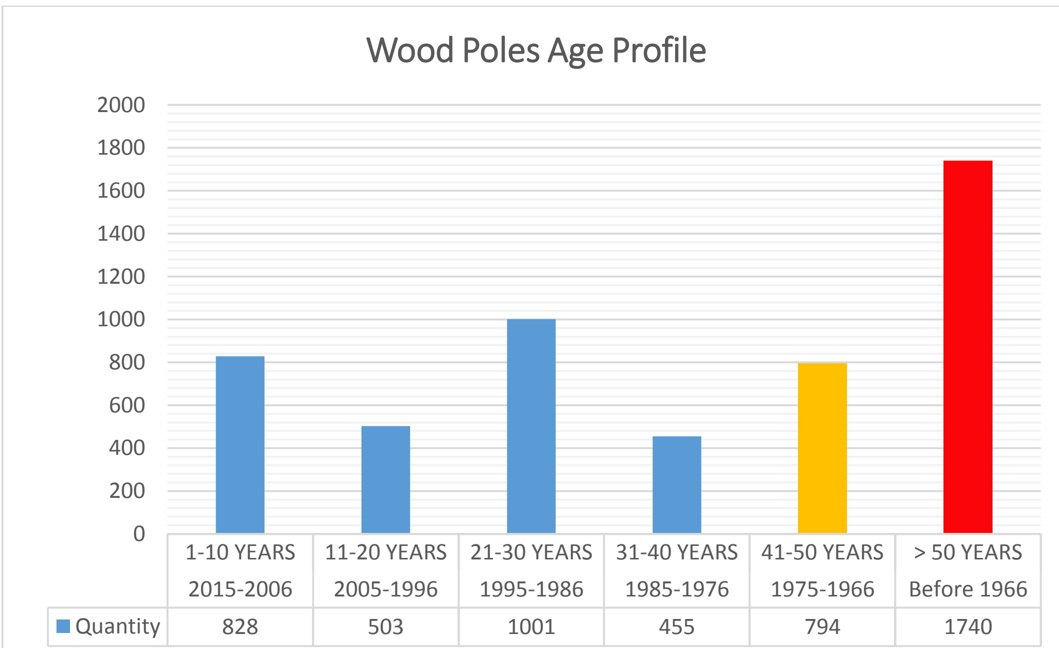


Figure 2 Age Demographics of Wood Poles

Table 40 Wood Poles Demographic Information

Pole Material	**Sample Size**	**Asset Age (in years)**					
		2015-2006	2005-1996	1995-1986	1985-1976	1975-1966	Before 1966
	#	1-10	11-20	21-30	31-40	41-50	>50
Wood	5321	828	503	1001	455	794	1740

Poles are employed in different configurations on overhead lines, some only low voltage circuits, while others may support multiple circuits of different voltages, requiring taller poles. The age profile of all sampled poles with respect to their heights is presented in **Figure 3** and **Table 41**. It is readily seen that majority of the aged poles (greater than 50 years of service) are 30 or 35 feet tall.

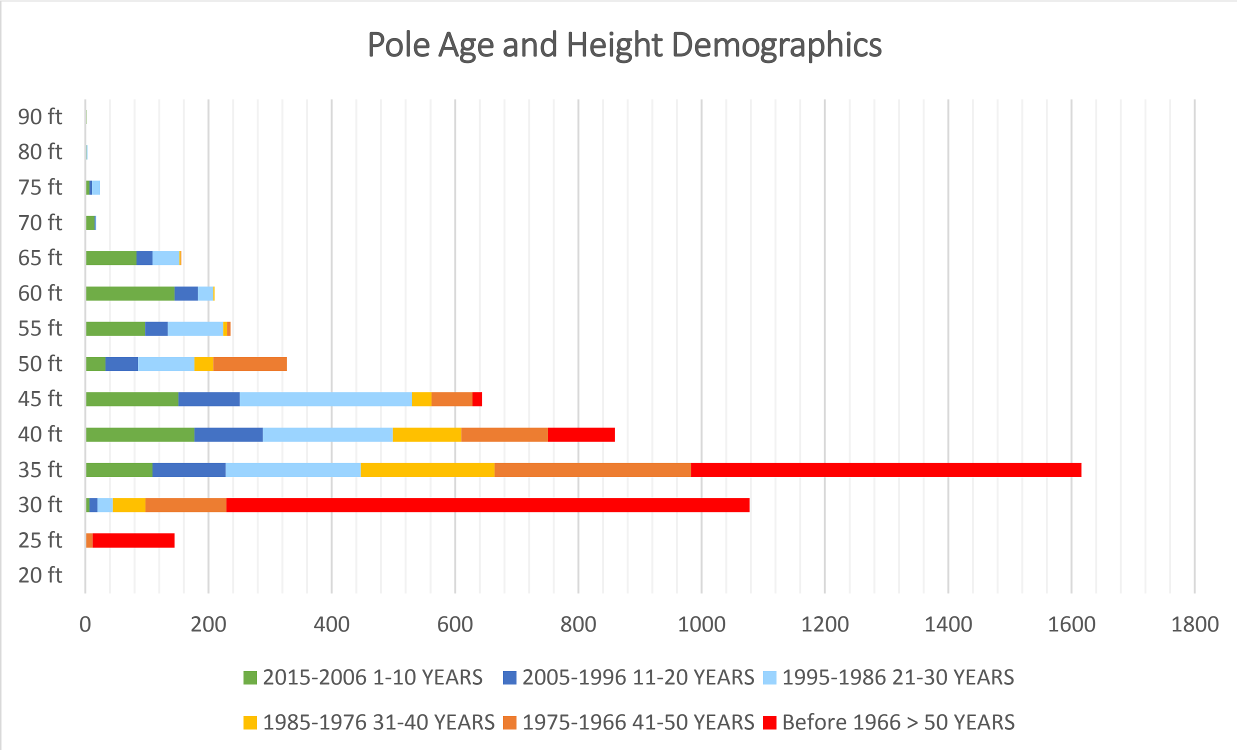


Figure 3 Age Profile of Wood Poles in Different Heights

Table 41 Wood Poles Detailed Age and Height Demographic Information

Pole Height	**Installed Quantity**	**Asset Age (in years)**					
		2006-2015	1996-2005	1986-1995	1976-1985	1966-1975	Before 1966
	#	1-10	11-20	21-30	31-40	41-50	>50
20 ft.	1	0	0	0	0	0	1
25 ft.	145	0	0	1	0	11	133
30 ft.	1078	7	13	25	53	131	849
35 ft.	1616	109	119	219	217	319	633
36 ft.	1	0	0	0	1	0	0
40 ft.	859	177	111	211	111	141	108
45 ft.	644	151	100	279	32	66	16
50 ft.	327	33	53	91	31	119	0
55 ft.	236	97	37	90	6	6	0
60 ft.	210	145	38	25	2	0	0
65 ft.	156	83	26	44	2	1	0
70 ft.	18	15	2	1	0	0	0
75 ft.	24	7	4	13	0	0	0
80 ft.	4	2	0	2	0	0	0
90 ft.	2	2	0	0	0	0	0
Total	**5321**	**828**	**503**	**1001**	**455**	**794**	**1740**

4.1.1.2 HI Calculation

InnPower tests a random sample (approximately one sixth of the total number) of wood poles to determine when the poles should be retested or require replacement. Over the past three years, 5321 poles were tested and rated. Recently, InnPower launched an additional pole inspection program to effectively manage pole line assets. Last year, approximately 470 wood poles were selected from 6 different areas for inspection. To calculate the health index for poles, visual inspection data were extracted from both the test report of 5321 poles as well as the inspection results of 470 poles. Data correlated to the remaining parameters in the health index formulation came from the test report.

4.1.1.3 Results

The health index score for the sampled 5321 poles is illustrated in **Figure 4**. It is observed that the overall pole condition is much better than what would be expected from the age profile. This is mainly due to the fact that a great number of old poles, that have reached more than 45 years of service, received "fair" rating. It should be noted that these poles, constituting over 85% of the fair poles, are expected to significantly deteriorate to poor condition or worse if the corresponding remaining strength drops below 80% or they start to reveal severe damage on the civil structure. Poles under this scenario are illustrated in a red box in **Figure 5**. Thus, these poles would require more frequent diagnostic testing and possible remedial work or replacement depending on criticality. Based on the health index score for the 5321 poles, the health index score for all wood poles is projected and presented in **Figure 6**.

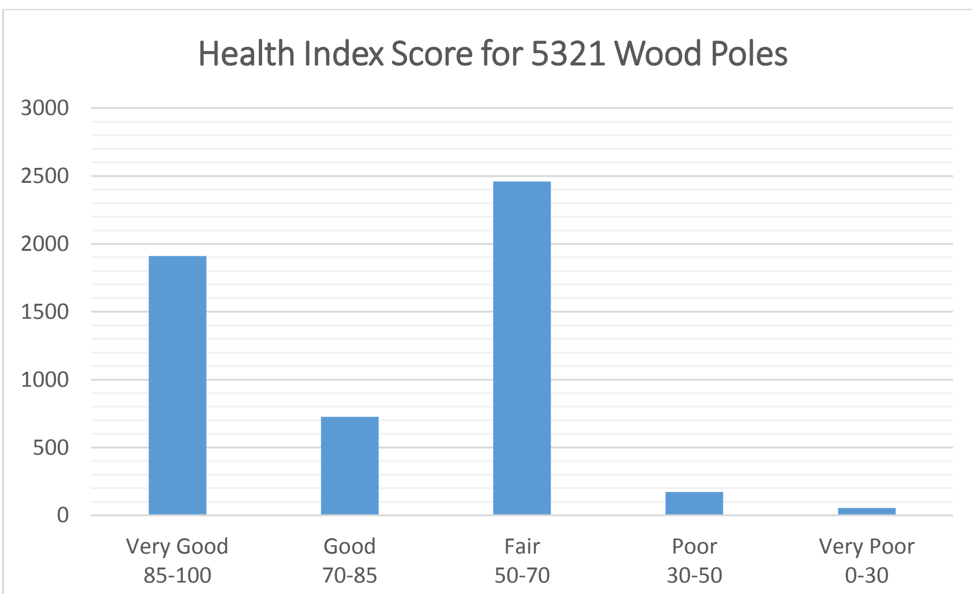


Figure 4 Wood Poles Health Index Score for Poles Tested in 2013-2015

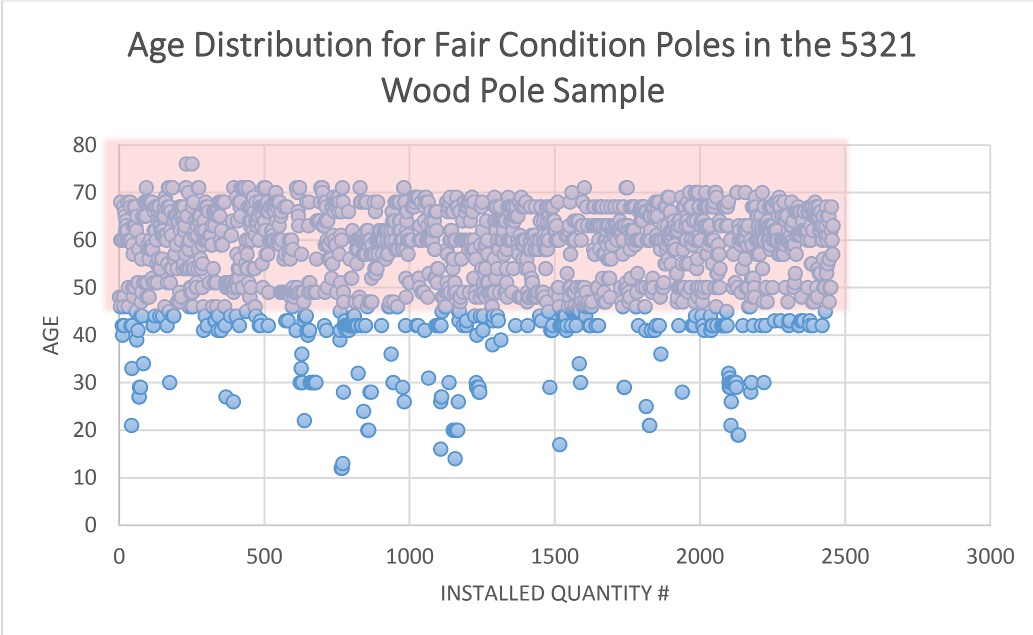


Figure 5 Age Distribution for Fair Condition Wood Poles Tested in 2013-2015

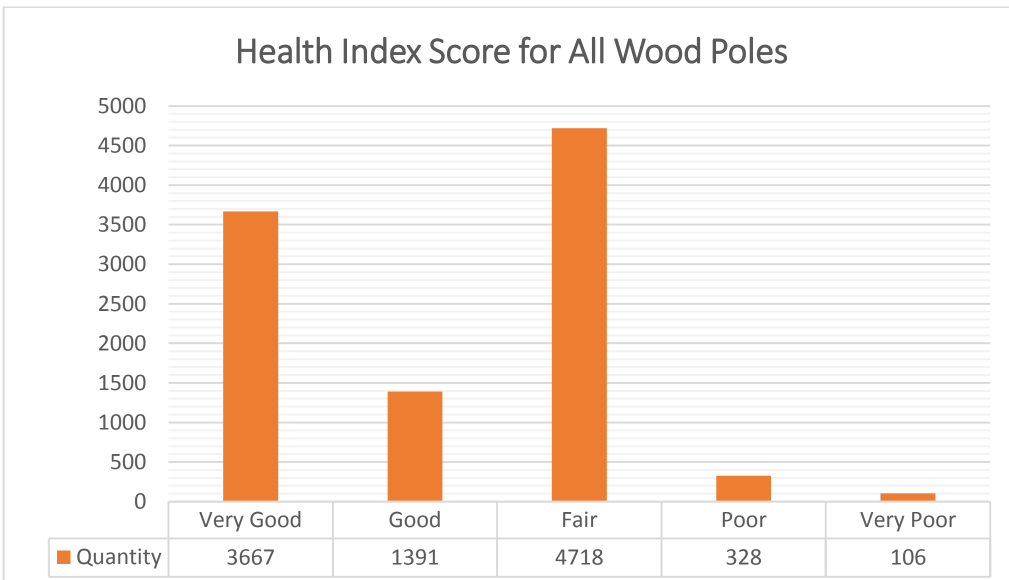


Figure 6 Wood Poles Health Index Score for All Poles

Almost 36% of wood pole population are in very good condition and 434 poles were found in poor or very poor condition, constituting 4.3% of the entire population.

4.1.2 <u>Overhead Conductors</u>

4.1.2.1 <u>Demographics</u>

The overhead distribution system owned by InnPower employs approximately 660 kilometers of overhead distribution lines. The overall age profile for primary conductors employed on all voltage levels is presented by phase in **Figure 7**. Approximately 41% of the conductors in service have reached a service age of greater than 45 years.

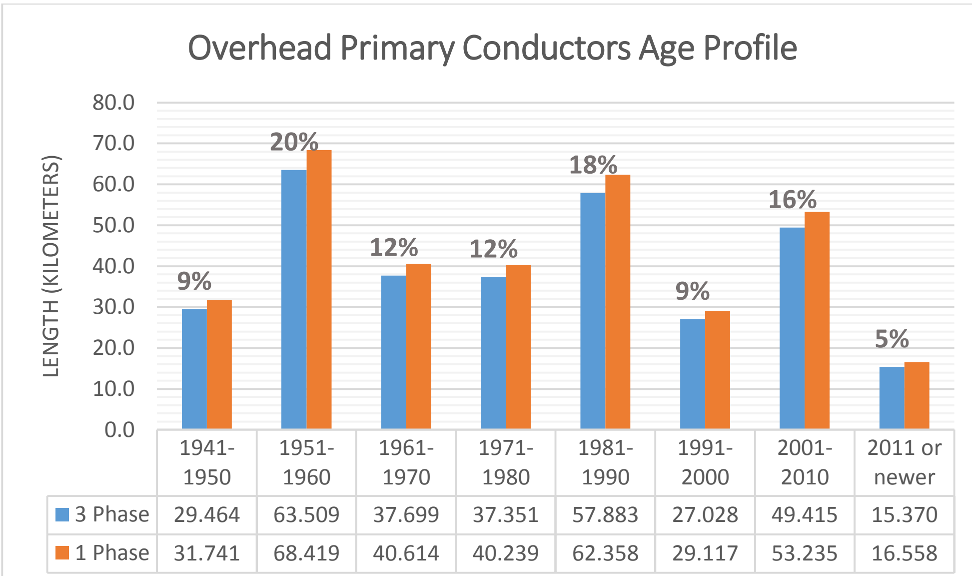


Figure 7 Age Profile for All Overhead Primary Conductors

4.1.2.2 <u>HI Calculation</u>

Due to data availability, the health index score for overhead primary conductors were calculated using age information only. Also, the condition for age rating is slightly modified to tailor to the format of InnPower's asset data, as specified in **Table 15**.

4.1.2.3 <u>Results</u>

The overall health index for all overhead primary conductors is summarized in **Figure 8**. It is determined that all the conductors in poor and very poor condition constitute 41% of the entire population. 20.4% of the lines are in very good condition and 26.7% are in good condition.

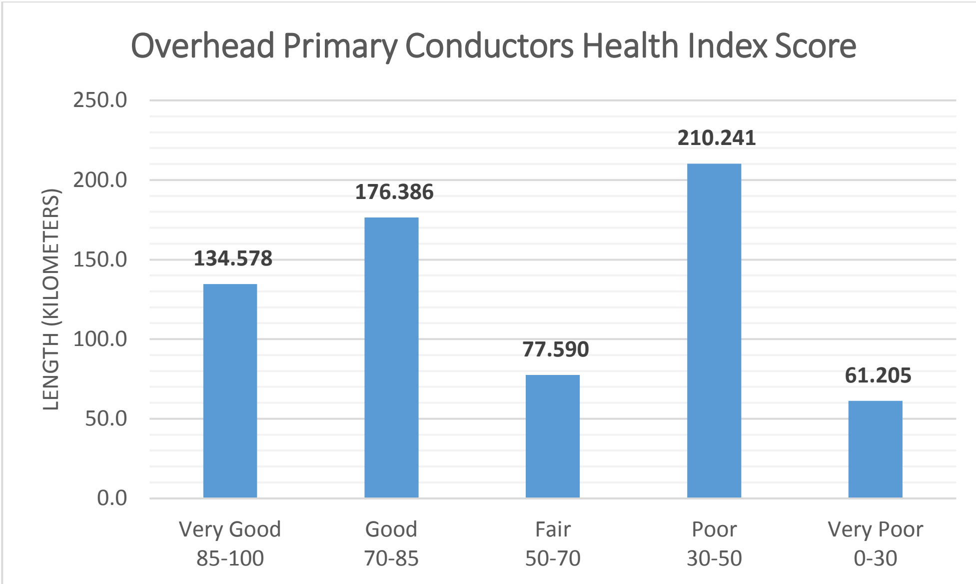


Figure 8 Overhead Primary Conductors Health Index Score

4.2 Underground Distribution System

4.2.1 Underground Cables

4.2.1.1 Demographics

The underground distribution network at InnPower employs 173 kilometers of primary underground conductors. The overall age profile of primary underground conductors is presented in **Figure 9**. 76% of the total primary underground conductors are less than 25 years old.

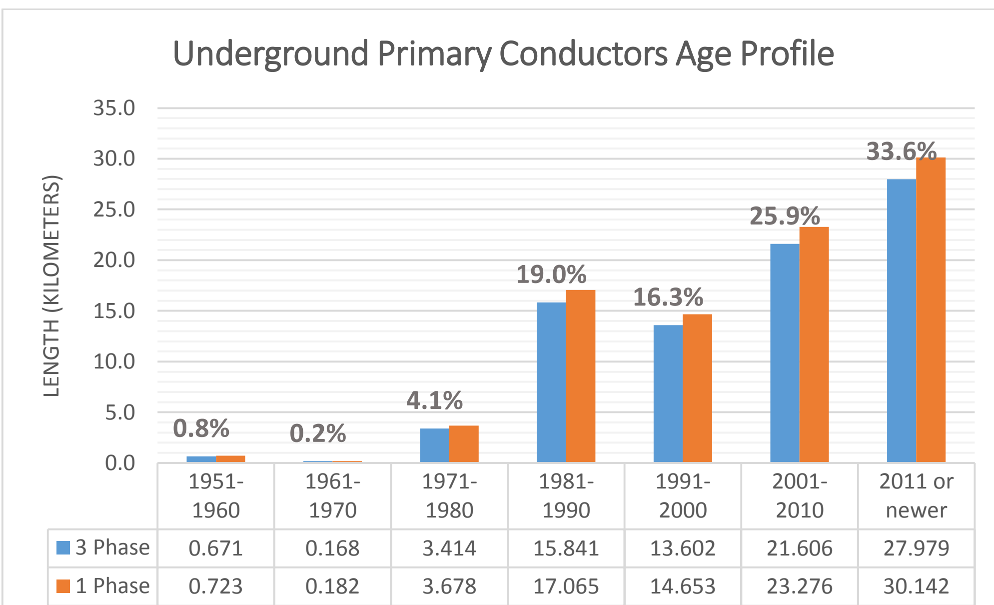


Figure 9 Age Profile for All Underground Primary Conductors

4.2.1.2 HI Calculation

Due to data availability, the health index score for underground primary conductors were calculated using age information only. Also, the condition for age rating is slightly modified to tailor to the format of InnPower's asset data, as specified in **Table 18**.

4.2.1.3 Results

The overall health index for all underground primary conductors is summarized in **Figure 10**. It is determined that all the conductors in poor and very poor condition only constitute 5% of the entire population. 59.5% of the cables are in very good condition and 16.3% are in good condition.

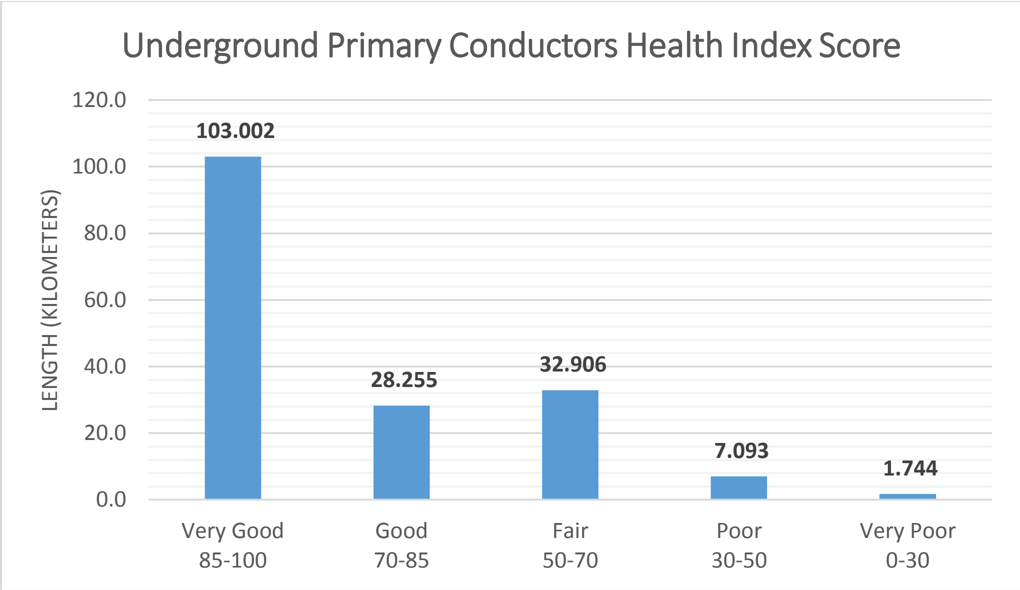


Figure 10 Underground Primary Conductors Health Index Score

4.3 Distribution Transformers

4.3.1 Demographics

The asset demographics of distribution transformers are given in **Figure 11** and **Table 42**.

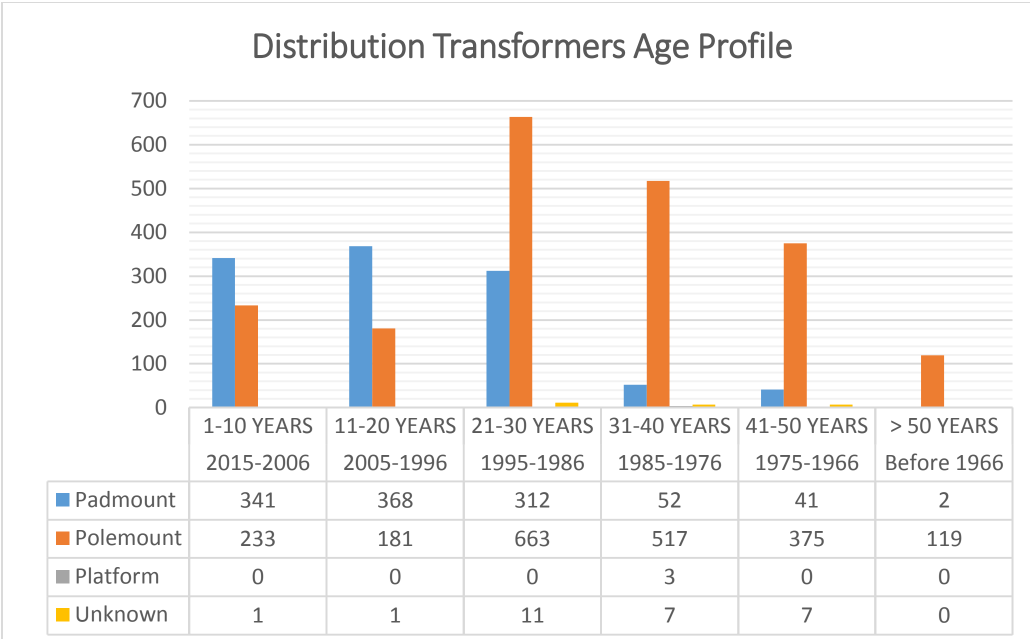


Figure 11 Age Demographics of Distribution Transformers

From the above figure, it can be observed that a vast majority of polemounted transformers have reached 21 or above years of service. Especially, there are 494 transformers that are in service for over 40 years, which have passed the typical useful life of polemounted transformer, contributing to 23% of the entire population. On contrary, approximately 90% of the padmounted transformers have been in service for 30 years or less. Also, number of transformers that have reached the typical useful life is less than 4% of the entire population.

Table 42 Distribution Transformers Detailed Demographic Information

Description	**Secondary Voltage**	**# Installed**	**Asset Age (in years)**						
Mounting Type - kVA			2015-2006	2005-1996	1995-1986	1985-1976	1975-1966	Before 1966	Unknown
			1-10	11-20	21-30	31-40	41-50	>50	
Padmount - 10kVA	120/240V	4	0	1	2	1	0	0	0
Padmount - 25kVA	120/240V	22	13	3	4	2	0	0	0
Padmount - 50kVA	120/240V	235	57	133	35	3	1	2	4
Padmount - 75kVA	120/240V	596	236	170	154	13	23	0	0
Padmount - 100kVA	120/240V	160	3	22	88	25	15	0	7
Padmount - 150kVA	120/240V	1	0	0	1	0	0	0	0
Padmount - 167kVA	120/240V	13	0	0	9	4	0	0	0
Padmount - 300kVA	120/240V	4	1	2	0	1	0	0	0

Padmount - 500kVA	120/240V	2	1	1	0	0	0	0	0
Padmount - 750kVA	120/240V	1	1	0	0	0	0	0	0
Padmount – Unknown	120/240V	2	2	0	0	0	0	0	0
Padmount - 75kVA	120/208V	4	1	3	0	0	0	0	0
Padmount - 150kVA	120/208V	12	3	5	1	2	1	0	0
Padmount - 225kVA	120/208V	2	2	0	0	0	0	0	0
Padmount - 300kVA	120/208V	9	2	2	3	1	0	0	1
Padmount - 500kVA	120/208V	1	0	0	1	0	0	0	0
Padmount - 75kVA	347V	1	0	0	1	0	0	0	0
Padmount - 150kVA	347V	12	3	5	4	0	0	0	0
Padmount - 225kVA	347V	1	0	0	1	0	0	0	0
Padmount - 300kVA	347V	9	4	2	3	0	0	0	0
Padmount - 500kVA	347V	17	6	9	1	0	1	0	0
Padmount - 1000kVA	347V	1	0	1	0	0	0	0	0
Padmount - 75kVA	600V	2	0	1	1	0	0	0	0
Padmount - 150kVA	600V	4	0	2	2	0	0	0	0
Padmount - 300kVA	600V	6	5	0	1	0	0	0	0
Padmount - 500kVA	600V	7	1	6	0	0	0	0	0
Subtotal (Padmount)		**1128**	**341**	**368**	**312**	**52**	**41**	**2**	**12**
Polemount - 3kVA	120/240V	3	0	0	0	0	0	1	2
Polemount - 5kVA	120/240V	69	0	0	0	0	42	15	12
Polemount - 10kVA	120/240V	248	1	22	64	79	50	18	14
Polemount - 15kVA	120/240V	107	0	37	0	2	37	23	8
Polemount - 25kVA	120/240V	702	117	42	259	165	78	31	10
Polemount - 37.5kVA	120/240V	77	0	0	0	1	62	11	3
Polemount - 50kVA	120/240V	610	52	48	257	174	63	11	5
Polemount - 75kVA	120/240V	136	19	12	33	44	23	3	2
Polemount - 100kVA	120/240V	21	4	0	8	6	3	0	0
Polemount - Unknown	120/240V	10	0	2	1	1	1	3	2
Polemount - 15kVA	120/208V	6	0	6	0	0	0	0	0
Polemount - 25kVA	120/208V	10	0	0	1	6	3	0	0
Polemount - 50kVA	120/208V	13	4	0	3	3	2	1	0
Polemount - 75kVA	120/208V	6	6	0	0	0	0	0	0
Polemount - 500kVA	120/208V	1	0	0	1	0	0	0	0
Polemount - 10kVA	347V	9	0	0	0	9	0	0	0
Polemount - 25kVA	347V	21	3	1	4	13	0	0	0
Polemount - 50kVA	347V	25	10	3	12	0	0	0	0
Polemount - 75kVA	347V	30	12	3	10	5	0	0	0
Polemount - 100kVA	347V	8	0	2	3	3	0	0	0
Polemount - 10kVA	600V	3	0	0	0	3	0	0	0
Polemount - 15kVA	600V	5	0	0	0	0	3	2	0
Polemount - 25kVA	600V	7	0	3	1	3	0	0	0
Polemount - 50kVA	600V	11	4	0	5	0	2	0	0
Polemount - 75kVA	600V	3	0	0	0	0	3	0	0
Polemount - 100kVA	600V	4	1	0	0	0	3	0	0
Polemount - 300kVA	600V	1	0	0	1	0	0	0	0
Subtotal (Polemount)		**2146**	**233**	**181**	**663**	**517**	**375**	**119**	**58**
Platform - 167kVA	347V	3	0	0	0	3	0	0	0
Subtotal (Platform)		**3**	**0**	**0**	**0**	**3**	**0**	**0**	**0**

Unknown - 5kVA	120/240V	2	0	0	0	0	2	0	0
Unknown - 10kVA	120/240V	4	0	0	3	1	0	0	0
Unknown - 15kVA	120/240V	1	0	0	0	0	1	0	0
Unknown - 25kVA	120/240V	9	0	0	3	3	3	0	0
Unknown - 37.5kVA	120/240V	1	0	0	0	0	1	0	0
Unknown - 50kVA	120/240V	3	0	0	1	2	0	0	0
Unknown - 75kVA	120/240V	2	0	1	0	1	0	0	0
Unknown - 100kVA	120/240V	4	0	0	4	0	0	0	0
Unknown - 500kVA	600V	1	1	0	0	0	0	0	0
Subtotal (Unknown)		**27**	**1**	**1**	**11**	**7**	**7**	**0**	**0**
Total		**3304**	**575**	**550**	**986**	**579**	**423**	**121**	**70**

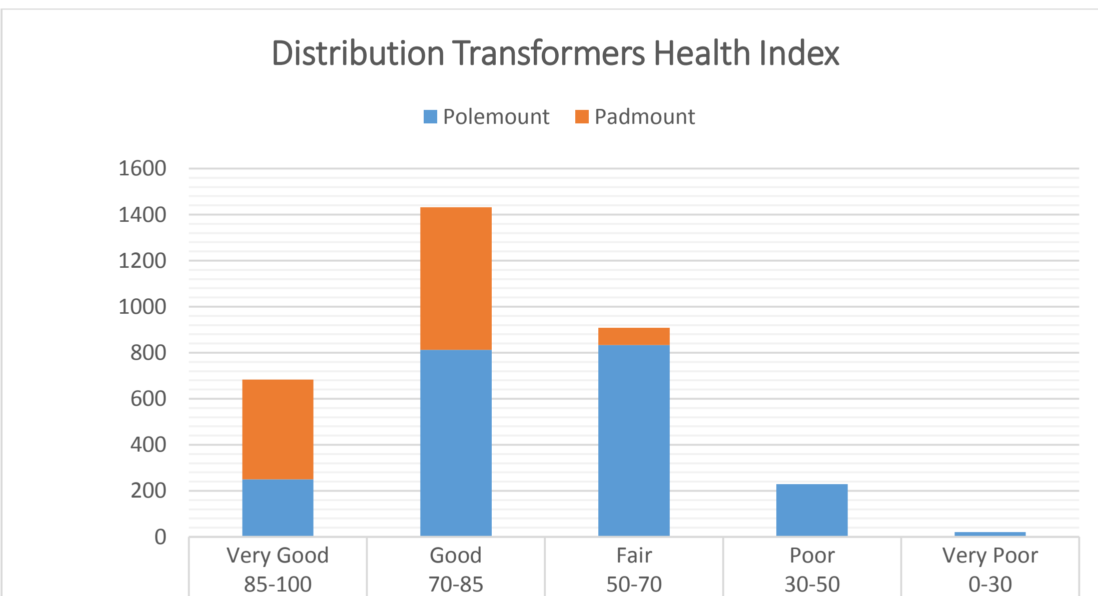
4.3.2 HI Calculation

For polemounted transformers, health index for a sample of transformers was formulated using visual inspection data extracted from InnPower`s pole inspection forms. Then, the health index for all transformers was extrapolated from the sample`s results.

For padmounted transformers, health index was first computed for a relatively large sample based on age demographics and condition data, i.e. peak loading and IR scan results. Condition of the entire population was then projected using the health index for the sampled padmounted transformers.

4.3.3 Results

The health index score for both mounting types of transformers is summarized in **Figure 12**.



	Very Good 85-100	Good 70-85	Fair 50-70	Poor 30-50	Very Poor 0-30
Padmount	433	620	75	0	0
Polemount	250	813	833	229	21

Figure 12 Distribution Transformers Health Index Score

Only 11.7% of the polemounted transformers are in very good condition. All transformers found in poor or very poor condition are polemounted type, constituting approximately 12% of the total polemounted transformers.

Over 90% of the padmounted transformers were determined to be very good or good. The overall condition of padmounted transformers is fairly good.

4.4 Distribution Devices

4.4.1 Demographics

There are six sub-classes of distribution devices owned by InnPower that fall under this category; namely, padmounted switchgear, motorized 44-kV switches, SCADA-Mate switches, line reclosers, capacitors, and voltage regulators. **Figure 13** presents the age demographics for all the major distribution devices employed on InnPower's distribution system, while **Table 43** lists the demographic information for all distribution devices. The ages of the four voltage regulators which InnPower owns are unknown.

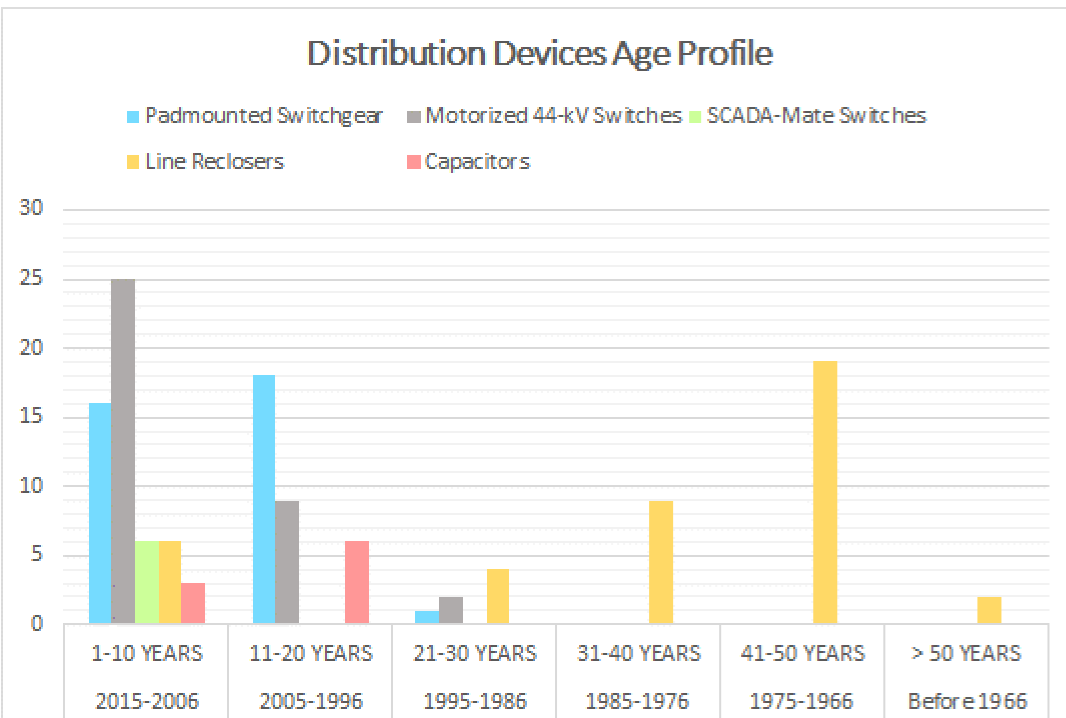


Figure 13 Age Demographics of Distribution Devices

Table 43 Distribution Devices Demographic Information

Switch Type	Installed Quantity	Asset Age (in years)					
		2015-2006	2005-1996	1995-1986	1985-1976	1975-1966	Before 1966
	#	1-10	11-20	21-30	31-40	41-50	>50
Padmounted Switchgear	35	16	18	1	0	0	0
Motorized 44-kV Switches	36	25	9	2	0	0	0
SCADA-Mate Switches	6	6	0	0	0	0	0
Line Reclosers	40	6	0	4	9	19	2
Capacitors	9	3	6	0	0	0	0
Voltage Regulators	4	Age Unknown					
Total	**126**	**56**	**33**	**7**	**9**	**19**	**2**

Table 44 below gives in detail the information of all the capacitors.

Table 44 Capacitors Detailed Demographic Information

Section ID	Address	Primary Voltage (KV)	Size (KVAR)	No. of Phases	Manufacturer	Year of Manufacture
0110P24662	5SR South of the 6th Line.	4.8	450	RWB	COOPER	2001
0110P24661	Highway 11 North of 5th line	4.8	450	RWB	COOPER	2001
0110P24663	20th S.R. North of County Road 89	4.8	450	RWB	COOPER	2001
0110P24664	St Johns Road	4.8	450	RWB	COOPER	2001
0110P24660	20SR North of 12th	4.8	450	RWB	COOPER	2001
0110P246659	BBP Rd East of Pinerock	4.8	450	RWB	COOPER	2001
CAP-7	E/0 1804 10th Line	4.8	450	RWB	COOPER	2007
CAP-8	Highway 11 North of 14th line	4.8	450	RWB	COOPER	2007
CAP-9	1474 shore Acres Dr.	4.8	450	RWB	COOPER	2007

4.4.2 HI Calculations

For padmounted switchgear, age demographics as well as condition data (i.e. IR scan results) were utilized to compute the health index score. Due to limited data availability, the health index scores for motorized 44-kV switches, SCADA-Mate switches, reclosers, and capacitors were calculated using age information only.

4.4.3 Results

The overall health index for all distribution devices is summarized in **Figure 14**. It is observed that all the poor and very poor switches are line reclosers, constituting 85% of the entire population of reclosers.

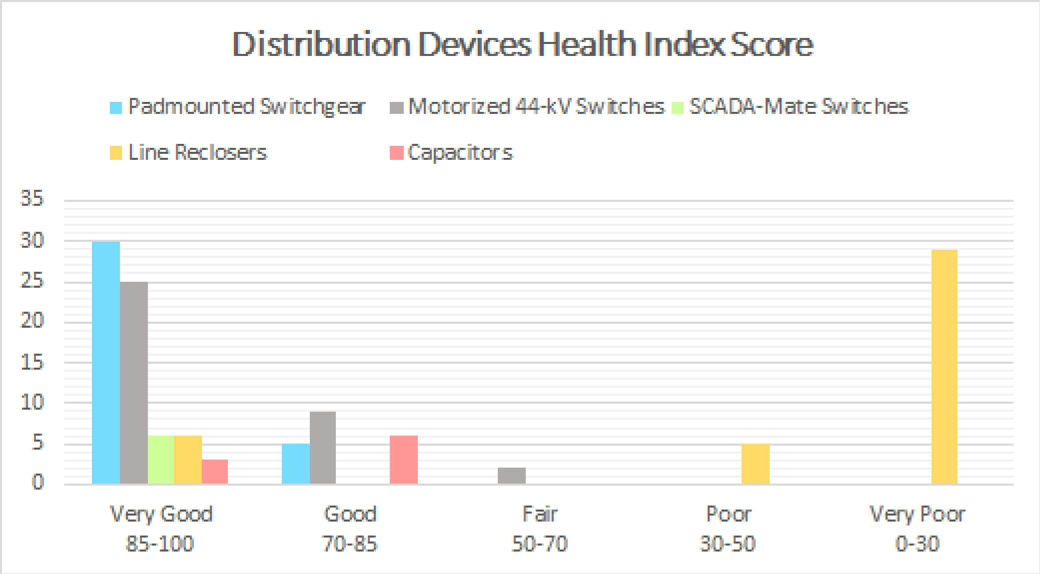


Figure 14 Distribution Switches and Switchgear Health Index Score

5 Replacement Recommendations

5.1 Asset Replacement Philosophy

From the calculated health indices, we can estimate the probability of failure and predict asset replacement rate. For a given asset class, the probability of failure is a function of age and condition as defined by health index. Usually, numerical representation of probability of failure, hazard rate functions, is used to quantify risks for economic life calculation. For the purpose of this report, the asset replacement philosophy is closely tied with health index scores calculated in Section 4 as well as typical useful life of each asset class. **Table 45** correlates the HI score with recommended intervention timelines, where intervention includes replacement, refurbishment, and maintenance.

Table 45 Asset Management Philosophy

Risk Assessment Philosophy		
Very Poor (HI < 30%)	**Poor (HI 30% - 50%)**	**Fair (HI 50% - 70%)**
Intervention recommended	Intervention recommended over the next 2-5 years	Plan for intervention over the next 5-10 years

Table 46 gives the typical useful life (TUL) values, attained from Kinectrics' report on "Asset Depreciation Study for the Ontario Energy Board".

Table 46 Distribution Assets Typical Useful Life

(From Kinectrics Report)			
Asset Class	***Min UL***	***TUL***	***Max UL***
Distribution Wood Poles	35	45	75
Overhead Conductors	50	60	75
Underground Conductors	35	40	55
Padmounted Distribution Transformers	25	40	45
Polemounted Distribution Transformers	30	40	60
Padmount Switchgear	20	30	45
Motorized 44-kV Switches	30	45	50
SCADA-Mate Switches	30	45	50
Line Reclosers	25	40	55
Polemounted Capacitor Banks	25	30	40

5.2 Overhead Pole Line Assets

5.2.1 Wood Poles

As identified in Section 4.1.1.3, a great number of old poles have reached service age of 45 years and beyond but received fair rating from the condition assessment. There are approximately 4048 poles that fall under this scenario. If these poles are scheduled for replacement after the 2017-2021 budget window, these poles would reach 50 years and the failure probability would increase to 7.5%. The number of poles that are expected to fail would be 304 each year. These poles should also be considered for replacement on top of the poor and very poor poles. Thus, as shown in

Table 47, it is recommended to replace 106 wood poles in very poor condition and 328 in poor condition in 2017. After 2017, it is recommended to allocate capital budget for replacing 304 poles per year between 2018 and 2021.

Table 47 Recommended Replacement Plan – Wood Poles

Asset	Forecasted Year of Replacement				
	2017	2018	2019	2020	2021
Distribution Wood Poles	434	304	304	304	304

Poles are commonly replaced through dedicated pole replacement programs and overhead rebuild projects. InnPower selected six areas with aging overhead infrastructure and provided inspection results for a sample of poles in each of these areas. Appendix A analyzes the inspections in these areas and lists poles that were inspected which would be good candidates for inclusion in an overhead rebuild project. The recommended pole replacement plan provided in **Table 47** includes poles which are replaced as part of an overhead rebuild project.

Pole replacement as a result of road widening and other third party infrastructure projects may also contribute to meeting the replacement plan recommended above.

5.2.2 Overhead Conductors

Given the fact that typical useful life of overhead conductors is 60 years, overhead lines owned by InnPower that have reached 60 years, should be considered for replacement. The probability of these conductors failing would be higher than that of conductors at mean life and will be increasing over time. Of the 61.2 km of conductors in very poor condition and 210.2 km in poor condition, it is assumed that only one quarter of the conductors with poor rating have reached 60 years of service. Hence, as seen in **Table 48**, it is recommended to allocate capital budget for replacing approximately 23 kilometers of conductors per year between 2017 and 2021.

Table 48 Recommended Replacement Plan – Overhead Conductors

Asset	Forecasted Year of Replacement				
	2017	2018	2019	2020	2021
Overhead Conductors (km)	22.75	22.75	22.75	22.75	22.75

5.3 Underground Distribution System

5.3.1 Underground Conductors

Given the fact that typical useful life of underground conductors is 40 years, underground cables owned by InnPower that have reached 40 years, should be considered for replacement. The probability of these conductors failing would be higher than that of conductors at mean life and will be increasing over time. Of the 1.7 km of conductors in very poor condition and 7.1 km in poor condition, it is assumed that only half of the conductors with poor rating have reached 40 years of service. Hence, as specified in **Table 49**, it is recommended to allocate capital budget for replacing approximately 1 kilometer of conductors per year between 2017 and 2021.

Table 49 Recommended Replacement Plan – Underground Conductors

Asset	Forecasted Year of Replacement				
	2017	2018	2019	2020	2021
Underground Conductors (km)	1.06	1.06	1.06	1.06	1.06

5.4 Distribution Transformers

5.4.1 Padmounted Transformers

Although none of the padmounted transformers were determined to be in poor or very poor condition, the aging equipment could be a potential hazard. Given the fact that typical useful life of a padmounted transformer is 40 years, transformers owned by InnPower that have reached 40 years, should be considered for replacement. The probability of these transformers failing would be higher than that of a transformer at mean life and will be increasing over time. If not replaced, the future condition of these assets would be expected to rapidly deteriorate in the next five to ten years, imposing reliability risks on the distribution system. Hence, as shown in **Table 50**, it is recommended to allocate adequate funding in capital budget to allow replacement of 9 transformers between 2017 and 2019, and 8 transformers per year in 2020 and 2021.

Table 50 Recommended Replacement Plan – Padmounted Transformers

Asset	Forecasted Year of Replacement				
	2017	2018	2019	2020	2021
Padmounted Transformers	9	9	9	8	8

5.4.2 Polemounted Transformers

It is recommended to allocate adequate funding in capital budgets to allow replacement of 21 transformers in 2017 since they received a very poor rating in the asset assessment. In order to levelize capital spending, 29 of the total poor-condition transformers will also be replaced in 2017. The replacement rate will remain at 50 transformers per year between 2018 and 2021 in order to address potential reliability risks imposed by the rest of the poor-condition transformers.

The proposed replacement plan is illustrated in the table below. These replacements may be realized through dedicated transformer replacement programs, overhead rebuild projects, or system access projects where a transformer size upgrade is needed.

Table 51 Recommended Replacement Plan – Polemounted Transformers

Asset	Forecasted Year of Replacement				
	2017	2018	2019	2020	2021
Polemounted Transformers	50	50	50	50	50

InnPower provided transformer loading data which indicated that 570 of InnPower's transformers exceeded their rated capacity during peak load. Transformers are designed to operate above their rated capacity for short periods of time, but longer durations of overloading cause accelerated degradation which can lead to premature failure. The transformers listed in Appendix B require additional investigation to determine the frequency and duration of overloading to assess its severity.

5.5 Distribution Devices

5.5.1 Padmount Switchgear

All of the padmount switchgear are in either very good or good condition. Meanwhile, these switchgear have been in service for less than 30 years, thus haven't surpassed the typical useful life. Therefore, as observed from **Table 52**, no replacement for padmount switchgear is recommended for the 5-year planning horizon from 2017 to 2021.

Table 52 Recommended Replacement Plan – Padmount Switchgear

Asset	Forecasted Year of Replacement				
	2017	2018	2019	2020	2021
Padmount Switchgear	0	0	0	0	0

5.5.2 Motorized 44-kV Switches

The majority of InnPower's motorized 44-kV switches are in either very good or good condition. Only 2 received a fair ranking. Meanwhile, these switchgear have been in service for less than 30 years, thus haven't surpassed the typical useful life. Since assets in fair condition are normally scheduled for replacement in the 10 year plan, no replacement for 44kV switches, also shown in the table below, is recommended for the 5-year planning horizon from 2017 to 2021.

Table 53 Recommended Replacement Plan – Motorized 44-kV Switches

Asset	Forecasted Year of Replacement				
	2017	2018	2019	2020	2021
Motorized 44-kV Switches	0	0	0	0	0

5.5.3 SCADA-Mate Switches

The 6 SCADA-Mate switches employed on InnPower's distribution system were determined to be in very good condition. Meanwhile, these switchgear have been in service for less than 10 years, thus haven't surpassed the typical useful life. Therefore, as illustrated in **Table 54**, no replacement for SCADA-Mate switches is recommended for the 5-year planning horizon from 2017 to 2021.

Table 54 Recommended Replacement Plan – SCADA-Mate Switches

Asset	Forecasted Year of Replacement				
	2017	2018	2019	2020	2021
SCADA-Mate Switches	0	0	0	0	0

5.5.4 Line Reclosers

Of the 29 reclosers in very poor condition and 5 in poor condition, 11 of the very worst, are scheduled for replacement in 2017. After 2017, 6 reclosers are scheduled to be replaced each year between 2018 and 2021. The proposed replacement plan is illustrated in the table below. Line reclosers are regularly refurbished by InnPower, which is the alternate intervention strategy compared to the replacement plan shown below.

Table 55 Recommended Replacement Plan – Line Reclosers

Asset	Forecasted Year of Replacement				
	2017	2018	2019	2020	2021
Line Reclosers	11	6	6	6	6

5.5.5 Capacitors

All of InnPower's capacitors are in either very good or good condition. Meanwhile, these capacitors have been in service for less than 20 years, thus haven't surpassed the typical useful life. Therefore, as seen in **Table 56**, no replacement for capacitors is recommended for the 5-year planning horizon from 2017 to 2021.

Table 56 Recommended Replacement Plan – Capacitors

Asset	Forecasted Year of Replacement				
	2017	2018	2019	2020	2021
Capacitors	0	0	0	0	0

5.5.6 Voltage Regulators

Neither the age nor the condition of InnPower's 4 voltage regulators are known. Therefore, as seen in **Table 57**, no replacement for voltage regulators is recommended for the 5-year planning horizon from 2017 to 2021. Instead it is recommended that InnPower should endeavour to collect age and condition information for its voltage regulators in order to assess their conditions.

Table 57 Recommended Replacement Plan – Voltage Regulators

Asset	Forecasted Year of Replacement				
	2017	2018	2019	2020	2021
Voltage Regulators	0	0	0	0	0

Appendix A – Results of Line Inspections

InnPower selected six areas with aging overhead infrastructure and provided inspection results for a sample of poles in each of these areas. **Figure 15** (next page) depicts the location of these six areas and **Table 58** summarizes the number of poles inspected in each area. **Table 58** also summarizes the number of poles in each sample that are recommended for replacement based on the inspection results.

Table 58 Summary of Pole Replacements by Area

Number on Map	Area Description	Number of Poles: Inspected	Number of Poles: Replacement Recommended
1	Cookstown	248	176
2	5th Side Road	57	38
3	Lockhart Road (Yonge to 25th Side Road)	42	21
4	Alcona	83	54
5	Lefroy	25	19
6	Strathallan Woods	15	14

The tables on the following pages list the poles which are recommended for replacement based on the results of the overhead line inspections. Since it is a sample, the tables are not an exhaustive list of the poles requiring replacement, but the poles indicated in the tables are good candidates for inclusion into overhead rebuild projects. Each table lists the pole identification number – or the description given where no identification number is available – of each pole recommended for replacement.

The poles which are recommended for replacement are listed in **Table 59** for Cookstown, **Table 60** for 5th Side Road, **Table 61** for Lockhart Road from Yonge Street to 25th Side Road, **Table 62** for Alcona, **Table 63** for Lefroy, and **Table 64** for Strathallan Woods.

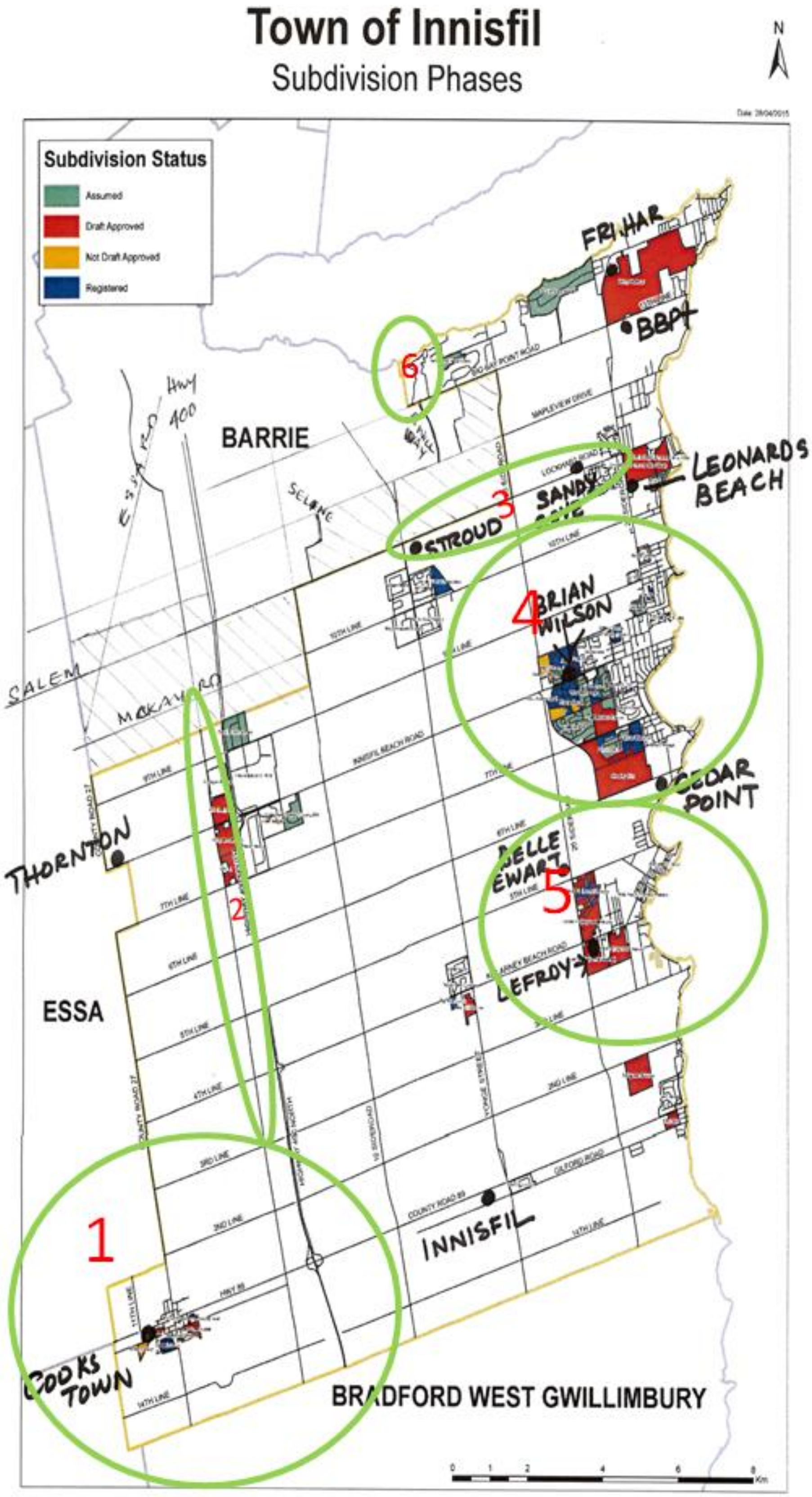


Figure 15 Map of Inspection Areas

Table 59 Cookstown – Poles Recommended for Replacement

648	2441	4617	4664	4725	4900
1274	2442	4618	4667	4727	4902
1278	2443	4619	4668	4728	4904
1281	2444	4620	4672	4732	5376
1282	2445	4621	4673	4733	5382
1283	2447	4622	4676	4734	5383
1284	2448	4625	4680	4735	2 poles south of Hwy 89 on King (east side)
1285	2449	4626	4688	4735	2 poles north of no. 4754
1286	2451	4630	4690	4736	2 poles north of Somers St on Elizabeth St
1288	2452	4631	4692	4737	2 poles south of east of John St on Elizabeth St
1290	2453	4632	4699	4739	36 King St
2415	2454	4633	4700	4740	7 King St
2416	2455	4634	4702	4741	8 King St
2418	2456	4636	4704	4742	Corner of King & Hwy 89
2421	2457	4638	4705	4743	East John/Elizabeth
2422	2458	4639	4706	4744	East John at Elizabeth
2423	2460	4640	4707	4745	East of King St, west of Elizabeth St, south of Somers St
2424	2462	4643	4708	4746	Elizabeth St
2425	2466	4644	4709	4747	Hwy 89 at west end of Cookstown
2427	2467	4645	4710	4748	In front of 33 Queen St
2428	2468	4646	4711	4749	In front of UPI energy gas station on King St
2429	2469	4647	4712	4750	King St @ AOT Stock
2431	2488	4649	4713	4750	South 36 King St
2433	4253	4651	4714	4751	South of east John on east side of King St
2434	4257	4654	4715	4753	Transformer pole @ Home Hardware on Hwy 89
2435	4364	4657	4716	4753	Transformer no. 48 on Elizabeth
2436	4610	4659	4718	4781	
2437	4611	4660	4720	4847	
2439	4613	4661	4722	4898	
2440	4616	4663	4724	4899	

Table 60 5th Side Road – Poles Recommended for Replacement

249	1004	1053	5568	5613
283	1008	1056	5576	5621
288	1012	1060	5579	5631
296	1019	1063	5593	5638
299	1027	1066	5596	6159 5th Side Road
781	1030	5541	5600	7009 5th Side Road
786	1041	5554	5606	
799	1045	5564	5609	

Table 61 Lockhart Road – Poles Recommended for Replacement

4972	7697	7732	7789
4974	7700	7735	7807
4977	7707	7742	2 poles west of 20th Side Road on Lockhart
4980	7713	7747	
5772	7717	7754	
7695	7721	7766	

Table 62 Alcona – Poles Recommended for Replacement

712	4004	6202	6713	6935	7244
3829	6019	6211	6772	6941	7254
3841	6026	6213	6797	7147	7596
3845	6026	6231	6798	7202	7603
3871	6036	6231	6799	7208	7626
3882	6054	6236	6826	7219	7633
3906	6151	6243	6849	7227	7858
3929	6153	6259	6854	7231	9890
3946	6173	6277	6865	7238	897 Lebanon Dr

Table 63 Lefroy – Poles Recommended for Replacement

1448	1490	2737
1472	1490	2738
1473	1491	2739
1480	1491	2740
1486	1495	2742
1487	1498	
1489	2736	

Table 64 Strathallan Woods – Poles Recommended for Replacement

8575	8584	8601
8576	8586	8607
8577	8589	8610
8578	8590	8615
8579	8596	

Appendix B – List of Overloaded Transformers

InnPower provided transformer loading data which indicated that 570 of InnPower's transformers exceeded their rated capacity during peak load. Transformers are designed to operate above their rated capacity for short periods of time, but longer durations of overloading cause accelerated degradation which can lead to premature failure. The transformers listed in **Table 65** require additional investigation to determine the frequency and duration of overloading to assess its severity.

Table 65 List of Overloaded Transformers

Location No.	Serial No.	Phase
H2600	LG2835	Red
H0066	580640	White
H0019	P116018	White
H0019	P115920	Red
H0019	P115919	Blue
H1738	527893	White
H1423	ATL132196	White
H0067	8903E4825007	Red
H0215	560427	Red
H0215	56045	White
H0215	560411	Blue
H3876	652929	Blue
H7673	922319	Red
H7673	977342	White
H7673	922318	Blue
H9715	856960	White
H9715	85697	Blue
H9715	85969	Red
H4116	C201971	Blue
H0413	294975	Blue
H1467	20658523	
H0823	6332276	Red
H4744	KW8313349	White
H3478	L0914125	White
H2128	560436	Red
H2128	560414	White
H2128	560432	Blue
H0179	8588216	Red
H0179	E726124	White
H0179	N05463	Blue
H1437	C993031	White
H1437	M59612	Red

Location No.	Serial No.	Phase
H1437	N52411	Blue
H0596	107935	White
H0136	ATL1085405	Blue
H10049	00C1148102	Blue
H10049	00C1148103	White
H10049	00C1148104	Red
H2920	294159	
H1697	46118	Blue
H6114	D5325	Blue
H6114	D5328	White
H6114	D5327	Red
H4218	LD49640	Blue
H10242	C232281	RWB
H1834	157169	Blue
H2881	20506735	Red
H0474	66980	Blue
H0727	200286423	Red
H0727	20022819	White
H0727	200286994	Blue
H9748	03E6137114	Blue
H9748	03E6137089	Red
H9748	03E3939087	White
H1089	03E6137090	Blue
H4299	7344372	Blue
H4299	7344370	Red
H4299	7344364	White
H0357	20001954	
H4952	WP82449474	Blue
H10511	ATL132167	Blue
H3832	2109275	Red
H3832	2109271	White
H3832	2109276	Blue

Location No.	Serial No.	Phase
H3605	147618	Red
H3605	8016844	White
H3605	EW147632	Blue
H10045	8313458	
H4182	163957	White
H2789	3E3920037	White
H2789	C983464	Blue
H2789	C200271	Red
H0813	67862247	Red
H0618	EW01114130	White
H3619	1459304	White
H0866	554821	White
H0130	26123	Blue
H0747	2021344	White
H3456	EW1461468	
H2624	EW1114227	White
H1375	03E6140021	Red
H3740	9134451	Red
H0750	678059	Blue
H0750	753548	White
H0750	678058	Red
H0954	195095	Blue
H2884	698199	Blue
H3614	20506712	Red
H3614	20506716	White
H3614	2050677	Blue
H0614	N052641	White
H0520	796792	White
H0152	107989	White
H0084	KW718710	
H0709	26034	White
H0804	2050674	Blue
H3113	423227	Blue
H0149	2008293	Red
H0149	2008291	White
H0149	2008296	Blue
H0186	FA50	Blue
H0644	T0066125	
H2425	102733	Red
H2358	743323	Blue

Location No.	Serial No.	Phase
H3497	KW9034128	Blue
H1844	M0598107	Red
H0143	21856	Blue
H1545	293413	Red
H4138	1459193	Blue
H9164	M14094	Red
H9164	M14014	White
H9164	M14092	Blue
H0846	KW8313472	Blue
H9596	2011941	
H1018	C952144	Blue
H1380	604	Blue
H3105	M062350	Blue
H0814	65331034	White
H3248	3837381	Blue
H0550	98949	Red
H0204	20689012	White
H10594	20506720	Blue
H0806	564188	Blue
H1551	17E004147	
H0137	KW8576109	Red
H3392	8313349	Red
H0672	678272	Blue
H9451	1M00385801	RWB
H6967	J44484	Red
H6967	LM20813	White
H6967	LM21126	Blue
H8772	78312641	Red
H8772	78312132	Blue
H8772	78312142	White
H0831	228263	Blue
H0706	200227466	Blue
H0917	2021341	White
H2100	2119174	Blue
H0943	KW07187252	Red
H2257	492188	Red
H3229	19108	
H3362	1224069	Blue
H3778	78312201	White
H0452	831590	Blue

Location No.	Serial No.	Phase
H0329	143058	Blue
H0358	880921	Red
H1535	KW85946	Blue
H1964	LD49618	Red
H2919	294189	Red
H2365	17E04187	Blue
H1852	129556	Blue
H2914	705032	
H7277	KW889012	Red
H2446	625835	White
H3190	91349	Red
H0304	2243171	Blue
H7015	209546	Blue
H2486	295093	Red
H0589	94468	Red
H1537	206842	White
H0467	C98059-3	White
H8947	276327	Red
H3918	KW860548	Red
H10387	2145178	Red
H2321	6332301	Red
H2321	6332338	White
H2321	6332333	Blue
H1528	L404292	Blue
H1726	T007181	
H0449	2134552	RWB
H0449	437054	RWB
H0449	2134953	RWB
H8577	2023552	Red
H8577	2023553	White
H8577	2023554	Blue
H0046	A4363-1	RWB
H0046	A4363-2	RWB
H0046	A4363-3	RWB
H0459	C952143	White
H1748	1M00451304	White
H3758	2049838	
H9101	L093312	Blue
H10144	370679	Blue
H1445	14927	Blue

Location No.	Serial No.	Phase
H2940	M59971	Red
H0044	162792	Blue
H1848	294983	Blue
H4782	17E0110295	Red
H2046	8593103	White
H3967	539363	White
H2082	20658524	Red
H8550	67862071	Blue
H10085	03E3937028	White
H1807	4079137	Red
H3122	WP82317973	Blue
H6569	200227379	White
H4808	413528	White
H4499	C972076	Red
H10249	C232165	Blue
H2302	271414	White
H4348	8588218	Red
H2090	1M00484906	Blue
H2764	96441	White
H1552	9003E6110258	Blue
H1504	2002743322	White
H0110	671328	Blue
H0355	78312115	Blue
H3816	25326Y74AA	
H0906	580518	Blue
H0753	617234	Blue
H2924	78311097	White
H4806	891503	
H0933	A4158-6	Blue
H2635	M144815	Red
H1847	LL18353	Red
H2210	200227366	
H4361	20689010	White
H0837	LK19021	White
H1391	3783311	Red
H0006	2132833	White
H10005	KC93123212	RWB
H2589	71691442	
H0967	C250254	White
H3022	03E1116073	Red

Location No.	Serial No.	Phase
H2056	WP81287675	Red
H3916	C961283	White
H2690	KW9094234	Red
H1700	L105265	Red
H1877	A41597	Blue
H9024	8803E3240171	Red
H0256	796737	Red
H10557	2004302	Blue
H0309	962518	
H3990	298127	Blue
H2122	8603E1070043	Red
H1886	700389	
H0554	67861967	White
H9298	03E3916068	Red
H4837	1224280	Red
H1452	KW9034116	White
H2838	K748226	Red
H1766	LG28122	White
H0379	2092924	White
H1088	823141165	Blue
H0863	2643284	Red
H0836	297935	White
H8906	7485455	Blue
H0200	C972074	Red
H0827	2103894	Blue
H1915	17E4182	Blue
H2941	LM21219	Red
H0688	7546357	White
H2511	LK20007	White
H1931	7600264	Red
H3835	192106	White
H1327	57350	Blue
H7046	408958	Blue
H0416	C961204	Red
H0901	J44476	Red
H2421	271809	Red
H1601	409942	Blue
H0288	67862544	Red
H0782	8585328	Blue
H0306	KC95B27235	White

Location No.	Serial No.	Phase
H2973	2105776	Blue
H0101	96411631	Red
H0919	633253	Red
H0845	LW1371165	White
H9294	2023542	Red
H9294	2023543	White
H9294	2023541	Blue
H2518	778467	White
H10359	C240311	Blue
H1200	KW857370	Blue
H0390	L091885	
H4133	588613	Blue
H3160	K67412	White
H3162	65331028	Red
H7742	2195284	White
H0359	8803E2612059	Blue
H8681	L09184	Red
H0964	T0071941	Blue
H0063	2156169	Red
H2657	KC93129204	White
H0961	A415814	Red
H8394	71691101	White
H9049	U1172073	Red
H0902	736435	Red
H1792	291248	White
H0487	C23158-1	Red
H0487	C23158-3	White
H0487	C23158-2	Blue
H2911	2134737	White
H0216	LF24801	White
H0125	P812871159	Red
H0354	SL1060	Blue
H4275	A41594	Blue
H8579	67951095	Blue
H0763	LK19873	Blue
H8890	17E0289122	
H10007	BC93J05203	
H2237	U1168024	Red
H10079	8903E3920036	Blue
H2209	N054974	Blue

Location No.	Serial No.	Phase
H0899	200021	Blue
H2560	745549	Red
H2560	E73049	Red
H2795	LJ30698	Red
H2011	LD48068	White
H0640	T0354006	Red
H4384	1224102	Red
H6208	2195325	Blue
H0040	2129350	Blue
H2785	ATL132197	Red
H4335	697118	White
H0963	7546278	Blue
H4303	30792	
H0928	2129208	White
H8553	67862079	Blue
H0742	KW8605147	White
H3749	B47841	Red
H0194	20506715	White
H0576	17E0289574	
H0743	2150566	
H3783	561348	Blue
H0904	LL18995	Blue
H1903	FA53	White
H3415	C231572	Red
H4514	662221	Red
H2157	C991593	
H0120	2195156	Red
H9399	78312276	Blue
H2588	1228990	White
H3599	9103E6149166	Red
H3599	9103E6149020	White
H3599	9103E6149091	Blue
H7416	T0066131	Blue
H0395	LD48717	Blue
H1912	C0952145	Red
H0132	8586234	Red
H0681	L091862	
H3424	LF23029	Red
H3424	03E1126017	White
H3424	LD49029	Blue

Location No.	Serial No.	Phase
H3254	8803E2612035	Red
H3369	C972072	White
H0564	8803E2617068	Red
H3109	85948	Red
H0384	108551	Red
H1082	200706	Red
H0114	200227766	White
H8748	71691750	White
H0960	633269	Red
H2048	8703E1132011	Red
H2897	8587166	Red
H3357	2150577	White
H0417	U1169027	Blue
H2806	604281276	Blue
H3306	891479	White
H2570	8586336	White
H0230	270816	Red
H3748	ATL132194	
H0158	K79288	Red
H0838	LL18985	Blue
H1004	214364	White
H1871	205206	Red
H4387	2216053	White
H3504	C200376	Red
H1494	03E3240161	Red
H4512	LJ25801	Red
H8798	7344258	Red
H2324	8588213	Red
H0940	2134706	Blue
H0941	767743	Red
H8535	6786657	Red
H0308	03E3244132	White
H4056	200227538	White
H1024	C231575	Red
H3391	03E3232083	White
H0505	78311960	Blue
H0195	785392	Red
H9056	108559	Red
H2716	65403	Red
H2735	20073313	Red

Location No.	Serial No.	Phase
H0931	7546275	White
H0148	1M00493107	Red
H0163	KW6957128	Red
H4157	ATL132182	White
H1473	60396119	Red
H1673	8587248	Blue
H0935	1137053	Blue
H0036	358000	Red
H2748	604281178	Red
H9013	8803E2677016	Blue
H9013	8803E2677007	White
H9013	8803E2677044	Red
H8426	803E244048	Red
H0855	KW7289123	
H0955	357261	White
H1957	200229138	White
H0921	593288	White
H3436	271782	White
H2680	T0071116	
H3863	271220	Blue
H6371	C200553	Blue
H2251	2129063	White
H4140	C961284	White
H0744	20547211011	White
H4802	20001959	
H0041	3113060	Blue
H0767	8629-8	Blue
H4075	LL18689	Blue
H7624	EW1459382	Blue
H0909	K6745	Red
H0392	U1169050	White
H1046	A415815	Red
H3077	C991594	Red
H2736	96KC352706	
H3694	C990852	White
H3954	P823171187	White
H2331	KC94E27211	Red
H0903	580511	Red
H2910	C951862	
H3581	03E4378030	

Location No.	Serial No.	Phase
H8145	67861079	Blue
H2527	1086287	Blue
H3175	96KC352712	
H0949	632776	Blue
H2078	1095946	Blue
H1165	1M00484901	Red
H3789	7492447	Blue
H0205	71671	Blue
H0770	KC95B27250	
H0774	17E024531	White
H1611	17E24539	Red
H2098	92691	Blue
H6624	C952146	
H3459	795285	Blue
H0965	APCSA025EAB	Red
H3487	C9908310	Red
H2886	A41581x	White
H4134	LJ27775	White
H10001	8703E1233009	Red
H0896	KW7187140	White
H0936	03E6147097	Blue
H3594	2002861038	
H0781	03E3932075	Red
H1073	200282227	Blue
H4274	2143010	
H5523	678368	Blue
H0042	81738	Blue
H2905	882858	White
H0456	B47948	White
H2087	767755	Red
H1221	03E114049	White
H3802	8803E2617123	White
H0222	LB33937	Blue
H6582	LV50033	Blue
H0178	244940	Blue
H3001	785391	Blue
H3799	1M00655205	Red
H6812	LJ12889	White
H0861	65358	White
H6685	17E1030169	Blue

Location No.	Serial No.	Phase
H3112	6795398	Red
H6501	E72738	Blue
H1758	LJ27327	White
H3273	ARP10616	Red
H2317	882882	
H0232	KW7187232	
H4174	964412	Red
H3444	1226460	Blue
H2550	796269	White
H6548	1223716	White
H0900	207386	Red
H2298	C952142	White
H8626	7169625	White
H4807	200227647	Blue
H0966	20036114	White
H2074	8588197	Blue
H4199	869164	Red
H4199	869972	White
H4199	869166	Blue
H3420	LL19189	Blue
H2985	250378	Red
H0942	1095945	Blue
H1335	512280	White
H3617	244892	Blue
H0939	8903E4825004	White
H4594	8585104	White
H2416	LF24805	White
H10148	M05986	Blue
H2229	KW860535	Red
H2445	C200272	Red
H0214	617101	Red
H10580	1M00280001	RWB
H0161	LC24312	Blue
H6029	C993033	Blue
H0769	KC95B27251	
H0157	746572	Red
H2608	126004	Blue
H0049	2-161894	Blue
H1829	65331284	Blue
H1936	LM11214	White

Location No.	Serial No.	Phase
H0150	2143629	Red
H2965	U1169005	Red
H0162	LC24530	Red
H2936	LB1237	White
H0337	LG28151	Blue
H1538	C961282	
H2182	9003E6137103	Blue
H9315	8803E3247114	White
H0048	2107934	White
H2675	741365	Red
H3385	696067	Red
H2012	528894	Red
H2854	200700441	
H8782	7387700	Blue
H0786	T61392	White
H1721	604281240	Blue
H0165	03E3920088	Red
H0950	ARP10613	Red
H3106	C231574	Red
H3435	512346	White
H1508	KW6957108	Red
H4493	511955	White
H0824	LE13528	Red
H8848	8903E3945096	Red
H0154	P823171163	Red
H8918	8803E3232099	Blue
H0057	2121607	Red
H0760	90844	White
H0226	617185	Red
H0352	LB16176	Red
H0117	FA01	Blue
H0144	698819	Blue
H2776	C200274	Blue
H2831	857520	Red
H3551	KW890253	Red
H0768	7387255	Blue
H1705	9110741	Red
H0368	C961201	
H0800	8003521	Red
H2482	J44470	White

Location No.	Serial No.	Phase
H2999	60428841	Red
H0356	ATL1332108	Red
H4465	7387973	White
H2759	3166330	White
H1163	857965	Blue
H3086	13099	Red
H9612	C25183	RWB
H3414	16403	White
H0923	E32172	Red
H2418	17E0110191	Red
H2844	C992032	White
H0055	2150564	Red
H1990	1092848	Blue

Location No.	Serial No.	Phase
H2888	2978	Red
H0762	862324	Blue
H2743	KC95B27229	
H2509	LL28208	
H3767	7169612	Blue
H3782	1086982	Red
H4760	604281205	White
H0453	B47470	White
H1803	7387736	White
H0951	604281214	Blue
H1010	03E2611071	White
H1868	LM20914	White
H1702	LL28206	Red

Appendix F: Station Asset Condition Assessment

METSCO
Energy Solutions

InnPower Corporation
Part B Station Condition Assessment

METSCO Project P-15-141-001

May 10, 2016

LICENSED PROFESSIONAL ENGINEER
D. F. THOMPSON
05/10/16
PROVINCE OF ONTARIO

Prepared By:

Daryn Thompson P.Eng.

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1 Introduction

This report summarizes the results of an Asset Condition Assessment study carried out by METSCO on behalf of InnPower, with the objective of establishing the health and condition of fixed assets employed in the step-down substations.

The assets covered in the report include the following fixed assets:

- Tier 1 Assets
    - Power Transformers
    - Transformer Tap Changers
    - Substation Reclosers
    - Substation Ground Grids
    - Substation Fences
    - 44-kV Transrupter
- Tier 2 Assets
    - Switches
    - Fuses
    - Station Service Transformers
    - Lightning Arrestors

The report is organized into seven (7) sections including this introductory section:

Section 2 describes the background information and the methodology for implementing Asset Condition Assessment.

Section 3 provides the results of asset condition assessment on both Tier 1 and Tier 2 assets.

Section 4 provides the results of grounding assessment.

Section 5 includes station by station report, which elaborates the condition of fixed assets and the structural equipment and identifies potential risks and hazards associated with the station.

Section 6 summarizes the results from Section 5 and provides recommendations on asset replacement, data deficiency improvement and design standards, as well as mitigating safety and environmental concerns.

Section 7 is the appendices of this report, divided into 3 individual attachments (separate from this document), which contain additional information on the asset evaluation process. These documents provide visual inspection pictures for identified issues, reference documents reviewed, and grounding assessment results.

2 Background and Supplied Info

2.1 Supplied Information

This project is based in general on information provided by InnPower, including to various degrees.

- Legacy Substation drawings (if available)
- Control Cabinet Wiring diagram (InnPower, redesigned substation SCADA RTU's in fiscal 2014)
- Substation inspection and Maintenance Records (Infrared, DGA and Equipment test records)
- Feeder Historical Loading
- Historical Outage Information
- Major Equipment Drawings (if available)
- Access to InnPower substations.

METSCO conducted a field audit of each station to collect visual condition and safety information and a further series of tests on the grounding system which are reflected in detail in a sub-report in the appendices.

2.2 Methodology

METSCO has refined the Asset Condition Assessment Approach over decades of experience with large and small utilities. The fundamentals of ACA for small utilities is to define a Health Index that will generate the desired assessment with the available data since a complicated and intensive formulation requiring data that is not available does not achieve the desired results.

The ACA methodology results in a detailed condition assessment of each individual asset in the station and provide a unified health metric that is useful for baseline condition assessment and rate planning.

The methodology of grounding assessment consists of three parts, namely soil resistivity, grid integrity, as well as Ground Potential Rise (GPR) and step and touch potential.

For soil resistivity testing, the Wenner method was applied. This method uses four test probes located in line, connected to Terminals C1, C2, P1 and P2 of a ground test meter and separated by equal distances. Measured resistance readings are repeated with the spacing typically increased through 1, 2, 5, 10, 20, 50 and 100 m where practical.

For grid integrity test, METSCO measures grid integrity using a portable, custom made, device that injects about 10 A dc between accessible grid loops. The voltage drop is read on a digital meter and converted to resistance, with resolution of 100 $\mu\Omega$. This is compared to the expected resistance based on the number of conductors and their geometry. The method can detect broken conductors due to trenching or deterioration, while the more global grid resistance test would not provide any indication of a problem until the last of several redundant conductors is broken.

For GPR testing, METSCO uses a modified fall-of-potential technique to measure station grounding impedance. This method uses arbitrary placement of current probe (C2) and potential probe (P2) preferably in opposite directions, at distances several times the grid diameter, and away from other conductors and lines over a sector of at least 60 degrees wide to either sides. An impedance measuring instrumentation system that resolves both magnitude and phase angles is used for the measurements. Using the information obtained from the soil resistivity test, proximity corrections (between the grid, P2 and C2) is applied to the measurements. The tests will be repeated at several P2 locations and the proximity corrected values will be averaged to find the station interconnected impedance. Current splits in distribution neutral connection were measured using a Rogowsky coil while a twisted pair test lead returns the current signal back to the measuring instrument. In this test both the magnitude and phase angle of each current split was measured and compared to the modeled values. These splits will be subtracted from the current injected to C2 as vector quantities (magnitude and phase angle) to allow resolving the current injected to remote earth by the local station grid.

METSCO observes that ground grid testing is not usually executed in the fall and early winter as results are generally more accurate when the testing is executed in the spring and summer months. However this project has specifically requested this timeline and METSCO has met the requirement.

In a “Best Practice” overview of assets, summarized in section 3-5, METSCO will provide analytical and graphical illustrations of:

- Asset age demographics
- Asset counts by class and station
- Assets beyond useful life
- Asset condition demographics

3 Asset Condition Assessment

3.1 Summary Table of Condition Assessment

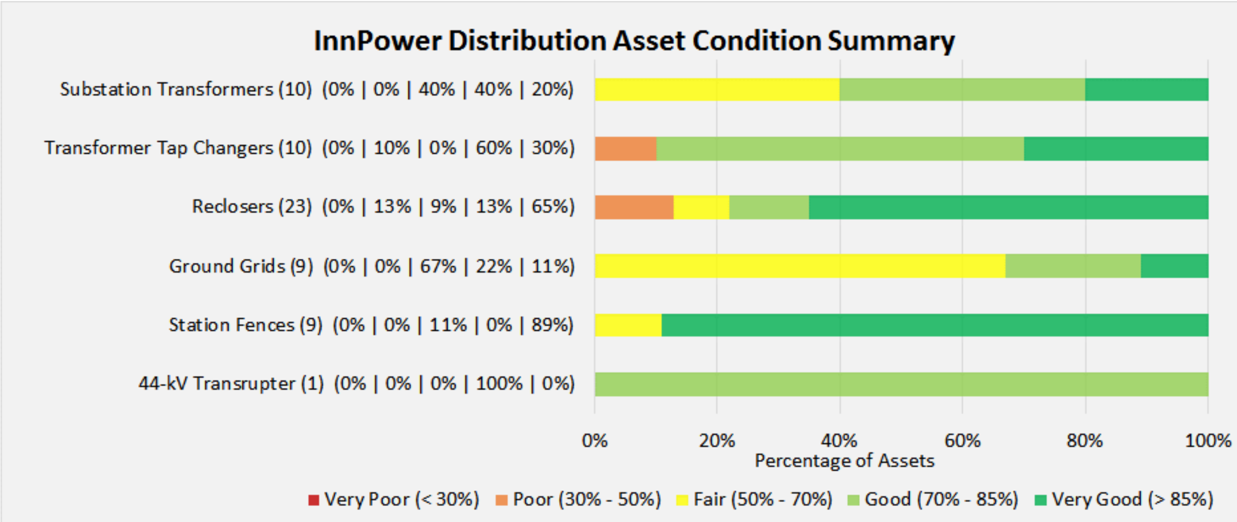

Figure 1 Station Asset Condition Summary

The table below correlates the HI score with typical forecast period for asset replacement:

Table 1 Replacement Planning Based on Asset Condition

Risk Assessment Philosophy		
Very Poor (< 30%)	**Poor (30% - 50%)**	**Fair (50% - 70%)**
Intervention recommended	Intervention recommended over the next 2-5 years	Plan for intervention over the next 5-10 years

3.2 List of Station Assets

The Tier 1 (major) assets are power transformers, transformer tap changers, reclosers, fences, ground grids, and 44-kV Transrupters. The Tier 2 (minor) assets include switches, fuses, station service transformers, and lightning arrestors.

3.3 Asset Assessment

3.3.1 Methodology

The Asset Condition Assessment methodology was applied for different categories of fixed assets that are employed in InnPower's distribution stations. Only 9 of the 10 distribution stations owned by InnPower were assessed, since Belle Ewart DS was constructed at the end of 2014 and was therefore not assessed. Adoption of this methodology would require periodic asset inspections and recording of their condition to identify the assets most at risk, requiring focused investments into risk mitigation.

Computing the Health Index for Tier 1 assets requires developing end-of-life criteria for various components associated with each individual asset type. Each criterion represents a factor that is critical in determining the component's condition relative to potential failure. These components and tests shown in the tables are weighted based on their importance in determining the assets end-of-life.

For the purpose of scoring the condition assessment, the letter condition ratings are assigned the following numbers shown as "factors":

- A = 5
- B = 4
- C = 3
- D = 2
- E = 1

These condition rating numbers (i.e., A = 5, B = 4, etc.) are multiplied by the assigned weights to compute weighted scores for each component and test. The weighted scores are totaled for each asset.

Totaled scores are used in calculating final Health Indices for each asset. For each component, the Health Index calculation involves dividing its total condition score by its maximum condition score, then multiplying by 100. This step normalizes scores by producing a number from 0-100 for each asset. For example, a transformer in perfect condition would have a Health Index of 100 while a completely degraded transformer would have a Health Index of 0.

3.3.1.1 Power Transformers

The condition assessment process for transformers includes scoring based on multiple parameter criteria as described below:

Table 2 Substation Transformers – Age Criteria Description

Condition Rating	Substation Transformer Age
A	0 to 10 years
B	10 to 20 years
C	20 to 30 years
D	30 to 50 years
E	50 years or older

Table 3 Substation Transformers – IR Scan Criteria Description

Grade	Corresponding condition
A	No Hotspots detected
B	Minor Hotspots detected (temperature difference from ambient of 0-9°C)
C	Minor Hotspots detected (temperature difference from ambient of 10-20°C)
D	Major Hotspots detected (temperature difference from ambient of 21-49°C)
E	Major Hotspots detected (temperature difference from ambient >50°C)

Table 4 Substation Transformers – Visual inspections Criteria Description

Condition Rating	Visual Inspections
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 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 or the cooling fans do not work

Table 5 Substation Transformers – Dissolved Gas Analysis Criteria Description

Condition Rating	Test Results
A	Test results indicate excellent insulation 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
E	Two or more of the tests indicate rapidly deteriorating insulation condition

Table 6 provides a summarized health index formulation for substation transformers:

Table 6 Substation Transformers – Health Index

Asset Class	Condition	Weight	Ranking	Max Grade
Power Transformers	Age	6	A-E	30
	IR Scan	4	A-E	20
	Visual Inspection	2	A,C,E	10
	Testing	8	A-E	40
Total Score				**100**

3.3.1.2 Transformer Tap Changers

The condition assessment process for transformer tap changers includes scoring based on multiple parameter criteria as described below:

Table 7 Transformer Tap Changers – Age Criteria Description

Condition Rating	Transformer Tap Changer Age
A	0 to 10 years
B	10 to 20 years
C	20 to 30 years
D	30 to 50 years
E	50 years or older

Table 8 Transformer Tap Changers – IR Scan Criteria Description

Grade	Corresponding condition
A	No Hotspots detected
B	Minor Hotspots detected (temperature difference from ambient of 0-9°C)
C	Minor Hotspots detected (temperature difference from ambient of 10-20°C)
D	Major Hotspots detected (temperature difference from ambient of 21-49°C)
E	Major Hotspots detected (temperature difference from ambient >50°C)

Table 9 Transformer Tap Changers – Visual Inspections Criteria Description

Condition Rating	Visual Inspections
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 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 or the cooling fans do not work

Table 10 Transformer Tap Changers – Dissolved Gas Analysis Criteria Description

Condition Rating	Test Results
A	Test results indicate excellent insulation 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
E	Two or more of the tests indicate rapidly deteriorating insulation condition

Table 11 provides a summarized health index formulation for substation transformer tap changers:

Table 11 Transformer Tap Changers – Health Index

Asset Class	Condition	Weight	Ranking	Max Grade
Transformer Tap Changers	Age	6	A-E	30
	IR Scan	4	A-E	20
	Visual Inspection	2	A,C,E	10
	Testing	8	A-E	40
Total Score				**100**

3.3.1.3 Substation Reclosers

The condition assessment process for reclosers includes scoring based on multiple parameter criteria as described below:

Table 12 Substation Reclosers – Age Criteria Description

Condition Rating	Age
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	41 years or older

Table 13 Substation Reclosers – Visual Inspections Criteria Description

Condition Rating	Visual Inspection Indicators
A	No rust on tank/enclosure, no damage to bushings, no leaks, controls and wiring in excellent condition
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/enclosure badly rusted or major damage to bushing or major oil leak
E	Two or more of the above indicated defects or the cooling fans do not work

Table 14 Substation Reclosers – Equipment Maintenance Tests Criteria Description

Condition Rating	Test Results
A	Test results indicate excellent condition of contacts, operating mechanism, insulation condition and protection relays
B	Normal aging, each of the four indicators within specified 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 specifications and cannot be brought to comply with the specifications

Table 15 provides a summarized health index formulation for substation reclosers:

Table 15 Reclosers – Health Index

Asset Class	Condition	Weight	Ranking	Max Grade
Reclosers	Age	8	A-E	40
	Visual Inspection	2	A,C,E	10
	Maintenance	4	A-E	20
Total Score				**70**

3.3.1.4 Substation Fences

The condition assessment process for fences includes scoring based on multiple parameter criteria as described below:

Table 16 Substation Fences – Visual Inspections Criteria Description

Condition Rating	Visual Inspections
A	No deficiencies in the fence
C	Only minor deficiencies
E	Major deficiencies requiring immediate attention

Table 17 provides a summarized health index formulation for substation fences:

Table 17 Fences – Health Index

Asset Class	Condition	Weight	Ranking	Max Grade
Fences	Visual Inspection	5	A-E	20
Total Score				**20**

3.3.1.5 Substation Ground Grids

The condition assessment process for ground grids includes scoring based on multiple parameter criteria as described below:

Table 18 Substation Ground Grids – Age Criteria Description

Condition Rating	Age
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 19 Substation Ground Grids – Ground Electrode Resistance and GPR

Condition Rating	Test Results
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 20 Substation Ground Grids – Condition of Surface Stone

Condition Rating	Test/Inspection Results
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

Table 21 provides a summarized health index formulation for substation ground grids:

Table 21 Ground Grids - Health Index

Asset Class	Condition	Weight	Ranking	Max Grade
Ground Grids	Age	8	A,C,E	40
	Testing	8	A,C,E	40
	Condition of Surface Stone	4	A,C,E	20
Total Score				**100**

3.3.1.6 44-kV Transrupters

InnPower only has one 44-kV Transrupter at its Bob Deugo DS, so a generalized Health Index methodology for 44-kV Transrupters was not developed. This Transrupter was put into service in 2006 and the visual inspection determined that it is in very good condition.

3.3.1.7 Tier 2 Assets

Based on data availability and asset criticality, the assets grouped under Tier 2 are assessed mainly based upon visual inspections and station maintenance records. While visual inspections reveal physical condition of the equipment, the IR scan and historical station maintenance records, which include testing results of the assets, provide a snap shot into the operating condition of the equipment. Combining these 3 pieces will provide a comprehensive assessment on the condition of Tier 2 assets.

3.3.2 Demographics

3.3.2.1 Substation Transformers

Figure 2 represents the age profile of substation transformers employed at different substations of InnPower. It can be observed that half of the transformers have reached 40 or more years of service. These are installed at Stroud DS, Sandy Cove DS, Leonards Beach DS, Lefroy DS, and Big Bay Point DS.

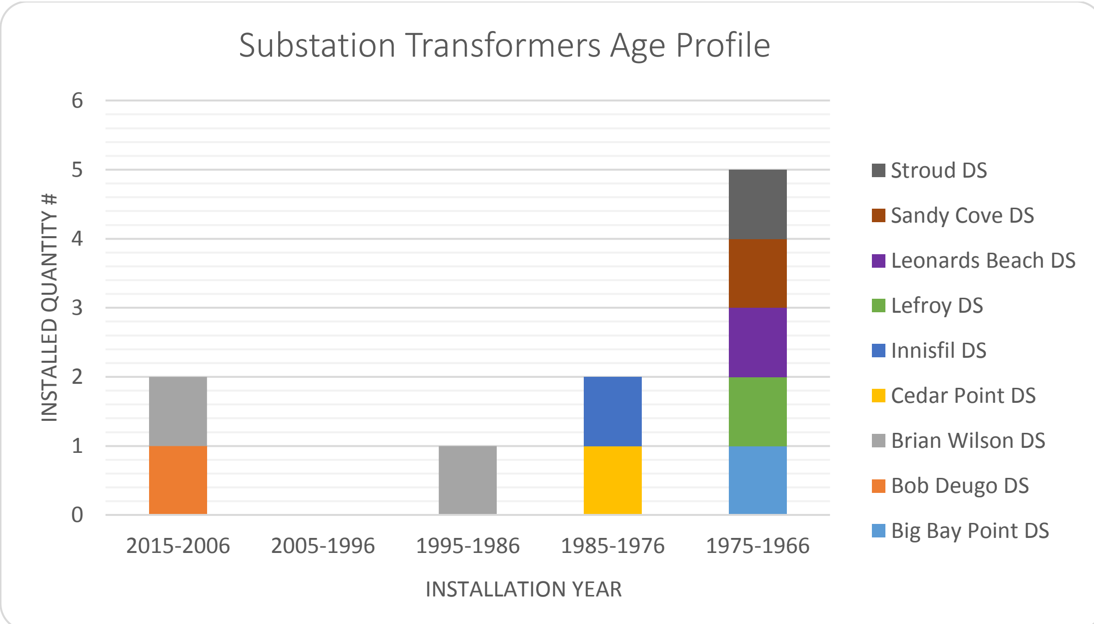

Figure 2 Substation Transformers Age Profile

Table 22 gives in detail the information on rating and in-service dates of all the substation transformers.

Table 22 Substation Transformer Details

Transformer Demographics				
Substation	**Location ID**	**Manufacturer**	**Year of Manufacture**	**HI Score**
Big Bay Point DS	22T1	Ferranti Packard	1971	78
Bob Deugo DS	T1	Northern TX	2006	96
Brian Wilson DS	T1	Federal Pioneer	1991	60
Brian Wilson DS	T2	Virginia TX	2014	100
Cedar Point DS	T1	Federal Pioneer	1976	66
Innisfil DS	31T1	Federal Pioneer	1976	70
Lefroy DS	55T1	Ferranti Packard	1970	78
Leonards Beach DS	41T1	Ferranti Packard	1974	70
Sandy Cove DS	A8T1	Ferranti Packard	1975	78
Stroud DS	50T1	Westinghouse	1969	78

3.3.2.2 Transformer Tap Changers

Figure 3 represents the age profile of transformer tap changers employed at different substations of InnPower. Similar to the transformers, it can be observed that half of the tap changers have reached 40 or more years of service. These are installed at Stroud DS, Sandy Cove DS, Leonards Beach DS, Lefroy DS, and Big Bay Point DS.

Table 23 gives in detail the information on rating and in-service dates of all the transformer tap changers.

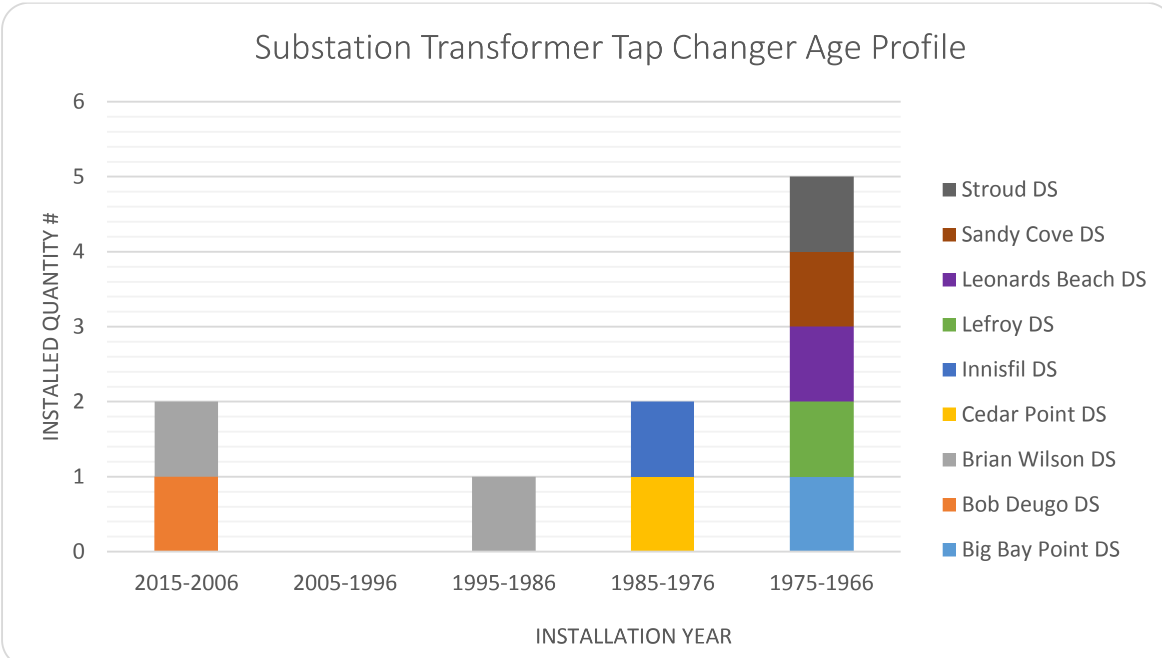

Figure 3 Substation Transformer Tap Changer Age Profile

Table 23 Substation Transformer Tap Changer Details

Transformer Tap Changer Demographics				
Substation	**Location ID**	**Manufacturer**	**Year of Manufacture**	**HI Score**
Big Bay Point DS	22T1-TC	Ferranti Packard	1971	82
Bob Deugo DS	TC	Northern TX	2006	100
Brian Wilson DS	T1TC	Federal Pioneer	1991	88
Brian Wilson DS	T2TC	Virginia TX	2014	100
Cedar Point DS	T1-TC	Federal Pioneer	1976	82
Innisfil DS	31T1-TC	Federal Pioneer	1976	50
Lefroy DS	55T1-TC	Ferranti Packard	1970	82
Leonards Beach DS	41T1-TC	Ferranti Packard	1974	82
Sandy Cove DS	A8T1-TC	Ferranti Packard	1975	82
Stroud DS	50T1-TC	Westinghouse	1969	74

3.3.2.3 Substation Reclosers

Figure 4 represents the age profile of substation reclosers employed at different substations of InnPower. It can be observed that over 60% of the reclosers are quite new and only 5 reclosers have reached 40 or more years of service. These are installed at Stroud DS and Sandy Cove DS.

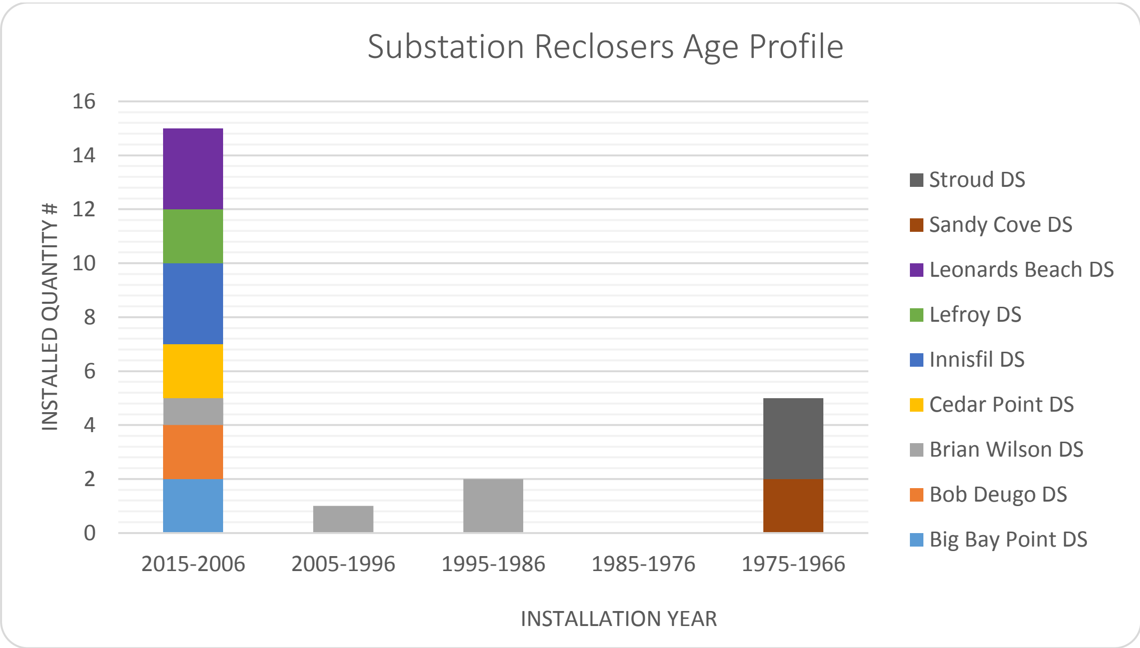

Figure 4 Substation Reclosers Age Profile

Table 24 gives in detail the information on rating and in-service dates of all the substation reclosers.

Table 24 Substation Recloser Details

Recloser Demographics				
Substation	**Location ID**	**Manufacturer**	**Year of Manufacture**	**HI Score**
Big Bay Point DS	22F1	G&W	2014	100
Big Bay Point DS	22F2	G&W	2014	100
Bob Deugo DS	F1-R	G&W	2006	100
Bob Deugo DS	F2-R	G&W	2006	100
Brian Wilson DS	F1-OCR	Cooper	1991	77
Brian Wilson DS	F2-OCR	Cooper	1991	77
Brian Wilson DS	F3-OCR	G&W	2013	100
Brian Wilson DS	F4-OCR	Cooper	2003	84
Cedar Point DS	F1	G&W	2013	100
Cedar Point DS	F2	G&W	2013	100
Innisfil DS	31F1	G&W	2013	100
Innisfil DS	31F2	G&W	2013	100
Innisfil DS	31F3	G&W	2013	100
Lefroy DS	55F1	G&W	2015	100
Lefroy DS	55F2	G&W	2015	100
Leonards Beach DS	41F1	G&W	2011	100
Leonards Beach DS	41F2	G&W	2011	100
Leonards Beach DS	41F3	G&W	2011	100
Sandy Cove DS	A8F1	McGraw Edison	1975	52
Sandy Cove DS	A8F3	McGraw Edison	1975	52
Stroud DS	50F1	McGraw Edison	1969	36
Stroud DS	50F2	McGraw Edison	1969	36
Stroud DS	50F3	McGraw Edison	1969	36

3.3.3 HI Score

3.3.3.1 Substation Transformers

Based on the condition assessment criteria described in Section 3, Health Index score is calculated for each substation transformer. The results are summarized in **Figure 5**.

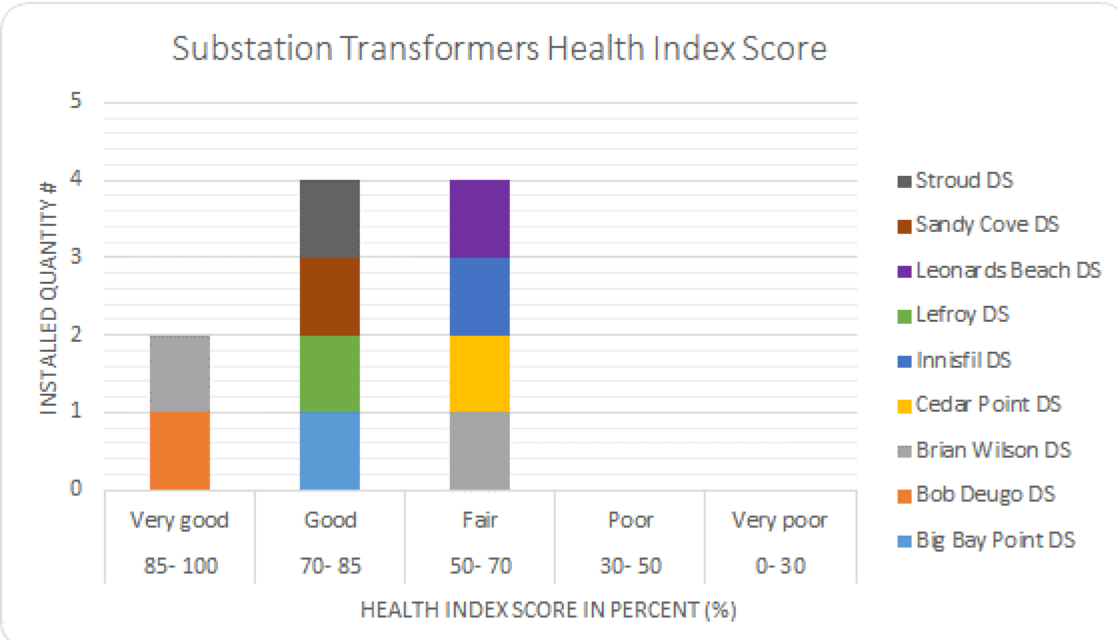

Figure 5 Substation Transformers Health Index Score

Four of the power transformers are determined to be in fair condition, based on the health index score. These are Brian Wilson DS-T1, Cedar Point DS, Innisfil DS, and Leonards Beach DS, with the latter two ranked at the boundary between good and fair. Although it can be seen that the transformers at Stroud DS, Sandy Cove DS, Lefroy DS, and Big Bay Point DS are currently in good condition, they are aging and are likely to degrade to worse condition in the next five to ten years. Brian Wilson DS-T2 and Bob Deugo DS were both assessed to be in very good condition.

3.3.3.2 Transformer Tap Changers

Based on the condition assessment criteria described in Section 3, Health Index score is calculated for each substation transformer tap changer. The results are summarized in **Figure 6**.

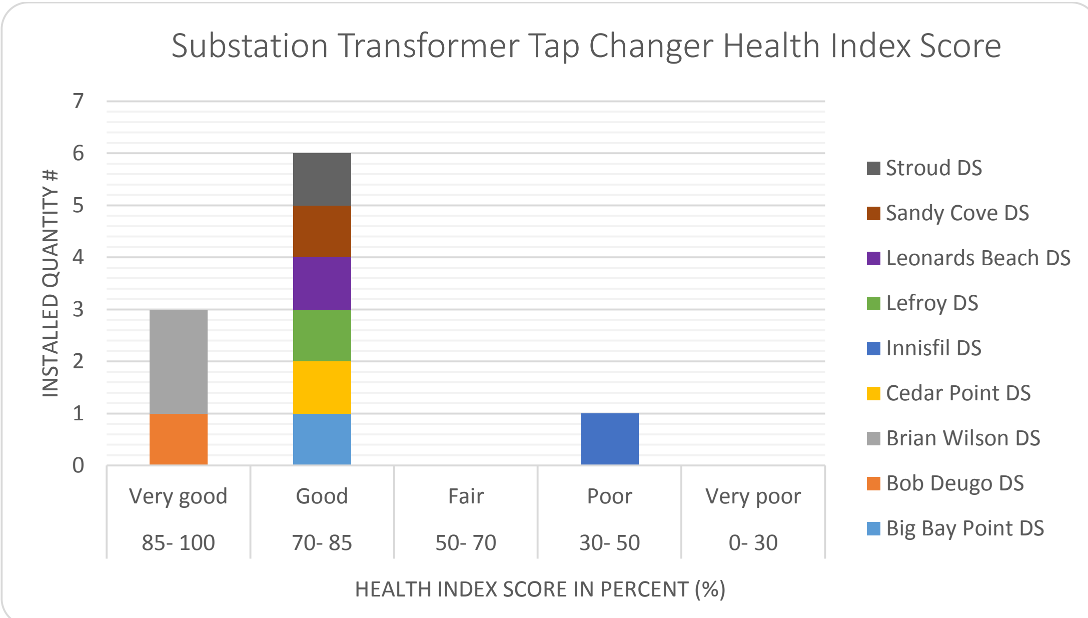

Figure 6 Substation Transformer Tap Changers Health Index Score

One of the tap changers, installed at Innisfil DS, is determined to be in poor condition, based on the health index score. Given the age of this tap changer, it will most likely degrade to poorer condition in the coming three to five years. Although it can be seen that other transformer tap changers, located at Stroud DS, Sandy Cove DS, Leonards Beach DS, Lefroy DS, and Big Bay Point DS, are currently in good condition, they have already passed the typical technical life and are likely to degrade to worse condition in the next five to ten years.

3.3.3.3 Substation Reclosers

Based on the condition assessment criteria described in Section 3, Health Index score is calculated for each substation recloser. The results are summarized in **Figure 7**.

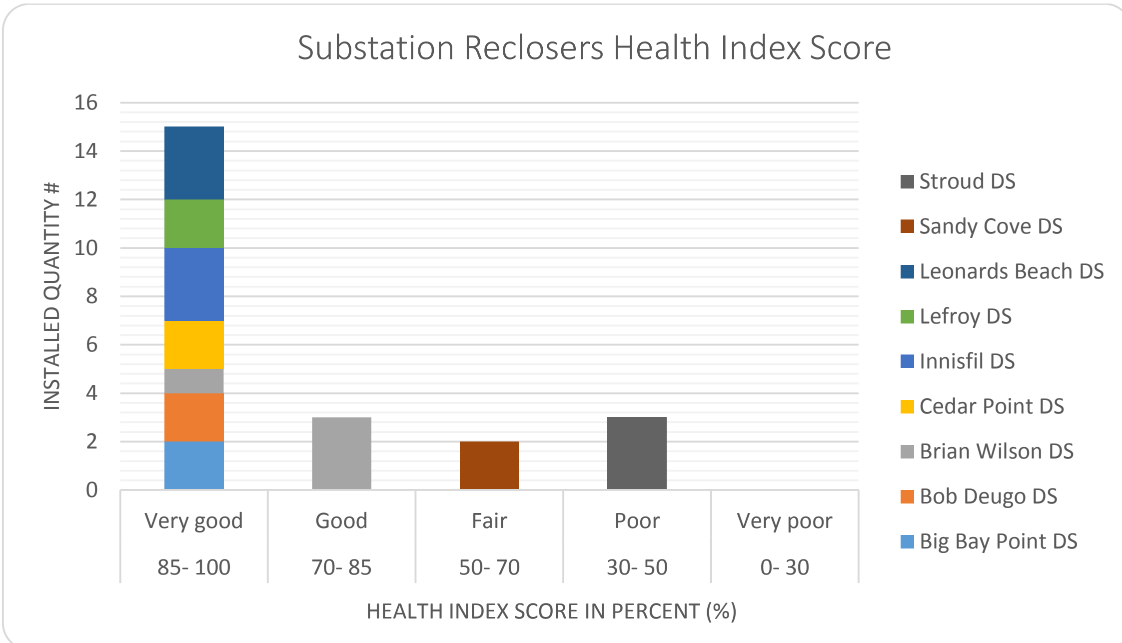

Figure 7 Substation Reclosers Health Index Score

As noted from the demographics analysis, over 60% of the reclosers are quite new, hence receiving a very good overall condition rating. Out of the 5 aged reclosers, 3 installed at Stroud DS are evaluated to be poor with a health index score of 36. The other 2 at Sandy Cove DS, are determined to be in fair-poor condition with a health index score of 52.

3.3.3.4 Substation Fences

Based on the condition assessment criteria defined in Section 3, the Health Index score as summarized in **Figure 8**, is calculated for substation fences. It is found that all the substation fences are in very good condition, except Innisfil DS.

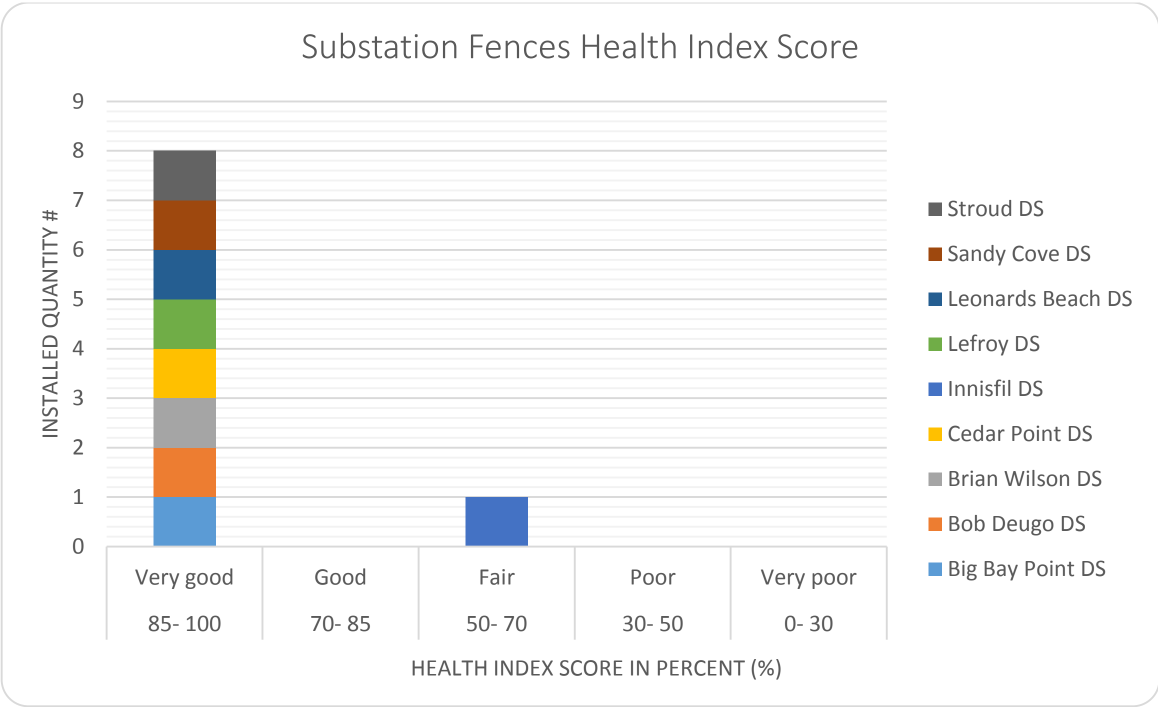

Figure 8 Substation Fences Health Index Score

3.3.3.5 Substation Ground Grids

Based on the information of installation year, grounding test report, and condition of the surface stone, the Health Index score is calculated for the ground grids, summarized in **Figure 9**.

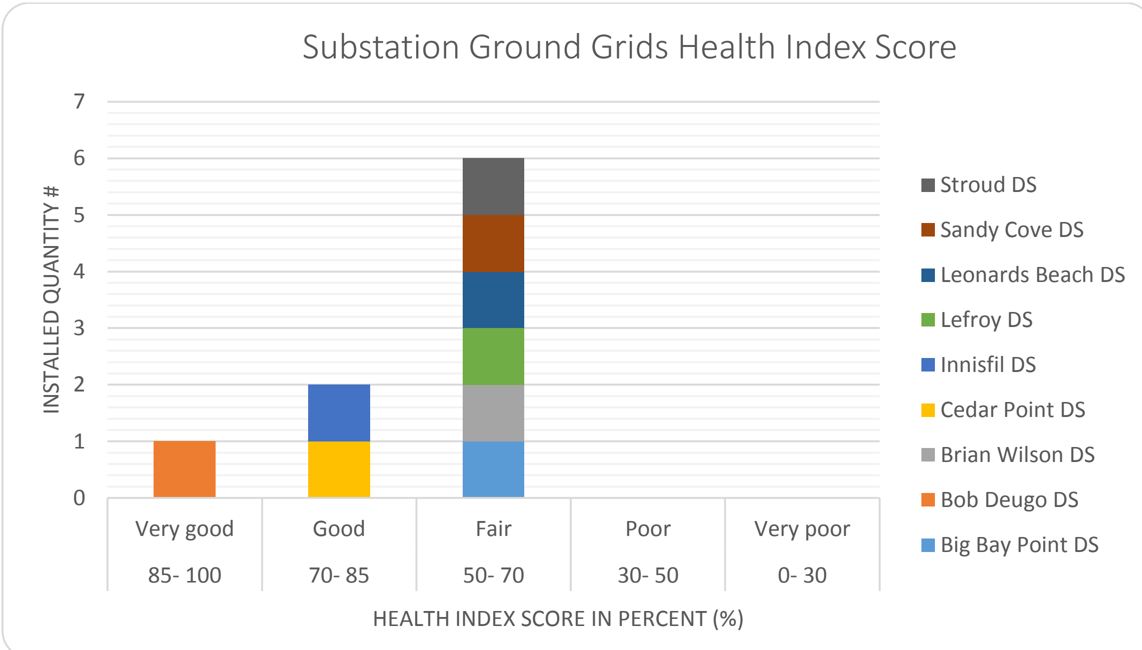

Figure 9 Substation Ground Grids Health Index Score

It is observed that ground grids for substations Bob Deugo DS, Cedar Point DS, and Innisfil DS are determined to be in very good or good condition. With the substations aging and gravel having sunk into the earth below, the rest are all in fair condition.

3.3.3.6 44-kV Transrupters

InnPower owns one 44-kV Transrupter at its Bob Deugo DS (T1-L,B,A). It was installed in 2006 and assessed to be in very good condition.

3.3.4 Predicting Asset Future Condition

From the calculated health indices, we can estimate the probability of failure and predict equipment end-of-life. For a given asset class, the probability of failure is a function of age and condition as defined by health index. Usually, numerical representation of probability of failure, hazard rate functions, is used to quantify risks for economic life calculation. For the purpose of this report, the prediction of assets' end of life is heavily based upon health index scores and typical useful life of each critical asset class. The health index scores are obtained from section 3.3.3. **Table 25** gives the typical useful life (TUL) values, attained from Kinectrics' report on "Asset Depreciation Study for the Ontario Energy Board".

Table 25 Typical Useful Life (TUL) for Tier 1 Assets

(From Kinectrics Report)			
Asset Class	**Min UL**	**TUL**	**Max UL**
Substation Transformers	*30*	***45***	*60*
Transformer Tap Changers	*20*	***30***	*60*
Substation Reclosers	*25*	***40***	*55*

3.3.4.1 Substation Transformers

As seen from **Table 26**, although transformers at Lefroy DS and Stroud DS received a health index score of 78, they have aged and passed the typical useful life of a power transformer. The future condition of these two transformers are very likely to degrade to a poorer condition. Also, transformers installed at Big Bay Point DS, Leonards Beach DS, and Sandy Cove DS have reached 40 years of service and are also approaching TUL. All of the aforementioned transformers can be considered for replacement in the next three to five years. If not replaced, monitoring, diagnostic testing, and close examination should be performed more frequently.

Table 26 Asset Useful Life Details – Substation Transformers

Asset Class	Asset Designation	Asset Age	Health Index	Exceeds TUL?
Substation Transformers TUL: 45 years	Big Bay Point DS-22T1	44	78	N
	Bob Deugo DS-T1	9	96	N
	Brian Wilson DS-T1	24	60	N
	Brian Wilson DS-T2	1	100	N
	Cedar Point DS-T1	39	66	N
	Innisfil DS-31T1	39	70	N
	Lefroy DS-55T1	45	78	**Y**
	Leonards Beach DS-41T1	41	70	N
	Sandy Cove DS-A8T1	40	78	N
	Stroud DS-50T1	46	78	**Y**

3.3.4.2 Transformer Tap Changers

As indicated in **Table 27**, the transformer tap changer at Innisfil DS received a health index score of 50. Since this tap changer has already passed the TUL and the probability of it failing would be much higher than that of a tap changer at mean life, it can be expected to deteriorate to a poorer condition in the next three years. Although it can be seen that other transformer tap changers, located at Big Bay Point DS, Cedar Point DS, Lefroy DS, Leonards Beach DS, Sandy Cove DS, and Stroud DS, are currently in good condition, they have already passed the TUL and are likely to degrade to worse condition in the next five to ten years. Hence it is recommended that they are included in the capital replacement plan.

Table 27 Asset Useful Life Details – Substation Transformer Tap Changers

Asset Class	Asset Designation	Asset Age	Health Index	Exceeds TUL?
Transformer Tap Changers TUL: 30 years	Big Bay Point DS-22T1-TC	44	82	**Y**
	Bob Deugo DS-TC	9	100	N
	Brian Wilson DS-T1TC	24	88	N
	Brian Wilson DS-T2TC	1	100	N
	Cedar Point DS-T1-TC	39	82	**Y**
	Innisfil DS-31T1-TC	39	50	**Y**
	Lefroy DS-55T1-TC	45	82	**Y**
	Leonards Beach DS-41T1-TC	41	82	**Y**
	Sandy Cove DS-A8T1-TC	40	82	**Y**
	Stroud DS-50T1-TC	46	74	**Y**

Substation Reclosers

As seen in **Table 28**, 3 aged reclosers installed at Stroud DS are in poor condition with a health index score of 36. They are recommended to be replaced in the next three to five years. The other 2 old oil reclosers at Sandy Cove DS received a health index score of 52. These reclosers have already reached or passed the TUL and are also recommended for replacement. The probability of these reclosers failing would be higher than that of a recloser at mean life and will be increasing over time. If not replaced, the future condition of these assets would be expected to rapidly deteriorate in the next five to ten years, imposing reliability risks on the distribution system.

Table 28 Asset Useful Life Details – Substation Reclosers

Asset Class	Asset Designation	Asset Age	Health Index	Exceeds TUL?
Substation Reclosers TUL: 40 years	Big Bay Point DS-22F1	1	100	N
	Big Bay Point DS-22F2	1	100	N
	Bob Deugo DS-F1-R	9	100	N
	Bob Deugo DS-F2-R	9	100	N
	Brian Wilson DS-F1-OCR	24	77	N
	Brian Wilson DS-F2-OCR	24	77	N
	Brian Wilson DS-F3-OCR	2	100	N
	Brian Wilson DS-F4-OCR	12	84	N
	Cedar Point DS-F1	2	100	N
	Cedar Point DS-F2	2	100	N
	Innisfil DS-31F1	2	100	N
	Innisfil DS-31F2	2	100	N
	Innisfil DS-31F3	2	100	N
	Lefroy DS-55F1	1	100	N
	Lefroy DS-55F2	1	100	N
	Leonards Beach DS-41F1	4	100	N
	Leonards Beach DS-41F2	4	100	N
	Leonards Beach DS-41F3	4	100	N
	Sandy Cove DS-A8F1	40	52	**Y**
	Sandy Cove DS-A8F3	40	52	**Y**
	Stroud DS-50F1	46	36	**Y**
	Stroud DS-50F2	46	36	**Y**
	Stroud DS-50F3	46	36	**Y**

3.3.5 Maintenance Assessment (and Testing Results)

The maintenance assessment in this report was performed to evaluate the condition of all major assets employed at InnPower's substations and to detect any issues that could potentially affect system performance or reliability. The scope of this maintenance program spans over visual inspection of site, gates, encroachments, yard, station building, cables, electrical structures, as well as electrical equipment. The inspection and condition forms employed by METSCO is provided in Appendix B as a separate attachment.

From METSCO's inspection, the overall condition of InnPower's substations was determined to be good with some concerns that should be addressed, which will be discussed in details in Section 5. Some of the general findings are described below:

1. Rust on the exterior of substation equipment and structures.
2. Wood pole installed close to the steel lattice structure could be a fire hazard that compromises the reliability of supply.
3. There is no arrangement of oil containment for transformer foundations (except for Bob Deugo DS).
4. Cables not supported by the structure and cable ducts not properly sealed.
5. Vegetation present in the yard.

4 Grounding System Assessment

The grounding assessment was performed for eight substations: the nine within the scope of the Asset Condition Assessment, excluding Bob Deugo DS. The detailed results of the grounding system analysis have not been included in the main body of this Asset Condition Assessment for brevity, but is attached as Appendix C – Station Grounding Assessment. The general recommendations of the grounding assessment are summarized in Section 6 of this report.

5 Station by Station Condition Report

The methodology described in detail in section 3 provides means of accurate and comprehensive condition assessment of all major assets employed in InnPower's substations.

In this section, METSCO has completed the condition assessment of the assets by taking into account all of the available information and asset condition specific data. It is recommended that complete data required for condition assessment of the assets, as described in detail Section 3 is not currently available, should be collected in the future for allocating capital investments into those assets that are at the highest risk of in-service failures.

This section of the report, essentially, provides an overview of assets conditions evaluated based on the demographic information and testing results provided by InnPower and METSCO's station inspection and grounding assessment. The condition of InnPower's substations is summarized into the following subsections where each section contains the condition assessment of assets at each substation. The overall condition of InnPower's substations is good and its system design is mostly compliant with industry accepted standards, with some concerns denoted in each subsection. **Table 29** provides a snapshot into the condition of major assets employed in each substation.

Table 29 Tier 1 Assets Health Index Score Overview by Station

	Substation Summary Table								
Substation	HI Score								
	Transformer		Tap Changer		Recloser		Fence	Ground Grid	44-kV Transrupter
Big Bay Point DS	22T1	78	22T1-TC	82	All	100	100	60	
Bob Deugo DS	T1	96	TC	100	All	100	100	100	100
Brian Wilson DS	T1	60	T1TC	88	F1-OCR, F2-OCR	77	100	68	
	T2	100	T2TC	100	F3-OCR	100			
					F4-OCR	84			
Cedar Point DS	T1	66	T1-TC	82	All	100	100	76	
Innisfil DS	31T1	70	31T1-TC	50	All	100	60	76	
Lefroy DS	55T1	78	55T1-TC	82	All	100	100	68	
Leonards Beach DS	41T1	70	41T1-TC	82	All	100	100	68	
Sandy Cove DS	A8T1	78	A8T1-TC	82	All	52	100	60	
Stroud DS	50T1	78	50T1-TC	74	All	36	100	52	

5.1 Big Bay Point DS

5.1.1 Health Index and Condition of Tier 1 Assets – Major assets in substations

Based on the condition assessment criteria described in Section 3, Health Index score is calculated for each transformer, tap changer, recloser, fences, and ground grids at this substation. The results are summarized in **Figure 10**.

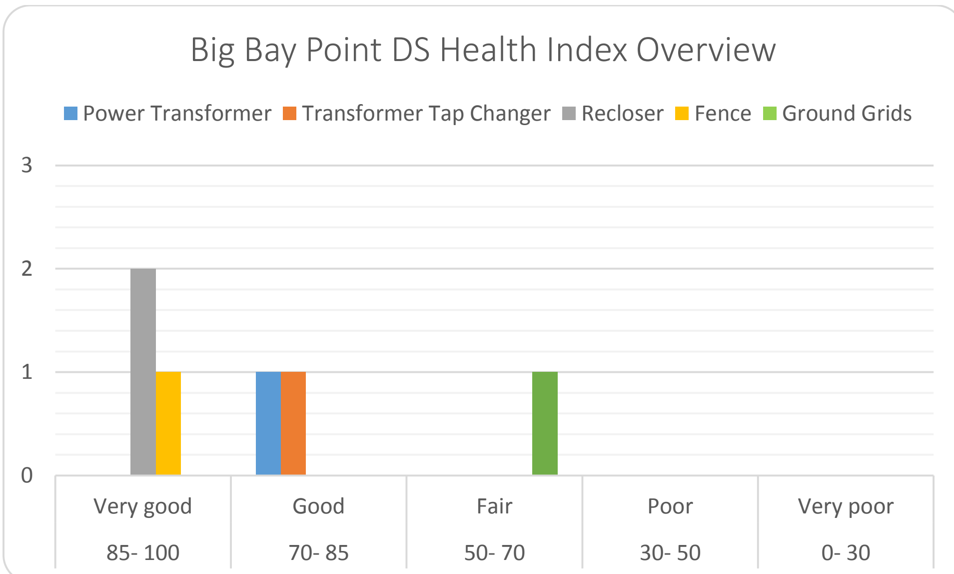

Figure 10 Big Bay Point DS – Tier 1 Asset Health Index Score

All the major assets are found to be in either very good or good condition except for ground grids. The aging station, along with the degradation of surface stones, is the primary reason behind the relatively low ground grids health index score. It should also be noted that both the transformer and tap changer has reached 44 years of service. Given the fact that typical life of a tap changer is 30 years, the tap changer at Big Bay Point has already passed its useful life and is likely to degrade to worse conditions in the next five to ten years.

5.1.2 Condition of Tier 2 Assets

With the available information, all Tier 2 assets are determined to be in good condition as there are no issues noted from visual inspections, nor are concerns reflected from IR scan reports and maintenance records.

Table 30 gives in detail the information on rating and comments on all the equipment. If there were no issues detected, a rating of Class A is given to the asset. If there were minor issues, the asset is rated in C. Rating E is assigned to the asset when there is serious deficiency.

Table 30 Big Bay Point DS – Tier 2 Asset Condition Details

Big Bay Point DS - Tier 2 Asset Condition Table					
Substation	**Location ID**	**Asset Class**	**Visual Inspection**	**IR Scan**	**Equipment Test/Maintenance Records**
Big Bay Point DS	22T1L-X	Fuse	A	Unknown	Maintenance Records Unavailable
Big Bay Point DS	T1LA1	Lightning Arrestor	A	A	Maintenance Records Unavailable
Big Bay Point DS	T1LA2	Lightning Arrestor	A	A	Maintenance Records Unavailable
Big Bay Point DS	SS PT	Service Transformer	A	Unknown	Maintenance Records Unavailable
Big Bay Point DS	22T1-L	Switch	A	Unknown	Within Station Maintenance Report
Big Bay Point DS	T1-B	Switch	A	Unknown	Within Station Maintenance Report

5.1.3 Condition of Structural Equipment

The condition of structural equipment at Big Bay Point DS was evaluated from the following categories:

Structure

There are no issues detected for the steel lattice and structural equipment. For transformer foundation, there is no arrangement for oil containment, which could potentially impact the environment.

Fence/Gate

There is no gravel outside of the station. The minimal width of specified surface stone should be 1500 mm on each side of the fence. This not only allows an acceptable range of touch potentials but also controls vegetation that could hinder the reliable operation of InnPower's electricity distribution system.

Site grading

The yard needs regrading. There is also vegetation and heaps of dry leaves present in the yard.

5.1.4 Identification of Risks and Hazards

There are underlying safety, reliability, and environmental concerns associated with the current condition of Big Bay Point DS. The safety concerns are embedded in the fact that power cables and control cables are hanging freely and not properly supported. The unattended dry leaves as well as the wood pole in the yard are also safety hazards that could potentially cause fire. In an unplanned incident where the wood pole catches fire due to a direct lightning stroke, the debris could be in contact with the steel lattice and other structural equipment, thereby compromising the reliability. In addition, the fact that transformer has no oil containment raises environmental concerns in the station.

5.2 Bob Deugo DS

5.2.1 Health Index and Condition of Tier 1 Assets – Major assets in substations

Based on the condition assessment criteria described in Section 3, Health Index score is calculated for each transformer, tap changer, recloser, fences, and ground grids at this substation. The results are summarized in **Figure 11**.

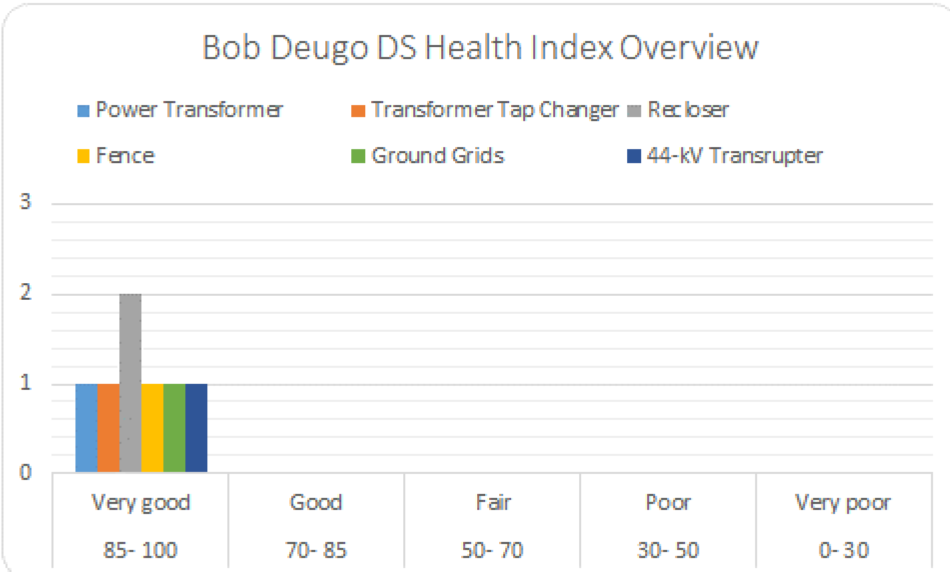

Figure 11 Bob Deugo DS – Tier 1 Asset Health Index Score

Bod Deugo DS is a relatively new substation with all the equipment installed in 2006. From the condition assessment, all the major assets are found to be in very good condition. However, it should be noted that there is some minor rust on the transformer's foundation, termination box, and fins. The water collected under the transformer could also deteriorate the rusting condition in the future.

5.2.2 Condition of Tier 2 Assets

With the available information, all Tier 2 assets are determined to be in good condition as there are no issues noted from visual inspections, nor are concerns reflected from IR scan reports and maintenance records.

Table 31 gives in detail the information on rating and comments on all the equipment. If there were no issues detected, a rating of Class A is given to the asset. If there were minor issues, the asset is rated in C. Rating E is assigned to the asset when there is serious deficiency.

Table 31 Bob Deugo DS – Tier 2 Asset Condition Details

Bob Deugo DS - Tier 2 Asset Condition Table					
Substation	**Location ID**	**Asset Class**	**Visual Inspection**	**IR Scan**	**Equipment Test/Maintenance Records**
Bob Deugo DS	LA	Lightning Arrestor	A	Unknown	A
Bob Deugo DS	SS-L1	Service Transformer	A	Unknown	Unknown
Bob Deugo DS	T1-L	Switch	A	Unknown	A
Bob Deugo DS	T1-B	Switch	A	Unknown	A
Bob Deugo DS	T1-A	Switch	A	Unknown	Unknown

5.2.3 Condition of Structural Equipment

The condition of structural equipment at Bob Deugo DS was evaluated from the following categories:

Structure

There are no issues detected for the steel lattice and structural equipment. Bob Deugo DS has oil containment.

Fence/Gate

There are no issues detected.

Site grading

There is vegetation and dry leaves present along the fence.

5.2.4 Identification of Risks and Hazards

There are underlying safety and environmental concerns associated with the current condition of Bob Deugo DS. The safety concerns are embedded in the fact that cable ducts are not properly sealed. The unattended dry leaves in the yard is also safety hazard that could potentially cause fire.

5.3 Brian Wilson DS

5.3.1 Health Index and Condition of Tier 1 Assets – Major assets in substations

Based on the condition assessment criteria described in Section 3, Health Index score is calculated for each transformer, tap changer, recloser, fences, and ground grids at this substation. The results are summarized in **Figure 12**.

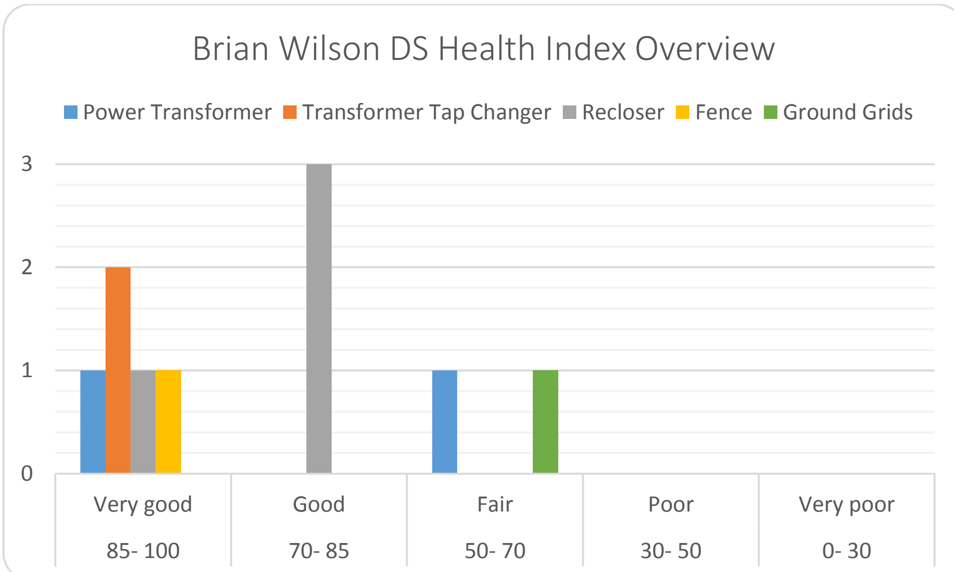

Figure 12 Brian Wilson DS – Tier 1 Asset Health Index Score

All the major assets are found to be in either very good or good condition except T1 transformer and ground grids at the station. This transformer received a fair condition from the assessment. Although there are no hot spots discovered from the infrared scanning, the DGA testing showed poor results for this transformer. Visual inspection performed by METSCO also determined that this transformer is rusting and requires repainting. The grounding assessment performed by METSCO determined that the resistivity of surface stones was significantly less than the safe limit and there were signs of vegetation growth. The poor condition of surface stones contributed to the overall fair condition of the ground grids at this station.

5.3.2 Condition of Tier 2 Assets

With the available information, all Tier 2 assets are determined to be in good condition as there are no issues noted from visual inspections, nor are concerns reflected from IR scan reports and maintenance records.

Table 32 gives in detail the information on rating and comments on all the equipment. If there were no issues detected, a rating of Class A is given to the asset. If there were minor issues, the asset is rated in C. Rating E is assigned to the asset when there is serious deficiency.

Table 32 Brian Wilson DS – Tier 2 Asset Condition Details

Brian Wilson DS - Tier 2 Asset Condition Table					
Substation	**Location ID**	**Asset Class**	**Visual Inspection**	**IR Scan**	**Equipment Test/Maintenance Records**
Brian Wilson DS	T1-X	Fuse	A	A	A
Brian Wilson DS	T2-X	Fuse	A	Unknown	Unknown
Brian Wilson DS	LA-1	Lightning Arrestor	A	A	A
Brian Wilson DS	LA-2	Lightning Arrestor	A	A	A
Brian Wilson DS	LA-3	Lightning Arrestor	A	Unknown	Maintenance Records Unavailable
Brian Wilson DS	LA-4	Lightning Arrestor	A	Unknown	Maintenance Records Unavailable
Brian Wilson DS		Service Transformer	A	Unknown	A
Brian Wilson DS		Service Transformer	A	Unknown	Maintenance Records Unavailable
Brian Wilson DS	T1-L	Switch	A	A	A
Brian Wilson DS	B1-B2	Switch	A	Unknown	A
Brian Wilson DS	T2-L	Switch	A	Unknown	Maintenance Records Unavailable

From visual inspections, rust was observed on the station service transformers, hence requires repainting. It should also be noted that all the insulators at Brian Wilson DS are made from porcelain and might have hidden defects, which may result in cascading failure that compromises the reliability of electricity supply.

5.3.3 Condition of Structural Equipment

The condition of structural equipment at Brian Wilson DS was evaluated from the following categories:

Structure

There are no issues detected for the steel lattice and structural equipment. For transformer foundation, there is no arrangement for oil containment, which could potentially impact the environment.

Fence/Gate

There is vegetation on the fences.

Site grading

Vegetation is present all over the yard. There is no proper drainage in the yard.

5.3.4 Identification of Risks and Hazards

There are underlying safety, reliability, and environmental concerns associated with the current condition of Brian Wilson DS. The safety concerns are embedded in the fact that power cables and control cables are not properly supported and ducts are unsealed. The large stones in the yard could also be a tripping hazard. Moreover, the substandard wood pole in the yard, which was installed to support bus tie disconnect switch, is a safety hazard that could potentially cause fire. In an unplanned incident where the wood pole catches fire due to a direct lightning stroke, the debris could be in contact with the steel lattice and other structural equipment, thereby compromising the reliability. In addition, the fact that transformer has no oil containment raises environmental concerns in the station.

Some other concerns include:

- Birds nest and wasp nests on the structures or the control cables of equipment: These should be removed to mitigate the probability of birds' population being multiplied in the substation or crews getting injured from the insects.
- Spare equipment is currently sitting in the yard. It should be properly stored to prevent static charge build-up.

5.4 Cedar Point DS

5.4.1 Health Index and Condition of Tier 1 Assets – Major assets in substations

Based on the condition assessment criteria described in Section 3, Health Index score is calculated for each transformer, tap changer, recloser, fences, and ground grids at this substation. The results are summarized in **Figure 13**.

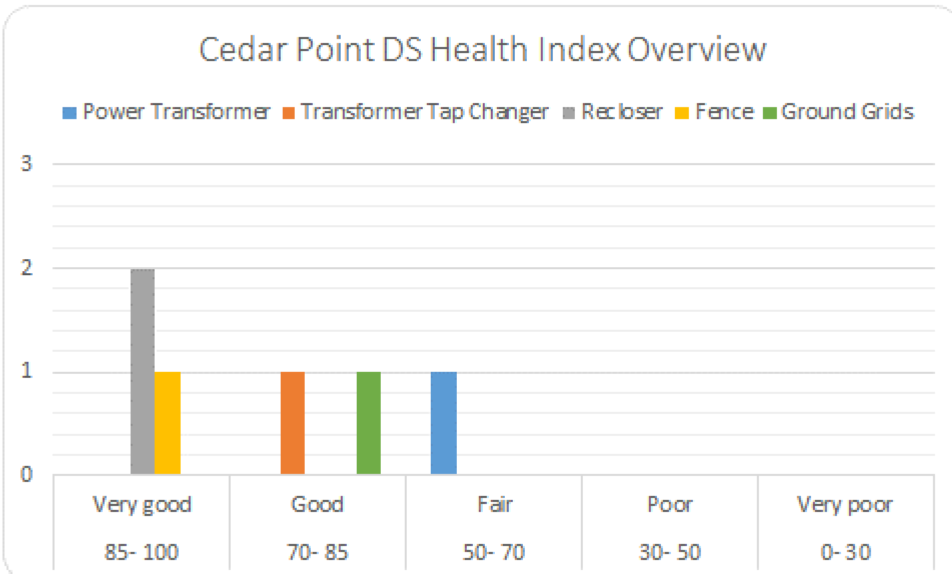

Figure 13 Cedar Point DS – Tier 1 Asset Health Index Score

Only the power transformer was found to be in fair condition, due to a high temperature rise found during the infrared scan of a bushing. It should also be noted that both the transformer and tap changer have reached 39 years of service. Given the fact that typical life of a tap changer is 30 years, the tap changer at Cedar Point has already passed its useful life and is likely to degrade to worse conditions in the next five to ten years.

5.4.2 Condition of Tier 2 Assets

With the available information, ratings are assigned according to visual inspections, IR scan reports and maintenance records. All Tier 2 assets are determined to be in good condition.

Table 33 gives in detail the information on rating and comments on all the equipment. If there were no issues detected, a rating of Class A is given to the asset. If there were minor issues, the asset is rated in C. Rating E is assigned to the asset when there is serious deficiency.

Table 33 Cedar Point DS – Tier 2 Asset Condition Details

Cedar Point DS - Tier 2 Asset Condition Table					
Substation	**Location ID**	**Asset Class**	**Visual Inspection**	**IR Scan**	**Equipment Test/Maintenance Records**
Cedar Point DS	T1-LX	Fuse	A	Unknown	A
Cedar Point DS	T1SA1	Lightning Arrestor	A	A	A
Cedar Point DS	T1SA2	Lightning Arrestor	A	A	Unknown
Cedar Point DS	SS1	Service Transformer	A	Unknown	A
Cedar Point DS	T1-L	Switch	A	Unknown	A
Cedar Point DS	T1-B	Switch	A	Unknown	Unknown

5.4.3 Condition of Structural Equipment

The condition of structural equipment at Cedar Point DS was evaluated from the following categories:

Structure

There are no issues detected for the steel lattice and structural equipment. For transformer foundation, there is no arrangement for oil containment, which could potentially impact the environment.

Fence/Gate

There is no gravel outside of the station. The minimal width of specified surface stone should be 1500 mm on each side of the fence. This not only allows an acceptable range of touch potentials but also controls vegetation that could hinder the reliable operation of InnPower's electricity distribution system.

Site grading

There are no concerning issues.

5.4.4 Identification of Risks and Hazards

There are underlying safety, reliability, and environmental concerns associated with the current condition of Cedar Point DS. The safety concerns are embedded in the fact that control cables and grounding cable are hanging freely and not properly supported. In addition, the fact that transformer has no oil containment raises environmental concerns in the station. And oil leakage was already observed from the transformer tap changer.

Some other concerns include:

- Birds nest and wasp nests on the supporting structure of station service transformer and disconnect switches: These should be removed to mitigate the probability of birds' population being multiplied in the substation or crews getting injured from the insects.
- Spare equipment is currently sitting in the yard. It should be properly stored to prevent static charge build-up.

5.5 Innisfil DS

5.5.1 Health Index and Condition of Tier 1 Assets – Major assets in substations

Based on the condition assessment criteria described in Section 3, Health Index score is calculated for each transformer, tap changer, recloser, fences, and ground grids at this substation. The results are summarized in **Figure 14**.

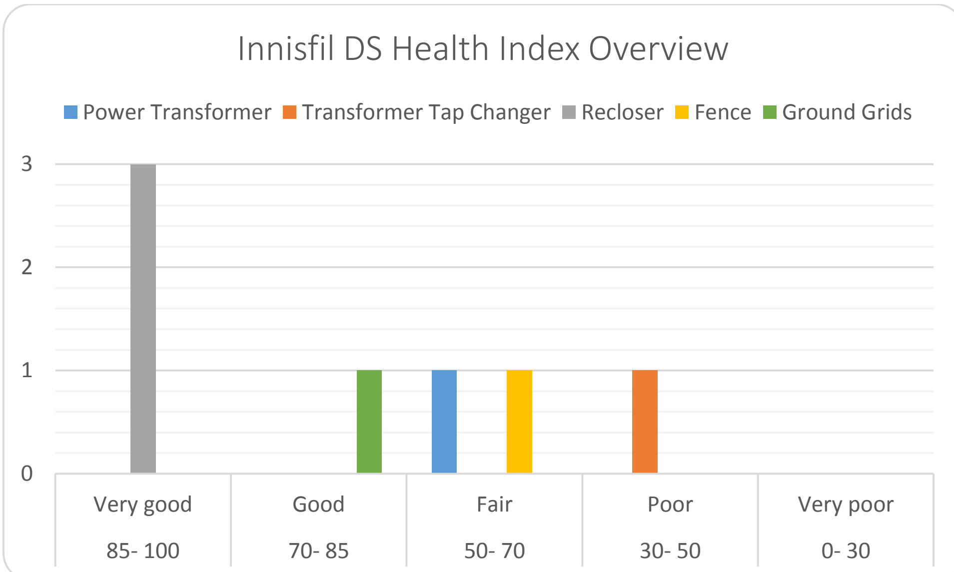

Figure 14 Innisfil DS – Tier 1 Asset Health Index Score

All the major assets are found to be in fair-poor condition except ground grids and the recently replaced reclosers. The fences have been degraded such that it is bending over in one spot. Also, the bottom of the fence is supressed by the wood pole installed behind the substation. With a low height, this fence is recommended to be rebuilt. The transformer received a fair rating whereas the tap changer was determined to be in poor condition. They both have reached 39 years of service. Given the fact that typical life of a tap changer is 30 years, the tap changer at Innisfil DS has already passed its useful life. And since it is already in poor condition, it will much likely degrade to very poor conditions in the next three to five years.

5.5.2 Condition of Tier 2 Assets

With the available information, ratings are assigned according to visual inspections, IR scan reports and maintenance records. All Tier 2 assets are determined to be in good condition except the primary switch and fuse, highlighted in red. These 2 assets were given a rating C due to severe rusting on the operating handles and rods, as discovered from the visual inspection.

Table 34 gives in detail the information on rating and comments on all the equipment. If there were no issues detected, a rating of Class A is given to the asset. If there were minor issues, the asset is rated in C. Rating E is assigned to the asset when there is serious deficiency.

Table 34 Innisfil DS – Tier 2 Asset Condition Details

Innisfil DS - Tier 2 Asset Condition Table					
Substation	**Location ID**	**Asset Class**	**Visual Inspection**	**IR Scan**	**Equipment Test/Maintenance Records**
Innisfil DS	31T1L-X	Fuse	C	Unknown	A
Innisfil DS	T1-LA	Lightning Arrestor	A	A	A
Innisfil DS	F1LA	Lightning Arrestor	A	Unknown	Unknown
Innisfil DS	F2LA	Lightning Arrestor	A	Unknown	Unknown
Innisfil DS	F3LA	Lightning Arrestor	A	Unknown	Unknown
Innisfil DS	T1PT	Service Transformer	A	Unknown	A
Innisfil DS	31T1-L	Switch	C	Unknown	A

5.5.3 Condition of Structural Equipment

The condition of structural equipment at Innisfil DS was evaluated from the following categories:

Structure

The foundations of steel lattice and structural equipment are cracked and require immediate remediation. Jumpers from Vipers to the bus bars do not have proper supports. Under high wind and snow conditions high stress could be exerted on the terminations of Vipers. The foundation of the transformer has sunk to a very low level and cracked along the length of transformer. Also, there is no arrangement for oil containment, which could potentially impact the environment.

Fence/Gate

There is no gravel outside of the station. The minimal width of specified surface stone should be 1500 mm on each side of the fence. This not only allows an acceptable range of touch potentials but also controls vegetation that could hinder the reliable operation of InnPower's electricity distribution system.

Site grading

There is vegetation and dry leaves both around the fence and in the yard.

5.5.4 Identification of Risks and Hazards

There are underlying safety, reliability, and environmental concerns associated with the current condition of Innisfil DS. The safety concerns are embedded in the fact that power cables and control cables are not properly supported and cable ducts are unsealed. The unattended dry leaves is a safety hazard that could potentially cause fire. In addition, the fact that transformer has no oil containment and oil leakage was observed from the oil sampling valve raises environmental concerns in the station.

Some other concerns include:

- Wasp nests on the supporting structure of station service transformer and disconnect switches: These should be removed to mitigate the probability of crews getting injured from the insects.
- Dead birds are rotting under the steel lattice in the yard: These should be immediately removed to prevent propagating health issues for the crews.

5.6 Lefroy DS

5.6.1 Health Index and Condition of Tier 1 Assets – Major assets in substations

Based on the condition assessment criteria described in Section 3, Health Index score is calculated for each transformer, tap changer, recloser, fences, and ground grids at this substation. The results are summarized in **Figure 15**.

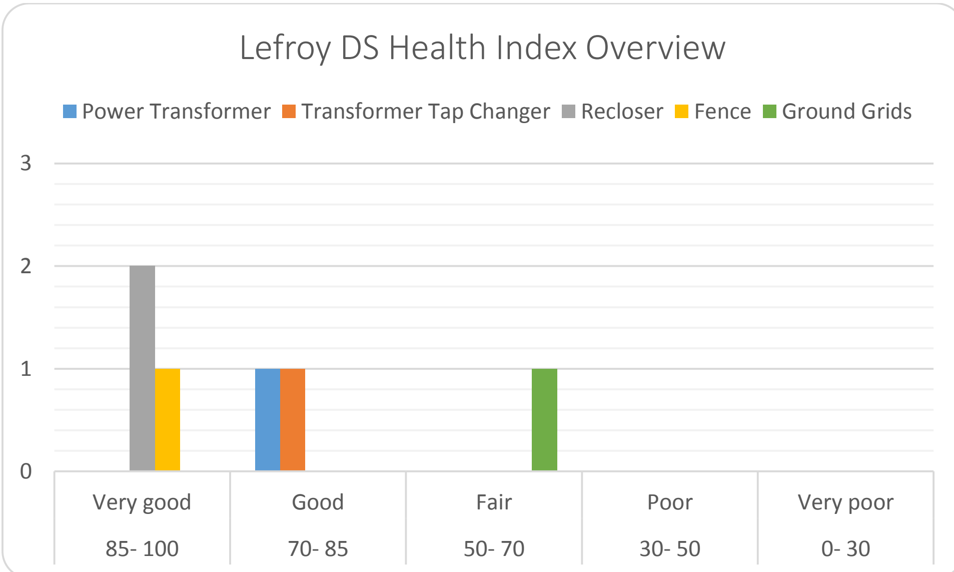

Figure 15 Lefroy DS – Tier 1 Asset Health Index Score

All the major assets are found to be in either very good or good condition except for ground grids. The aging station, along with the degradation of surface stones, is the primary reason behind the relatively low ground grids health index score. It should also be noted that both the transformer and tap changer has reached 45 years of service. Given the fact that typical life of a tap changer is 30 years, the tap changer at Lefroy has already passed its useful life and is likely to degrade to worse conditions in the next five to ten years.

5.6.2 Condition of Tier 2 Assets

With the available information, all Tier 2 assets are determined to be in good condition as there are no issues noted from visual inspections, nor are concerns reflected from IR scan reports and maintenance records.

Table 35 gives in detail the information on rating and comments on all the equipment. If there were no issues detected, a rating of Class A is given to the asset. If there were minor issues, the asset is rated in C. Rating E is assigned to the asset when there is serious deficiency.

Table 35 Lefroy DS – Tier 2 Asset Condition Details

Lefroy DS - Tier 2 Asset Condition Table					
Substation	**Location ID**	**Asset Class**	**Visual Inspection**	**IR Scan**	**Equipment Test/Maintenance Records**
Lefroy DS	55T1-LX	Fuse	A	A	A
Lefroy DS	T1LA1	Lightning Arrestor	A	A	A
Lefroy DS	T1LA2	Lightning Arrestor	A	A	Unknown
Lefroy DS	SS.PT	Service Transformer	A	A	Unknown
Lefroy DS	55T1-L	Switch	A	A	A
Lefroy DS	T1-B	Switch	A	A	Unknown

5.6.3 Condition of Structural Equipment

The condition of structural equipment at Lefroy DS was evaluated from the following categories:

Structure

Rust was seen on the structures. The foundation of the 44kV primary switch is cracked. For transformer foundation, there is no arrangement for oil containment, which could potentially impact the environment.

Fence/Gate

There is no gravel outside of the station. The minimal width of specified surface stone should be 1500 mm on each side of the fence. This not only allows an acceptable range of touch potentials but also controls vegetation that could hinder the reliable operation of InnPower's electricity distribution system.

Site grading

There is vegetation around the fence and in the yard. The gravel is unleveled in the yard, needs regrading.

5.6.4 Identification of Risks and Hazards

There are underlying safety, reliability, and environmental concerns associated with the current condition of Lefroy DS. The safety concerns are embedded in the fact that no intermediate support has been provided for power cables and grounding cables. The unleveled gravel in the yard could be a tripping hazard. Also, the substandard wood pole in the yard is a safety hazard that could potentially cause fire. In an unplanned incident where the wood pole catches fire due to a direct lightning stroke, the debris could be in contact with the steel lattice and other structural equipment, thereby compromising the reliability. In addition, the fact that transformer has no oil containment raises environmental concerns in the station.

5.7 Leonards Beach DS

5.7.1 Health Index and Condition of Tier 1 Assets – Major assets in substations

Based on the condition assessment criteria described in Section 3, Health Index score is calculated for each transformer, tap changer, recloser, fences, and ground grids at this substation. The results are summarized in **Figure 16**.

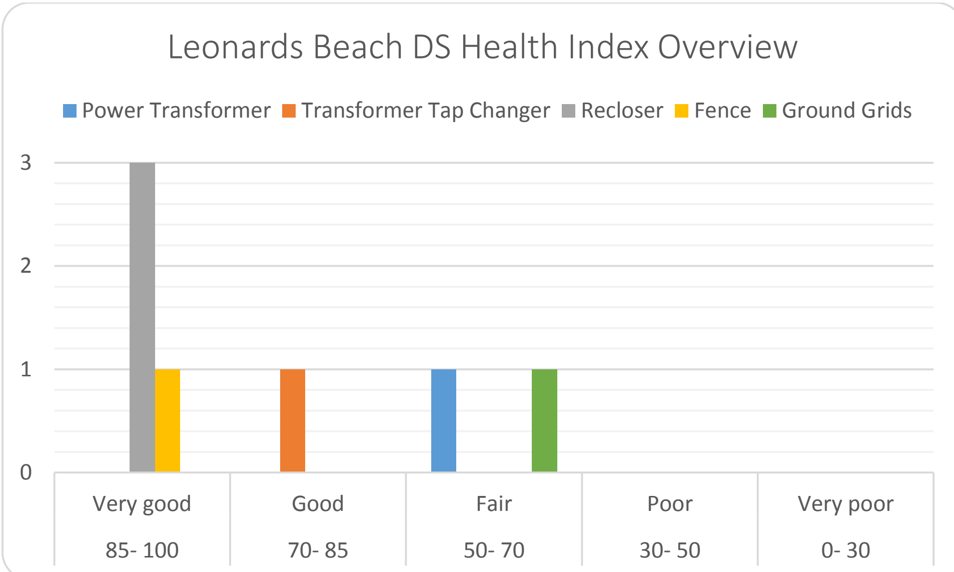

Figure 16 Leonards Beach DS – Tier 1 Asset Health Index Score

All the major assets are found to be in either very good or good condition except the transformer and ground grids at the station. Both the transformer and ground grids received a fair condition from the assessment. The aging station, along with the degradation of surface stones, is the primary reason behind the relatively low ground grids health index score. Although there is no hot spot discovered from the infrared scanning, the DGA results showed aging in the insulation of paper. Visual inspection performed by METSCO also determined that this transformer is rusting and requires repainting.

5.7.2 Condition of Tier 2 Assets

With the available information, all Tier 2 assets are determined to be in good condition as there are no issues noted from visual inspections, nor are concerns reflected from IR scan reports and maintenance records.

Table 36 gives in detail the information on rating and comments on all the equipment. If there were no issues detected, a rating of Class A is given to the asset. If there were minor issues, the asset is rated in C. Rating E is assigned to the asset when there is serious deficiency.

Table 36 Leonards Beach DS – Tier 2 Asset Condition Details

Leonards Beach DS - Tier 2 Asset Condition Table					
Substation	**Location ID**	**Asset Class**	**Visual Inspection**	**IR Scan**	**Equipment Test/Maintenance Records**
Leonards Beach DS	41T1L-X	Fuse	A	Unknown	A
Leonards Beach DS	T1-LA	Lightning Arrestor	A	Unknown	A
Leonards Beach DS	F1LA	Lightning Arrestor	A	A	Unknown
Leonards Beach DS	F2LA	Lightning Arrestor	A	A	Unknown
Leonards Beach DS	F3LA	Lightning Arrestor	A	A	Unknown
Leonards Beach DS	PT	Service Transformer	A	A	A
Leonards Beach DS	41T1-L	Switch	A	Unknown	A

5.7.3 Condition of Structural Equipment

The condition of structural equipment at Leonards Beach DS was evaluated from the following categories:

Structure

Rust was seen on the structures. For transformer foundation, there is no arrangement for oil containment, which could potentially impact the environment.

Fence/Gate

There is no gravel outside of the station. The minimal width of specified surface stone should be 1500 mm on each side of the fence. This not only allows an acceptable range of touch potentials but also controls vegetation that could hinder the reliable operation of InnPower's electricity distribution system. There is also minor rust observed on fence posts.

Site grading

There is vegetation around the fence and in the yard.

5.7.4 Identification of Risks and Hazards

There are underlying safety, reliability, and environmental concerns associated with the current condition of Leonards Beach DS. The safety concerns are embedded in the fact that neutral on the bus bar is not directly connected to the ground grids, but looped around the grounding structure first. In addition, the fact that transformer has no oil containment raises environmental concerns in the station.

5.8 Sandy Cove DS

5.8.1 Health Index and Condition of Tier 1 Assets – Major assets in substations

Based on the condition assessment criteria described in Section 3, Health Index score is calculated for each transformer, tap changer, recloser, fences, and ground grids at this substation. The results are summarized in **Figure 17**.

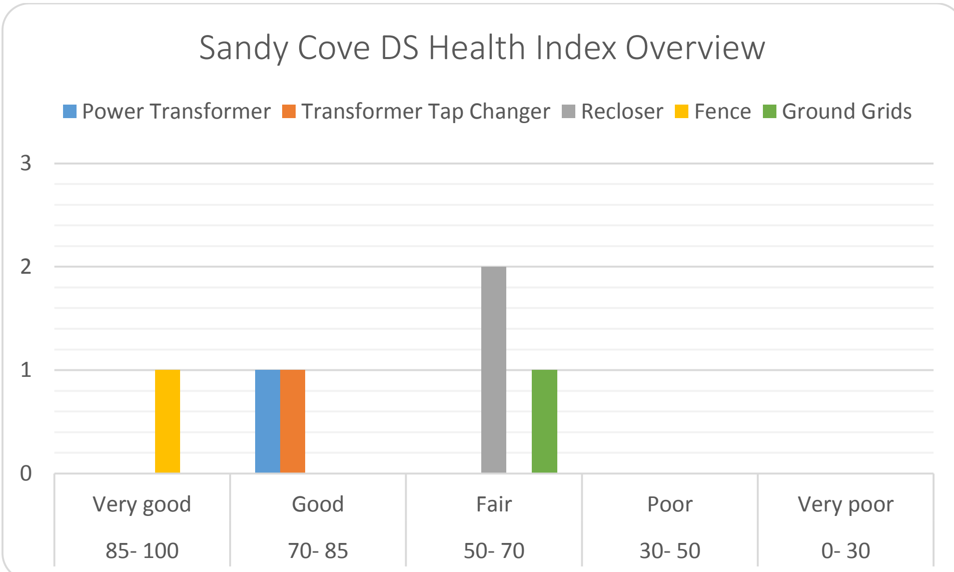

Figure 17 Sandy Cove DS – Tier 1 Asset Health Index Score

All the major assets are found to be in either very good or good condition, except for the reclosers and ground grids at the station. However, it should be noted that both the transformer and tap changer have reached 40 years of service. Given the fact that typical life of a tap changer is 30 years, the tap changer at Sandy Cove has already passed its useful life and is likely to degrade to worse conditions in the next five to ten years. The reclosers and ground grids received a fair condition from the assessment. Although there are no defects discovered from the visual inspections, these reclosers have reached 40 years of service, which is the typical life of an outdoor oil recloser. For ground grids, the aging station, along with the degradation of surface stones, is the primary reason behind the relatively low health index score. It should also be noted that temperature devices on the tap changer as well as exterior of the transformer are rusting.

5.8.2 Condition of Tier 2 Assets

With the available information, all Tier 2 assets are determined to be in good condition as there are no issues noted from visual inspections, nor are concerns reflected from IR scan reports and maintenance records.

Table 37 gives in detail the information on rating and comments on all the equipment. If there were no issues detected, a rating of Class A is given to the asset. If there were minor issues, the asset is rated in C. Rating E is assigned to the asset when there is serious deficiency.

Table 37 Sandy Cove DS – Tier 2 Asset Condition Details

Sandy Cove DS - Tier 2 Asset Condition Table					
Substation	**Location ID**	**Asset Class**	**Visual Inspection**	**IR Scan**	**Equipment Test/Maintenance Records**
Sandy Cove DS	A8T1-LX	Fuse	A	A	A
Sandy Cove DS	T1LA1	Lightning Arrestor	A	A	A
Sandy Cove DS	T1LA2	Lightning Arrestor	A	A	A
Sandy Cove DS	A8SS	Service Transformer	A	A	A
Sandy Cove DS	ABT1-L	Switch	A	A	A
Sandy Cove DS	A8T1-B	Switch	A	A	A

5.8.3 Condition of Structural Equipment

The condition of structural equipment at Sandy Cove DS was evaluated from the following categories:

Structure

Rust was seen on the structures and metal cabinet. For transformer foundation, there is no arrangement for oil containment, which could potentially impact the environment.

Fence/Gate

There is no gravel outside of the station. The minimal width of specified surface stone should be 1500 mm on each side of the fence. This not only allows an acceptable range of touch potentials but also controls vegetation that could hinder the reliable operation of InnPower's electricity distribution system. There is also rust observed on fence posts.

Site grading

There is vegetation and dry leaves around the fence and all over the yard. The gravel is unleveled in the yard, needs regrading. Water currently drains towards the foundation of structures, leading to a higher probability of rusting on the structures. Thus, the drainage system is recommended to be redesigned and upgraded.

5.8.4 Identification of Risks and Hazards

There are underlying safety, reliability, and environmental concerns associated with the current condition of Sandy Cove DS. The safety concerns are embedded in the fact that no intermediate support has been provided for power cables and control cables. The unleveled gravel in the yard could be a tripping hazard. Also, the unattended dry leaves and wood pole in the yard are safety hazards that could potentially cause fire. In an unplanned incident where the wood pole catches fire due to a direct lightning stroke, the debris could be in contact with the steel lattice and other structural equipment, thereby compromising the reliability. In addition, the fact that transformer has no oil containment raises environmental concerns in the station.

5.9 Stroud DS

5.9.1 Health Index and Condition of Tier 1 Assets – Major assets in substations

Based on the condition assessment criteria described in Section 3, Health Index score is calculated for each transformer, tap changer, recloser, fences, and ground grids at this substation. The results are summarized in Figure 18.

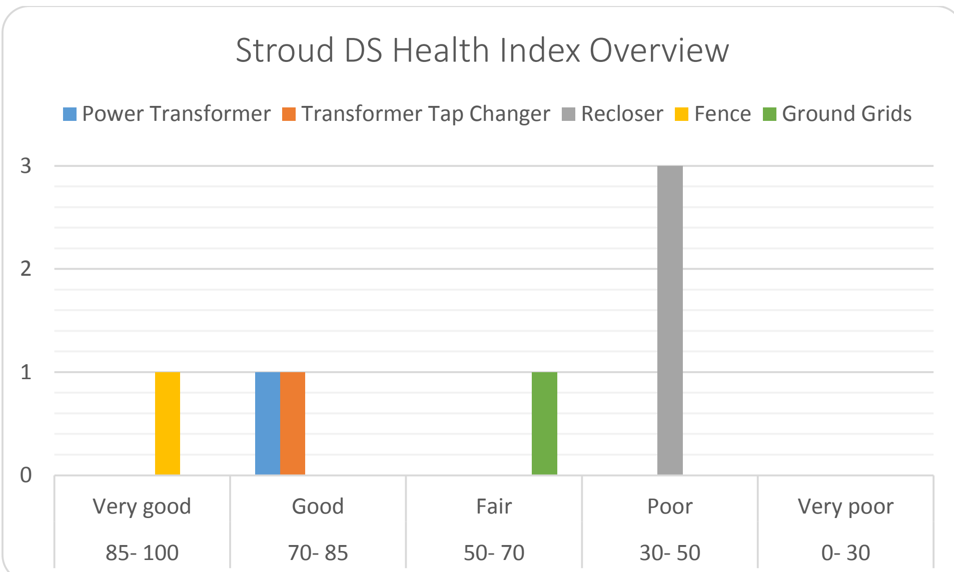

Figure 18 Stroud DS – Tier 1 Asset Health Index Score

All the major assets are found to be in either very good or good condition except the reclosers and ground grids at the station. However, it should be noted that both the transformer and tap changer has reached 46 years of service. Given the fact that typical life of a tap changer is 30 years, the tap changer at Stroud has already passed its useful life and is likely to degrade to worse conditions in the next five to ten years. The reclosers received a poor condition from the assessment. Although there are no defects discovered from the visual inspections, these reclosers have reached 46 years of service, which also passed the typical useful life of an outdoor oil recloser. This has contributed to its poor condition rating. Ground grids received a fair rating from the assessment. The aging station, along with the degradation of surface stones, is the primary reason behind the relatively low health index score. It should also be noted that the base and fins of the transformer are rusting.

5.9.2 Condition of Tier 2 Assets

With the available information, all Tier 2 assets are determined to be in good condition as there are no issues noted from visual inspections, nor are concerns reflected from IR scan reports and maintenance records.

Table 38 gives in detail the information on rating and comments on all the equipment. If there were no issues detected, a rating of Class A is given to the asset. If there were minor issues, the asset is rated in C. Rating E is assigned to the asset when there is serious deficiency.

Table 38 Stroud DS – Tier 2 Asset Condition Details

Stroud DS - Tier 2 Asset Condition Table					
Substation	**Location ID**	**Asset Class**	**Visual Inspection**	**IR Scan**	**Equipment Test/Maintenance Records**
Stroud DS	50T1-LX	Fuse	A	A	A
Stroud DS	T1-LA	Lightning Arrestor	A	A	A
Stroud DS	F1LA	Lightning Arrestor	A	A	Unknown
Stroud DS	F2LA	Lightning Arrestor	A	A	Unknown
Stroud DS	T1PT	Service Transformer	A	A	A
Stroud DS	50T1-L	Switch	A	A	A

5.9.3 Condition of Structural Equipment

The condition of structural equipment at Stroud DS was evaluated from the following categories:

Structure

Rust was seen on the structures whose foundation also starts to deteriorate. There are deficiencies observed from the control building where no padlock is present. For transformer foundation, there is no arrangement for oil containment, which could potentially impact the environment.

Fence/Gate

There is not enough gravel outside of the station. The minimal width of specified surface stone should be 1500 mm on each side of the fence. This not only allows an acceptable range of touch potentials but also controls vegetation that could hinder the reliable operation of InnPower's electricity distribution system. There is also rust observed on fence posts. Also, the fence height is low and is rusted.

Site grading

There is vegetation and grass around the fence and all over the yard.

5.9.4 Identification of Risks and Hazards

There are underlying safety, reliability, and environmental concerns associated with the current condition of Stroud DS. The safety concerns are embedded in the fact that cable ducts are unsealed. Also, the grass and wood pole in the yard are safety hazards that could potentially cause fire. In an unplanned incident where the wood pole catches fire due to a direct lightning stroke, the debris could be in contact with the steel lattice and other structural equipment, thereby compromising the reliability. In addition, the fact that transformer has no oil containment raises environmental concerns in the station.

Some other concerns include:

- Wasp nests on the control building: These should be removed to mitigate the probability of crews getting injured from the insects.

6 Recommendations

6.1 Recommended Asset Health Activities (Renewal)

6.1.1 Identification of Asset Repair/Replacement

- Monitor the aging transformers and tap changers at Stroud DS, Sandy Cove DS, Leonards Beach DS, Lefroy DS, and Big Bay Point DS for trends which may indicated accelerated degradation.
- Intervene on "hot spot" on the transformer bushing at Cedar Point DS.
- Replace the poor-condition tap changer at Innisfil DS within the next five years.
- Monitor aging tap changers at Stroud DS, Sandy Cove DS, Leonards Beach DS, Lefroy DS, and Big Bay Point DS for trends which may indicate accelerated degradation.
- Replace the poor-condition reclosers at Stroud DS within the next five years.
- Monitor aging reclosers at Sandy Cove DS for trends which may indicated accelerated degradation.
- Replace the wooden pole structure, installed at Big Bay Point DS, Brian Wilson DS, Lefroy DS, Sandy Cove DS, as well as Stroud DS, with steel or concrete to eliminate fire hazards.
- Provide proper support and sealing of cable and cable ducts in every substation to address safety concerns.
- Repaint structures where applicable to prevent further rusting.

Table 39 Asset Replacement Recommendation

Substation Summary Table					
Substation	Recommended Intervention (#Assets/Asset Designation)				Number of Assets Exceeding TUL
	Transformers	Transformer Tap Changers	Reclosers	Tier 2 Assets	
Big Bay Point DS	0	0	0	None	**1**
Bob Deugo DS	0	0	0	None	0
Brian Wilson DS	0	0	0	None	0
Cedar Point DS	0	0	0	None	**1**
Innisfil DS	0	**1**	0	None	**1**
Lefroy DS	0	0	0	None	**2**
Leonards Beach DS	0	0	0	None	**1**
Sandy Cove DS	0	0	0	None	**3**
Stroud DS	0	0	**3**	None	**5**

6.2 Further Condition Related Recommendations

6.2.1 Identification of (Data) Deficiencies and Recommendations

- Station maintenance program should be performed annually for each substation, collecting complete sets of data.
- Complete IR scanning needs to be performed for each individual asset in the station.
- Asset demographics data need to be fully collected, including installation year, manufacturer, as well as the model/type.

6.2.2 Recommended Site Condition Remediation

- Upgrade station design such that all the supporting structures installed at Big Bay Point DS, Brian Wilson DS, Lefroy DS, Sandy Cove DS, and Stroud DS are upgraded from wood to steel to eliminate fire hazards.
- Upgrade the fence surroundings installed at Big Bay Point DS, Cedar Point DS, Innisfil DS, Lefroy DS, Leonards Beach DS, and Sandy Cove DS to have 1500 mm of gravel on each side of the fence. This not only allows an acceptable range of touch potentials but also controls vegetation that could hinder the reliable operation of InnPower's electricity distribution system.
- Conduct maintenance exercise to clean vegetation and leaves in substations Big Bay Point DS, Bob Deugo DS, Brian Wilson DS, Innisfil DS, Lefroy DS, Leonards Beach DS, Sandy Cove DS, and Stroud DS.

6.2.3 Recommended Safety and Environmental Remediation

- To eliminate safety hazards:
  - Cables need to be properly supported to structures in Big Bay Point DS, Brian Wilson DS, Cedar Point DS, Innisfil DS, Lefroy DS, and Sandy Cove DS and cable ducts are required to be sealed in substations Bob Deugo DS, Brian Wilson DS, Innisfil DS, as well as Stroud DS.
  - Dry leaves need to be cleaned and removed from substations Big Bay Point DS, Bob Deugo DS, Innisfil DS, and Sandy Cove DS.
  - Wooden pole structure, installed at Big Bay Point DS, Brian Wilson DS, Lefroy DS, Sandy Cove DS, and Stroud DS should be replaced to mitigate potential fire hazard.
  - Unleveled gravel observed at Lefroy DS and Sandy Cove DS should be regraded and the large stones present in Brian Wilson DS should be removed to prevent field crews from tripping.
  - Wasp nests observed on the structures or buildings at substations Brian Wilson DS, Cedar Point DS, Innisfil DS, and Stroud DS need to be removed to mitigate health-related concerns.
- To eliminate environmental impact:
  - Oil containment should be built to the transformer foundation at each substation (except Bob Deugo DS, which already has oil containment).

6.2.4 Recommended Grounding Remediation

- Bond the station fence of Innisfil DS to the ground grid through several locations.
- Raise the depth of gravel to be at least 80mm for Brian Wilson DS, Cedar Point DS, Lefroy DS, Leonards Beach DS, Sandy Cove DS, and Stroud DS.
- Cover the gate swing area with specific surface stones at all substations.
- Replace the wedge connectors and upgrade all bonding connectors with compression connectors at all substations.
- Replace aluminum ground wires with copper wires at all substations.
- Establish a single connection from the insulated neutral bus to the ground grids employed at all substations.
- Increase the thickness of meshed parallel slats for the gradient control mats in all substations.
- Repair the ground wire at Lefroy DS and Sandy Cove DS.
- Bond all the equipment and metallic objects that are inside the station to the ground grid via two parallel paths for redundancy at Brian Wilson DS, Innisfil DS, Leonards Beach DS, and Stroud DS.
- Correct concentric neutral installations or derate the cables at Big Bay Point DS, Brian Wilson DS, Cedar Point DS, Lefroy DS, and Sandy Cove DS.

6.2.5 Recommended Standards Consideration

- Station maintenance standards
- Station Design Standards (e.g. use of wooden structures)
- Use of Oil Containment.

7 Appendices

Appendix A, B, and C are included as separate attachments:

- P-15-141-001 Part B InnPower Station Condition Assessment - Appendix A Visual Inspection and Testing Results
- P-15-141-001 Part B InnPower Station Condition Assessment - Appendix B Station Inspection Forms
- P-15-141-001 Part B InnPower Station Condition Assessment - Appendix C Station Grounding Assessment

Appendix A Visual Inspection and Testing Results

Appendix A – Visual Inspection and Testing Results

In order to assess the condition of InnPower's assets, a wide range of documents were reviewed, including Dissolved Gas Analysis testing reports, IR scan reports, as well as Station Maintenance Records. All the visual inspection results were obtained from METSCO's field inspection. The detailed results are included in Appendix B as a separate attachment. This appendix includes all the major issues discovered from the aforementioned documents and inspection forms, which serves as a reference for the ACA report. It is organized by station and each subsection includes visual inspection pictures and report extracts that revealed concerning issues.

A.1 <u>Big Bay Point DS</u>

There is no gravel outside of the station.

There is wood pole, vegetation and dry leaves present in the yard.

Cables are not properly supported.

Transformer has no oil containment.

A.2 Bob Deugo DS

There is dry leaves along the fences.

Transformer has oil containment.

A.3 Brian Wilson DS

There is vegetation on the fences.

Vegetation is all over the yard.

Cables are not properly supported.

Wood pole present in the yard to support bus tie disconnect switch.

Neither the transformer T1 (left) nor T2 (right) has oil containment.

A.4 Cedar Point DS

There is no gravel outside of the station.

Cables are not properly supported.

Oil leakage spotted.

Transformer has no oil containment.

A.5 <u>Innisfil DS</u>

The operating rods and handles are badly rusted.

Cracked foundation of structural equipment.

Jumpers are not properly supported from the reclosers to the bus bar.

The foundation of transformer has sunk to a very low level.

Transformer has no oil containment; leakage observed.

There is no gravel outside of the station.

There is vegetation and dry leaves around the fences and in the yard.

A.6 Lefroy DS

Rust observed from the structure.

Cracked foundation of the 44kV primary switch.

There is no gravel outside of the station.

Cables are not properly supported.

Wood pole present in the yard.

Transformer has no oil containment.

A.7 Leonards Beach DS

There is no gravel outside of the station.

There is a loop between the neutral cable and the grounding structure.

Transformer has no oil containment.

A.8 Sandy Cove DS

There is no gravel outside of the station.

There is vegetation and dry leaves around the fences and all over the yard.

There is rust seen on the structure and cabinet.

Cables are not properly supported.

Water drains towards the foundation of the structure.

Wood pole present in the yard.

Transformer has no oil containment.

A.9 Stroud DS

There is no gravel outside of the station.

There is vegetation and dry leaves around the fences and all over the yard.

Fence height is low and rusted.

Rust observed on the structure.

The foundation of the structure is deteriorating.

Cable ducts are not properly sealed.

Wood pole present in the yard.

Transformer has no oil containment.

Appendix B Station Inspection Forms

Distribution System

Asset Condition Assessment

Stations Inspection
(Visual Inspection)

Prepared by

November 2015

METSCO Energy Solutions

Condition Assessment Form

STATION INSPECTION

Station/Substation Big Bay Point DS (BBP)

Built in Year 1971

How to interpret this form: A square is checked off/crossed in case of a concern. A blank square means no concern is observed. The explanation to a concern is given in Comments.

A. Important Topics for Consideration

- ☐ Public Safety
- ☒ Worker Safety
- ☒ Environmental Hazard
- ☒ Maintenance Issues
- ☒ Reliability
- ☐ Operational Issues
- ☐ Legal Non- Compliance (Municipal)
- ☐ Regulatory Non-Compliance (ESA/IESO)
- ☐ Any concern report filed? (Kindly attach here)

B. Site Concerns

- ☐ **Proximity**
- ☐ Private Property
- ☐ Residential
- ☐ Commercial
- ☐ Industrial
- ☐ Schools
- ☐ Bike paths
- ☐ Roads/Railways
- ☐ Laneways
- ☐ Noise barriers
- ☐ Explosion Barriers

- ☐ **Fences & Gates**
- ☐ Grounding
- ☐ Bonding
- ☐ Rust
- ☐ Falling over
- ☐ Height
- ☐ Opening
- ☐ Bottom of the fence
- ☐ Between the supports
- ☐ Vegetation on fence
- ☐ Inappropriate attachments
- ☐ Foundations
- ☐ Substandard construction
- ☐ Padlocks
- ☐ Gates open in and out
- ☒ Gravel outside the fence

Comments:

Transformer foundations do not have any arrangement for oil containment.
There is no crushed stone around the station fences. (It not only provides safety to touch potentials but also stops vegetation near the fence)
Wooden pole is installed close to the substation structures. In the event if the pole catches fire due to a direct lightning stroke its debris could fall on the station structures and compromise reliability of supply.
Dead squirrel in the yard could cause health issues for the workers.
Dry leaves all over the yard. Tripping hazard due to unleveled yard surface.

METSCO Energy Solutions

Condition Assessment Form

- [ ] **Encroachments**
- [ ] Trees
- [ ] Neighbours
- [ ] **Other Station Issues**
- [ ] Shrubs and grass maintenance
- [ ] Spare equipment
- [ ] Housekeeping
- [ ] **Yard**
- [ ] Grounding / Connections
- [ ] Bonding
- [x] Vegetation
- [ ] Gravel or Stone
- [ ] Tree overhanging
- [ ] Switch/ Ground mat
- [ ] Trenches, ducts or conduits
- [x] Lighting
- [ ] Signage
- [ ] **Animals**
- [x] Birds/ squirrels
- [ ] Racoons
- [ ] **Waterways**
- [ ] Rivers/ pond
- [ ] Ditch
- [ ] Storm sewer

- [ ] **Station Building**
- [ ] Masonry/ concrete
- [ ] Steel/ metallic
- [ ] Grounding
- [ ] Bonding
- [ ] Paint
- [ ] Galvanizing
- [ ] Stairs
- [ ] Roof
- [ ] Windows
- [ ] Doors
- [ ] Station Doors
- [ ] Equipment doors
- [ ] Padlocks
- [ ] Card entry
- [ ] Slippery floor
- [ ] Floor drain present
- [ ] Accessible to children
- [ ] Security
- [ ] Water damage potential

C. <u>Control Building Equipment Concerns</u>

- [ ] Control equipment (RTU, fire and security)
- [ ] Switchgear
- [ ] AC/DC Suppliers
- [ ] Metering (kWh, SCADA, Transducers)
- [ ] Protection Control Systems

Comments:

Dead squirrel in the yard; could cause health issues for the workers. The yard needs regrading. Vegetation (dry and green) and heaps of dry leaves are present in and outside (along the fence) station the yard.

D. Cable Concerns

- [ ] Guarding and grounding
- [ ] Leaking potheads
- [x] Cable supports
- [ ] Termination
- [ ] Oil-filled cables
- [ ] Cable condition
- [ ] Lead sheath cables
- [x] Unsealed Cable ducts/ conduits
- [ ] Other Issues

E. Miscellaneous Electrical Issues

Metal Enclosed/ Metal Clad Equipment

- [x] Enclosure Rust (Cabinet)
- [ ] Grounding
- [ ] PCB
- [x] Porcelain Insulators
- [ ] Fuses
- [ ] Switches
- [ ] Interlocks
- [ ] Foundations
- [ ] Inoperability
- [ ] Bus
- [ ] Damaged Insulator
- [ ] Station service TX
- [ ] Multiple sizes of voltage

Structures

- [ ] Grounding
- [ ] Porcelain arrestors
- [ ] Porcelain switches
- [ ] Height clearance
- [ ] Working clearance
- [ ] Safe limit approach
- [ ] Guarding
- [ ] Substandard design
- [ ] Switching Area difficult
- [ ] Reclosers
- [ ] Connections
- [ ] Foundations
- [ ] Alignment
- [ ] Locks
- [ ] Designation
- [x] Rust
- [ ] Insulators
- [ ] Station device TX
- [ ] Cut-out

Comments:

Power Cable and control cables are not supported properly.
Control cables are hanging freely and are not rooted properly.
Rust observed on metal cabinet and structures. (If the enclosures are not in use these are just crowding the structures; and could be removed.)

METSCO Energy Solutions

Condition Assessment Form

Transformers/ Regulators

Points of Concern	TX 1	TX 2	TX 3	TX 4	TX 5	Spare
Identify the transformer ----->	22T1					
Grounding/ connections						
Age	1971					
Clearances						
Condensation						
Oil Containment	X					
Rust	X					
Oil leakage/ sweating						
Cracked bushings						
Arrestors						
Bushings						
Cooling fans						
Terminations						
Temperature devices						
Tap changers						
PCB > 50 ppm historically						
PCB last reading						
Birds/ Animals						

Comments:

Transformer foundations do not have any arrangement for oil containment.
Rust observed on transformer.
Wasp nest in the transformer.

Inspected by: DSJutla **Date:** 4 November 2015

(Devinder S. Jutla, P.Eng.)

METSCO Energy Solutions

Condition Assessment Form

STATION INSPECTION

Station/Substation	Bob Deugo DS (BD)
Built in Year	2006

How to interpret this form: A square is checked off/crossed in case of a concern. A blank square means no concern is observed. The explanation to a concern is given in Comments.

A. Important Topics for Consideration

- ☐ Public Safety
- ☐ Worker Safety
- ☐ Environmental Hazard
- ☐ Maintenance Issues
- ☐ Reliability
- ☐ Operational Issues
- ☐ Legal Non- Compliance (Municipal)
- ☐ Regulatory Non-Compliance (ESA/IESO)
- ☐ Any concern report filed? (Kindly attach here)

B. Site Concerns

- ☐ **Proximity**
- ☐ Private Property
- ☐ Residential
- ☐ Commercial
- ☐ Industrial
- ☐ Schools
- ☐ Bike paths
- ☐ Roads/Railways
- ☐ Laneways
- ☐ Noise barriers
- ☐ Explosion Barriers

- ☐ **Fences & Gates**
- ☐ Grounding
- ☐ Bonding
- ☐ Rust
- ☐ Falling over
- ☐ Height
- ☐ Opening
- ☐ Bottom of the fence
- ☐ Between the supports
- ☐ Vegetation on fence
- ☐ Inappropriate attachments
- ☐ Foundations
- ☐ Substandard construction
- ☐ Padlocks
- ☐ Gates open in and out
- ☐ Gravel outside the fence

Comments:

METSCO Energy Solutions

Condition Assessment Form

☐ **Encroachments**
☐ Trees
☐ Neighbours
☐ Other Station Issues
☐ Shrubs and grass maintenance
☐ Spare equipment
☒ Housekeeping
☐ **Yard**
☐ Grounding / Connections
☐ Bonding
☐ Vegetation
☐ Gravel or Stone
☐ Tree overhanging
☐ Switch/ Ground mat
☐ Trenches, ducts or conduits
☐ Lighting
☐ Signage
☐ **Animals**
☐ Birds/ squirrels
☐ Racoons
☐ **Waterways**
☐ Rivers/ pond
☐ Ditch
☐ Storm sewer

☐ **Station Building**
☐ Masonry/ concrete
☐ Steel/ metallic
☐ Grounding
☐ Bonding
☐ Paint
☐ Galvanizing
☐ Stairs
☐ Roof
☐ Windows
☐ Doors
☐ Station Doors
☐ Equipment doors
☐ Padlocks
☐ Card entry
☐ Slippery floor
☐ Floor drain present
☐ Accessible to children
☐ Security
☐ Water damage potential

C. Control Building Equipment Concerns

☐ Control equipment (RTU, fire and security)
☐ Switchgear
☐ AC/DC Suppliers
☐ Metering (kWh, SCADA, Transducers)
☐ Protection Control Systems

Comments:

Vegetation and dry leaves (along the fence) is present.

D. Cable Concerns

- [ ] Guarding and grounding
- [ ] Leaking potheads
- [ ] Cable supports
- [ ] Termination
- [ ] Oil-filled cables
- [ ] Cable condition
- [ ] Lead sheath cables
- [x] Unsealed Cable ducts/ conduits
- [ ] Other Issues

E. Miscellaneous Electrical Issues

Metal Enclosed/ Metal Clad Equipment

- [ ] Enclosure Rust
- [ ] Grounding
- [ ] PCB
- [ ] Porcelain
- [ ] Fuses
- [ ] Switches
- [ ] Interlocks
- [ ] Foundations
- [ ] Inoperability
- [ ] Bus
- [ ] Insulator
- [ ] Station service TX
- [ ] Multiple sizes of voltage

Structures

- [ ] Grounding
- [ ] Porcelain arrestors
- [ ] Porcelain switches
- [ ] Height clearance
- [ ] Working clearance
- [ ] Safe limit approach
- [ ] Guarding
- [ ] Substandard design
- [ ] Switching Area difficult
- [ ] Reclosers
- [ ] Connections
- [ ] Foundations
- [ ] Alignment
- [ ] Locks
- [ ] Designation
- [ ] Rust
- [ ] Insulators
- [ ] Station device TX
- [ ] Cut-out

Comments:

Transformers/ Regulators

Points of Concern	TX 1	TX 2	TX 3	TX 4	TX 5	Spare
Identify the transformer ----->	T1					
Grounding/ connections						
Age	2006					
Clearances						
Condensation	X					
Oil Containment						
Rust	X					
Oil leakage/ sweating						
Cracked bushings						
Arrestors						
Bushings						
Cooling fans						
Terminations						
Temperature devices						
Tap changers						
PCB > 50 ppm historically						
PCB last reading						
Birds/ Animals						

Comments:

Minor rust observed on transformer.
There is condensation in gauges.
Water collected under the transformer.

Inspected by: [signature] **Date:** 3 November 2015

(Devinder S. Jutla, P.Eng.)

METSCO Energy Solutions

Condition Assessment Form

STATION INSPECTION

Station/Substation Brian Wilson D.S.

Built in Year 1991

How to interpret this form: A square is checked off/crossed in case of a concern. A blank square means no concern is observed. The explanation to a concern is given in Comments.

A. Important Topics for Consideration

- ☐ Public Safety
- ☒ Worker Safety
- ☒ Environmental Hazard
- ☒ Maintenance Issues
- ☒ Reliability
- ☐ Operational Issues
- ☐ Legal Non- Compliance (Municipal)
- ☐ Regulatory Non-Compliance (ESA/IESO)
- ☐ Any concern report filed? (Kindly attach here)

B. Site Concerns

- ☐ **Proximity**
- ☐ Private Property
- ☒ Residential
- ☒ Commercial
- ☐ Industrial
- ☐ Schools
- ☐ Bike paths
- ☐ Roads/Railways
- ☐ Laneways
- ☐ Noise barriers
- ☐ Explosion Barriers

- ☐ **Fences & Gates**
- ☐ Grounding
- ☐ Bonding
- ☐ Rust
- ☐ Falling over
- ☐ Height
- ☐ Opening
- ☐ Bottom of the fence
- ☐ Between the supports
- ☒ Vegetation on fence
- ☐ Inappropriate attachments
- ☐ Foundations
- ☐ Substandard construction
- ☐ Padlocks
- ☐ Gates open in and out

Comments:

Transformer foundations do not have any arrangement for oil containment.
The station is located across the residential and commercial area. Vegetation is present on the fences.
Large stones in the yard could cause tripping hazard. Conduits are running on the surface and not properly buried.
In the middle of steel structure a wooden structure is installed to support bus tie disconnect switch.
In a case of fire on wood structure, it would compromise the reliability of the station.
Long rod bolt stick out of T2 fins and could injure workers.

METSCO Energy Solutions

Condition Assessment Form

- [ ] **Encroachments**
- [x] Trees
- [ ] Neighbours
- [ ] **Other Station Issues**
- [ ] Shrubs and grass maintenance
- [x] Spare equipment
- [ ] Housekeeping
- [ ] **Yard**
- [ ] Grounding / Connections
- [ ] Bonding
- [x] Vegetation
- [x] Gravel or Stone
- [ ] Tree overhanging
- [ ] Switch/ Ground mat
- [ ] Trenches, ducts or conduits
- [x] Lighting
- [ ] Signage
- [x] Drainage
- [ ] **Animals**
- [ ] Birds/ squirrels
- [ ] Racoons
- [ ] **Waterways**
- [ ] Rivers/ pond
- [ ] Ditch
- [ ] Storm sewer

- [ ] **Station Building**
- [ ] Masonry/ concrete
- [ ] Steel/ metallic
- [ ] Grounding
- [ ] Bonding
- [ ] Paint
- [ ] Galvanizing
- [ ] Stairs
- [ ] Roof
- [ ] Windows
- [ ] Doors
- [ ] Station Doors
- [ ] Equipment doors
- [ ] Padlocks
- [ ] Card entry
- [ ] Slippery floor
- [ ] Floor drain present
- [ ] Accessible to children
- [ ] Security
- [ ] Water damage potential

C. Control Building Equipment Concerns

- [x] Control equipment (RTU, fire and security)
- [ ] Switchgear
- [ ] AC/DC Suppliers
- [ ] Metering (kWh, SCADA, Transducers)
- [ ] Protection Control Systems

Comments:

Vegetation is present all over the yard. Large stones in the yard could cause tripping hazard. Yard should be provided with proper drainage.
Spare Equipment are sitting in the Station.
The ducts coming into the control building are unsealed. The mice are already living there. The control building is heated and mice will multiply there. Control cabinet was left open with all relay and batteries. A spare SEL relay is stored not properly. Vents need cleaning.

D. Cable Concerns

- ☐ Guarding and grounding
- ☐ Leaking potheads
- ☒ Cable supports
- ☐ Termination
- ☐ Oil-filled cables
- ☐ Cable condition
- ☐ Lead sheath cables
- ☒ Unsealed Cable ducts/ conduits
- ☐ Other Issues

E. Miscellaneous Electrical Issues

Metal Enclosed/ Metal Clad Equipment

- ☐ Enclosure Rust
- ☐ Grounding
- ☐ PCB
- ☐ Porcelain
- ☐ Fuses
- ☐ Switches
- ☐ Interlocks
- ☐ Foundations
- ☐ Inoperability
- ☐ Bus
- ☒ Insulator
- ☒ Station service TX
- ☐ Multiple sizes of voltage

Structures

- ☐ Grounding
- ☒ Porcelain arrestors
- ☒ Porcelain insulator for switches
- ☐ Height clearance
- ☐ Working clearance
- ☐ Safe limit approach
- ☐ Guarding
- ☒ Substandard design (wooden structure)
- ☐ Switching Area difficult
- ☐ Reclosers
- ☐ Connections
- ☐ Foundations
- ☐ Alignment
- ☐ Locks
- ☐ Designation
- ☒ Rust
- ☐ Insulators
- ☐ Station device TX
- ☐ Cut-out

Comments:

Cable are installed near structures without any intermediate supports. The control cables are hanging along the structures. There is bird nest on control cables.
The station transformer is rusty. Insulators are all porcelain.
Wooden pole is used to support bus tie switch which could compromise the station in fire/ flash over. (Should be in metal support structure to maintain the reliability of D.S)
Rust observed on boxes.

METSCO Energy Solutions

Condition Assessment Form

Transformers/ Regulators

Points of Concern	TX 1	TX 2	TX 3	TX 4	TX 5	Spare
Identify the transformer ----->	T1	T2				
Grounding/ connections						
Age	1991	2014				
Clearances						
Condensation						
Oil Containment	X	X				
Rust	X					
Oil leakage/ sweating	X					
Cracked bushings						
Arrestors						
Bushings						
Cooling fans						
Terminations						
Temperature devices						
Tap changers						
PCB > 50 ppm historically						
PCB last reading						
Birds/ Animals						

Comments:

Transformers foundations do not have any arrangement for oil containment.
Wasp Nest on T1 disconnect switched and T1 enclosure. Rust observed on T1.
Long rod bolt stick out of T2 fins and could injure workers.

Inspected by: DSJutla **Date:** 3 November 2015

(Devinder S. Jutla, P.Eng.)

METSCO Energy Solutions

Condition Assessment Form

STATION INSPECTION

Station/Substation Cedar Point D.S. (CDP)

Built in Year 1976

How to interpret this form: A square is checked off/crossed in case of a concern. A blank square means no concern is observed. The explanation to a concern is given in Comments.

A. Important Topics for Consideration

- ☐ Public Safety
- ☐ Worker Safety
- ☒ Environmental Hazard
- ☐ Maintenance Issues
- ☐ Reliability
- ☐ Operational Issues
- ☐ Legal Non- Compliance (Municipal)
- ☐ Regulatory Non-Compliance (ESA/IESO)
- ☐ Any concern report filed? (Kindly attach here)

B. Site Concerns

- ☐ **Proximity**
- ☐ Private Property
- ☐ Residential
- ☐ Commercial
- ☐ Industrial
- ☐ Schools
- ☐ Bike paths
- ☐ Roads/Railways
- ☐ Laneways
- ☐ Noise barriers
- ☐ Explosion Barriers

- ☐ **Fences & Gates**
- ☐ Grounding
- ☐ Bonding
- ☐ Rust
- ☐ Falling over
- ☐ Height
- ☐ Opening
- ☐ Bottom of the fence
- ☐ Between the supports
- ☐ Vegetation on fence
- ☐ Inappropriate attachments
- ☐ Foundations
- ☐ Substandard construction
- ☐ Padlocks
- ☐ Gates open in and out
- ☒ Gravel outside the fence

Comments:

Transformer foundations do not have any arrangement for oil containment.
There is no crushed stone around the station fences. (It not only provides safety to touch potentials but also stops vegetation near the fence)

METSCO Energy Solutions

Condition Assessment Form

- [ ] **Encroachments**
- [ ] Trees
- [ ] Neighbours
- [ ] **Other Station Issues**
- [ ] Shrubs and grass maintenance
- [x] Spare equipment
- [ ] Housekeeping
- [ ] **Yard**
- [ ] Grounding / Connections
- [ ] Bonding
- [ ] Vegetation
- [ ] Gravel or Stone
- [ ] Tree overhanging
- [ ] Switch/ Ground mat
- [ ] Trenches, ducts or conduits
- [ ] Lighting
- [ ] Signage
- [ ] **Animals**
- [x] Birds/ squirrels
- [ ] Racoons
- [ ] **Waterways**
- [ ] Rivers/ pond
- [ ] Ditch
- [ ] Storm sewer

- [ ] **Station Building**
- [ ] Masonry/ concrete
- [ ] Steel/ metallic
- [ ] Grounding
- [ ] Bonding
- [ ] Paint
- [ ] Galvanizing
- [ ] Stairs
- [ ] Roof
- [ ] Windows
- [ ] Doors
- [ ] Station Doors
- [ ] Equipment doors
- [ ] Padlocks
- [ ] Card entry
- [ ] Slippery floor
- [ ] Floor drain present
- [ ] Accessible to children
- [ ] Security
- [ ] Water damage potential

C. Control Building Equipment Concerns

- [ ] Control equipment (RTU, fire and security)
- [ ] Switchgear
- [ ] AC/DC Suppliers
- [ ] Metering (kWh, SCADA, Transducers)
- [ ] Protection Control Systems

Comments:

Spare transformer is sitting in the yard.
Bird nest on station transformer supporting structure.
Wasp nest on disconnect switches.

D. Cable Concerns

- [x] Guarding and grounding
- [ ] Leaking potheads
- [x] Cable supports
- [ ] Termination
- [ ] Oil-filled cables
- [ ] Cable condition
- [ ] Lead sheath cables
- [x] Unsealed Cable ducts/ conduits
- [ ] Other Issues

E. Miscellaneous Electrical Issues

Metal Enclosed/ Metal Clad Equipment

- [x] Enclosure Rust
- [ ] Grounding
- [ ] PCB
- [x] Porcelain insulator
- [ ] Fuses
- [ ] Switches
- [ ] Interlocks
- [ ] Foundations
- [ ] Inoperability
- [ ] Bus
- [ ] Insulator
- [ ] Station service TX
- [ ] Multiple sizes of voltage

Structures

- [ ] Grounding
- [ ] Porcelain arrestors
- [ ] Porcelain switches
- [ ] Height clearance
- [ ] Working clearance
- [ ] Safe limit approach
- [ ] Guarding
- [ ] Substandard design
- [ ] Switching Area difficult
- [ ] Reclosers
- [ ] Connections
- [ ] Foundations
- [ ] Alignment
- [ ] Locks
- [ ] Designation
- [x] Rust
- [ ] Insulators
- [ ] Station device TX
- [ ] Cut-out

Comments:

Cables are not well supported to the structures. Ground cable connecting concentric neutral of cable terminations to the ground grid is too long and not supported in the middle section.
Rust observed on metal cabinet and structures. (If the enclosures are not in use these are just crowding the structures; and could be removed.)

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Condition Assessment Form

Transformers/ Regulators

Points of Concern	TX 1	TX 2	TX 3	TX 4	TX 5	Spare
Identify the transformer ----->	T1					
Grounding/ connections						
Age	1976					
Clearances						
Condensation	X					
Oil Containment	X					
Rust	X					
Oil leakage/ sweating	X					
Cracked bushings						
Arrestors						
Bushings						
Cooling fans						
Terminations						
Temperature devices						
Tap changers						
PCB > 50 ppm historically						
PCB last reading						
Birds/ Animals						

Comments:

Transformer foundations do not have any arrangement for oil containment
Rust observed on transformer.
The PCB sticker is not visible.
There is condensation in pressure gauge
Oil leakage observed from transformer tap changer.

Inspected by: DS Jutla **Date:** 3 November 2015

(Devinder S. Jutla, P.Eng.)

METSCO Energy Solutions

Condition Assessment Form

STATION INSPECTION

Station/Substation Innisfil D.S. (INN)

Built in Year 1976

How to interpret this form: A square is checked off/crossed in case of a concern. A blank square means no concern is observed. The explanation to a concern is given in Comments.

A. Important Topics for Consideration

- ☒ Public Safety
- ☒ Worker Safety
- ☒ Environmental Hazard
- ☒ Maintenance Issues
- ☒ Reliability
- ☐ Operational Issues
- ☐ Legal Non- Compliance (Municipal)
- ☐ Regulatory Non-Compliance (ESA/IESO)
- ☐ Any concern report filed? (Kindly attach here)

B. Site Concerns

- ☐ **Proximity**
- ☐ Private Property
- ☒ Residential
- ☐ Commercial
- ☐ Industrial
- ☐ Schools
- ☐ Bike paths
- ☐ Roads/Railways
- ☐ Laneways
- ☐ Noise barriers
- ☐ Explosion Barriers

- ☐ **Fences & Gates**
- ☐ Grounding
- ☐ Bonding
- ☐ Rust
- ☒ Falling over
- ☒ Height
- ☒ Opening
- ☒ Bottom of the fence
- ☐ Between the supports
- ☒ Vegetation on fence
- ☐ Inappropriate attachments
- ☐ Foundations
- ☒ Substandard construction
- ☐ Padlocks
- ☐ Gates open in and out
- ☒ Gravel outside the fence

Comments:

Transformer foundations do not have any arrangement for oil containment.
There is no crushed stone around the station fences. (It not only provides safety to touch potentials but also stops vegetation near the fence)
Fences and gates are compromised. The fence height is low. The fence is bending over in one spot. The wood poles stored beside the station are pushing the bottom of the fence. Vegetation present on the fence. (Rebuild the fence)
Dead birds are rotting in the yard and could cause health issues for the workers.

METSCO Energy Solutions

Condition Assessment Form

- [ ] **Encroachments**
- [ ] Trees
- [ ] Neighbours
- [ ] **Other Station Issues**
- [x] Shrubs and grass maintenance
- [ ] Spare equipment
- [x] Housekeeping
- [ ] **Yard**
- [ ] Grounding / Connections
- [ ] Bonding
- [x] Vegetation
- [ ] Gravel or Stone
- [ ] Tree overhanging
- [ ] Switch/ Ground mat
- [ ] Trenches, ducts or conduits
- [x] Lighting
- [ ] Signage
- [ ] **Animals**
- [x] Birds/ squirrels
- [ ] Racoons
- [ ] **Waterways**
- [ ] Rivers/ pond
- [ ] Ditch
- [ ] Storm sewer

- [ ] **Station Building**
- [ ] Masonry/ concrete
- [ ] Steel/ metallic
- [ ] Grounding
- [ ] Bonding
- [x] Paint
- [ ] Galvanizing
- [ ] Stairs
- [ ] Roof
- [ ] Windows
- [ ] Doors
- [ ] Station Doors
- [ ] Equipment doors
- [ ] Padlocks
- [ ] Card entry
- [ ] Slippery floor
- [ ] Floor drain present
- [ ] Accessible to children
- [ ] Security
- [ ] Water damage potential

C. <u>Control Building Equipment Concerns</u>

- [x] Control equipment (RTU, fire and security)
- [ ] Switchgear
- [ ] AC/DC Suppliers
- [ ] Metering (kWh, SCADA, Transducers)
- [ ] Protection Control Systems

Comments:

Vegetation issues in the yard.
Dead birds in the yard under the bus bar structures are rotting and could cause health issues.)

Condition Assessment Form

D. Cable Concerns

- [ ] Guarding and grounding
- [ ] Leaking potheads
- [x] Cable supports
- [ ] Termination
- [ ] Oil-filled cables
- [ ] Cable condition
- [ ] Lead sheath cables
- [x] Unsealed Cable ducts/ conduits
- [x] Other Issues

E. Miscellaneous Electrical Issues

Metal Enclosed/ Metal Clad Equipment

- [ ] Enclosure Rust
- [ ] Grounding
- [ ] PCB
- [ ] Porcelain
- [ ] Fuses
- [ ] Switches
- [ ] Interlocks
- [ ] Foundations
- [ ] Inoperability
- [x] Bus
- [x] Porcelain Insulator
- [ ] Station service TX
- [ ] Multiple sizes of voltage

Structures

- [ ] Grounding
- [x] Porcelain arrestors
- [ ] Porcelain switches
- [ ] Height clearance
- [ ] Working clearance
- [ ] Safe limit approach
- [ ] Guarding
- [x] Substandard design
- [ ] Switching Area difficult
- [ ] Reclosers
- [ ] Connections
- [x] Foundations
- [ ] Alignment
- [ ] Locks
- [ ] Designation
- [x] Rust
- [ ] Insulators
- [x] Station device TX
- [ ] Cut-out

Comments:

Cables are not supported properly.
The foundations are cracked. (Need immediate attention)
Bus supports are rusting. 44kV switch operating handle and rods are rusted.
Station services transformer needs painting.
Jumpers from Vipers to the bus bars do not have proper supports. (Under high wind and snow conditions high stress could be exerted on the terminations of Vipers.)

METSCO Energy Solutions

Condition Assessment Form

Transformers/ Regulators

Points of Concern	TX 1	TX 2	TX 3	TX 4	TX 5	Spare
Identify the transformer ----->	31T1					
Grounding/ connections						
Age	1976					
Clearances						
Condensation						
Oil Containment	X					
Rust	X					
Oil leakage/ sweating	X					
Cracked bushings						
Arrestors						
Bushings						
Cooling fans						
Terminations						
Temperature devices						
Tap changers						
PCB > 50 ppm historically						
PCB last reading						
Birds/ Animals						

Comments:

Transformer foundations do not have any arrangement for oil containment.
Rust observed on transformer.
There is oil leakage on the oil sampling valve.
The foundation of the transformer is very low and cracked all the way along the length of transformer.

Inspected by: ______________________ **Date:** 3 November 2015

(Devinder S. Jutla, P.Eng.)

METSCO Energy Solutions

Condition Assessment Form

STATION INSPECTION

Station/Substation Lefroy DS (LEF)

Built in Year 1970

How to interpret this form: A square is checked off/crossed in case of a concern. A blank square means no concern is observed. The explanation to a concern is given in Comments.

A. Important Topics for Consideration

- ☐ Public Safety
- ☒ Worker Safety
- ☒ Environmental Hazard
- ☒ Maintenance Issues
- ☒ Reliability
- ☐ Operational Issues
- ☐ Legal Non- Compliance (Municipal)
- ☐ Regulatory Non-Compliance (ESA/IESO)
- ☐ Any concern report filed? (Kindly attach here)

B. Site Concerns

- ☐ **Proximity**
- ☐ Private Property
- ☐ Residential
- ☐ Commercial
- ☐ Industrial
- ☐ Schools
- ☐ Bike paths
- ☐ Roads/Railways
- ☐ Laneways
- ☐ Noise barriers
- ☐ Explosion Barriers

- ☐ **Fences & Gates**
- ☐ Grounding
- ☐ Bonding
- ☒ Rust
- ☐ Falling over
- ☐ Height
- ☐ Opening
- ☐ Bottom of the fence
- ☐ Between the supports
- ☒ Vegetation on fence
- ☐ Inappropriate attachments
- ☐ Foundations
- ☐ Substandard construction
- ☐ Padlocks
- ☐ Gates open in and out
- ☒ Gravel outside the fence

Comments:

Transformer foundations do not have any arrangement for oil containment.
There is no crushed stone around the station fences. (It not only provides safety to touch potentials but also stops vegetation near the fence)
Wooden pole is installed close to the substation structures. In the event if the pole catches fire due to a direct lightning stroke its debris could fall on the station structures and compromise reliability of supply.
The fences post are rusted. Vegetation are present on fences.
Tripping hazard due to unleveled gravel in the yard.

- [ ] **Encroachments**
- [ ] Trees
- [ ] Neighbours
- [ ] **Other Station Issues**
- [ ] Shrubs and grass maintenance
- [ ] Spare equipment
- [ ] Housekeeping
- [ ] **Yard**
- [ ] Grounding / Connections
- [ ] Bonding
- [x] Vegetation
- [ ] Gravel or Stone
- [ ] Tree overhanging
- [ ] Switch/ Ground mat
- [ ] Trenches, ducts or conduits
- [x] Lighting
- [ ] Signage
- [ ] **Animals**
- [ ] Birds/ squirrels
- [ ] Racoons
- [ ] **Waterways**
- [ ] Rivers/ pond
- [ ] Ditch
- [ ] Storm sewer

- [ ] **Station Building**
- [ ] Masonry/ concrete
- [ ] Steel/ metallic
- [ ] Grounding
- [ ] Bonding
- [ ] Paint
- [ ] Galvanizing
- [ ] Stairs
- [ ] Roof
- [ ] Windows
- [ ] Doors
- [ ] Station Doors
- [ ] Equipment doors
- [ ] Padlocks
- [ ] Card entry
- [ ] Slippery floor
- [ ] Floor drain present
- [ ] Accessible to children
- [ ] Security
- [ ] Water damage potential

C. Control Building Equipment Concerns

- [ ] Control equipment (RTU, fire and security)
- [ ] Switchgear
- [ ] AC/DC Suppliers
- [ ] Metering (kWh, SCADA, Transducers)
- [ ] Protection Control Systems

Comments:

Vegetation are present within the yard.
Tripping hazard due to unleveled gravel in the yard.

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Condition Assessment Form

D. Cable Concerns

- ☐ Guarding and grounding
- ☐ Leaking potheads
- ☒ Cable supports
- ☐ Termination
- ☐ Oil-filled cables
- ☐ Cable condition
- ☐ Lead sheath cables
- ☒ Unsealed Cable ducts/ conduits
- ☐ Other Issues

E. Miscellaneous Electrical Issues

Metal Enclosed/ Metal Clad Equipment

- ☒ Enclosure Rust
- ☐ Grounding
- ☐ PCB
- ☒ Porcelain insulator
- ☐ Fuses
- ☐ Switches
- ☐ Interlocks
- ☐ Foundations
- ☐ Inoperability
- ☐ Bus
- ☐ Insulator
- ☐ Station service TX
- ☐ Multiple sizes of voltage

Structures

- ☐ Grounding
- ☐ Porcelain arrestors
- ☐ Porcelain switches
- ☐ Height clearance
- ☐ Working clearance
- ☐ Safe limit approach
- ☐ Guarding
- ☐ Substandard design
- ☐ Switching Area difficult
- ☐ Reclosers
- ☐ Connections
- ☒ Foundations
- ☐ Alignment
- ☐ Locks
- ☐ Designation
- ☒ Rust
- ☐ Insulators
- ☐ Station device TX
- ☐ Cut-out

Comments:

The power cables and ground cables from terminations are not proper intermediate supports.
Rust seen on the structures.
Rust observed on metal cabinet and structures. (If the enclosures are not in use these are just crowding the structures; and could be removed.)
The 44kV switch foundation is cracked.

METSCO Energy Solutions

Condition Assessment Form

Transformers/ Regulators

Points of Concern	TX 1	TX 2	TX 3	TX 4	Spare
Identify the transformer ----->	55T1				
Grounding/ connections					
Age	1970 (Refurbished 2014)				
Clearances					
Condensation					
Oil Containment	X				
Rust	X				
Oil leakage/ sweating					
Cracked bushings					
Arrestors					
Bushings					
Cooling fans					
Terminations					
Temperature devices					
Tap changers					
PCB > 50 ppm historically					
PCB last reading					
Birds/ Animals					

Comments:

Transformer foundations do not have any arrangement for oil containment.
Rust observed on transformer.

Inspected by: DSJutla **Date:** 3 November 2015

(Devinder S. Jutla, P.Eng.)

Condition Assessment Form

STATION INSPECTION

Station/Substation	Leonards Beach DS (LB)
Built in Year	1974

How to interpret this form: A square is checked off/crossed in case of a concern. A blank square means no concern is observed. The explanation to a concern is given in Comments.

A. Important Topics for Consideration

- ☐ Public Safety
- ☐ Worker Safety
- ☒ Environmental Hazard
- ☐ Maintenance Issues
- ☐ Reliability
- ☐ Operational Issues
- ☐ Legal Non- Compliance (Municipal)
- ☐ Regulatory Non-Compliance (ESA/IESO)
- ☐ Any concern report filed? (Kindly attach here)

B. Site Concerns

- ☐ **Proximity**
- ☐ Private Property
- ☐ Residential
- ☐ Commercial
- ☐ Industrial
- ☐ Schools
- ☐ Bike paths
- ☐ Roads/Railways
- ☐ Laneways
- ☐ Noise barriers
- ☐ Explosion Barriers

- ☐ **Fences & Gates**
- ☐ Grounding
- ☐ Bonding
- ☒ Rust
- ☐ Falling over
- ☐ Height
- ☐ Opening
- ☐ Bottom of the fence
- ☐ Between the supports
- ☒ Vegetation on fence
- ☐ Inappropriate attachments
- ☐ Foundations
- ☐ Substandard construction
- ☐ Padlocks
- ☐ Gates open in and out
- ☒ Gravel outside the fence

Comments:

Transformer foundations do not have any arrangement for oil containment.
There is no crushed stone around the station fences. (It not only provides safety to touch potentials but also stops vegetation near the fence)
Fences posts are starting to rust. Vegetation is present on the fences.

- [ ] **Encroachments**
- [ ] Trees
- [ ] Neighbours
- [ ] Other Station Issues
- [ ] Shrubs and grass maintenance
- [ ] Spare equipment
- [ ] Housekeeping
- [ ] **Yard**
- [ ] Grounding / Connections
- [ ] Bonding
- [x] Vegetation
- [ ] Gravel or Stone
- [ ] Tree overhanging
- [ ] Switch/ Ground mat
- [ ] Trenches, ducts or conduits
- [x] Lighting
- [ ] Signage
- [ ] **Animals**
- [ ] Birds/ squirrels
- [ ] Racoons
- [ ] **Waterways**
- [ ] Rivers/ pond
- [ ] Ditch
- [ ] Storm sewer

- [ ] **Station Building**
- [ ] Masonry/ concrete
- [ ] Steel/ metallic
- [ ] Grounding
- [ ] Bonding
- [ ] Paint
- [ ] Galvanizing
- [ ] Stairs
- [ ] Roof
- [ ] Windows
- [ ] Doors
- [ ] Station Doors
- [ ] Equipment doors
- [ ] Padlocks
- [ ] Card entry
- [ ] Slippery floor
- [ ] Floor drain present
- [ ] Accessible to children
- [ ] Security
- [ ] Water damage potential

C. Control Building Equipment Concerns

- [ ] Control equipment (RTU, fire and security)
- [ ] Switchgear
- [ ] AC/DC Suppliers
- [ ] Metering (kWh, SCADA, Transducers)
- [ ] Protection Control Systems

Comments:

Vegetation is present in the yard

D. Cable Concerns

- [x] Guarding and grounding
- [ ] Leaking potheads
- [ ] Cable supports
- [ ] Termination
- [ ] Oil-filled cables
- [ ] Cable condition
- [ ] Lead sheath cables
- [ ] Unsealed Cable ducts/ conduits
- [ ] Other Issues

E. Miscellaneous Electrical Issues

Metal Enclosed/ Metal Clad Equipment

- [ ] Enclosure Rust
- [ ] Grounding
- [ ] PCB
- [x] Porcelain insulators
- [ ] Fuses
- [ ] Switches
- [ ] Interlocks
- [ ] Foundations
- [ ] Inoperability
- [ ] Bus
- [ ] Insulator
- [x] Station service TX
- [ ] Multiple sizes of voltage

Structures

- [ ] Grounding
- [x] Porcelain arrestors
- [ ] Porcelain switches
- [ ] Height clearance
- [ ] Working clearance
- [ ] Safe limit approach
- [ ] Guarding
- [ ] Substandard design
- [ ] Switching Area difficult
- [ ] Reclosers
- [ ] Connections
- [ ] Foundations
- [ ] Alignment
- [ ] Locks
- [ ] Designation
- [x] Rust
- [ ] Insulators
- [ ] Station device TX
- [ ] Cut-out

Comments:

Station service transformer needs painting.
Rust observed on metal cabinet and structures. (If the enclosures are not in use these are just crowding the structures; and could be removed.)
Neutral has multiple joints, including connection to the structure ground before connecting to the ground grid. (Neutral should be connected directly the ground grid.)

METSCO Energy Solutions

Condition Assessment Form

Transformers/ Regulators

Points of Concern	TX 1	TX 2	TX 3	TX 4	TX 5	Spare
Identify the transformer ----->	41T1					
Grounding/ connections						
Age	1974					
Clearances						
Condensation						
Oil Containment	X					
Rust	X					
Oil leakage/ sweating						
Cracked bushings						
Arrestors						
Bushings						
Cooling fans						
Terminations						
Temperature devices						
Tap changers						
PCB > 50 ppm historically						
PCB last reading						
Birds/ Animals						

Comments:

Transformer foundations do not have any arrangement for oil containment.
Rust observed on transformer.
There is only one grounding.

Inspected by: ______________________ **Date:** 3 November 2015

(Devinder S. Jutla, P.Eng.)

METSCO
Energy Solutions

Condition Assessment Form

STATION INSPECTION

Station/Substation Sandy Cove DS (SC)

Built in Year 1975

How to interpret this form: A square is checked off/crossed in case of a concern. A blank square means no concern is observed. The explanation to a concern is given in Comments.

A. Important Topics for Consideration

- ☐ Public Safety
- ☐ Worker Safety
- ☒ Environmental Hazard
- ☒ Maintenance Issues
- ☒ Reliability
- ☐ Operational Issues
- ☐ Legal Non- Compliance (Municipal)
- ☐ Regulatory Non-Compliance (ESA/IESO)
- ☐ Any concern report filed? (Kindly attach here)

B. Site Concerns

- ☐ **Proximity**
- ☐ Private Property
- ☐ Residential
- ☐ Commercial
- ☐ Industrial
- ☐ Schools
- ☐ Bike paths
- ☐ Roads/Railways
- ☐ Laneways
- ☐ Noise barriers
- ☐ Explosion Barriers

- ☐ **Fences & Gates**
- ☐ Grounding
- ☐ Bonding
- ☒ Rust
- ☐ Falling over
- ☐ Height
- ☐ Opening
- ☐ Bottom of the fence
- ☐ Between the supports
- ☒ Vegetation on fence
- ☐ Inappropriate attachments
- ☐ Foundations
- ☐ Substandard construction
- ☐ Padlocks
- ☐ Gates open in and out
- ☒ Gravel outside the fence

Comments:

Transformer foundations do not have any arrangement for oil containment.
There is no crushed stone around the station fences. (It not only provides safety to touch potentials but also stops vegetation near the fence)
Fences posts are rusted. Vegetation are present on the fences.
Wooden pole is installed close to the substation structures. In the event if the pole catches fire due to a direct lightning stroke its debris could fall on the station structures and compromise reliability of supply.
Dry leaves all over the yard.
Tripping hazard due to unleveled yard surface.

METSCO Energy Solutions

Condition Assessment Form

- [ ] **Encroachments**
- [ ] Trees
- [ ] Neighbours
- [ ] **Other Station Issues**
- [ ] Shrubs and grass maintenance
- [ ] Spare equipment
- [ ] Housekeeping
- [ ] **Yard**
- [ ] Grounding / Connections
- [ ] Bonding
- [x] Vegetation
- [x] Gravel or Stone
- [ ] Tree overhanging
- [ ] Switch/ Ground mat
- [ ] Trenches, ducts or conduits
- [x] Lighting
- [ ] Signage
- [ ] **Animals**
- [ ] Birds/ squirrels
- [ ] Racoons
- [ ] **Waterways**
- [ ] Rivers/ pond
- [ ] Ditch
- [ ] Storm sewer

- [ ] **Station Building**
- [ ] Masonry/ concrete
- [ ] Steel/ metallic
- [ ] Grounding
- [ ] Bonding
- [ ] Paint
- [ ] Galvanizing
- [ ] Stairs
- [ ] Roof
- [ ] Windows
- [ ] Doors
- [ ] Station Doors
- [ ] Equipment doors
- [ ] Padlocks
- [ ] Card entry
- [ ] Slippery floor
- [ ] Floor drain present
- [ ] Accessible to children
- [ ] Security
- [ ] Water damage potential

C. Control Building Equipment Concerns

- [ ] Control equipment (RTU, fire and security)
- [ ] Switchgear
- [ ] AC/DC Suppliers
- [ ] Metering (kWh, SCADA, Transducers)
- [ ] Protection Control Systems

Comments:

Vegetation and leaves are all over the yard.
Gravel/stones in the yard need releveling.

D. Cable Concerns

- ☐ Guarding and grounding
- ☐ Leaking potheads
- ☒ Cable supports
- ☐ Termination
- ☐ Oil-filled cables
- ☐ Cable condition
- ☐ Lead sheath cables
- ☒ Unsealed Cable ducts/ conduits
- ☐ Other Issues

E. Miscellaneous Electrical Issues

Metal Enclosed/ Metal Clad Equipment

- ☒ Enclosure Rust
- ☐ Grounding
- ☐ PCB
- ☒ Porcelain insulators
- ☐ Fuses
- ☐ Switches
- ☐ Interlocks
- ☐ Foundations
- ☐ Inoperability
- ☐ Bus
- ☐ Insulator
- ☐ Station service TX
- ☐ Multiple sizes of voltage

Structures

- ☐ Grounding
- ☐ Porcelain arrestors
- ☐ Porcelain switches
- ☐ Height clearance
- ☐ Working clearance
- ☐ Safe limit approach
- ☐ Guarding
- ☐ Substandard design
- ☐ Switching Area difficult
- ☐ Reclosers
- ☐ Connections
- ☒ Foundations
- ☐ Alignment
- ☐ Locks
- ☐ Designation
- ☐ Rust
- ☐ Insulators
- ☐ Station device TX
- ☐ Cut-out

Comments:

Power Cable and control cables are not supported properly.
Water drains toward foundations. (Upgrade the drainage system in the yard.)
Rust observed on metal cabinet. (If the enclosures are not in use these are just crowding the structures; and could be removed.)

METSCO Energy Solutions

Condition Assessment Form

Transformers/ Regulators

Points of Concern	TX 1	TX 2	TX 3	TX 4	TX 5	Spare
Identify the transformer ----->	22T1					
Grounding/ connections						
Age	1971					
Clearances						
Condensation						
Oil Containment	X					
Rust	X					
Oil leakage/ sweating						
Cracked bushings						
Arrestors						
Bushings						
Cooling fans						
Terminations						
Temperature devices	X					
Tap changers						
PCB > 50 ppm historically						
PCB last reading						
Birds/ Animals						

Comments:

Transformer foundations do not have any arrangement for oil containment. Rust observed on the transformer.
There is only one grounding.
There is condensation in temperature gauge.
Oil level gauge cover and load tap changer indicators are rusting. Off load tap changer operator cover is rusting.

Inspected by: [signature] **Date:** 4 November 2015

(Devinder S. Jutla, P.Eng.)

METSCO Energy Solutions

Condition Assessment Form

STATION INSPECTION

Station/Substation: Stroud DS (STR)

Built in Year: 1969

How to interpret this form: A square is checked off/crossed in case of a concern. A blank square means no concern is observed. The explanation to a concern is given in Comments.

A. Important Topics for Consideration

- ☐ Public Safety
- ☐ Worker Safety
- ☒ Environmental Hazard
- ☒ Maintenance Issues
- ☒ Reliability
- ☐ Operational Issues
- ☐ Legal Non- Compliance (Municipal)
- ☐ Regulatory Non-Compliance (ESA/IESO)
- ☐ Any concern report filed? (Kindly attach here)

B. Site Concerns

- ☐ **Proximity**
- ☐ Private Property
- ☐ Residential
- ☐ Commercial
- ☐ Industrial
- ☐ Schools
- ☐ Bike paths
- ☐ Roads/Railways
- ☐ Laneways
- ☐ Noise barriers
- ☐ Explosion Barriers

- ☐ **Fences & Gates**
- ☐ Grounding
- ☐ Bonding
- ☒ Rust
- ☐ Falling over
- ☒ Height
- ☐ Opening
- ☐ Bottom of the fence
- ☐ Between the supports
- ☒ Vegetation on fence
- ☐ Inappropriate attachments
- ☐ Foundations
- ☐ Substandard construction
- ☐ Padlocks
- ☐ Gates open in and out
- ☒ Gravel outside the fence

Comments:

Transformer foundations do not have any arrangement for oil containment.
There is no crushed stone around the station fences. (It not only provides safety to touch potentials but also stops vegetation near the fence)
Fences and gates are rusted. Vegetation is observed on the fences. Fence height is low.
Wooden pole is installed close to the substation structures. In the event if the pole catches fire due to a direct lightning stroke its debris could fall on the station structures and compromise reliability of supply.
Yard is covered with lawn dry grass that could be a fire hazard.

METSCO Energy Solutions

Condition Assessment Form

- [ ] **Encroachments**
- [ ] Trees
- [ ] Neighbours
- [ ] **Other Station Issues**
- [x] Shrubs and grass maintenance
- [x] Spare equipment
- [x] Housekeeping
- [ ] **Yard**
- [ ] Grounding / Connections
- [ ] Bonding
- [x] Vegetation
- [ ] Gravel or Stone
- [ ] Tree overhanging
- [ ] Switch/ Ground mat
- [ ] Trenches, ducts or conduits
- [x] Lighting
- [ ] Signage
- [x] **Animals**
- [ ] Birds/ squirrels
- [ ] Racoons
- [ ] **Waterways**
- [ ] Rivers/ pond
- [ ] Ditch
- [ ] Storm sewer

- [ ] **Station Building**
- [ ] Masonry/ concrete
- [ ] Steel/ metallic
- [ ] Grounding
- [ ] Bonding
- [ ] Paint
- [ ] Galvanizing
- [ ] Stairs
- [ ] Roof
- [ ] Windows
- [ ] Doors
- [ ] Station Doors
- [ ] Equipment doors
- [ ] Padlocks
- [ ] Card entry
- [ ] Slippery floor
- [ ] Floor drain present
- [ ] Accessible to children
- [ ] Security
- [ ] Water damage potential

C. <u>Control Building Equipment Concerns</u>

- [x] Control equipment (RTU, fire and security)
- [ ] Switchgear
- [ ] AC/DC Suppliers
- [ ] Metering (kWh, SCADA, Transducers)
- [ ] Protection Control Systems

Comments:

Yard is all covered with grass.
There is not enough crushed stones.
Spare transformer is sitting in yard. Control building is compromised.
There is no padlock on control building door.
There is wasp nest on control building.

D. Cable Concerns

- [ ] Guarding and grounding
- [ ] Leaking potheads
- [ ] Cable supports
- [ ] Termination
- [ ] Oil-filled cables
- [ ] Cable condition
- [ ] Lead sheath cables
- [x] Unsealed Cable ducts/ conduits
- [ ] Other Issues

E. Miscellaneous Electrical Issues

Metal Enclosed/ Metal Clad Equipment

- [ ] Enclosure Rust
- [ ] Grounding
- [ ] PCB
- [x] Porcelain insulators
- [ ] Fuses
- [ ] Switches
- [ ] Interlocks
- [ ] Foundations
- [ ] Inoperability
- [ ] Bus
- [ ] Insulator
- [ ] Station service TX
- [ ] Multiple sizes of voltage

Structures

- [ ] Grounding
- [ ] Porcelain arrestors
- [ ] Porcelain switches
- [ ] Height clearance
- [ ] Working clearance
- [ ] Safe limit approach
- [ ] Guarding
- [ ] Substandard design
- [ ] Switching Area difficult
- [ ] Reclosers
- [ ] Connections
- [x] Foundations
- [ ] Alignment
- [ ] Locks
- [ ] Designation
- [x] Rust
- [ ] Insulators
- [ ] Station device TX
- [ ] Cut-out

Comments:

Foundations start to deteriorate. Rust is observed on structures.

METSCO Energy Solutions

Condition Assessment Form

Transformers/ Regulators

Points of Concern	TX 1	TX 2	TX 3	TX 4	TX 5	Spare
Identify the transformer ----->	50T1					
Grounding/ connections						
Age	1982					
Clearances						
Condensation						
Oil Containment	X					
Rust	X					
Oil leakage/ sweating						
Cracked bushings						
Arrestors						
Bushings						
Cooling fans						
Terminations						
Temperature devices	X					
Tap changers						
PCB > 50 ppm historically						
PCB last reading						
Birds/ Animals						

Comments:

Transformer foundations do not have any arrangement for oil containment.
Rust observed on transformer.
There is condensation in liquid temperature gauge.
The vacuum gauge is broken.
Transformer fins and base are rusty

Inspected by: ____________________ **Date:** 3 November 2015

(Devinder S. Jutla, P.Eng.)

Appendix C Station Grounding Assessment

METSCO
Energy Solutions

InnPower Corporation
Part B – Station Grounding Assessment

METSCO Project P-15-141-001-GND

Rev.1

May 2016

LICENSED PROFESSIONAL ENGINEER
B.J.
B. JAMALI-FIROUZABADI
PROVINCE OF ONTARIO

Prepared By: ______________________________

Babak Jamali, P.Eng.

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1 INTRODUCTION AND WORK SCOPE

InnPower, formely known as Innisfil Hydro, provides electric power to the residential, commercial and industrial customers in the Town of Innisfil and South Barrie. The utility owns and operates ten distribution substations which are all supplied by Hydro One transformer stations at 44 kV. The service territory of InnPower is about 290 square kilometres which is fed by 29 feeders at lower voltage levels (27.6 and 8.32 kV).

As part of Project # 2015-DO-14-Part B, to evaluate and assess condition of the distribution stations under InnPower service territory, METSCO grounding assessment team was retained to provide a complete assessment on grounding system of eight of the stations by performing grounding inspection, test and modelling.

2 ASSESSMENT TECHNIQUES

2.1 SOIL RESISTIVITY TESTING

METSCO believes that the Wenner method is the most practical resistivity technique for ground grid design. This method uses four test probes located in line, connected to Terminals C1, C2, P1 and P2 of a ground test meter and separated by equal distances. Measured resistance readings are repeated with the spacing typically increased through 1, 2, 5, 10, 20, 50 and 100 m where practical. The apparent resistivity values will then be calculated and entered into custom software. The software will fit a curve to the measured data which represents a two layer soil model.

Four locations, in and around the InnPower service area, were chosen for soil resistivity measurement. The tests provide us a good understanding of the soil condition at the substations.

2.2 INTEGRITY MEASUREMENT

METSCO staff's past experience with some commercial micro-ohm meters reveals that they can produce unreliable measurement with as little as 100 mV of 60 Hz noise present between the test points. This level of interference is common in substations.

METSCO measures grid integrity using a portable, custom made, device that injects about 10 A dc between accessible grid loops. The voltage drop is read on a digital meter and converted to resistance, with resolution of 100 $\mu\Omega$. This is compared to the expected resistance based on the number of conductors and their geometry. The method can detect broken conductors due to trenching or deterioration, while the more global grid resistance test would not provide any indication of a problem until the last of several redundant conductors is broken.

Integrity measurements were conducted at all of the stations, between nearby grounded objects which have buried (non-visible) connections/bonds to the station ground grid.

2.3 GPR, Fall of Potential, Step and Touch Potential Measurement

Since the station grounding impedance with interconnected distribution neutral cannot be measured using the classical fall-of-potential method, METSCO uses a modified fall-of-potential technique to measure this impedance. This method uses arbitrary placement of current probe (C2) and potential probe (P2) preferably in opposite directions, at distances several times the grid diameter, and away from other conductors and lines over a sector of at least 60 degrees wide to either sides. An impedance measuring instrumentation system that resolves both magnitude and phase angles is used for the measurements. Using the information obtained from the soil resistivity test, proximity corrections (between the grid, P2 and C2) is applied to the measurements. The tests will be repeated at several P2 locations and the proximity corrected values will be averaged to find the station interconnected impedance. Current splits in distribution neutral connection were measured using a Rogowsky coil while a twisted pair test lead returns the current signal back to the measuring instrument. In this test both the magnitude and phase angle of each current split was measured and compared to the modeled values. These splits will be subtracted from the current injected to C2 as vector quantities (magnitude and phase angle) to allow resolving the current injected to remote earth by the local station grid.

A complete fall of potential measurement was performed at three of the stations. This test provides us with a good understand about impedance of the neutral at the station.

3 Power Quality

Steady potential of 11.4 V at was measured between station grid and remote earth at Innisfil DS, using a Fluke multi-meter. This voltage exceeds exceeds the 10 V threshold appropriate for distribution systems. Same neutral potential measurement at four other stations provided a value of 5 V and above. This potential is lower than the allowable limit but could be felt by barefoot customers in their backyard (for example when using grounded tools, touching exterior water faucets or adjusting thermostats on an exterior hot tub).

It is recommended to perform further neutral-to-earth harmonic voltage measurement, using instrument appropriate for this task, at and along the feeders leaving Innisfil DS, to understand the magnitude of the neutral-to-earth voltage on different frequencies and recommend mitigation techniques to lower the voltage, at each frequency, based on the measured values.

The harmonic voltage presented on the 8.32 or 27.6 kV bus may exceed the IEEE harmonic standard due to resonance. Such a resonant condition could also lead to failure of capacitor banks, if existed.

4 Grounding Analysis Results

The following subsections represent result of our analysis at the eight stations under the scope of work.

4.1 BIG BAY POINT DS

4.1.1 CONCLUSION / RECOMMENDATION

Conclusion	Recommendation
Integrity testing confirms that the resistance of the bond wire between the metallic objects at the station is less than 2 mΩ.This is consistent with a 67 mm^2 (AWG 2/0) bond conductor having resistances of 0.25 mΩ/m.	
Integrity testing shows that the fence and gate has good longitudinal conductivity.	
The fence around the yard is isolated from station ground. This is acceptable since there is no grounded equipment within the 2 m hand-to-hand reach distance of the fence.	The utility should not bond any metallic object closer than 2 m to the fence to the station ground grid.
A buried longitudinal conductor bonds each sides of the gate. This reduces the hand-to-hand potential when staff opening the gate	
Fence of the communication antenna on the west side of the station is not bonded to the station grid. This is acceptable since the communication antenna is not part of the station.	
Over time, the gravel at the station has sunk into the earth below, became contaminated with windblown fines and vegetation. This reduces effectiveness of the gravel and decreases allowable levels of step and touch potentials. Depth of the gravel at the station is acceptable. There is no sign of vegetation at the station.	1500 mm beyond all areas occupied by equipment and structures should be covered by specified stone with resistivity of 3000 Ωm and depth of at least 80 mm. Vegetation inside of the station should be removed, if any.
There is no gravel outside of the station fence	The minimal width of specified surface stone should be 1500 mm on each side of the fence

Conclusion	Recommendation
There is no gravel around the gate swing area	The area encompassed by the maximum swing of a gate should be covered with specified surface stone. The areas covered by asphalt or concrete are exceptions.
Several aluminum fence risers are connected to copper risers at ground level with Ampact/wedge connectors.	The ampact/wedge connector cannot be used at or under the ground level or in wet locations. It is preferred to be replaced by compression type connections.
The aluminum rise, used to bond the station fence to the longitudinal copper conductor around the fence is brought to the grade level.	Aluminum ground wire shall not be used below grade or in wet locations.
And unapproved and unrated connectors (such as split-bolt type), with uncertain mechanical and electrical properties, is used to bond the metallic equipment at the station.	All the bonding connectors shall meet tests specified by IEEE Std. 837 with the preference being compression connection.
The station does not contain an insulated neutral bus which holds connection to the transformer neutral as well as the feeder neutrals.	An isolated neutral bus should be established with a single connection to the ground grid. The neutral bus returns medium voltage fault current to the station transformer. Multiple neutral connections to station ground allow unbalanced load current to enter the grounding system, a duty for which it is not designed
The permanent gradient control mat under the disconnect switch has sunk into the gravel.	The gradient control mat should contain meshed parallel slats with sufficient thickness to prevent the foot from contacting the underlying soil or stone.
The concentric neutral of the feeder cables are bonded at both ends. This allows return of the unbalance current through the cable.	Derating of the cable ampacity should be considered.

4.1.2 GROUNDING PARAMETERS

Description	Value
First Layer Soil Resistivity (Ωm)	52
Depth of the First Layer (m)	2.25
Second Layer Soil Resistivity (Ωm)	200
Isolated Grid Resistance (Ω)	4.383 ∠ 0
Neutral Impedance (Ω)	0.689 ∠ 34.1
Interconnected Impedance (Ω)	0.608 ∠ 29.6
44kV Fault Current at the station (A)	1052
Current Split into the Ground Grid (A)	146
Ground Potential Rise (V)	640
Touch Potential – Allowable – Specified Stone (V)	630
Touch Potential – Inside of the Fenced Area (V)	169
Touch Potential – Around the Fence (V)	20
Step Potential – Allowable – Specified Stone (V)	2083
Step Potential – Inside and around the Perimeter Fence (V)	19

4.2 STROUD DS

4.2.1 CONCLUSION / RECOMMENDATION

Conclusion	Recommendation
Integrity testing confirms that the resistance of the bond wire between the metallic objects at the station is less than 2 mΩ.This is consistent with a 67 mm^2 (AWG 2/0) bond conductor having resistances of 0.25 mΩ/m.	
Integrity testing shows that the fence and gate has good longitudinal conductivity.	
The fence around the yard is isolated from station ground. This is acceptable since there is no grounded equipment within the 2 m hand-to-hand reach distance of the fence.	The utility should not bond any metallic object closer than 2 m to the fence to the station ground grid.
Measurement shows that the buried longitudinal conductor, bonding each sides of the gate. Is damaged. This bond is need to reduce the hand-to-hand potential when staff opening the gate	The buried bond conductor between each side of the gate should be repaired.
Over time, the gravel at the station has sunk into the earth below, became contaminated with windblown fines and vegetation. This reduces effectiveness of the gravel and decreases allowable levels of step and touch potentials.	1500 mm beyond all areas occupied by equipment and structures should be covered by specified stone with resistivity of 3000 Ωm and depth of at least 80 mm. Vegetation inside of the station should be removed, if any.
There is no gravel outside of the station fence	The minimal width of specified surface stone should be 1500 mm on each side of the fence
There is no gravel around the gate swing area	The area encompassed by the maximum swing of a gate should be covered with specified surface stone. The areas covered by asphalt or concrete are exceptions.

Conclusion	Recommendation
Several aluminum fence risers are connected to copper risers at ground level with Ampact/wedge connectors	The ampact/wedge connector cannot be used at or under the ground level or in wet locations. It is preferred to be replaced by compression type connections.
The aluminum rise, used to bond the station fence to the longitudinal copper conductor around the fence is brought to the grade level.	Aluminum ground wire shall not be used below grade or in wet locations.
And unapproved and unrated connectors (such as split-bolt type), with uncertain mechanical and electrical properties, is used to bond the metallic equipment at the station	All the bonding connectors shall meet tests specified by IEEE Std. 837 with the preference being compression connection.
The station contains an insulated neutral bus for the feeders but missing connection to the transformer neutral.	An isolated neutral bus should be established with a single connection to the ground grid. The neutral bus returns medium voltage fault current to the station transformer. Multiple neutral connections to station ground allow unbalanced load current to enter the grounding system, a duty for which it is not designed
The permanent gradient control mat under the disconnect switch has sunk into the gravel.	The gradient control mat should contain meshed parallel slats with sufficient thickness to prevent the foot from contacting the underlying soil or stone.
The metering shack is bonded to the station grid at just one location with no redundancy.	All equipment, metallic objects and fences inside of the station should be bonded to the station grid through two parallel paths for redundancy.

4.2.2 GROUNDING PARAMETERS

Description	Value
First Layer Soil Resistivity (Ωm)	190
Depth of the First Layer (m)	5.5
Second Layer Soil Resistivity (Ωm)	88
Isolated Grid Resistance (Ω)	$6.912 \angle 0$
Neutral Impedance (Ω)	$0.577 \angle 33.8$
Interconnected Impedance (Ω)	$0.539 \angle 31.3$
44kV Fault Current at the station (A)	1702
Current Split into the Ground Grid (A)	133
Ground Potential Rise (V)	917
Touch Potential – Allowable – Specified Stone (V)	642
Touch Potential – Inside of the Fenced Area (V)	458
Touch Potential – Around the Fence (V)	20
Step Potential – Allowable – Specified Stone (V)	2132
Step Potential – Inside and around the Perimeter Fence (V)	19

4.3 SANDY COVE DS

4.3.1 CONCLUSION / RECOMMENDATION

Conclusion	Recommendation
Integrity testing confirms that the resistance of the bond wire between the metallic objects at the station is less than 2 mΩ.This is consistent with a 67 mm^2 (AWG 2/0) bond conductor having resistances of 0.25 mΩ/m.	
Integrity testing shows that the fence and gate has good longitudinal conductivity.	
The fence around the yard is isolated from station ground. This is acceptable since there is no grounded equipment within the 2 m hand-to-hand reach distance of the fence.	The utility should not bond any metallic object closer than 2 m to the fence to the station ground grid.
A buried longitudinal conductor bonds each sides of the gate. This reduces the hand-to-hand potential when staff opening the gate	
Over time, the gravel at the station has sunk into the earth below, became contaminated with windblown fines and vegetation. This reduces effectiveness of the gravel and decreases allowable levels of step and touch potentials.	1500 mm beyond all areas occupied by equipment and structures should be covered by specified stone with resistivity of 3000 Ωm and depth of at least 80 mm. Vegetation inside of the station should be removed, if any.
There is no gravel outside of the station fence	The minimal width of specified surface stone should be 1500 mm on each side of the fence
There is no gravel around the gate swing area	The area encompassed by the maximum swing of a gate should be covered with specified surface stone. The areas covered by asphalt or concrete are exceptions.

Conclusion	Recommendation
Several aluminum fence risers are connected to copper risers at ground level with Ampact/wedge connectors	The ampact/wedge connector cannot be used at or under the ground level or in wet locations. It is preferred to be replaced by compression type connections.
The aluminum rise, used to bond the station fence to the longitudinal copper conductor around the fence is brought to the grade level.	Aluminum ground wire shall not be used below grade or in wet locations.
And unapproved and unrated connectors (such as split-bolt type), with uncertain mechanical and electrical properties, is used to bond the metallic equipment at the station	All the bonding connectors shall meet tests specified by IEEE Std. 837 with the preference being compression connection.
The station does not contain an insulated neutral bus which holds connection to the transformer neutral as well as the feeder neutrals.	An isolated neutral bus should be established with a single connection to the ground grid. The neutral bus returns medium voltage fault current to the station transformer. Multiple neutral connections to station ground allow unbalanced load current to enter the grounding system, a duty for which it is not designed
The permanent gradient control mat under the disconnect switch has sunk into the gravel.	The gradient control mat should contain meshed parallel slats with sufficient thickness to prevent the foot from contacting the underlying soil or stone.
The concentric neutral of the feeder cables are bonded at both ends. This allows return of the unbalance current through the cable.	Derating of the cable ampacity should be considered.
Concentric neutral of the west side feeder is bonded to the street neutral via a #4 ground wire. This wire is mechanically not strong enough to carry the fault current.	The ground wire between the concentric neutral and the street neutral should be replaced by a properly rated wire.
At the feeder rise pole, the ground wire between the lightning arrestor and the ground rod is broken due to vandalism.	The ground wire require repair

4.3.2 GROUNDING PARAMETERS

Description	Value
First Layer Soil Resistivity (Ωm)	52
Depth of the First Layer (m)	2.25
Second Layer Soil Resistivity (Ωm)	200
Isolated Grid Resistance (Ω)	4.642 ∠ 0
Neutral Impedance (Ω)	0.585 ∠ 34.1
Interconnected Impedance (Ω)	0.528 ∠ 30.4
44kV Fault Current at the station (A)	1276
Current Split into the Ground Grid (A)	145
Ground Potential Rise (V)	674
Touch Potential – Allowable – Specified Stone (V)	630
Touch Potential – Inside of the Fenced Area (V)	180
Touch Potential – Around the Fence (V)	19
Step Potential – Allowable – Specified Stone (V)	2083
Step Potential – Inside and around the Perimeter Fence (V)	18

4.4 LEONARDS BEACH DS

4.4.1 CONCLUSION / RECOMMENDATION

Conclusion	Recommendation
Integrity testing confirms that the resistance of the bond wire between the metallic objects at the station is less than 2 mΩ.This is consistent with a 67 mm^2 (AWG 2/0) bond conductor having resistances of 0.25 mΩ/m.	
Integrity testing shows that the fence and gate has good longitudinal conductivity.	
The fence around the yard is isolated from station ground. This is acceptable since there is no grounded equipment within the 2 m hand-to-hand reach distance of the fence.	The utility should not bond any metallic object closer than 2 m to the fence to the station ground grid.
A buried longitudinal conductor bonds each sides of the gate. This reduces the hand-to-hand potential when staff opening the gate	
Gravel at the yard has a resistivity value which is higher than the specific value. Depth of the specified stone is acceptable.	
There is no gravel outside of the station fence	The minimal width of specified surface stone should be 1500 mm on each side of the fence
There is no gravel around the gate swing area	The area encompassed by the maximum swing of a gate should be covered with specified surface stone. The areas covered by asphalt or concrete are exceptions.
Several aluminum fence risers are connected to copper risers at ground level with Ampact/wedge connectors	The ampact/wedge connector cannot be used at or under the ground level or in wet locations. It is preferred to be replaced by compression type connections.

Conclusion	Recommendation
The aluminum rise, used to bond the station fence to the longitudinal copper conductor around the fence is brought to the grade level.	Aluminum ground wire shall not be used below grade or in wet locations.
And unapproved and unrated connectors (such as split-bolt type), with uncertain mechanical and electrical properties, is used to bond the metallic equipment at the station	All the bonding connectors shall meet tests specified by IEEE Std. 837 with the preference being compression connection.
The station contains an insulated neutral bus for the feeders but missing connection to the transformer neutral. Also, connection between the messenger of the communication cable and the feeders steel structure bypasses the neutral insulator which is planned to provide isolation between the neutral and the ground grid.	An isolated neutral bus should be established with a single connection to the ground grid. The neutral bus returns medium voltage fault current to the station transformer. Multiple neutral connections to station ground allow unbalanced load current to enter the grounding system, a duty for which it is not designed
The permanent gradient control mat under the disconnect switch has sunk into the gravel.	The gradient control mat should contain meshed parallel slats with sufficient thickness to prevent the foot from contacting the underlying soil or stone.
The transformer and the metering shack are bonded to the station grid at just one location with no redundancy.	All equipment, metallic objects and fences inside of the station should be bonded to the station grid through two parallel paths for redundancy.

4.4.2 GROUNDING PARAMETERS

Description	Value
First Layer Soil Resistivity (Ωm)	52
Depth of the First Layer (m)	2.25
Second Layer Soil Resistivity (Ωm)	200
Isolated Grid Resistance (Ω)	4.552 ∠ 0
Neutral Impedance (Ω)	0.39 ∠ 34.1
Interconnected Impedance (Ω)	0.364 ∠ 31.5
44kV Fault Current at the station (A)	753
Current Split into the Ground Grid (A)	60
Ground Potential Rise (V)	274
Touch Potential – Allowable – Specified Stone (V)	630
Touch Potential – Inside of the Fenced Area (V)	73
Touch Potential – Around the Fence (V)	10
Step Potential – Allowable – Specified Stone (V)	2083
Step Potential – Inside and around the Perimeter Fence (V)	10

4.5 BRIAN WILSON DS

4.5.1 CONCLUSION / RECOMMENDATION

Conclusion	Recommendation
Integrity testing confirms that the resistance of the bond wire between the metallic objects at the station is less than 2 mΩ.This is consistent with a 67 mm^2 (AWG 2/0) bond conductor having resistances of 0.25 mΩ/m.	
Integrity testing shows that the fence and gate has good longitudinal conductivity.	
The fence around the yard is isolated from station ground. This is acceptable since there is no grounded equipment within the 2 m hand-to-hand reach distance of the fence.	The utility should not bond any metallic object closer than 2 m to the fence to the station ground grid.
A buried longitudinal conductor bonds each sides of the gate. This reduces the hand-to-hand potential when staff opening the gate	
Over time, the gravel at the station has sunk into the earth below, became contaminated with windblown fines and vegetation. This reduces effectiveness of the gravel and decreases allowable levels of step and touch potentials.	1500 mm beyond all areas occupied by equipment and structures should be covered by specified stone with resistivity of 3000 Ωm and depth of at least 80 mm. Vegetation inside of the station should be removed, if any.
There is no gravel outside of the station fence	The minimal width of specified surface stone should be 1500 mm on each side of the fence
There is no gravel around the gate swing area	The area encompassed by the maximum swing of a gate should be covered with specified surface stone. The areas covered by asphalt or concrete are exceptions.
Several aluminum fence risers are connected to copper risers at ground level with Ampact/wedge connectors	The ampact/wedge connector cannot be used at or under the ground level or in wet locations. It is preferred to be replaced by compression type connections.

Conclusion	Recommendation
The aluminum rise, used to bond the station fence to the longitudinal copper conductor around the fence is brought to the grade level.	Aluminum ground wire shall not be used below grade or in wet locations.
And unapproved and unrated connectors (such as split-bolt type), with uncertain mechanical and electrical properties, is used to bond the metallic equipment at the station	All the bonding connectors shall meet tests specified by IEEE Std. 837 with the preference being compression connection.
The station does not contain an insulated neutral bus which holds connection to the transformer neutral as well as the feeder neutrals.	An isolated neutral bus should be established with a single connection to the ground grid. The neutral bus returns medium voltage fault current to the station transformer. Multiple neutral connections to station ground allow unbalanced load current to enter the grounding system, a duty for which it is not designed
The permanent gradient control mat under the disconnect switch has sunk into the gravel.	The gradient control mat should contain meshed parallel slats with sufficient thickness to prevent the foot from contacting the underlying soil or stone.
The concentric neutral of the feeder cables are bonded at both ends. This allows return of the unbalance current through the cable.	Derating of the cable ampacity should be considered.
The gradient control mat for T2-L disconnect switch is bonded to the station grid at just one location with no redundancy.	All equipment, metallic objects and fences inside of the station should be bonded to the station grid through two parallel paths for redundancy.

4.5.2 GROUNDING PARAMETERS

Description	Value
First Layer Soil Resistivity (Ωm)	57
Depth of the First Layer (m)	11
Second Layer Soil Resistivity (Ωm)	96
Isolated Grid Resistance (Ω)	1.56 ∠ 0
Neutral Impedance (Ω)	0.385 ∠ 33.8
Interconnected Impedance (Ω)	0.318 ∠ 27.3
44kV Fault Current at the station (A)	964
Current Split into the Ground Grid (A)	197
Ground Potential Rise (V)	307
Touch Potential – Allowable – Specified Stone (V)	631
Touch Potential – Inside of the Fenced Area (V)	91
Touch Potential – Around the Fence (V)	10
Step Potential – Allowable – Specified Stone (V)	2085
Step Potential – Inside and around the Perimeter Fence (V)	10

4.6 Cedar Point DS

4.6.1 Conclusion / Recommendation

Conclusion	Recommendation
Integrity testing confirms that the resistance of the bond wire between the metallic objects at the station is less than 2 mΩ.This is consistent with a 67 mm^2 (AWG 2/0) bond conductor having resistances of 0.25 mΩ/m.	
Integrity testing shows that the fence and gate has good longitudinal conductivity.	
The fence around the yard is isolated from station ground. This is acceptable since there is no grounded equipment within the 2 m hand-to-hand reach distance of the fence.	The utility should not bond any metallic object closer than 2 m to the fence to the station ground grid.
A buried longitudinal conductor bonds each sides of the gate. This reduces the hand-to-hand potential when staff opening the gate	
Gravel at the yard has a resistivity value which is higher than the specific value. Depth of the specified stone is acceptable.	
There is no gravel outside of the station fence	The minimal width of specified surface stone should be 1500 mm on each side of the fence
There is no gravel around the gate swing area	The area encompassed by the maximum swing of a gate should be covered with specified surface stone. The areas covered by asphalt or concrete are exceptions.
Several aluminum fence risers are connected to copper risers at ground level with Ampact/wedge connectors	The ampact/wedge connector cannot be used at or under the ground level or in wet locations. It is preferred to be replaced by compression type connections.

Conclusion	Recommendation
The aluminum rise, used to bond the station fence to the longitudinal copper conductor around the fence is brought to the grade level.	Aluminum ground wire shall not be used below grade or in wet locations.
And unapproved and unrated connectors (such as split-bolt type), with uncertain mechanical and electrical properties, is used to bond the metallic equipment at the station	All the bonding connectors shall meet tests specified by IEEE Std. 837 with the preference being compression connection.
The station does not contain an insulated neutral bus which holds connection to the transformer neutral as well as the feeder neutrals.	An isolated neutral bus should be established with a single connection to the ground grid. The neutral bus returns medium voltage fault current to the station transformer. Multiple neutral connections to station ground allow unbalanced load current to enter the grounding system, a duty for which it is not designed
The permanent gradient control mat under the disconnect switch has sunk into the gravel.	The gradient control mat should contain meshed parallel slats with sufficient thickness to prevent the foot from contacting the underlying soil or stone.
The concentric neutral of the feeder cables are bonded at both ends. This allows return of the unbalance current through the cable.	Derating of the cable ampacity should be considered.

4.6.2 GROUNDING PARAMETERS

Description	Value
First Layer Soil Resistivity (Ωm)	57
Depth of the First Layer (m)	11
Second Layer Soil Resistivity (Ωm)	96
Isolated Grid Resistance (Ω)	2.162 ∠ 0
Neutral Impedance (Ω)	0.336 ∠ 33.8
Interconnected Impedance (Ω)	0.297 ∠ 29.4
44kV Fault Current at the station (A)	605
Current Split into the Ground Grid (A)	83
Ground Potential Rise (V)	180
Touch Potential – Allowable – Specified Stone (V)	631
Touch Potential – Inside of the Fenced Area (V)	63
Touch Potential – Around the Fence (V)	4
Step Potential – Allowable – Specified Stone (V)	2085
Step Potential – Inside and around the Perimeter Fence (V)	4

4.7 LEFROY DS

4.7.1 CONCLUSION / RECOMMENDATION

Conclusion	Recommendation
Integrity testing confirms that the resistance of the bond wire between the metallic objects at the station is less than 2 mΩ.This is consistent with a 67 mm^2 (AWG 2/0) bond conductor having resistances of 0.25 mΩ/m.	
Integrity testing shows that the fence and gate has good longitudinal conductivity.	
The fence around the yard is isolated from station ground. This is acceptable since there is no grounded equipment within the 2 m hand-to-hand reach distance of the fence.	The utility should not bond any metallic object closer than 2 m to the fence to the station ground grid.
A buried longitudinal conductor bonds each sides of the gate. This reduces the hand-to-hand potential when staff opening the gate	
Gravel at the yard has a resistivity value which is higher than the specific value. Depth of the specified stone is lower than the acceptable value.	1500 mm beyond all areas occupied by equipment and structures should be covered by specified stone with resistivity of 3000 Ωm and depth of at least 80 mm. Vegetation inside of the station should be removed, if any.
There is no gravel outside of the station fence	The minimal width of specified surface stone should be 1500 mm on each side of the fence
There is no gravel around the gate swing area	The area encompassed by the maximum swing of a gate should be covered with specified surface stone. The areas covered by asphalt or concrete are exceptions.
Several aluminum fence risers are connected to copper risers at ground level with Ampact/wedge connectors	The ampact/wedge connector cannot be used at or under the ground level or in wet locations. It is preferred to be replaced by compression type connections.

Conclusion	Recommendation
The aluminum rise, used to bond the station fence to the longitudinal copper conductor around the fence is brought to the grade level.	Aluminum ground wire shall not be used below grade or in wet locations.
And unapproved and unrated connectors (such as split-bolt type), with uncertain mechanical and electrical properties, is used to bond the metallic equipment at the station	All the bonding connectors shall meet tests specified by IEEE Std. 837 with the preference being compression connection.
The station does not contain an insulated neutral bus which holds connection to the transformer neutral as well as the feeder neutrals.	An isolated neutral bus should be established with a single connection to the ground grid. The neutral bus returns medium voltage fault current to the station transformer. Multiple neutral connections to station ground allow unbalanced load current to enter the grounding system, a duty for which it is not designed
The permanent gradient control mat under the disconnect switch has sunk into the gravel.	The gradient control mat should contain meshed parallel slats with sufficient thickness to prevent the foot from contacting the underlying soil or stone.
The concentric neutral of the feeder cables are bonded at both ends. This allows return of the unbalance current through the cable.	Derating of the cable ampacity should be considered.
The west side fence shows an excessive resistance of 20.3 mΩ between the corners.	A new 67 mm^2 (AWG 2/0) bond should be run between these points.
At the feeder rise pole, the ground wire between the lightning arrestor and the ground rod is broken due to vandalism.	The ground wire require repair

4.7.2 GROUNDING PARAMETERS

Description	Value
First Layer Soil Resistivity (Ωm)	57
Depth of the First Layer (m)	11

Second Layer Soil Resistivity (Ωm)	96
Isolated Grid Resistance (Ω)	2.487 ∠ 0
Neutral Impedance (Ω)	0.563 ∠ 33.8
Interconnected Impedance (Ω)	0.471 ∠ 27.8
44kV Fault Current at the station (A)	686
Current Split into the Ground Grid (A)	130
Ground Potential Rise (V)	323
Touch Potential – Allowable – Specified Stone (V)	631
Touch Potential – Inside of the Fenced Area (V)	124
Touch Potential – Around the Fence (V)	8
Step Potential – Allowable – Specified Stone (V)	2085
Step Potential – Inside and around the Perimeter Fence (V)	8

4.8 Innisfil DS

4.8.1 Conclusion / Recommendation

Conclusion	Recommendation
Integrity testing confirms that the resistance of the bond wire between the metallic objects at the station is less than 2 mΩ.This is consistent with a 67 mm^2 (AWG 2/0) bond conductor having resistances of 0.25 mΩ/m.	
Integrity testing shows that the fence and gate has good longitudinal conductivity.	
Grounding system of the communication antenna is bonded to the city neutral at the entrance panel. The grounding system is also bonded to the fence which is part of the distributions station fence. This voids the idea of having an isolation fence at the distribution station and bonds the fence to the grounding system of the distribution station through a weak connection.	The station fence should be bonded to the distribution station ground grid at several locations via a 67 mm^2 (AWG 2/0) bond conductor
A buried longitudinal conductor bonds each sides of the gate. This reduces the hand-to-hand potential when staff opening the gate	
Gravel at the yard has a resistivity value which is higher than the specific value. Depth of the specified stone is acceptable.	
There is no gravel outside of the station fence	The minimal width of specified surface stone should be 1500 mm on each side of the fence
There is no gravel around the gate swing area	The area encompassed by the maximum swing of a gate should be covered with specified surface stone. The areas covered by asphalt or concrete are exceptions.

Conclusion	Recommendation
Several aluminum fence risers are connected to copper risers at ground level with Ampact/wedge connectors	The ampact/wedge connector cannot be used at or under the ground level or in wet locations. It is preferred to be replaced by compression type connections.
The aluminum rise, used to bond the station fence to the longitudinal copper conductor around the fence is brought to the grade level.	Aluminum ground wire shall not be used below grade or in wet locations.
And unapproved and unrated connectors (such as split-bolt type), with uncertain mechanical and electrical properties, is used to bond the metallic equipment at the station	All the bonding connectors shall meet tests specified by IEEE Std. 837 with the preference being compression connection.
The station contains an insulated neutral bus for the feeders but missing connection to the transformer neutral.	An isolated neutral bus should be established with a single connection to the ground grid. The neutral bus returns medium voltage fault current to the station transformer. Multiple neutral connections to station ground allow unbalanced load current to enter the grounding system, a duty for which it is not designed
The permanent gradient control mat under the disconnect switch has sunk into the gravel.	The gradient control mat should contain meshed parallel slats with sufficient thickness to prevent the foot from contacting the underlying soil or stone.
The metering shack is bonded to the station grid at just one location with no redundancy.	All equipment, metallic objects and fences inside of the station should be bonded to the station grid through two parallel paths for redundancy.

4.8.2 GROUNDING PARAMETERS

Description	Value
First Layer Soil Resistivity (Ωm)	250
Depth of the First Layer (m)	3
Second Layer Soil Resistivity (Ωm)	100
Isolated Grid Resistance (Ω)	4.072 ∠ 0
Neutral Impedance (Ω)	0.452 ∠ 33.3
Interconnected Impedance (Ω)	0.413 ∠ 30.1
44kV Fault Current at the station (A)	825
Current Split into the Ground Grid (A)	84
Ground Potential Rise (V)	341
Touch Potential – Allowable – Specified Stone (V)	647
Touch Potential – Inside of the Fenced Area (V)	125
Touch Potential – Around the Fence (V)	153
Step Potential – Allowable – Specified Stone (V)	2154
Step Potential – Inside and around the Perimeter Fence (V)	67

NOTE:
Fence is considered to be bonded in this calculation.

Appendix G: Renewable Energy Generation Investments Plan

Renewable Energy Generation Investments Plan

Filed with

InnPower Corporation

2017 COS Application

31 December 2015

Executive Summary

This **Renewable Energy Generation (REG) Investments Plan**, identifying investment requirements for accommodating Renewable Energy Generation connections, provides information to the Ontario Energy Board and interested stakeholders regarding the readiness of InnPower Corporation's distribution system to connect renewable energy generation. This includes investment requirements for any expansion or reinforcement necessary to remove grid constraints in order to accommodate the connections of renewable energy generation over the forecast period of 2017-2021.

There are approximately 1,681 kilo-watts (kW) of renewable energy installations connected to InnPower's distribution system, and 500 kW of renewable energy installations connected to InnPower's sub-transmission system under Feed-in-Tariff (FIT) and microFIT programs, all of which are solar photovoltaic projects. This includes 5 FIT projects and 78 microFIT projects. There are currently no FIT projects that have been issued an Offer to Connect by InnPower, but have yet to be grid-connected. Additionally, there are currently 29 microFIT projects with a combined capacity of approximately 281 kW that have applied to InnPower.

Power is supplied to InnPower owned distribution stations from two transmission stations (TS) owned by Hydro One Networks Inc. (HONI) at 44,000 volts, namely Alliston TS and Barrie TS. InnPower also owns four distribution feeders that are supplied power from two HONI owned distribution stations, at 8,320 volts, namely Cookstown West DS and Thornton DS, which are supplied by Alliston TS and Everett TS, respectively.

InnPower had employed the services of Metsco, a renowned Engineering Consulting company, to analyze its circuits for REG connectivity, and to calculate available capacity for REG connection on each feeder. Based on the recommendations of Metsco, InnPower is not proposing any capital investments to increase the capacity of its distribution system to enable further renewable energy generation connectivity over the next five years, from 2017 to 2021.

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1 Introduction

INNPOWER Corporation is preparing the Cost of Service Rate Application as set out in the Report of the Board: Renewed Regulatory Framework for Electricity (RRFE), for rates to be in effect January 01, 2017. In accordance with the Ontario Energy Board's (OEB) Filing Requirements for Electricity Transmission and Distribution Applications – Chapter 5 – Consolidated Distribution System Plan Filing Requirements (EB-2010-377), INNPOWER has prepared this Renewable Energy Generation Investments Plan, identifying the investment requirements for accommodating Renewable Energy Generation connections for its service territory for the five year period 2017-2021.

This Renewable Energy Generation Investments Plan, identifying investment requirements for accommodating new REG connections, provides information to the OEB and interested stakeholders, regarding the readiness of InnPower's distribution system to connect renewable energy generation.

2 INNPOWER Corporation's Distribution Grid

InnPower Corporation owns, operates, and maintains a distribution system currently serving approximately 16,000 customers within an area of about 300 square kilometers. The service territory encompasses all of the Town of Innisfil, which includes the communities of Stroud, Alcona, Lefroy, Churchill, Cookstown, Gilford, Sandy Cove, and Big Bay Point. InnPower also serve communities in South Barrie. A majority of our customers are located in the above noted urban centers. We also serve a smaller percentage of customers who are farmers.

InnPower's industrial customer base is minimal in comparison to residential customers. We have had a steady growth within our service territory in the past 10 years but expect this trend to increase significantly in the next decade. We predict our customer base to double in the next 8-12 years. Our Business Plan and industry projections support this growth projection.

We currently operate our subtransmission system at 44,000 volts and our three-phase distribution system at 27,600 and 8,320 volts. We own, operate and maintain ten (10) distribution substations. We jointly own, operate, and maintain four (4) private substations; and inspect and maintain seven (7) other customer owned substations.

InnPower owns and maintains approximately 130 kM of 44,000 volts sub-transmission conductors, 173 kM of 27,600 volts distribution conductors, and 461 kM of 8,320 volts rated distribution conductors.

InnPower is embedded into Hydro One Networks Inc.'s (HONI) subtransmission system. We currently own, operate, and maintain four (4) subtransmission feeders from our border connection point, all of which have been identified by HONI to have available capacity to connect FIT or micro-FIT generators.

2.1 Municipal Substations

InnPower has ten (10) substations serving the community. The total design capacity is 75 MVA. The subtransmission system (44 kV) allows for transfer of loads between stations as required.

Table 1: Distribution Feeder Data

SUBSTATION	LOCATION	SIZE (kVA)	OWNER	FEEDER #	Volt (kV)	Vintage
BELLE EWART DS	1214 20th Sideroad	10,000	InnPower	F1 & F2	44/27.6	2014
BIG BAY POINT DS	709 13th Line	5,000	InnPower	F1 & F2	44/8.32	1971
BOB DEUGO DS	2033 Commerce Park Drive	10,000	InnPower	F1 & F2	44/27.6	2006
BRIAN WILSON DS	1434 Innisfil Beach Road	10,000	InnPower	F1, F2	44/27.6	1991 (T1)
		10,000		F3 & F4		2014 (T2)
CEDAR POINT DS	733 6th Line	5,000	InnPower	F1 & F2	44/8.32	1976
INNISFIL DS	2255 Highway #89	5,000	InnPower	F1, F2 & F3	44/8.32	1978
LEFROY DS	1495 Killarney Beach Road	5,000	InnPower	F1, F2 & F3	44/8.32	1967
LEONARDS BEACH DS	2895 25th Sideroad	5,000	InnPower	F1 & F2	44/8.32	1974
SANDY COVE DS	1104 Lockhart Road	5,000	InnPower	F1 & F3	44/8.32	1975
STROUD DS	2135 Lockhart Road	5,000	InnPower	F1, F2 & F3	44/8.32	1969

Table 2: Sub-transmission Feeder Capacity Status for DG Connectivity (HONI owned feeders)

Feeder	TS	Voltage	Rating	Available DG Capacity
9M1	Alliston	44 kV	600 amps	27.5MW
9M2	Alliston	44 kV	600 amps	29.75MW
9M4	Alliston	44 kV	600 amps	29MW
13M3	Barrie	44 kV	600 amps	28.5MW

2.2 Thermal Capacity Constraints[1]

The thermal capacity of the distribution system is the ability of its equipment to carry current. Cables and conductors are rated for the load current they carry (InnPower designs for feeders to be loaded to 50% of their rating such that two feeders can be tied together), therefore the anti-islanding constraints prevent the thermal capacity of cables and conductors from being exceeded due to DG. Transformers are more

[1] Excepts from Metsco Energy solutions Report dated 22-December-2015, “InnPower Corporation Part D System Plan”.

sensitive to reverse power flow; therefore, InnPower calculates thermal capacity as 60% of the transformer's nameplate rating added to the minimum load of the transformer; based on Hydro One Networks Inc. guidelines[2].

The table below presents the available thermal capacity for DG at each substation transformer in InnPower's distribution system. The 2016 minimum load is estimated as 25% of the lesser of the summer and winter peaks. The connected and in-progress DG includes both microFIT and Fit for the purpose of the thermal capacity calculation. As shown the DG nameplate ratings do not come close to the thermal capacity of the transformers. Note that Thornton DS and Cookstown West DS are both owned by Hydro One Networks Inc. (HONI), therefore the minimum load and connected/in-progress DG are unknown for feeders not owned by InnPower. The thermal capacities for these two transformers were obtained from HONI's Station and Feeder Capacity Calculator [2].

Table 3: Available thermal capacity for DG

Transformer	Nominal Rating (MVA)	2016 Minimum Load (MVA)	Total Thermal Capacity (MVA)	Connected and In-Progress DG (MW)	Available Thermal Capacity (MVA)
Bob Deugo	10	0.69	6.69	0.162	6.53
Brian Wilson T1	10	1.05	7.05	0.312	6.73
Innisfil	5	0.98	3.98	0.170	3.81
Lefroy	5	0.96	3.96	0.070	3.89
Cedar Point	5	0.90	3.90	0.043	3.85
Belle Ewart	10	0.87	6.87	0.066	6.80
Leonard's Beach	5	0.68	3.68	0.011	3.66
Thornton[9]	5	HONI station	3.26	HONI station	HONI station
Brian Wilson T2	10	1.48	7.48	0.063	7.41
Cookstown West[9]	7	HONI station	4.75	HONI station	HONI station
Sandy Cove	5	0.52	3.52	0.010	3.51
Big Bay Point	5	0.90	3.90	0.013	3.88
Stroud	5	0.69	3.69	0.265	3.42

[9] Owned by HONI.

2.3 Voltage Regulation[3]

InnPower, through the advice provided by its Consultant in 2015, has identified the following instances that could cause voltage regulation issues on its distribution lines with possible impact on REG connectivity. It is currently reviewing the Consultant's report which recommends undertaking a detail static voltage regulation study of its feeders that includes the locations and characteristics of the DG to identify if any of these voltage regulation issues exist in the system.

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[2] Hydro One Networks Inc. (2015, December 9). Station and Feeder Capacity Calculator [Online]. Available: http://www.hydroone.com/Generators/Pages/StationCapacityCalculator.aspx
[3] Excepts from Metsco Energy solutions Report dated 22-December-2015, "InnPower Corporation Part D System Plan".

- Low voltage downstream of a voltage regulator due to insufficient reactive power supplied by the DG.
- Low voltage due to DG drawing lagging reactive power.
- High voltage due to real and leading reactive power produced by DG.
- Voltage unbalance for single phase DG.
- Excessive operation of voltage regulators.
- Reverse power flow through voltage regulation devices.
- Improper voltage regulation when switching to alternate sources.

3 Existing and Proposed Renewable Energy Generation Connections

As of this report date, 24 distribution feeders and 1 Subtransmission feeder have a total of 2.46 MW of solar generation already connected or pending approval.

Among InnPower's 29 distribution feeders, 27 feeders (93%) have not reached the theoretical limit for distributed generation connectivity (when considering the sum of both connections and applications), noted in the IEEE Standard 1547 which is a common industry standard referenced by LDC's in calculating available capacity.

Table 4: REG Installations under the FIT Program

Name	Fuel Source	kW rating	ADDRESS	TS/Feeder	DS/Feeder	Phase	Generation Start Date
Wardlaw Poultry Farm	Solar	150	6037 CTY RD 27, INNISFIL	Everett/9M6	Cookstown/F4	Three Phase	23/08/2012
Innisfil Self Storage	Solar	225	7244 YONGE ST., INNISFIL	Barrie/13M3	Stroud/F1	Three Phase	07/11/2011
Emmanuel Baptist Church	Solar	216	374 SALEM ROAD, BARRIE	Alliston/9M4	Thornton/F2	Three Phase	19/08/2015
Herbert's Boots	Solar	65	2044 COMMERCE PK DR., INNISFIL	Alliston/9M1	Bob Deugo/F1	Three Phase	19/12/2014
Nantyr Shores	Solar	250	1146 ANNA MARIA AVE., INNISFIL	Alliston/9M1	Belle Ewart/F2*	Three Phase	18/09/2015
Robtrans	Solar	57	2252 BOWMAN ST., INNISFIL	Alliston/9M1	Bob Deugo/F1	Single Phase	10/04/2015
Home Hardware	Solar	500	61 QUEEN STREET WEST, COOKSTOWN	Alliston/9M2	N/A (connected to Alliston/9M2)	Three Phase	05/02/2015

* Based on circuit reconfiguration planned in 2016 (currently connected to Brian Wilson F2)

Table 5: REG Installations under the Micro-FIT Program

Address	Capacity (kW)	Fuel Type	Station-TS	Feeder	Year
3379 9th Line, Innisfil	10	SOLAR	ALLISTON	Bob Deugo F2	2010
1833 Innisbrook St, Innisfil	10	SOLAR	ALLISTON	Bob Deugo F2	2010
2543 Gilford Rd, Gilford	10	SOLAR	ALLISTON	Innisfil F1	2010
1782 3rd Line, Churchill	10	SOLAR	ALLISTON	Innisfil F3	2010
1869 2nd Line, Churhill	10	SOLAR	ALLISTON	Innisfil F3	2010
2453 2nd Line, Churchill	10	SOLAR	ALLISTON	Innisfil F3	2010
5695 Hwy 11, Gilford	10	SOLAR	ALLISTON	Innisfil F3	2010
1993 3rd Line, Churchill	10	SOLAR	ALLISTON	Innisfil F3	2010
2000 Kilarney Beach Road, Churchill	10	SOLAR	ALLISTON	Innisfil F3	2010
2298 Meadowland Drive, Churchill	10	SOLAR	ALLISTON	Lefroy F2	2010
6688 Yonge St, Lefroy	10	SOLAR	ALLISTON	Lefroy F2	2010
3053 Sandy Cove, Innisfil	2.5	SOLAR	ALLISTON	Leonard’s Beach F3	2010
6554 5th SD RD, Innisfil	10	SOLAR	ALLISTON	Thornton F1	2010
3699 9th Line, Innisfil	10	SOLAR	ALLISTON	Thornton F1	2010
7667 10th SD RD, Innisfil	10	SOLAR	ALLISTON	Bob Deugo F2	2011
2147 Innisfil Beach Road, Innisfil	10	SOLAR	ALLISTON	Bob Deugo F2	2011
656 Glen Cedar Cre, Innisfil	3	SOLAR	ALLISTON	Brian Wilson F1	2011
2052 Innisfil Beach Road, Innisfil	10	SOLAR	ALLISTON	Brian Wilson F1	2011
654 Glen Cedar Drive, Innisfil	3	SOLAR	ALLISTON	Brian Wilson F1	2011
1871 7th Line, Innisfil	10	SOLAR	ALLISTON	Belle Ewart F2	2011
1698 Innisfil Beach Road, Innisfil	10	SOLAR	ALLISTON	Belle Ewart F2	2011
2011 Innisfil Beach Road, Innisfil	10	SOLAR	ALLISTON	Belle Ewart F2	2011
2348 Innisfil Beach Road, Innisfil	10	SOLAR	ALLISTON	Belle Ewart F2	2011
2037 Wilson St, Innisfil	5	SOLAR	ALLISTON	Brian Wilson F3	2011
2316 Guilford Rd, Gilford	10	SOLAR	ALLISTON	Innisfil F1	2011
2543 Gilford Rd, Gilford	10	SOLAR	ALLISTON	Innisfil F1	2011
5385 Yonge St, Innisfil	10	SOLAR	ALLISTON	Innisfil F1	2011
1154 Glen Kerr Dr, Gilford	10	SOLAR	ALLISTON	Innisfil F2	2011
2313 3rd Line, Churchill	10	SOLAR	ALLISTON	Innisfil F3	2011
2566 Hwy 89, Gilford	10	SOLAR	ALLISTON	Innisfil F3	2011
5971 Yonge St, Churchill	10	SOLAR	ALLISTON	Innisfil F3	2011
1103 Ferrier Ave, Lefroy	10	SOLAR	ALLISTON	Lefroy F1	2011
4112 7th Line, Innisfil	10	SOLAR	ALLISTON	Thornton F1	2011
3657 2nd Line, Cookstown	10	SOLAR	ALLISTON	Thornton F1	2011
7076 5th SD RD, Innisfil	10	SOLAR	ALLISTON	Thornton F1	2011
7403 County Rd 27, Innisfil	10	SOLAR	ALLISTON	Thornton F2	2011
3825 9th Line, Innisfil	10	SOLAR	ALLISTON	Thornton F2	2011
49 Sunny Point Drive, Innisfil	3	SOLAR	BARRIE	Big Bay Point F1	2011
3559 Crescent Harbor, Innisfil	10	SOLAR	BARRIE	Big Bay Point F2	2011
2155 Southview Ave, Innisfil	10	SOLAR	BARRIE	Stroud F3	2011
2591 10th Line, Innisfil	10	SOLAR	BARRIE	Stroud F3	2011
6181 5th SD SRD, Cookstown	10	SOLAR	EVERETT	Cookstown West F2	2011
3288 4th Line, Cookstown	10	SOLAR	EVERETT	Cookstown West F4	2011

(Continued)

Address	Capacity (kW)	Fuel Type	Station-TS	Feeder	Year
1702 Innisfil Beach Road, Innisfil	10	SOLAR	ALLISTON	Belle Ewart F2	2011
5658 Yonge St, Innisfil	10	SOLAR	ALLISTON	Innisfil F3	2011
2823 13th Line, West Gwillimbury (LTLT)	10	SOLAR	ALLISTON	Innisfil F1	2012
1574 9th Line, Innisfil	10	SOLAR	ALLISTON	Brian Wilson F1	2012
1624 9th Line, Innisfil	10	SOLAR	ALLISTON	Brian Wilson F1	2012
1514 Rankin Way, Innisfil	10	SOLAR	ALLISTON	Brian Wilson F1	2012
2154 Willard Ave, Innisfil	10	SOLAR	ALLISTON	Brian Wilson F3	2012
1206 Inniswood St, Innisfil	10	SOLAR	ALLISTON	Brian Wilson F3	2012
909 Adams Rd, Innisfil	10	SOLAR	ALLISTON	Brian Wilson F3	2012
1010 Evans Place, Belle Ewart	5	SOLAR	ALLISTON	Cedar Point F2	2012
917 Sheppards Trail, Innisfil	10	SOLAR	ALLISTON	Cedar Point F2	2012
1141 Parkway Dr, Gilford	10	SOLAR	ALLISTON	Innisfil F2	2012
1450 3rd Line, Innisfil	10	SOLAR	ALLISTON	Lefroy F3	2012
2191 Southview Ave, Innisfil	10	SOLAR	BARRIE	Stroud F3	2012
1121 Booth Ave, Innisfil	7	SOLAR	ALLISTON	Belle Ewart F2	2013
1125 Booth Ave, Innisfil	3	SOLAR	ALLISTON	Belle Ewart F2	2013
1916 Romina Crt, Innisfil	6.25	SOLAR	ALLISTON	Belle Ewart F2	2013
1955 Swan St, Innisfil	10	SOLAR	ALLISTON	Brian Wilson F3	2013
2083 Inglewood Drive, Innisfil	10	SOLAR	ALLISTON	Brian Wilson F3	2013
1015 Arnold St, Lefroy	10	SOLAR	ALLISTON	Cedar Point F2	2013
949 Goldie St, Belle Ewart	10	SOLAR	ALLISTON	Cedar Point F2	2013
1369 Killarney Beach Road	10	SOLAR	ALLISTON	Lefroy F1	2013
450 Limerick St, Churchill	10	SOLAR	ALLISTON	Lefroy F3	2013
3622 McCormick Gate, Innisfil	10	SOLAR	BARRIE	Sandy Cove F1	2013
213 Parkside Crescent, Innisfil	10	SOLAR	BARRIE	Stroud F1	2013
5380 County Rd 27, Thornton (LTLT)	10	SOLAR	ALLISTON	Thornton F1	2013
1441 Bassingthwaite Court, Innisfil	10	SOLAR	ALLISTON	Brian Wilson F1	2014
721 Happy Vale Drive, Innisfil	6.25	SOLAR	ALLISTON	Brian Wilson F1	2014
2196 Nevils St, Innisfil	8	SOLAR	ALLISTON	Brian Wilson F4	2014
4375 14th Line, Cookstown	10	SOLAR	EVERETT	Cookstown West F2	2014
7 Cloverhill Cres, Cookstown	8	SOLAR	EVERETT	Cookstown West F2	2014
Lot 20 Concession 1, Churchill (1627 2nd Line)	10	SOLAR	ALLISTON	Innisfil F3	2014
2765 Ireton St, Innisfil	10	SOLAR	ALLISTON	Brian Wilson F1	2015
1026 Anna Marie Ave, Innisfil	10	SOLAR	ALLISTON	Cedar Point F1	2015
3801 West St, Innisfil	7.6	SOLAR	BARRIE	Big Bay Point F1	2015

Table 6: REG applications awaiting approval for grid connection under the Micro-FIT program

Address	Capacity (kW)	Fuel Type	Station-TS	Feeder
2758 Innisfil Beach Road, Innisfil	10	SOLAR	ALLISTON	Bob Deugo F2
783 Bayview Dr, Barrie	10	SOLAR	ALLISTON	Brian Wilson F1
2632 Wilson Place, Innisfil	10	SOLAR	ALLISTON	Brian Wilson F1
2835 McKee CRT, Innisfil	10	SOLAR	ALLISTON	Brian Wilson F1
1588 7th Line, Innisfil	10	SOLAR	ALLISTON	Belle Ewart F2
1119 Booth Ave, Innisfil	10	SOLAR	ALLISTON	Belle Ewart F2
1229 Hill ST, Innisfil	10	SOLAR	ALLISTON	Brian Wilson F3
1954 Webster Blvd, Innisfil	10	SOLAR	ALLISTON	Brian Wilson F3
1958 Romina Crt, Innisfil	10	SOLAR	ALLISTON	Brian Wilson F3
1988 Wilson St, Innisfil	10	SOLAR	ALLISTON	Brian Wilson F3
1257 Gina St, Innisfil	10	SOLAR	ALLISTON	Brian Wilson F3
1285 Lowrie St, Innisfil	10	SOLAR	ALLISTON	Brian Wilson F3
1263 Gina Dr, Innisfil	10	SOLAR	ALLISTON	Brian Wilson F3
2245 Sproule St, Innisfil	10	SOLAR	ALLISTON	Brian Wilson F4
2252 Dawson Crescent, Innisfil	10	SOLAR	ALLISTON	Brian Wilson F4
1003 Garden Ave, Innisfil	10	SOLAR	ALLISTON	Cedar Point F1
1866 Simcoe Blvd, Innisfil	10	SOLAR	ALLISTON	Cedar Point F1
1164 North Shore Dr	10	SOLAR	ALLISTON	Innisfil F2
995 Isabella St, Belle Ewart	10	SOLAR	ALLISTON	Lefroy F1
1076 Ewart St, Innisfil	10	SOLAR	ALLISTON	Lefroy F1
1078 Wisker Ave, Innisfil	10	SOLAR	ALLISTON	Lefroy F1
3794 7th Line, Innisfil	10	SOLAR	ALLISTON	Thornton F1
685 Pine Grove Ave, Innisfil	10	SOLAR	BARRIE	Big Bay Point F2
223 Nelson Cres, Innisfil	10	SOLAR	BARRIE	Stroud F1
11 Kidd's lane RR4 Cookstown	3	SOLAR	EVERETT	Cookstown West F2
29 Cloverhill Cres, Innisfil	9	SOLAR	EVERETT	Cookstown West F2
4293 2nd Line, Innisfil	9	SOLAR	EVERETT	Cookstown West F4
104 Golfview Rd, Innisfil	10	SOLAR	ALLISTON	Innisfil F2
1171 Andrade Lane, Innisfil	10	SOLAR	ALLISTON	Brian Wilson F3

4 System Assessment to Identify Constraints

InnPower had employed the services of Metsco, a renowned Engineering Consulting company, to analyze it's circuits for REG connectivity, and to calculate available capacity for REG connection on each feeder.

Based on their evaluations, and considering the sum of both connections and applications, 2 of our distribution feeders (7%) have been identified on InnPower's distribution system as having reached the threshold for distributed generation connectivity (and six others are less than 20kW from reaching their threshold), as per the criteria described in the IEEE Standard 1547, which limits the total distributed generation connectivity to under 33% of the minimum load on a given feeder. Since all of InnPower's distributed generation connections use solar based generation, and since all such generators use inverters that switch off when a frequency disparity is observed, the constraints noted in the above IEEE standard will therefore theoretically have little to no impact on creating "islanding issues".

The Consultant has, however, recommended that InnPower consider a different methodology than the commonly referenced IEEE Standard 1547 which uses a "rule-of thumb" approach, and which is based on assumptions and a worst-case-scenario type analysis. Instead it is recommended that we consider the use of a preferred methodology of performing dynamic (real time based) studies using an Electro-Magnetic Transients Program (EMTP) to calculate real time constraints on each phase of every feeder that would more accurately determine actual constraints on the grid, and to develop methodologies and specific projects to enhance REG connectivity subsequent to the EMTP analysis.

Following the advice from the Consultant InnPower is currently reviewing their recommendation to conduct the EMTP study, and therefore InnPower is not proposing any capital investments at this time to mitigate constraints on the distribution system.

Table 7: Distribution Feeder Level Capacity Summary (DG capacity based on anti-islanding guidelines)

Feeder	2016 Minimum Load Estimation (kVA)	Connected and In-Progress microFIT (kW)	Remaining DG Capacity – 33% of Min. Load (kW)	Remaining DG Capacity – 67% of Min. Load (kW)
Belle Ewart F1	68	0	23	45
Belle Ewart F2	798	86	180	446
Big Bay Point F1	469	11	146	302
Big Bay Point F2	426	20	122	264
Bob Deugo F1	463	0	154	309
Bob Deugo F2	225	50	25	100
Brian Wilson F1	1045	102	246	594
Brian Wilson F2*	0	0	N/A	N/A
Brian Wilson F3	1248	135	281	697
Brian Wilson F4	197	28	38	103
Cedar Point F1	373	30	94	219
Cedar Point F2	523	35	139	314
Cookstown West F2	149	40	10	59
Cookstown West F4	120	19	21	61
Innisfil F1	415	50	88	227
Innisfil F2	250	40	43	127
Innisfil F3	315	110	-5	100
Lefroy F1	458	50	103	255
Lefroy F2	340	20	93	207
Lefroy F3	158	20	33	85
Leonard's Beach F1	215	0	72	143
Leonard's Beach F3	280	3	91	184
Sandy Cove F1	253	10	74	159
Sandy Cove F3	153	0	51	102
Stroud F1	311	20	84	187
Stroud F2	40	0	13	27
Stroud F3	310	30	73	177
Thornton F1	120	70	-30	10
Thornton F2	110	20	17	53

* All of Brian Wilson F2 load is to be transferred to Belle Ewart F2 in 2016 (when the Belle Ewart DS transformer is repaired and the station is re-energized). Since all system planning and load forecast studies are based on this circuit reconfiguration, to be consistent with other reports this table shows the intended REG feeder connectivity scheme)

4.1 Future Growth and its impact on REG Connectivity:

The projected increase in our customer base to 200% of its current level in the next 8-12 years has required InnPower to expand and/or upgrade several circuits in it long term capital plan to meets new load requirements. This infrastructure investment will further enhance REG connectivity, thus enabling more InnPower customers to participate in the Micro-FIT program.

5 Proposed Investments to Facilitate Renewable Energy Generation Connections

As noted in section 4 above, based on the recommendations made by Metsco, InnPower is not proposing any capital investments to increase the capacity of its distribution system to enable further renewable energy generation connectivity over the next five years, from 2017 to 2021.

END OF REPORT: RENEWABLE ENERGY GENERATION INVESTMENTS PLAN

Appendix H: IESO Comment Letter on Renewable Energy Generation Investments Plan

IESO Letter of Comment

InnPower Corporation

Renewable Energy Generation Investments Plan

Date: January 29, 2016

Independent Electricity System Operator

Introduction

On March 28, 2013, the Ontario Energy Board ("the OEB" or "Board") issued its Filing Requirements for Electricity Transmission and Distribution Applications; Chapter 5 – Consolidated Distribution System Plan Filing Requirements (EB-2010-0377). Chapter 5 implements the Board's policy direction on 'an integrated approach to distribution network planning', outlined in the Board's October 18, 2012 Report of the Board - A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach.

As outlined in the Chapter 5 filing requirements, the Board expects that the Ontario Power Authority[1] ("OPA") comment letter will include:

- the applications it has received from renewable generators through the FIT program for connection in the distributor's service area;
- whether the distributor has consulted with the OPA, or participated in planning meetings with the OPA;
- 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 DS Plan are consistent with any Regional Infrastructure Plan.

InnPower Corporation – Distribution System Plan

On January 8, 2016, InnPower Corporation ("InnPower") provided its Renewable Energy Generation ("REG") Investments Plan ("Plan") dated December 31, 2015 to the Independent Electricity System Operator ("IESO") covering a 5-year planning period from 2017-2021. The IESO has reviewed InnPower's Plan and provides the following comments.

OPA FIT/microFIT Applications Received

The Plan indicates that InnPower has 6 FIT projects and 78 microFIT projects that are connected to its distribution system and 1 FIT project connected to its sub-transmission system, representing 2.18 MW of capacity.

According to the IESO's information, as of December 31, 2015, the IESO has offered contracts to 7 FIT projects totalling 1.46 MW and to 79 microFIT projects totalling 706 kW of capacity. Altogether the IESO has offered contracts to 2.17 MW of projects. The renewable energy generation connections information in InnPower's Plan is therefore reasonably consistent with that of the IESO.

[1] On January 1, 2015, the Ontario Power Authority ("OPA") merged with the Independent Electricity System Operator ("IESO") to create a new organization that will combine the OPA and IESO mandates. The new organization is called the Independent Electricity System Operator.

Independent Electricity System Operator
1600 – 120 Adelaide Street West, Toronto, ON M5H 1T1
t 416 967-7474 f 416 967-1947 toll free 1-800-797-9604 customer.relations@ieso.ca www.ieso.ca

Consultation / Participation in Planning Meetings; Coordination with Distributors / Transmitters / Others; Consistency with Regional Plans

For regional planning purposes, along with the IESO, Hydro One Networks Inc. ("HONI") (Distribution and Transmission), PowerStream Inc., COLLUS PowerStream Corp., Lakeland Power Distribution Ltd., Midland Power Utility Corp., Orangeville Hydro Ltd., Orillia Power Distribution Corp., Parry Sound Power Corp., Newmarket-Tay Power Distribution Ltd., Veridian Connections Inc., and Wasaga Distribution Inc., InnPower Corporation is part of "Group 2" and the South Georgian Bay/Muskoka Region.

The Plan indicates that InnPower is embedded in HONI's sub-transmission system.[2] Under the new regional planning process endorsed by the OEB in August 2013, while the host distributor is required to gather information from their respective embedded LDCs, it is not required that embedded LDCs be directly involved in the regional planning process. However, as confirmed in the IESO's Scoping Assessment Report dated June 22, 2015, InnPower is part of the regional study team, specifically for the Barrie Innisfil Integrated Regional Resource Plan ("IRRP").

InnPower has been actively involved as a Working Group member in the Barrie Innisfil IRRP, contributing to the completion of the first phase of the IRRP, identifying a near-term wires solution to address end of life and capacity needs at Barrie TS. The Working Group is currently developing the medium- and long-term plan for the Barrie Innisfil area.

The IESO looks forward to continuing to work with InnPower Corporation on regional planning for the South Georgian Bay/Muskoka Region, specifically on the Barrie Innisfil IRRP, and appreciates the opportunity to comment on the information provided as part of its Plan at this time.

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[2] InnPower Corporation, Renewable Energy Generation (REG) Investments Plan, Page 2.

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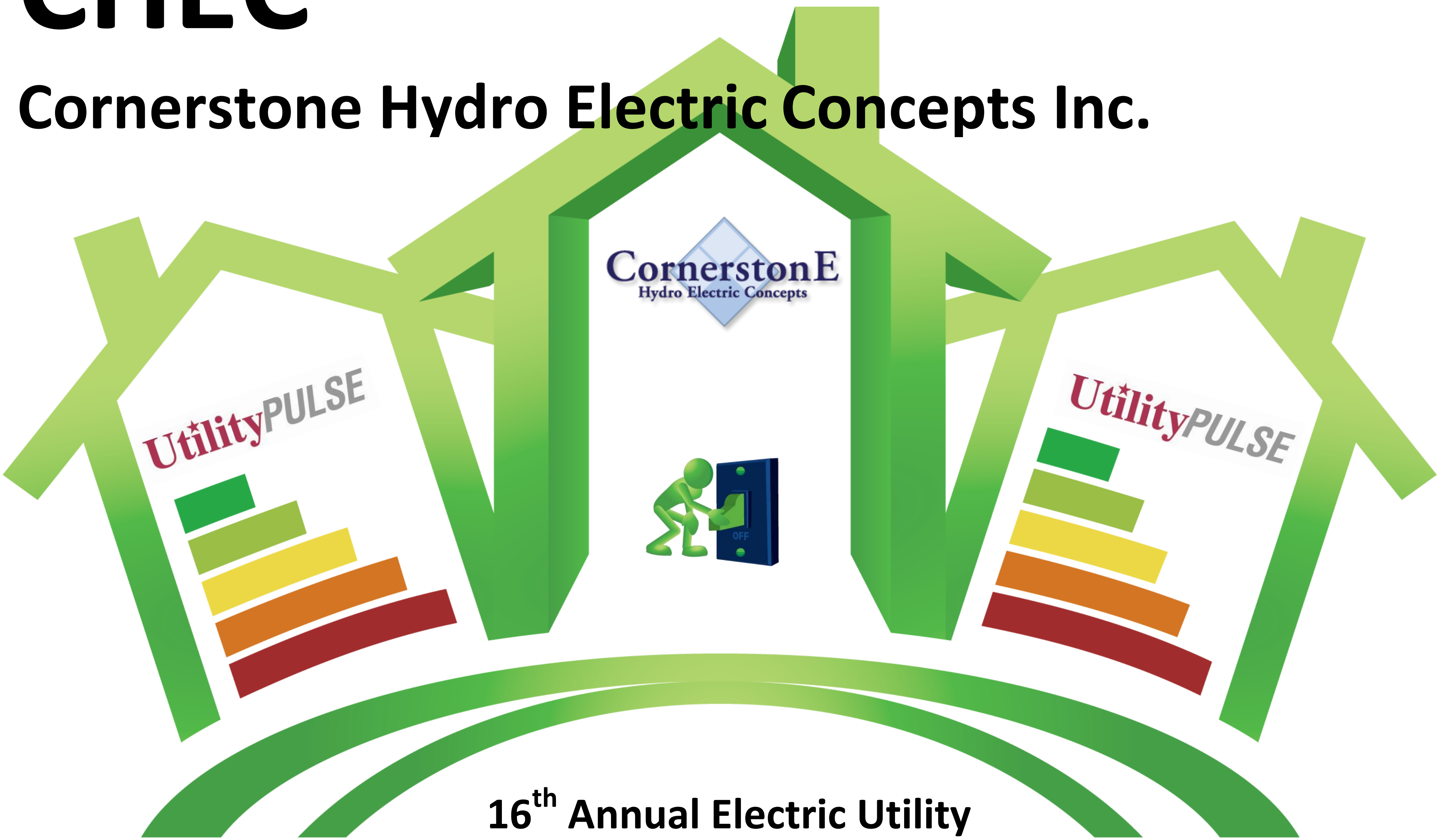
t 416 967-7474 f 416 967-1947 toll free 1-800-797-9604 customer.relations@ieso.ca www.ieso.ca

Appendix I: UtilityPULSE Survey

CHEC

Cornerstone Hydro Electric Concepts Inc.



16th Annual Electric Utility Customer Satisfaction Survey

The purpose of this report is to profile the connection between Cornerstone Hydro Electric Concepts Inc. (CHEC) and its customers.

The primary objective of the Electric Utility Customer Satisfaction Survey is to provide information that will support discussions about improving customer care at every level in your utility.

The UtilityPULSE Report Card® and survey analysis contained in this report do not merely capture state of mind or perceptions about your customers' needs and wants - the information contained in this survey provides actionable and measurable feedback from your customers.

All comments and questions should be addressed to:

Sid Ridgley, UtilityPULSE division, Simul Corporation

Toll free: 1-888-291-7892 or Local: 905-895-7900

Email: sidridgley@utilitypulse.com or sridgley@simulcorp.com

Executive summary

Rosemarie LeClair, Chair of the Ontario Energy Board, in a recent presentation (Ontario Energy Network, April 28, 2014) said the OEB's consumer centric regulatory framework defines the utility's obligation for planning, obligations for customer engagement and its responsibilities for monitoring and measuring performance results.

EB-2010-0379 Report of the Board: Scorecard Approach (ROB-SA) (March 5, 2014)

Throughout this report are connections to the OEB's Report of the Board. Where possible we have addressed the specifics in the document and, the "spirit" of the Scorecard Approach.

We believe that the data from interviewing over 10,000 electric utility customers so far, in 2014, supports 3 main conclusions:

1- Customers, almost universally, are concerned about the cost of electricity

2- Customers are resilient and can adapt to adversity, in fact, they are very tolerant when a utility goes through a very difficult situation

3- In a utility world that is used to "pushing information out", it has to invest in and hone its competencies in having 2-way interactions with customers.

Reasonable costs

9,943 Ontario survey respondents were asked if they agree or disagree with the following statement *"The cost of electricity is reasonable when compared to other utilities".* 50% agree in 2014, and 62% agreed in 2010. Satisfaction with the utility is about the same in those respective years.

We can also say that issues in the electricity industry, as a whole, show that satisfaction ratings and other important measures are lower in 2014 than they were in 2013. A customer may be upset with the amount that electricity costs, or what is going on in the industry, but that may not translate to being upset with their own local utility.

Data from the 2014 survey shows that respondents who give their utilities high marks for respect, trust, and social responsibility also give their utilities high marks for providing high quality services, and better marks for both cost efficiency and reasonableness of costs.

The attributes which help an LDC to be seen as trusted and highly credible are: knowledge, integrity, involvement and trust. On demonstrating Credibility and Trust, CHEC has done well.
Overall, CHEC 85% [Ontario 77%; National 80%].

EB-2010-0379 ROB-SA: Comparability

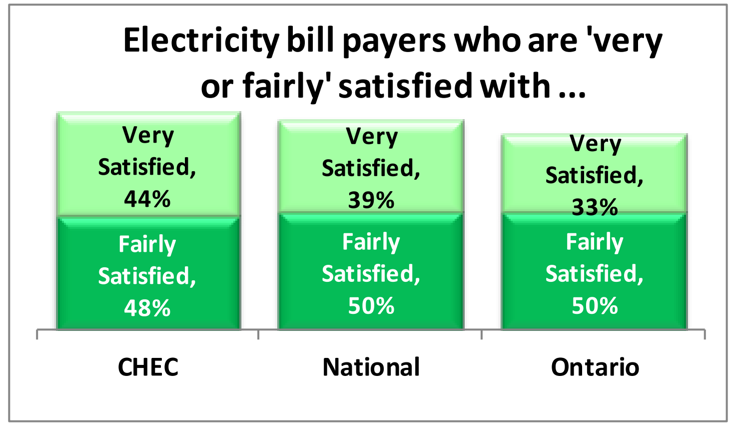
Your 2014 report contains data comparisons to:

- An Ontario-wide LDC benchmark
- A National LDC benchmark
- Previous year's ratings (where available)

- Ontario LDCs participating in the 2014 survey
- UtilityPULSE database

EB-2010-0379 ROB-SA: Customer Focus

There are 2 identified Performance Categories in the OEB Report, they are Customer Satisfaction & Service Quality. Performance measurements for these areas range from *'relatively easy to attain production statistics'* to *'harder to define and measure qualitative items'*. None-the-less this survey provides you with insights about how customers perceive performance of the utility.



Base: total respondents

EB-2010-0379 ROB-SA: Customer Focus - Customer Satisfaction - Satisfaction Survey Results

Customer satisfaction is one of the measures in the consumer centric regulatory framework. This rating is known as an effectiveness rating as it represents a sum total of perceptions and expectations that a customer has about their utility. Those expectations go far beyond “keeping the lights on”, “billing me properly”, and “restoring power quickly”.

CHEC SATISFACTION SCORES – Electricity customers' satisfaction					
Top 2 Boxes: 'very + fairly satisfied'	**2014**	**2013**	**2012**	**2011**	**2010**
PRE: Initial Satisfaction Scores	92%	92%	-	-	-
POST: End of Interview	93%	94%	-	-	-

Base: total respondents / (-) not a participant of the survey year

- ***Satisfaction*** *happens when utility core services meet or exceed customer's needs, wants, or expectations.*
- ***Loyalty*** *(Affinity) occurs when a customer makes an emotional connection with their electric utility on a diverse range of expectations beyond core services.*

Customer Affinity

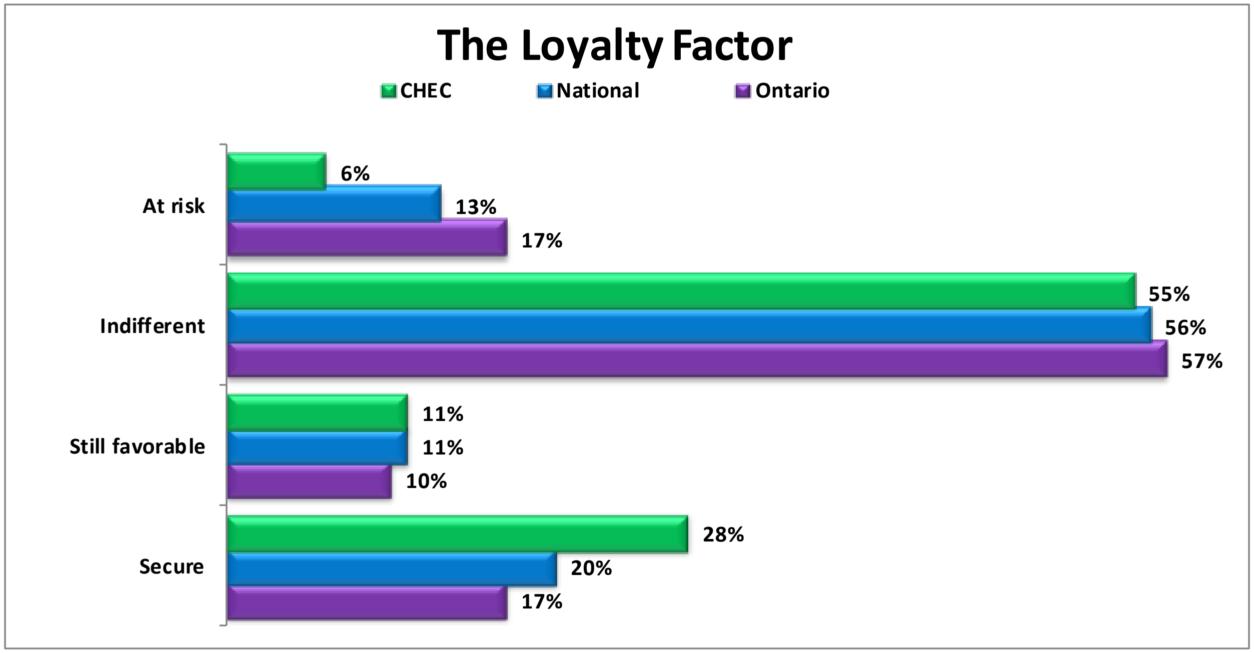
Loyalty, for private industry, is a behaviourial metric. Loyalty, for natural monopolies (like LDCs) is an attitudinal metric.

Customer Loyalty Groups				
	Secure	**Favorable**	**Indifferent**	**At Risk**
CHEC				
2014	28%	11%	55%	6%
2013	33%	13%	49%	5%

Base: total respondents

Even if customers can't defect, there is enormous value in making more of them loyal. Customers after all make the company's reputation. Reputation is ultimately what customers think – nothing else. To be successful and profitable, companies must take account of how they are perceived because companies do operate in a climate of opinion.

Loyal customers are more likely to see the world the way hydro management sees it. Customers feel their interests and the hydro's are often in common. Our survey results do reveal, loyal customers enhance the value of the utility. One example, 99% of Secure customers agree that overall CHEC 'provides excellent quality services' versus 58% of At Risk customers.



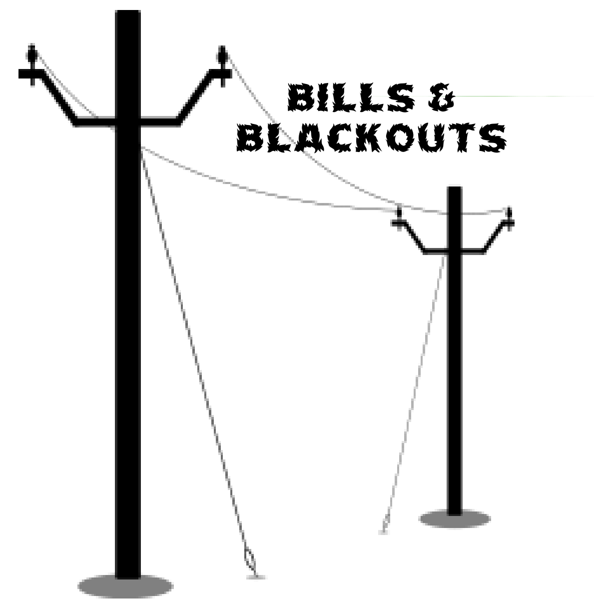
Base: total respondents

Utilities benefit from a trusted relationship with their empowered Customers. Higher levels of trust are the hallmarks of Secure customers. When people interact, either face-to-face, by telephone or on-line, if people do not trust each other, the interaction is not going to be efficient. Trust improves the speed at which the interaction can be accomplished. At Risk customers recall experiencing more outages and more billing problems than Secure customers. What makes matters worse is, At Risk customers are about 2X more likely to contact the utility to deal with it.

None-the-less problems will happen.

The Killer B's (Blackouts and Bills)

It is inevitable that there will be blackouts/power outages – the key is how a utility anticipates outages and more importantly, how it deals with them. It should also be noted that there is a disconnect between what a utility might call a "billing problem" and what a customer defines as a "billing problem". Though both viewpoints are valid, employees need to be trained to answer those which cause the most concern with customers.



Percentage of Respondents indicating that they had a Blackout or Outage problem in the last 12 months

	CHEC	National	Ontario
2014	36%	47%	49%
2013	36%	41%	35%
2012	-	44%	46%
2011	-	43%	43%
2010	-	45%	41%

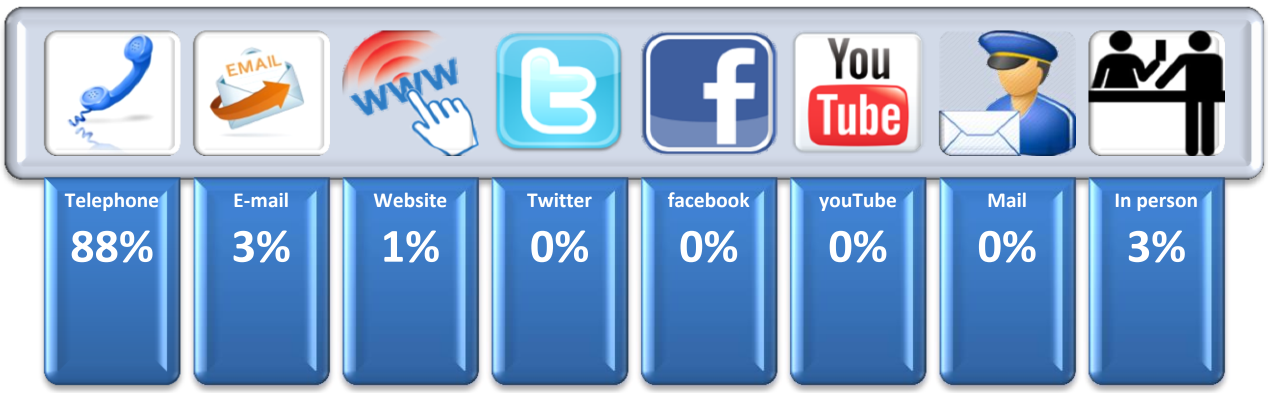
Base: total respondents / (-) not a participant of the survey year

Percentage of Respondents indicating that they had a Billing problem in the last 12 months			
	CHEC	National	Ontario
2014	12%	16%	25%
2013	10%	8%	10%
2012	-	12%	13%
2011	-	10%	16%
2010	-	10%	12%

Base: total respondents / (-) not a participant of the survey year

What method did you use to contact your electric utility when you had a problem?

Base: data from the full 2014 database



Customers may prefer a particular communication channel today (i.e., 88% telephone), however, that does not mean the customer who prefers the telephone will not want, or eventually want another channel for communications. In addition, there could be variances in preferences based on the type of issue or transaction.

EB-2010-0379 ROB-SA: Customer Focus – Customer Satisfaction – Billing Accuracy

There is a difference between what a customer believes is a billing problem versus a technical or production level measurement. Without the benefit of production level numbers, 88% of respondents 'agree strongly + somewhat' that the utility has "accurate billing". The Ontario benchmark rating is 77%.

EB-2010-0379 ROB-SA: Customer Focus – Customer Satisfaction – First Contact Resolution

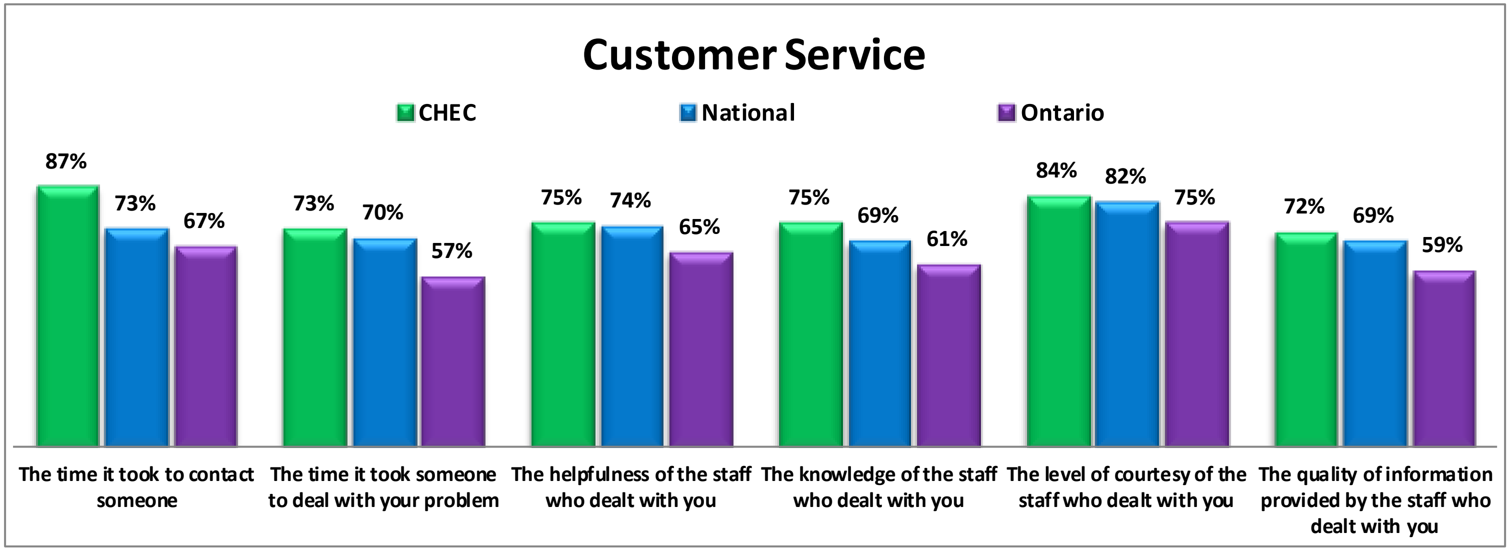
This performance measure is not defined in the EB-2010-0379 ROB-SA March 5, 2014 document. First contact resolution is an outcome base measurement which is affected by: type of problem, competency levels of staff, empowerment levels of staff, and organization culture to name a few.

Your 2014 survey gives you the following information from respondents:

1- Satisfaction with the contact experience
2- A problem solved rating
3- A Customer Experience Performance rating (CEPr)

Satisfaction with the contact experience

When there are problems, how they are handled can validate or invalidate a customer's perception about the utility's competency in handling the problem, and in running the operation. Here is how Customers, who contacted your LDC, rated their one-on-one transaction.



Base: total respondents who contacted the utility

Customer expectations are on the rise and continue to change. Customers expect their utility to have customer care practices and services that are in-line with any other organization that is important to their everyday life. Setting realistic expectations and consistently delivering to those expectations are keys to higher levels of Customer satisfaction. The setting of customer expectations is tough, but the harder part is to deliver consistency.

Overall satisfaction with most recent experience			
	CHEC	**National**	**Ontario**
Top 2 Boxes: ‘very + fairly satisfied’	78%	75%	62%

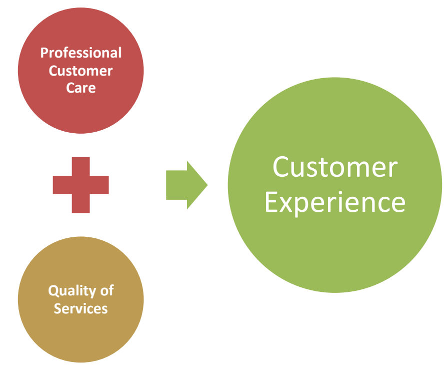
Base: total respondents who contacted the utility

Problem solved rating

Respondents who said that they contacted the utility were also asked “Do you consider the problem solved or not solved?” 72% of your LDC’s respondents said the problem was solved. The Ontario benchmark rating is 61%.

Customer Experience Performance rating (CEPr)

What do customers anticipate contact will be with their local utility when they have a problem? Will it be adversarial, or cooperative, or pleasant, etc. High numbers in CEPr indicate that a large majority of customers would agree that their next contact will be a good or positive one.



Customer Experience Performance rating (CEPr)			
	CHEC	**National**	**Ontario**
CEPr: all respondents	87%	82%	79%

Base: total respondents

EB-2010-0379 ROB-SA: Customer Focus – Service Quality

The three performance measures identified are all time based measures. They are: New Residential Services Connected on Time; Scheduled Appointments Met on Time; and, Telephone Calls Answered on Time. These are good examples of efficiency measures. In addition to time, there are other dimensions of Service Quality that Customers value.

Customer Service Quality			
Top 2 boxes, ‘strongly + somewhat agree’	**CHEC**	**National**	**Ontario**
Deals professionally with customers’ problems	87%	82%	78%
Pro-active in communicating changes and issues affecting Customers	81%	74%	73%
Quickly deals with issues that affect customers	85%	79%	74%
Customer-focused and treats customers as if they’re valued	83%	74%	72%
Is a company that is 'easy to do business with'	88%	79%	75%
Cost of electricity is reasonable when compared to other utilities	64%	60%	55%
Provides good value for money	73%	67%	63%
Delivers on its service commitments to customers	89%	84%	82%

Base: total respondents with an opinion

EB-2010-0379 ROB-SA: Operational Effectiveness

With the exception of the Public Safety measure, which is yet to be defined, performance measures would typically take the form of a monitoring and measuring (quantitative) rating. Though customers may not have the benefit of numbers, they do have a perception.

Management Operations			
Top 2 boxes, 'strongly + somewhat agree'	**CHEC**	**National**	**Ontario**
Provides consistent, reliable electricity	92%	89%	86%
Quickly handles outages and restores power	90%	86%	83%
Makes electricity safety a top priority for employees and contractors	90%	89%	87%
Operates a cost effective electricity system	78%	69%	62%
Overall the utility provides excellent quality services	88%	83%	80%

Base: total respondents with an opinion

UtilityPULSE Report Card®

The purpose of the UtilityPULSE Report Card is to provide your utility with a snapshot of performance – it represents the sum total of respondents' ratings on 6 categories of attributes that research has shown are important to customers in influencing satisfaction and affinity levels with their utility.

CHEC's UtilityPULSE Report Card®

Performance

	CATEGORY	CHEC	National	Ontario
1	**Customer Care**	**B+**	**B+**	**B**
	Price and Value	B	B	C+
	Customer Service	A	B+	B
2	**Company Image**	**A**	**B+**	**B+**
	Company Leadership	A	B+	B+
	Corporate Stewardship	A	A	B+
3	**Management Operations**	**A**	**A**	**A**
	Operational Effectiveness	A	A	B+
	Power Quality and Reliability	A+	A	A
	OVERALL	**A**	**B+**	**B+**

Base: total respondents

Corporate Image

Reputation, image, brand have to be actively managed. Positive impressions beget positive perceptions. Marketing communication includes positioning the utility in a way that makes customers want your utility and its services. Every utility has a brand, why not have the brand you want?

Attributes strongly linked to a hydro utility's image

	CHEC	National	Ontario
Is a respected company in the community	88%	81%	78%
A leader in promoting energy conservation	84%	78%	77%
Keeps its promises to customers and the community	87%	79%	76%
Is a socially responsible company	88%	78%	77%
Is a trusted and trustworthy company	88%	82%	77%
Adapts well to changes in customer expectations	78%	71%	68%
Is 'easy to do business with'	88%	79%	75%
Provides good value for your money	73%	67%	63%
Overall the utility provides excellent quality services	88%	83%	80%
Operates a cost effective hydro-electric system	78%	69%	62%

Base: total respondents with an opinion

Customers, as human beings, are both rational and emotional. The rational side of the customer holds the LDC accountable for doing its job (as contracted), thereby fulfilling the customer's basic needs. The emotional side of the customer is about fulfilling expectations. Meeting rational needs – at best – gets the customer to a neutral state and at worst creates dissatisfaction. Emotional needs, when met, assuming base level rational needs are met, can move a customer from neutral to higher levels of satisfaction. The industry is obsessed with rational concerns about customer behaviour, but the real motivation for customer behaviour is emotional, not rational.

What do customers think about electricity costs?

Ask a utility customer – anywhere in the province of Ontario – what do they think about electricity, there is a very high probability they will say electricity costs are too high or too expensive. For customers who said that they had a billing problem in the last 12 months, and stated that the problem was "high bills" or "high rates or charges", there was very little variability between customers who could be called Secure, Favourable, Indifferent or At Risk. There was also very little variability between age groupings or income groupings.

Our survey database shows 50% more customers in 2014 citing complaints with "high bills" or "high rates or charges" than in 2010. There is a growing concern over electricity costs, especially as it relates to its portion of a household budget. This means the industry needs to monitor "ability to pay".

Is paying for electricity a worry or major problem …

	CHEC	National	Ontario
Not really a worry	66%	69%	59%
Sometimes I worry	22%	20%	26%
Often it is a major problem	8%	7%	11%
Depends	2%	3%	2%

Base: total respondents

Supplemental Insights

Recognizing that customers' interests and needs continue to shift, we have provided data and insights, on a number of subjects such as e-care, e-billing, conservation and more.

Electric Industry Knowledge & SMART Grid

Beyond knowing that they need electricity to maintain their day to day activities, does the average person feel that they are actually knowledgeable about the electric utility industry?

Knowledge level about the electric utility industry

	Ontario
Extremely knowledgeable	2%
Very knowledgeable	11%
Moderately knowledgeable	47%
Slightly knowledgeable	26%
Not very knowledgeable	14%
Don't know	1%

Base: total respondents in the Ontario Benchmark survey

Two-thirds (60%) of those polled in the Ontario Benchmark survey considered themselves moderately to extremely knowledgeable about the electric industry.

While it is evident that the SMART grid is still not a much talked about concept, only 34% have a basic or good understanding of what it is, oddly enough, 60% still think that it is important to pursue SMART grid implementation. It is also clear that the majority of respondents are very + somewhat supportive of the utility working with neighbouring utilities on SMART grid initiatives.

Level of knowledge about the SMART Grid

	Ontario
I have a fairly good understanding of what it is and how it might benefit homes and businesses	9%
I have a basic understanding of what it is and how it might work	25%
I've heard of the term, but don't know much about it	36%
I have not heard of the term	29%
Don't know	1%

Base: total respondents in the Ontario Benchmark survey

Efforts to reduce energy consumption

Do customers believe there is a real pay-off for trying to reduce their energy consumption? Does this impact overall efforts to reduce consumption? Respondents were asked *"How active have you been in trying to reduce your electricity consumption?"* (Base: total respondents in the Ontario Benchmark survey)

- 94% feel they are "very + somewhat active" in trying to reduce electricity consumption, and
- 81% of those do believe their efforts have resulted in reduced energy consumption, of which
- 44% estimate that they were able to offset an energy consumption reduction of more than 10%, and
- 72% believe that these efforts translated to savings on their electricity bills.

Level of Activity in trying to reduce electricity consumption	
	Ontario
Very active	52%
Somewhat active	42%
Neither proactive or inactive	0%
Not active	2%
Not very active	3%

Base: total respondents in the Ontario Benchmark survey

Estimate of percentage reduction in consumption	
	Ontario
1 – 2 %	5%
3 – 5 %	10%
6 – 8 %	4%
9 – 10 %	15%
More than 10%	44%
Don't know	21%

Base: total respondents in the Ontario Benchmark survey whose active efforts have reduced consumption

Active efforts have reduced energy consumption

81%

16%

Base: total respondents in the Ontario Benchmark survey who have been active in trying to reduce energy consumption

Efforts to conserve have translated into savings on your electricity bill

72%

24%

Base: total respondents in the Ontario Benchmark survey whose active efforts have reduced consumption

Energy Conservation & Efficiency

Energy efficiency can be broken down into two areas: *better use of energy through improved energy-efficient technologies;* and *energy saving through changes in customer awareness and behaviour.*

Efforts to conserve energy

Ontario LDCs	Yes	No	Already Done	Don't Know
Install energy-efficient light bulbs or lighting equipment	19%	9%	70%	1%
Install timers on lights or equipment	12%	50%	35%	2%
Shift use of electricity to lower cost periods	22%	17%	58%	3%
Install window blinds or awnings	12%	27%	60%	2%
Install a programmable thermostat	13%	25%	60%	2%
Have an energy expert conduct an energy audit	9%	71%	16%	4%
Removing old refrigerator or freezer for free	14%	44%	38%	4%
Join the peaksaverPLUS™ program	15%	49%	21%	16%
Replacing furnace with a high efficiency model	12%	33%	52%	4%
Replacing air-conditioner with a high efficiency model	14%	38%	44%	4%
Use a coupon to purchase qualified energy saving products	35%	39%	22%	5%

Base: An aggregate of respondents from 2014 participating LDCs

E-care and E-billing

Technology – specifically the internet—has allowed people access to far more information than ever before and the ability to do more than ever before.

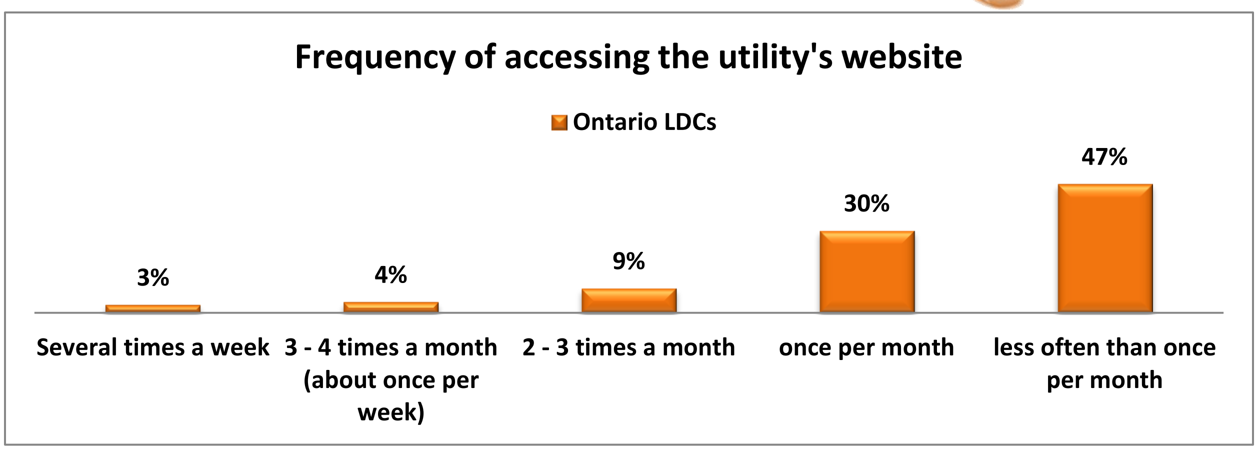
Over the past six months have you accessed your local utility website?

29% **70%**

Base: An aggregate of respondents from 2014 participating LDCs

Do you have access to the internet?	
	Ontario LDCs
Yes	87%
No	13%

Base: An aggregate of respondents from 2014 participating LDCs



Base: An aggregate of respondents from 2014 participating LDCs

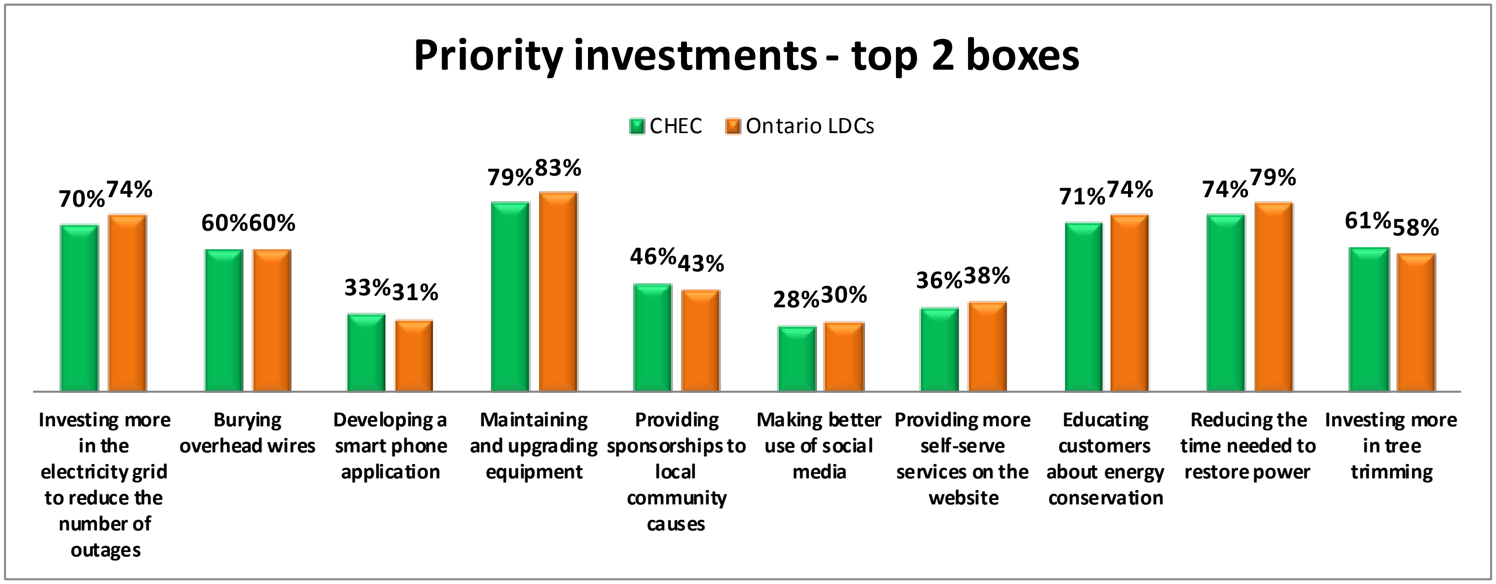
Likelihood of using the internet for future customer care needs for things such as:	
Top 2 Boxes: 'very + somewhat likely'	**Ontario LDCs**
Setting up a new account	31%
Arranging a move	38%
Accessing information about your bill	55%
Accessing information about your electricity usage	54%
Accessing energy saving tips and advice	45%
Accessing information about Time Of Use rates	51%
Maintaining information about your account or preferences	51%
Paying your bill through the utility's website	32%
Getting information about power outages	47%
Arranging for service	40%

Base: An aggregate of respondents from 2014 participating LDCs

As society becomes increasingly more familiar with technology it will become a more popular medium for giving and receiving information. One could also say, demographics will also put more pressure on the technology channels. Unfortunately, customers adopt technology on their own timetable. This causes the utility to continue to improve existing channels while building the technological channels wanted by some today, but by the year 2020, demanded by many. Will your utility be ready?

Priority Investments

While regulation and reliability are top concerns in the utility industry, aging infrastructure is now a top operational concern. Customers agree with industry insiders that infrastructure renewal is a high priority. This year, respondents were asked for their views about prioritizing investments.



Base: An aggregate of respondents from 2014 participating LDCs / 90% of total respondents from the local

Some findings shown above correlate with some of the suggestions made by respondents on things the utility could do to improve. Percentage of comments received from all Ontario respondents were:

- 14% improve reliability (10% in 2010)
- 11% better maintenance (3% in 2010)

- 10% better communication (7% in 2010)

Are CHEC customers willing to foot the bill for further improvements? 46% of CHEC respondents expressed a willingness to pay at least something to better their electricity system. 46% of respondents were not willing to incur any additional costs while 9% were not sure of their position. Where respondents varied was on how much they were actually willing to pay.

Willingness to pay for further improvements

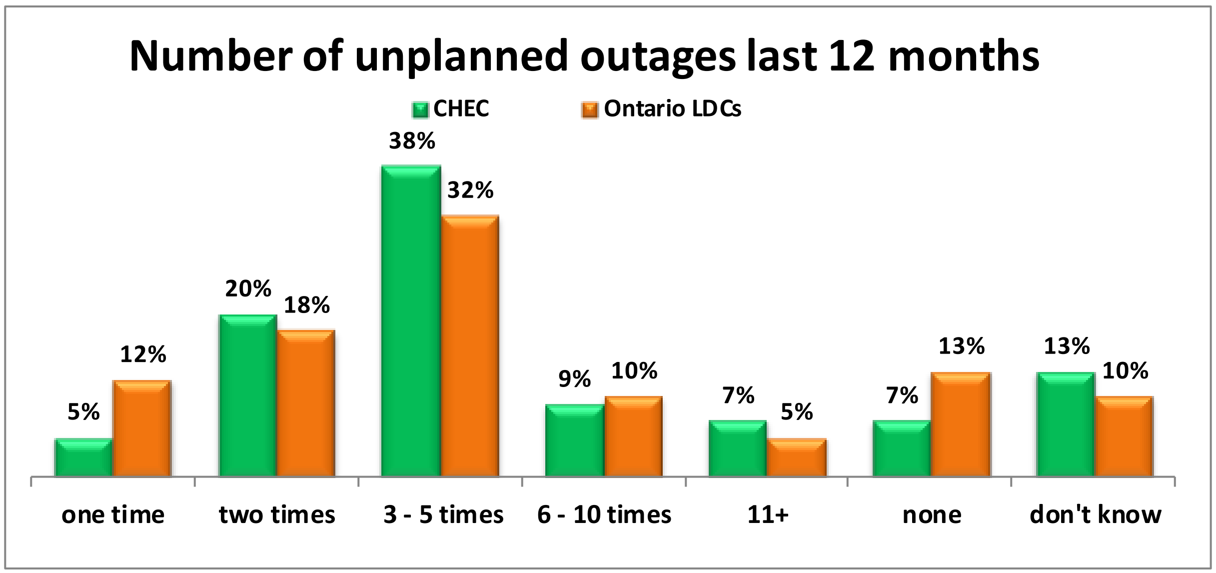
Using the scale of $0 to $10 per month	CHEC
$0	46%
$1 - 2	7%
$3 - 4	5%
$5 - 6	21%
$7 - 8	1%
$9 - 10	11%
$11+	1%
Don’t know	9%

Base: total respondents

Outage Management

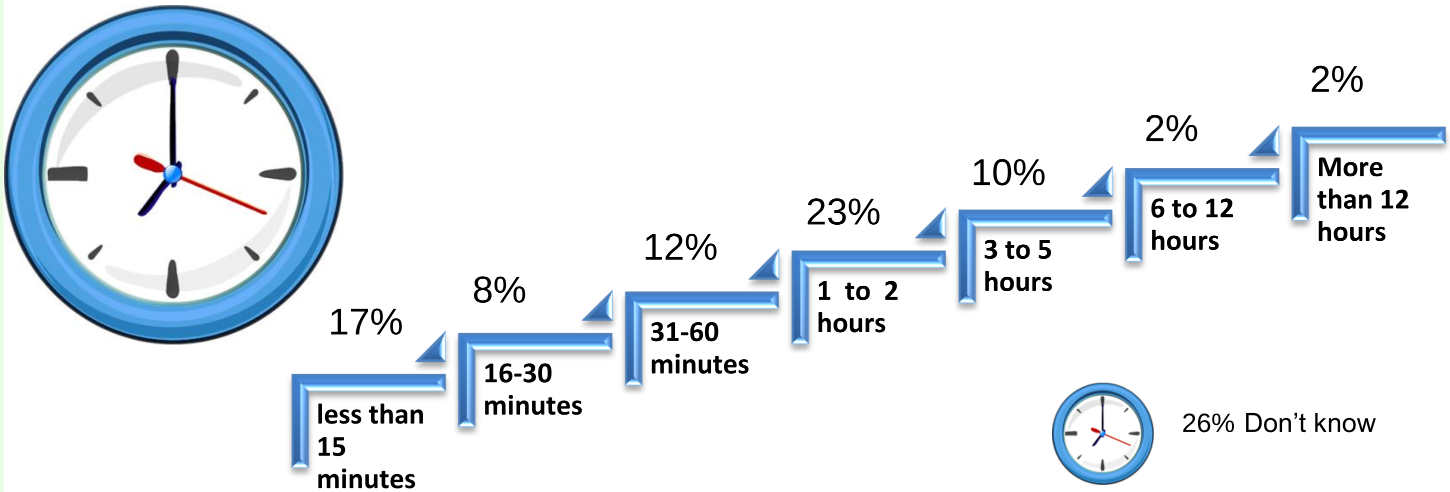
Whether an outage is planned or unplanned, the reality is that it is going to cause disruption and inconvenience under best case scenario and under worst case scenarios there could be safety and financial consequences.

However, one thing for certain, no matter what the scenario happens to be, customers are expecting their utility to keep them continually updated on the status of outages. Most importantly, and top priority, is to know the estimated restoration time. They also want to know the cause of the outage because they do not want to be a frequent outage customer.



Base: An aggregate of respondents from 2014 participating LDCs / 90% of total respondents from the local utility

When an unplanned outage occurs, how long, on average, is the outage?



Base: 90% of total respondents from the local utility

How a utility chooses to handle, manage and communicate with customers during an outage situation does affect customers' satisfaction with their utility. Customers want timely, accurate and relevant information about an outage and customers expect a utility to use various communication channels to ensure their message is getting out there. This means not only obtaining information via the call centre and IVR but customers have increasing expectations for proactive two-way communication through social media, utility websites and modern communication devices (e.g. tablets, smartphones) and apps.

Inability to provide the above information accurately and in a timely manner will result in customer complaints, increased call volumes to your call centres, create unwanted public and media attention, and negatively impact customer satisfaction.

Utility's effectiveness during an unplanned outage		
Top 2 Boxes: 'very + somewhat effective'	**Ontario LDCs**	**CHEC**
Responding to questions	61%	71%
Providing a reason for the outage	61%	63%
Providing an estimate when power will be restored	60%	60%
Responding to the power outage	81%	84%
Restoring power quickly	85%	86%
Communicating updates periodically	64%	66%
Posting information to the website	35%	30%
Using media channels for providing updates	53%	45%

Base: An aggregate of respondents from 2014 participating LDCs / 90% of total respondents from the local utility

On December 20, 2013, a severe ice storm struck the central and eastern portions of Canada and the northeastern United States. The storm's devastation caused major damage to utility distribution lines, towers, transformers, poles and entire substations and resulted in large scale outages and blackouts for long periods of time. The data suggests that customers are both tolerant and understanding when major outages take place.

Did you have a power outage during the ice storm in December 2013?

33%

48%

Base: total respondents

Percentage of Respondents who contacted their utility about the ice storm power outage	
	CHEC
Yes	17%
No	82%

Base: total respondents affected by the ice storm

CHEC
Length of outage (during Ice Storm 2013)

Less than 2 hours	2 – 4 hours	4+ hours or ½ day	12-18 hours or ½ - ¾ day	19-24 hours or 1 day	1 to 1.5 days	1.6 to 2 days	More than 2 days
21%	26%	14%	7%	6%	3%	1%	2%

Base: total respondents affected by the ice storm

Using social media and multi-channel communication modes still appear to be the exception when it comes to customers contacting their utilities. Results from this year's survey indicate that the telephone is still the most used and the preferred method of contact. Overall, 87% of all Ontario respondents affected by the ice storm who informed their local utility they were experiencing a power outage did so via telephone; 93% of CHEC customers used the telephone to contact their utility.

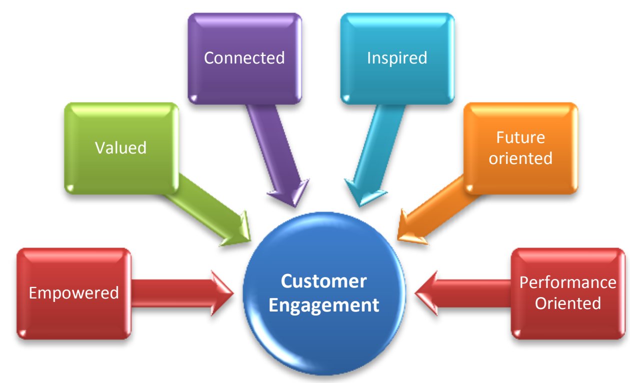
In your view, what is an acceptable period of time to go without electricity in situations like the ice storm?

Base: total respondents affected by the ice storm

•None (the power shouldn't be going out)	8%
•Less than 2 hours	8%
•2 - 4 hours	18%
•4+ hours or 1/2 day	17%
•12 - 18 hours or 1/2 day to 3/4 day	7%
•19 - 24 hours or 1 day	13%
•1 to 1.5 days	6%
•1 .6 to 2 days	4%
•More than 2 days	6%

Customer Centric Engagement Index (CCEI)

The EB-2010-0379 ROB-SA report includes the following: “better engage with their customers to better understand and respond to their needs…” Conducting surveys (like this one), holding town hall meetings, focus groups, etc. are examples of engaging your customers. We call this an activity based definition of engagement. Asking 100 people to complete a survey is an engagement activity. This survey also provides you with an emotional look at engagement.



The CCEI index is a gauge of the amount of goodwill that has been generated. High numbers in CCEI suggests that there is a high level of goodwill amongst your customers – this is important for two reasons. First when something goes awry for the utility, goodwill helps the utility to be resilient. Second, goodwill encourages active participation in requests to participate in engagement activities or program offerings from the utility.

Utility Customer Centric Engagement Index (CCEI)

	CHEC	National	Ontario
CCEI	83%	79%	76%

Base: total respondents

In a world of chaos and confusion what will a customer do? Find someone to help. In the electricity industry, the vast majority of customers turn to, and rely on, their local utility. Knowing that customers will turn to their electric utility requires utilities to really know their customers. Not easy when customer expectations continue to shift.

The shift is on. 15 years ago a utility could think about their customers in terms of usage, now they have to think about them in terms of personas (i.e., customer type). Currently, customer segmentation, for most utilities, consists of a number of "personas". While this may be adequate today, in order to achieve high customer participation in programs and to optimize business processes there will be a need for granular targeting of communications.

Most utilities are quite comfortable “pushing” out communications in a one-way world. However, the shift is on because the new channels are 2-way; even without the new channels customers are expecting 2-way dialogue. The impact on a utility’s marketing-communications is significant.

Value is what a customer perceives they get in exchange for what they give up. The real challenge is educating customers on the value they receive. In the absence of a value proposition the primary thing people will talk about is cost.

We recommend having meaningful two-way dialogue with employees (and others) to leverage the results from your 2014 customer satisfaction survey derived from speaking with 612 CHEC customers [April 24 - May 2, 2014]. The electric utility business has demanding customers with high expectations.

UtilityPULSE

Sid Ridgley

Simul/UtilityPULSE

Email: sidridgley@utilitypulse.com or sridgley@simulcorp.com

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Culture, Leadership & Performance – Organizational Development	Focus Groups, Surveys, Polls, Diagnostics	Customer Service Excellence
Leadership development	Diagnostics ie. Change Readiness, Leadership Effectiveness, Managerial Competencies	Service Excellence Leadership
Strategic Planning	Surveys & Polls	Telephone Skills
Teambuilding	Customer Satisfaction and Loyalty Benchmarking Surveys	Customer Care
Organizational Culture Transformation	Organization Culture Surveys	Dealing with Difficult Customers

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Your personal contact is:

Sid Ridgley, CSP, MBA

Phone: (905) 895-7900 Fax: (905) 895-7970 E-mail: sidridgley@utilitypulse.com or sridgley@simulcorp.com