2.2 Exhibit 2: RATE BASE

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APPENDICES

2.2 RATE BASE

2.2.1.1 RATE BASE OVERVIEW

The rate base used for the purpose of calculating the revenue requirement in this Application follows *Chapter 2 of the Filing Requirements for Electricity Distribution Applications* issued by the Ontario Energy Board ("Board") on July 14, 2016 (the "Filing Requirements"). In accordance with the Filing Requirements, Welland Hydro-Electric System Corp. ("WHESC") has calculated the rate base as an average of the net capital balances at the beginning and the end of the 2017 Test Year plus a working capital allowance, which is 7.5% (see below) of the sum of the cost of power and controllable expenses.

On May 19, 2016, the Board issued Decision and Vary Order EB-2016-0147 granting WHESC's requested variance of the Board's decision and order setting just and reasonable rates for WHESC effective May 1, 2013. In this Decision and Vary Order, the Board found that:

> "This decision is contingent on Welland Hydro adopting in its next cost of service application the OEB's default working capital factor, currently set at 7.5% of the sum of the cost of power and OM&A costs. No costs related to a lead-lag study would therefore be recoverable."

WHESC has adopted the OEB's default working capital factor of 7.5%. WHESC further confirms that it has incurred no costs related to a lead-lag study.

WHESC has adopted the change-over to Modified International Standard ("MIFRS") as of January 1, 2015 with comparatives completed in MIFRS for 2014. There were no changes to total fixed asset balances in 2014 as a result of the adoption of IFRS as there were no early retirement of assets for 2014. On July 17, 2013 the Board issued a statement that changes to depreciation rates and capitalization policies that would have been implemented under International Financial Reporting Standards ("IFRS") could be made in 2012 under Canadian Generally Accepted Accounting Principles ("CGAAP") (i.e. effective January 1, 2012), and must be made no later than 2013 (i.e. effective January 1, 2013), regardless of whether the Canadian Accounting Standards Board (AcSB) permitted further deferrals beyond 2013 for the changeover to IFRS (Board Letter, July 17, 2013 *"Regulatory accounting policy direction regarding changes to depreciation expense and capitalization policies"*). WHESC implemented the change to depreciation rates and capitalization policies in 2012 and reflected these changes in its 2013 COS Rate Application EB-2012-0173. The policies relating to depreciation expense (useful lives) and capitalization (overheads) of assets have not changed since the 2013 COS Rate Application. However, the adoption of IFRS effective January 1, 2015 eliminates the "pooling of assets" methodology and now requires that assets be removed from both gross assets and accumulated depreciation values upon removal from service and the difference between the two recognized as a gain or loss. The gain or loss associated with the elimination of "pooling of assets"

was not reflected in WHESC's 2013 COS Rate Application and as a result is not reflected in current distribution rates. The conversion to IFRS effective January 1, 2015 required a restatement of capital dispositions for the 2014 fiscal year for categories which were previously pooled. WHESC had no gain or loss associated with the disposition of assets previously pooled in 2014. However, an actual loss on the premature disposition of assets was recognized in 2015. Further dispositions are recognized in both the 2016 Bridge Year and 2017 Test Year and are expected to occur for the balance of years until the next COS rate application. For all three years from 2015 to 2017, gross assets and accumulated depreciation have been reduced to reflect the assets removed from service. The losses from 2015 Actual Year and 2016 Test Year have been charged to account 1575 IFRS-CGAAP Transitional PP&E Amounts. The 2014-2016 (2014 $NIL) early retirement losses are being requested for disposition in this rate application which is discussed in more detail in Exhibit 9. WHESC has reflected the 2017 Test Year loss on the disposition of assets previously pooled as a sub account of 4355 Gain/Loss on Disposition of Utility Property which is discussed in more detail in Exhibit 3.

Net capital assets include in service assets that are associated with activities that enable the conveyance of electricity for distribution purposes minus accumulated depreciation and contributed capital from third parties. For purposes of this Exhibit, distribution assets refer to those assets that are most directly related to the distribution system, such as poles, overhead and underground lines, and transformers. General plant refers to assets that support the operation of the distribution system such as computer hardware and software, vehicles, buildings, and equipment. Capital assets include property, plant and equipment ("PP&E") and intangible assets; these are referred to as "capital" or "fixed" assets throughout this evidence. The rate base calculation excludes any non-distribution assets. WHESC has not applied for, nor received, any Incremental Capital Module ("ICM") adjustments. A capital expenditure in 2014 related to a pole line expansion to connect a renewable generation site is currently included in account 1531. The Direct Benefit portion of this expenditure is being transferred to rate base in the 2017 Test Year.

WHESC has completed the requirement of Appendix 2-BA in Tables 2-10 through 2-14.

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

WHESC has provided its rate base calculations for the years 2013 Board Approved, 2013 Actual, 2014 Actual, 2015 Actual, 2016 Bridge Year and 2017 Test Year in Table 2-1 below:

Table 2-1 - Summary of Rate Base

Description	2013 Board Approved	2013 Actual	2014 Actual	2015 Actual	2016 Bridge Year	2017 Test Year
Reporting Basis	**RCGAAP**	**RCGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Gross Fixed Assets Opening Balance	52,960,995	52,958,978	53,399,922	55,536,143	57,539,532	59,977,670
Gross Fixed Assets Closing Balance	54,804,509	53,399,922	55,536,143	57,539,532	59,977,670	62,246,233
Average Gross Fixed Assets	**53,882,752**	**53,179,450**	**54,468,033**	**56,537,838**	**58,758,601**	**61,111,952**
Accumulated Depreciation Opening Balance	27,870,816	27,845,388	27,527,212	28,641,826	29,909,229	30,962,895
Accumulated Depreciation Closing Balance	28,966,530	27,527,212	28,641,826	29,909,229	30,962,895	32,272,392
Average Accumulated Depreciation	**28,418,673**	**27,686,300**	**28,084,519**	**29,275,528**	**30,436,062**	**31,617,644**
Average Net Book Value	**25,464,079**	**25,493,150**	**26,383,514**	**27,262,310**	**28,322,537**	**29,494,306**
Working Capital	49,764,903	47,954,899	49,329,537	49,491,012	53,054,147	53,574,437
Working Capital Allowance (%)	12.0%	12.0%	12.0%	12.0%	12.0%	7.5%
Working Capital Allowance	**5,971,788**	**5,754,588**	**5,919,544**	**5,938,921**	**6,366,498**	**4,018,083**
Rate Base	**31,435,867**	**31,247,738**	**32,303,059**	**33,201,231**	**34,689,035**	**33,512,388**

- WHESC has calculated its 2017 rate base as $33,512,388, an increase of $2,076,521 over the 2013 Board Approved rate base of $31,435,867. This increase in rate base of $2,076,521 is attributable to an increase in the average net book value of capital assets of $4,030,227 and a decrease in the working capital allowance of $1,953,706. WHESC has invested significantly in its distribution system since the last Cost of Service (COS) application and this is reflected in the net book value variance. The increase in the Cost of Power applied an upward cost pressure on the Working Capital Allowance. However, the reduction in the Working Capital Allowance Percentage from 12% to 7.5% results in a net decrease in Working Capital Allowance from the 2013 COS Rate Application. The overall increase in rate base from the 2013 COS to the 2017 Test Year is 6.6% or 1.65% per year.

WHESC has provided a summary of its calculations of the cost of power and controllable expenses used in the calculations for determining working capital for the years 2013 Board Approved, 2013 Actual, 2014 Actual, 2015 Actual, 2016 Bridge Year and 2017 Test Year in Table 2-2 below. Further details of WHESC's calculation of its cost of power calculations are provided in Table 2-22. The 2016 Bridge Year is forecasted data.

Table 2-2 - Summary of Working Capital Calculation

Description	2013 Board Approved	2013 Actual	2014 Actual	2015 Actual	2016 Bridge Year	2017 Test Year
Reporting Basis	**RCGAAP**	**RCGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Distribution Expenses Operations	1,392,257	1,232,459	1,275,287	1,320,244	1,401,297	1,508,493
Distribution Expenses Maintenance	1,621,552	1,653,693	1,651,437	1,834,314	1,854,122	1,884,210
Billing and Collecting	1,407,275	1,379,546	1,591,426	1,382,233	1,475,391	1,539,473
Community Relations	134,249	116,716	89,463	128,286	137,204	144,123
Administrative and General Expenses	1,803,667	1,735,439	1,599,129	1,639,861	1,797,772	1,910,708
Donations Leap	11,000	11,150	11,250	11,500	11,750	12,900
Taxes Other than Income Taxes	0	64,457	0	0	0	0
Power Supply Expenses	43,394,903	41,761,439	43,111,545	43,174,574	46,376,611	46,574,530
Total Working Capital Expenses	**49,764,903**	**47,954,899**	**49,329,537**	**49,491,012**	**53,054,147**	**53,574,437**

VARIANCE ANALYSIS OF RATE BASE

The following Table 2-3 sets out WHESC's rate base and working capital calculations for the 2017 Test Year, 2016 Bridge Year, 2015 Actual, 2014 Actual, 2013 Board Approved and Actual, and the following variances:

- 2017 Test Year against 2016 Bridge Year;
- 2016 Bridge Year against 2015 Actual;
- 2015 Actual against 2014 Actual;
- 2014 Actual against 2013 Actual;
- 2013 Actual against 2013 Board Approved.

Table 2-3 – Rate Base Variances

Description	2013 Board Approved	2013 Actual	Variance from 2013 Board Approved	2014 Actual	Variance from 2013 Actual	2015 Actual	Variance from 2014 Actual	2016 Bridge Year	Variance from 2015 Actual	2017 Test Year	Variance from 2016 Bridge
Reporting Basis	**RCGAAP**	**RCGAAP**	**RCGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Average Net Book Value	**25,464,079**	**25,493,150**	**29,071**	**26,383,514**	**890,364**	**27,262,310**	**878,797**	**28,322,537**	**1,060,227**	**29,494,306**	**1,171,769**
Working Capital	49,764,903	47,954,899	-1,810,004	49,329,537	1,374,638	49,491,012	161,475	53,054,147	3,563,135	53,574,437	520,290
Working Capital Allowance (%)	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	7.5%	-4.5%
Working Capital Allowance	**5,971,788**	**5,754,588**	**-217,200**	**5,919,544**	**164,957**	**5,938,921**	**19,377**	**6,366,498**	**427,576**	**4,018,083**	**-2,348,415**
Rate Base	**31,435,867**	**31,247,738**	**-188,128**	**32,303,059**	**1,055,321**	**33,201,231**	**898,173**	**34,689,035**	**1,487,803**	**33,512,388**	**-1,176,647**

WHESC has calculated the materiality threshold on its rate base to be $53,000 for 2017 in accordance with the Filing Requirements. This calculation is summarized in Exhibit 4 Table 4-6.

WHESC offers the following comments in respect of the relevant variances identified above:

2017 Test Year vs. 2016 Bridge Year:

Table 2-3A

Description	2016 Bridge Year	2017 Test Year	Variance from 2016 Bridge
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**
Average Net Book Value	**28,322,537**	**29,494,306**	**1,171,769**
Working Capital	53,054,147	53,574,437	520,290
Working Capital Allowance (%)	12.0%	7.5%	-4.5%
Working Capital Allowance	**6,366,498**	**4,018,083**	**-2,348,415**
Rate Base	**34,689,035**	**33,512,388**	**-1,176,647**

The total rate base is expected to be $1,176,647 lower in the 2017 Test Year than in the 2016 Bridge Year. This decrease is shown above and is attributable to an increase in average net book value of $1,171,769 offset by a decrease in working capital allowance of $2,348,415. The addition to gross fixed assets in 2017 is $2,413,986 and Table 2-17 provides a more detailed variance of the year over year changes to gross assets. Details with respect to WHESC's 2017 capital expenditure program are provided in WHESC's Distribution System Plan ("DSP"), found in Appendix 2-A.

The adoption of extended useful lives and changes to capitalized overheads in 2012 has created a scenario in which capital costs have exceeded depreciation expense. The resultant decrease to depreciation expense from the extended useful lives far exceeded the impact of changes to capitalized overheads. Before the change to capitalized overheads, WHESC did not capitalize significant amounts of indirect overheads. The majority of capital expenditures has for the most part always been comprised of materials and direct labor or contracted labor. As a result, the average net book value of working capital has increased annually since the adoption of these two changes in policies.

The working capital allowance decrease was primarily the result of a reduction in the working capital allowance percentage from 12% to 7.5%. WHESC has elected to use the Board's default working capital percentage for the 2017 Test Year in a manner consistent with the Board's May 19, 2016 Decision and Vary Order EB-2016-0147.

Approximately 38% of the increase in working capital can be attributed to the increase in cost of power expenses; the detailed calculation of the cost of power expense for the 2017 Test Year can be found in Table 2-23.

2016 Bridge Year vs. 2015 Actual:

Table 2-3B

Description	2015 Actual	2016 Bridge Year	Variance from 2015 Actual
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**
Average Net Book Value	**27,262,310**	**28,322,537**	**1,060,227**
Working Capital	49,491,012	53,054,147	3,563,135
Working Capital Allowance (%)	12.0%	12.0%	12.0%
Working Capital Allowance	**5,938,921**	**6,366,498**	**427,576**
Rate Base	**33,201,231**	**34,689,035**	**1,487,803**

The total rate base for the 2016 Bridge Year is expected to be $34,689,035, which represents an increase of $1,487,803 over the 2015 Actual year. This increase is shown above and is attributable primarily to an increase in average net book value of $1,060,227. The addition to gross fixed assets in 2016 is $2,785,090. Table 2-17 and the subsequent narrative provide a more detailed explanation of the change in gross assets year over year. Capital expenditures in the 2016 Bridge Year exceed previous year's actuals and the 2017 Test Year. WHESC will make two significant vehicle purchases in 2016 to update its aging fleet. A Digger Derrick truck used in capital construction has over 28 years of service and replacement parts are very difficult to find. WHESC's capital plans would be at risk without the replacement of this vehicle.

Approximately 90% of the increase in the 2016 working capital allowance can be attributed to the increase in cost of power expenses from 2015. A summary of the Cost of Power Expenses for 2013 through 2017 can be found in Table 2-22.

2015 Actual vs. 2014 Actual:

Table 2-3C

Description	2014 Actual	2015 Actual	Variance from 2014 Actual
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**
Average Net Book Value	**26,383,514**	**27,262,310**	**878,797**
Working Capital	49,329,537	49,491,012	161,475
Working Capital Allowance (%)	12.0%	12.0%	12.0%
Working Capital Allowance	**5,919,544**	**5,938,921**	**19,377**
Rate Base	**32,303,059**	**33,201,231**	**898,173**

The rate base of $33,201,231 for 2015 Actual increased over 2014 Actual by $898,173. This increase is shown above and is driven significantly by an increase in the average net book value of $878,797. The addition to gross fixed assets in 2015 is $2,084,574. System Renewal accounts for over 80% of capital spending in 2015. Table 2-17 and the subsequent narrative provide a more detailed explanation of the change in gross assets year over year.

2014 Actual vs. 2013 Actual:

Table 2-3D

Description	2013 Actual	2014 Actual	Variance from 2013 Actual
Reporting Basis	**RCGAAP**	**MIFRS**	**MIFRS**
Average Net Book Value	**25,493,150**	**26,383,514**	**890,364**
Working Capital	47,954,899	49,329,537	1,374,638
Working Capital Allowance (%)	12.0%	12.0%	12.0%
Working Capital Allowance	**5,754,588**	**5,919,544**	**164,957**
Rate Base	**31,247,738**	**32,303,059**	**1,055,321**

The rate base of $32,303,059 for 2014 Actual increased over 2013 Actual by $1,055,321. This increase is shown above and is made up of a change in average net assets of $890,364 as a result of capital expenditures. The addition to gross fixed assets in 2014 is $2,281,219. System Renewal accounts for over 70% over capital spending in 2014. Capital Spending in Computer Hardware was significantly higher in 2014 compared to other years as a result of the replacement of internal hardware servers. Table 2-17

and the subsequent narrative provide a more detailed explanation of the change in gross assets year over year.

The working capital allowance increased by $1,374,638 of which $1,350,106 is related to the cost of power expenses. A summary of the cost of power expenses can be found in Table 2-22.

2013 Actual vs. 2013 Board Approved:

Table 2-3E

Description	2013 Board Approved	2013 Actual	Variance from 2013 Board Approved
Reporting Basis	**RCGAAP**	**RCGAAP**	**RCGAAP**
Average Net Book Value	**25,464,079**	**25,493,150**	**29,071**
Working Capital	49,764,903	47,954,899	-1,810,004
Working Capital Allowance (%)	12.0%	12.0%	12.0%
Working Capital Allowance	**5,971,788**	**5,754,588**	**-217,200**
Rate Base	**31,435,867**	**31,247,738**	**-188,128**

The rate base of $31,247,738 for 2013 Actual was lower than the 2013 Board Approved by $188,218.

Average 2013 net book value was slightly over 2013 Board approved as capital additions and depreciation expenses were in line with forecasted amounts.

The decrease in Working Capital of $1,810,004 is for the most part comprised of Cost of Power expenses which were $1,633,464 lower than Board Approved in 2013. Growth in residential customers in the 2013 COS Rate Application were overly optimistic. The City of Welland has also seen a significant decline in industrial manufacturing over the past ten years. This trend continued from 2013 to 2015 and includes the loss of WHESC's last remaining Large Use customer in 2015.

FIXED ASSET CONTINUITY SCHEDULES WITH WORK IN PROGRESS

Table 2-5 through Table 2-9 provide the Fixed Asset Continuity Schedules, including WIP for each of 2013 Actual, 2014 Actual, 2015 Actual, 2016 Bridge Year, and 2017 Test Year.

The total gross asset balances in WHESC's Fixed Asset Continuity Statements do not balance to the opening and closing balances of gross assets used to calculate the fixed asset component of rate base. WIP has been removed from the fixed asset continuity schedule balances for rate base calculation purposes, as mandated by the Board. A reconciliation of year-end NBV by year is provided in Table 2-4

below. The opening and closing balances of accumulated depreciation used to calculate the fixed asset component of rate base correspond to the fixed asset continuity schedule. As such there is no reconciliation required for accumulated depreciation.

Table 2-4 – Reconciliation of Opening and Closing Balances

Description	2013 Board Approved	2013 Actual	2014 Actual	2015 Actual	2016 Bridge Year	2017 Test Year
Reporting Basis	**RCGAAP**	**RCGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Total Gross Assets for Rate Base	54,804,509	53,399,921	55,536,144	57,539,533	59,977,671	62,246,234
Work in Progress (WIP)	0	137,172	55,500	153,290	0	0
Total Gross Assets Including WIP	**54,804,509**	**53,537,093**	**55,591,644**	**57,692,823**	**59,977,671**	**62,246,234**
Total Accumulated Depreciation for Rate Base	**28,966,530**	**27,527,212**	**28,641,826**	**29,909,229**	**30,962,895**	**32,272,392**
Total Net Book Value for Rate Base	25,837,979	25,872,709	26,894,318	27,630,304	29,014,776	29,973,842
Work in Process	0	137,172	55,500	153,290	0	0
Total Net Book Value including WIP	**25,837,979**	**26,009,881**	**26,949,818**	**27,783,594**	**29,014,776**	**29,973,842**

Table 2-5 - Fixed Asset Continuity Schedule as at December 31, 2013, RCGAAP

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**
N/A	1805	Land	158,686	0	0	158,686	0	0	0	0	158,686
CEC	1806	Land Rights	70,296	0	0	70,296	59,631	640	0	60,272	10,025
47	1808	Buildings and Fixtures	96,568	0	0	96,568	59,992	1,236	0	61,228	35,340
47	1815	Transformer Station Equipment - Normally Primary above 50 kV	467,359	0	0	467,359	37,847	14,857	0	52,703	414,655
47	1820	Distribution Station Equipment - Normally Primary below 50 kV	4,223,152	3,532	199,818	4,026,865	2,545,494	86,093	199,818	2,431,769	1,595,097
47	1830	Poles, Towers and Fixtures	7,201,902	786,758	0	7,988,661	1,175,217	140,076	0	1,315,293	6,673,367
47	1835	Overhead Conductors and Devices	12,748,640	174,979	0	12,923,620	8,305,774	122,746	0	8,428,520	4,495,100
47	1840	Underground Conduit	916,576	154,014	0	1,070,590	129,886	18,603	0	148,489	922,101
47	1845	Underground Conductors and Devices	11,873,205	666,205	0	12,539,411	7,430,028	232,479	0	7,662,507	4,876,903
47	1850	Line Transformers	6,781,896	337,635	40,018	7,079,513	3,417,552	113,827	38,229	3,493,150	3,586,362
47	1855	Services	699,038	27,157	0	726,195	121,581	16,631	0	138,212	587,983
47	1860	Meters	2,996,731	65,532	58,242	3,004,021	663,800	195,498	58,242	801,056	2,202,965
N/A	1865	Other Installation on Customer's Premises	8,010	0	8,010	0	8,010	0	8,010	0	0
47	1908	Buildings and Fixtures	2,485,177	22,165	4,088	2,503,254	1,022,867	69,916	4,088	1,088,695	1,414,559
8	1915	Office Furniture and Equipment	101,345	1,403	0	102,748	58,530	9,014	0	67,544	35,204
10	1920	Computer Equipment - Hardware	301,070	14,809	169,507	146,372	260,140	18,704	169,507	109,337	37,035
12	1925	Computer Software	1,089,119	16,621	364,897	740,843	553,375	140,667	364,897	329,145	411,698
10	1930	Transportation Equipment	1,391,448	325,615	132,851	1,584,212	1,154,944	40,672	132,851	1,062,766	521,446
8	1935	Stores Equipment	30,023	0	0	30,023	27,850	759	0	28,609	1,414
8	1940	Tools, Shop and Garage Equipment	114,950	0	35,269	79,681	87,313	6,748	35,269	58,792	20,889
8	1945	Measurement and Testing Equipment	26,058	(711)	4,896	20,450	17,328	1,699	4,896	14,130	6,320
8	1955	Communication Equipment	282,461	0	56,496	225,966	143,637	22,100	56,496	109,242	116,724
8	1960	Miscellaneous Equipment	315,235	0	0	315,235	81,551	11,128	0	92,679	222,556
47	1980	System Supervisory Equipment	1,143,045	4,047	459,096	687,996	914,874	35,701	459,096	491,479	196,516
47	1995	Contributions and Grants - Credit	(2,563,013)	(625,629)	0	(3,188,642)	(431,836)	(86,571)	0	(518,406)	(2,670,235)
		Total before Work in Process	**52,958,978**	**1,974,133**	**1,533,189**	**53,399,922**	**27,845,387**	**1,213,224**	**1,531,400**	**27,527,212**	25,872,710
WIP		Work in Process	0	137,172	0	137,172	0	0	0	0	137,172
		Total after Work in Process	**52,958,978**	**2,111,305**	**1,533,189**	**53,537,093**	**27,845,387**	**1,213,224**	**1,531,400**	**27,527,212**	26,009,881

Less: Fully Allocated Depreciation	
Transportation	0
Communication	0
Net Depreciation	1,213,224

Table 2-6 - Fixed Asset Continuity Schedule as at December 31, 2014, MIFRS

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

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land	158,686			158,686	0			0	158,686
CEC	1806	Land Rights	70,296			70,296	60,272	640		60,912	9,384
47	1808	Buildings and Fixtures	96,568			96,568	61,228	1,236		62,463	34,104
47	1815	Transformer Station Equipment - Normally Primary above 50 kV	467,359			467,359	52,703	14,857		67,560	399,799
47	1820	Distribution Station Equipment - Normally Primary below 50 kV	4,026,865			4,026,865	2,431,769	76,134		2,507,902	1,518,963
47	1830	Poles, Towers and Fixtures	7,988,661	973,203		8,961,863	1,315,293	157,676		1,472,969	7,488,894
47	1835	Overhead Conductors and Devices	12,923,620	202,465		13,126,085	8,428,520	126,520		8,555,040	4,571,045
47	1840	Underground Conduit	1,070,590	72,305		1,142,895	148,489	20,866		169,355	973,540
47	1845	Underground Conductors and Devices	12,539,411	280,038		12,819,448	7,662,507	227,357		7,889,865	4,929,584
47	1850	Line Transformers	7,079,513	319,776	49,635	7,349,654	3,493,150	121,999	43,340	3,571,810	3,777,844
47	1855	Services	726,195	82,721		808,916	138,212	18,005		156,217	652,699
47	1860	Meters	3,004,021	63,482		3,067,502	801,056	199,799		1,000,855	2,066,648
N/A	1865	Other Installations on Customer's Premises	0			0	0			0	0
47	1908	Buildings and Fixtures	2,503,254	33,433		2,536,687	1,088,695	70,862		1,159,557	1,377,130
8	1915	Office Furniture and Equipment	102,748		12,302	90,446	67,544	8,924	12,302	64,166	26,280
10	1920	Computer Equipment - Hardware	146,372	118,498	80,441	184,428	109,337	32,764	80,441	61,660	122,768
12	1925	Computer Software	740,843	146,486		887,329	329,145	137,287		466,432	420,897
10	1930	Transportation Equipment	1,584,212	88,771		1,672,983	1,062,766	57,223		1,119,989	552,994
8	1935	Stores Equipment	30,023			30,023	28,609	707		29,316	707
8	1940	Tools, Shop and Garage Equipment	79,681	5,980	2,618	83,043	58,792	8,786	2,618	64,960	18,084
8	1945	Measurement and Testing Equipment	20,450			20,450	14,130	1,146		15,276	5,174
8	1955	Communication Equipment	225,966	72,266		298,231	109,242	22,394		131,636	166,596
8	1960	Miscellaneous Equipment	315,235			315,235	92,679	11,128		103,807	211,429
47	1980	System Supervisory Equipment	687,996			687,996	491,479	35,802		527,282	160,714
47	1995	Contributions and Grants	(3,188,642)	(178,205)		(3,366,847)	(518,406)	(98,797)		(617,204)	(2,749,643)
		Total before Work in Process	**53,399,922**	**2,281,218**	**144,997**	**55,536,143**	**27,527,212**	**1,253,315**	**138,702**	**28,641,825**	**26,894,319**
WIP		Work in Process	137,172	(81,672)		55,500	0			0	55,500
		Total after Work in Process	**53,537,093**	**2,199,547**	**144,997**	**55,591,643**	**27,527,212**	**1,253,315**	**138,702**	**28,641,825**	**26,949,819**

Less: Fully Allocated Depreciation	
Transportation	0
Communication	0
Net Depreciation	1,253,315

Table 2-7 - Fixed Asset Continuity Schedule as at December 31, 2015, MIFRS

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

			Cost						Accumulated Depreciation						
CCA Class	**OEB**	**Description**	**Opening Balance**	**Pole Line Generation Adjustment**	**Contributed Capital Adjustment**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Pole Line Generation Adjustment**	**Contributed Capital Adjustment**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land	158,686					158,686	0					0	158,686
CEC	1806/1612	Land Rights	70,296					70,296	60,912			640		61,552	8,744
47	1808	Buildings and Fixtures	96,568					96,568	62,463			1,236		63,699	32,868
47	1815	Transformer Station Equipment - Normally Primary above 50 kV	467,359					467,359	67,560			14,857		82,417	384,942
47	1820	Distribution Station Equipment - Normally Primary below 50 kV	4,026,865			137,899		4,164,764	2,507,902			89,148		2,597,050	1,567,714
47	1830	Poles, Towers and Fixtures	8,961,863	(88,852)	(304,761)	715,872	921	9,283,201	1,472,969	(889)	(45,290)	167,017	183	1,593,624	7,689,577
47	1835	Overhead Conductors and Devices	13,126,085			291,539		13,417,624	8,555,040			131,460		8,686,500	4,731,124
47	1840	Underground Conduit	1,142,895			175,209		1,318,104	169,355			23,341		192,696	1,125,408
47	1845	Underground Conductors and Devices	12,819,448		(2,144,360)	518,127		11,193,215	7,889,865		(444,741)	167,769		7,612,893	3,580,323
47	1850	Line Transformers	7,349,654		(736,211)	348,934	20,940	6,941,437	3,571,810		(124,462)	112,667	11,847	3,548,168	3,393,269
47	1855	Services	808,916			51,055		859,971	156,217			19,677		175,894	684,077
47	1860	Meters	3,067,502		(3,310)	50,858	59,324	3,055,726	1,000,855		(331)	203,390	24,776	1,179,138	1,876,589
N/A	1865	Other Installations on Customer's Premises	0					0	0					0	0
47	1908	Buildings and Fixtures	2,536,687			18,710		2,555,397	1,159,557			72,466		1,232,023	1,323,374
8	1915	Office Furniture and Equipment	90,446					90,446	64,166			8,540		72,706	17,740
10	1920	Computer Equipment - Hardware	184,428			67,324		251,752	61,660			46,697		108,357	143,395
12	1925/1611	Computer Software	887,329			10,640		897,969	466,432			107,665		574,097	323,872
10	1930	Transportation Equipment	1,672,983			31,498		1,704,481	1,119,989			63,281		1,183,270	521,211
8	1935	Stores Equipment	30,023					30,023	29,316			707		30,023	0
8	1940	Tools, Shop and Garage Equipment	83,043					83,043	64,960			5,878		70,838	12,206
8	1945	Measurement and Testing Equipment	20,450					20,450	15,276			771		16,047	4,403
8	1955	Communication Equipment	298,231					298,231	131,636			28,678		160,314	137,918
8	1960	Miscellaneous Equipment	315,235					315,235	103,807			11,128		114,935	200,301
47	1980	System Supervisory Equipment	687,996			88,737		776,733	527,282			36,802		564,084	212,649
47	1995/2440	Contributions and Grants	(3,366,847)	88,852	3,188,642	(421,828)		(511,181)	(617,204)	889	614,824	(9,603)		(11,094)	(500,087)
		Total before Work in Process	**55,536,143**	**0**	**0**	**2,084,574**	**81,185**	**57,539,532**	**28,641,825**	**0**	**0**	**1,304,209**	**36,806**	**29,909,231**	**27,630,302**
WIP	2055	Work in Process	55,500			97,790		153,290	0					0	153,290
		Total after Work in Process	**55,591,643**	**0**	**0**	**2,182,364**	**81,185**	**57,692,822**	**28,641,825**	**0**	**0**	**1,304,209**	**36,806**	**29,909,231**	**27,783,592**

Less: Fully Allocated Depreciation	
Transportation	0
Communication	0
Net Depreciation	1,304,209

Table 2-8 - Fixed Asset Continuity Schedule as at December 31, 2016, MIFRS

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**
N/A	1805	Land	158,686			158,686	0			0	158,686
CEC	1806/1612	Land Rights	70,296			70,296	61,552	640		62,192	8,104
47	1808	Buildings and Fixtures	96,568			96,568	63,699	1,236		64,935	31,632
47	1815	Transformer Station Equipment - Normally Primary above 50 kV	467,359			467,359	82,417	14,857		97,274	370,085
47	1820	Distribution Station Equipment - Normally Primary below 50 kV	4,164,764	200,000		4,364,764	2,597,050	82,986		2,680,036	1,684,728
47	1830	Poles, Towers and Fixtures	9,283,201	768,000		10,051,201	1,593,624	181,838		1,775,462	8,275,739
47	1835	Overhead Conductors and Devices	13,417,624	120,000		13,537,624	8,686,500	135,576		8,822,076	4,715,548
47	1840	Underground Conduit	1,318,104	165,000		1,483,104	192,696	26,743		219,439	1,263,665
47	1845	Underground Conductors and Devices	11,193,215	271,000		11,464,215	7,612,893	180,921		7,793,814	3,670,402
47	1850	Line Transformers	6,941,437	259,000		7,200,437	3,548,168	119,921		3,668,089	3,532,348
47	1855	Services	859,971	40,000		899,971	175,894	20,815		196,709	703,262
47	1860	Meters	3,055,726	60,000	60,000	3,055,726	1,179,138	203,126	30,680	1,351,584	1,704,143
N/A	1865	Other Installations on Customer's Premises	0			0	0			0	0
47	1908	Buildings and Fixtures	2,555,397	70,000		2,625,397	1,232,023	76,902		1,308,925	1,316,472
8	1915	Office Furniture and Equipment	90,446			90,446	72,706	5,675		78,381	12,065
10	1920	Computer Equipment - Hardware	251,752	25,000	12,400	264,352	108,357	52,839	12,400	148,796	115,556
12	1925/1611	Computer Software	897,969	100,490		998,459	574,097	105,364		679,461	318,998
10	1930	Transportation Equipment	1,704,481	754,100	274,552	2,184,029	1,183,270	86,155	269,903	999,522	1,184,507
8	1935	Stores Equipment	30,023			30,023	30,023			30,023	0
8	1940	Tools, Shop and Garage Equipment	83,043	5,500		88,543	70,838	5,381		76,219	12,325
8	1945	Measurement and Testing Equipment	20,450			20,450	16,047	771		16,818	3,632
8	1955	Communication Equipment	298,231			298,231	160,314	28,678		188,992	109,240
8	1960	Miscellaneous Equipment	315,235			315,235	114,935	11,128		126,063	189,173
47	1980	System Supervisory Equipment	776,733			776,733	564,084	42,184		606,268	170,465
47	1995/2440	Contributions and Grants	(511,181)	(53,000)		(564,181)	(11,094)	(17,086)		(28,180)	(536,001)
		Total before Work in Process	**57,539,532**	**2,785,090**	**346,952**	**59,977,670**	**29,909,231**	**1,366,650**	**312,983**	**30,962,898**	**29,014,773**
WIP	2055	Work in Process	153,290	(153,290)		0	0			0	0
		Total after Work in Process	**57,692,822**	**2,631,800**	**346,952**	**59,977,670**	**29,909,231**	**1,366,650**	**312,983**	**30,962,898**	**29,014,773**

Less: Fully Allocated Depreciation	
Transportation	
Communication	
Net Depreciation	1,366,650

Table 2-9 - Fixed Asset Continuity Schedule as at December 31, 2017, MIFRS

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**
N/A	1805	Land	158,686			158,686	0			0	158,686
CEC	1806/1612	Land Rights	70,296			70,296	62,192	640		62,832	7,464
47	1808	Buildings and Fixtures	96,568			96,568	64,935	1,236		66,171	30,396
47	1815	Transformer Station Equipment - Normally Primary above 50 kV	467,359			467,359	97,274	14,857		112,131	355,228
47	1820	Distribution Station Equipment - Normally Primary below 50 kV	4,364,764	170,000		4,534,764	2,680,036	88,934		2,768,970	1,765,794
47	1830	Poles, Towers and Fixtures	10,051,201	673,986		10,725,187	1,775,462	196,258		1,971,720	8,753,467
47	1835	Overhead Conductors and Devices	13,537,624	115,000		13,652,624	8,822,076	137,926		8,960,002	4,692,622
47	1840	Underground Conduit	1,483,104	225,000		1,708,104	219,439	30,643		250,082	1,458,022
47	1845	Underground Conductors and Devices	11,464,215	330,000		11,794,215	7,793,814	190,937		7,984,751	3,809,465
47	1850	Line Transformers	7,200,437	435,000		7,635,437	3,668,089	128,596		3,796,685	3,838,752
47	1855	Services	899,971	40,000		939,971	196,709	21,815		218,524	721,447
47	1860	Meters	3,055,726	100,000	60,000	3,095,726	1,351,584	204,635	34,680	1,521,539	1,574,188
N/A	1865	Other Installations on Customer's Premises	0			0	0			0	0
47	1908	Buildings and Fixtures	2,625,397	125,000		2,750,397	1,308,925	68,738		1,377,663	1,372,734
8	1915	Office Furniture and Equipment	90,446			90,446	78,381	3,896		82,277	8,169
10	1920	Computer Equipment - Hardware	264,352	25,000		289,352	148,796	55,555		204,351	85,001
12	1925/1611	Computer Software	998,459	40,000		1,038,459	679,461	92,996		772,457	266,002
10	1930	Transportation Equipment	2,184,029	70,000	35,423	2,218,606	999,522	114,183	35,423	1,078,282	1,140,324
8	1935	Stores Equipment	30,023			30,023	30,023			30,023	0
8	1940	Tools, Shop and Garage Equipment	88,543	5,000		93,543	76,219	5,401		81,620	11,924
8	1945	Measurement and Testing Equipment	20,450			20,450	16,818	771		17,589	2,861
8	1955	Communication Equipment	298,231			298,231	188,992	28,678		217,670	80,562
8	1960	Miscellaneous Equipment	315,235			315,235	126,063	11,128		137,191	178,045
47	1980	System Supervisory Equipment	776,733	110,000	50,000	836,733	606,268	50,560	50,000	606,828	229,905
47	1995/2440	Contributions and Grants	(564,181)	(50,000)		(614,181)	(28,180)	(18,783)		(46,963)	(567,218)
		Total before Work in Process	**59,977,670**	**2,413,986**	**145,423**	**62,246,233**	**30,962,898**	**1,429,600**	**120,103**	**32,272,395**	**29,973,839**
WIP	2055	Work in Process	0			0	0			0	0
		Total after Work in Process	**59,977,670**	**2,413,986**	**145,423**	**62,246,233**	**30,962,898**	**1,429,600**	**120,103**	**32,272,395**	**29,973,839**

Less: Fully Allocated Depreciation	
Transportation	
Communication	
Net Depreciation	1,429,600

FIXED ASSET CONTINUITY SCHEDULES EXCLUDING WORK IN PROGRESS

Table 2-10 through Table 2-14 below provide the Fixed Asset Continuity Schedules excluding WIP for each of 2013 Actual, 2014 Actual, 2015 Actual, 2016 Bridge Year, and 2017 Test Year and are consistent with Appendix 2-BA as required in the Filing Requirements.

As discussed above, WHESC implemented changes to its capitalization and depreciation policies in 2012, therefore no continuity schedule is required for before and after the policy changes. These changes were included in distribution rates in the 2013 COS Rate Application.

The "CCA Class" for fixed assets agrees with the CCA Class used for tax purposes in WHESC's tax returns. WHESC has one asset class that is different from those shown in Appendix 2-BA as provided by the Board. For tax purposes WHESC has classified Computer Hardware as Class 50 with a CCA rate of 55%, incorporating a 50% rule in the year of acquisition.

Upon the date of IFRS adoption, customer contributions are no longer recorded in Account 1995 Contributions & Grants, but are recorded in Account 2440, Deferred Revenue and amortized to revenue over the service life of the related asset. In addition, historical amounts recorded in Account 1995 prior to the transition year are to be netted against the assets in PP&E that they relate to, no longer accounted separately as an offset to PP&E. For purposes of cost allocation, and continuity within this application, WHESC has continued to utilize Account 1995 to track customer contributions, including contributed capital forecast for the 2016 Bridge Year and the 2017 Test Year. A breakdown of this account showing the reclassification is provided in Table 2-15. Depreciation is explained in further detail in the "Capitalization Policy" section of this Exhibit and Exhibit 4 – Operating Costs.

For reporting purposes under IFRS, WHESC has accounted for the retirement of assets within its calculation of rate base for the 2014 Actual (NIL), 2015 Actual, 2016 Bridge Year and the 2017 Test Year. Retirement of assets previously pooled for the 2014 Actual (NIL), 2015 Actual and 2016 Bridge Year have been charged to account 1575. Differences between Gross Assets and Accumulated Depreciation for retirement of assets previously pooled in the 2017 Test Year have been reclassified to account 4355 Other Revenue. The reclassification of losses to Other Revenue is disclosed separately and explained further in the "Capitalization Policy" section of this Exhibit and Exhibit 3 – Operating Revenues.

Table 2-10 - Fixed Asset Continuity Schedule as at December 31, 2013, RCGAAP

Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Accounting Standard CGAAP Revised
Year 2013

			Cost						Accumulated Depreciation						
CCA Class [2]	OEB Account [3]	Description [3]	Opening Balance			Additions [4]	Disposals [6]	Closing Balance	Opening Balance			Additions	Disposals [6]	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 1,089,119			$ 16,621	-$ 364,897	$ 740,843	-$ 553,375			-$ 140,667	$ 364,897	-$ 329,145	$ 411,698
CEC	1612	Land Rights (Formally known as Account	$ 70,296					$ 70,296	-$ 59,631			-$ 640		-$ 60,271	$ 10,025
N/A	1805	Land	$ 158,686					$ 158,686						$ -	$ 158,686
47	1808	Buildings	$ 96,568					$ 96,568	-$ 59,993			-$ 1,236		-$ 61,229	$ 35,339
13	1810	Leasehold Improvements						$ -						$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 467,359					$ 467,359	-$ 37,847			-$ 14,857		-$ 52,704	$ 414,655
47	1820	Distribution Station Equipment <50 kV	$ 4,223,152			$ 3,532	-$ 199,818	$ 4,026,866	-$ 2,545,494			-$ 86,093	$ 199,818	-$ 2,431,769	$ 1,595,097
47	1825	Storage Battery Equipment						$ -						$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 7,201,902			$ 786,758		$ 7,988,660	-$ 1,175,216			-$ 140,076		-$ 1,315,292	$ 6,673,368
47	1835	Overhead Conductors & Devices	$ 12,748,640			$ 174,979		$ 12,923,619	-$ 8,305,774			-$ 122,746		-$ 8,428,520	$ 4,495,099
47	1840	Underground Conduit	$ 916,576			$ 154,014		$ 1,070,590	-$ 129,886			-$ 18,603		-$ 148,489	$ 922,101
47	1845	Underground Conductors & Devices	$ 11,873,205			$ 666,205		$ 12,539,410	-$ 7,430,028			-$ 232,479		-$ 7,662,507	$ 4,876,903
47	1850	Line Transformers	$ 6,781,896			$ 337,635	-$ 40,018	$ 7,079,513	-$ 3,417,552			-$ 113,827	$ 38,230	-$ 3,493,149	$ 3,586,364
47	1855	Services (Overhead & Underground)	$ 699,038			$ 27,157		$ 726,195	-$ 121,581			-$ 16,631		-$ 138,212	$ 587,983
47	1860	Meters	$ 97,019				-$ 58,242	$ 38,777	-$ 97,019				$ 58,242	-$ 38,777	$ -
47	1860	Meters (Smart Meters)	$ 2,899,712			$ 65,532		$ 2,965,244	-$ 566,780			-$ 195,498		-$ 762,278	$ 2,202,966
N/A	1865	Other Installations on Customer Premises	$ 8,010				-$ 8,010	$ -	-$ 8,010				$ 8,010	$ -	$ -
N/A	1905	Land						$ -						$ -	$ -
47	1908	Buildings & Fixtures	$ 2,485,177			$ 22,165	-$ 4,088	$ 2,503,254	-$ 1,022,867			-$ 69,916	$ 4,088	-$ 1,088,695	$ 1,414,559
13	1910	Leasehold Improvements						$ -						$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 101,345			$ 1,403		$ 102,748	-$ 58,530			-$ 9,014		-$ 67,544	$ 35,204
8	1915	Office Furniture & Equipment (5 years)						$ -						$ -	$ -
10	1920	Computer Equipment - Hardware	$ 301,070			$ 14,809	-$ 169,507	$ 146,372	-$ 260,140			-$ 18,704	$ 169,507	-$ 109,337	$ 37,035
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)						$ -						$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)						$ -						$ -	$ -
10	1930	Transportation Equipment	$ 1,391,448			$ 325,615	-$ 132,851	$ 1,584,212	-$ 1,154,944			-$ 40,672	$ 132,851	-$ 1,062,765	$ 521,447
8	1935	Stores Equipment	$ 30,023					$ 30,023	-$ 27,852			-$ 760		-$ 28,612	$ 1,411
8	1940	Tools, Shop & Garage Equipment	$ 114,950				-$ 35,269	$ 79,681	-$ 87,313			-$ 6,748	$ 35,269	-$ 58,792	$ 20,889
8	1945	Measurement & Testing Equipment	$ 26,058			-$ 711	-$ 4,896	$ 20,451	-$ 17,328			-$ 1,699	$ 4,896	-$ 14,131	$ 6,320
8	1950	Power Operated Equipment						$ -						$ -	$ -
8	1955	Communications Equipment	$ 282,461				-$ 56,496	$ 225,965	-$ 143,637			-$ 22,100	$ 56,496	-$ 109,241	$ 116,724
8	1955	Communication Equipment (Smart Meters)						$ -						$ -	$ -
8	1960	Miscellaneous Equipment	$ 315,235					$ 315,235	-$ 81,551			-$ 11,128		-$ 92,679	$ 222,556
47	1970	Load Management Controls Customer Premises						$ -						$ -	$ -
47	1975	Load Management Controls Utility Premises						$ -						$ -	$ -
47	1980	System Supervisor Equipment	$ 1,143,045			$ 4,047	-$ 459,096	$ 687,996	-$ 914,874			-$ 35,701	$ 459,096	-$ 491,479	$ 196,517
47	1985	Miscellaneous Fixed Assets						$ -						$ -	$ -
47	1990	Other Tangible Property						$ -						$ -	$ -
47	1995	Contributions & Grants	-$ 2,563,013			-$ 625,629		-$ 3,188,642	$ 431,835			$ 86,571		$ 518,406	-$ 2,670,236
47	2440	Deferred Revenue [5]						$ -						$ -	$ -
		Sub-Total	**$ 52,958,978**			**$ 1,974,133**	**-$ 1,533,189**	**$ 53,399,922**	**-$ 27,845,387**			**-$ 1,213,224**	**$ 1,531,400**	**-$ 27,527,212**	**$ 25,872,710**
		Less Socialized Renewable Energy Generation Investments (input as negative)						$ -						$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)						$ -						$ -	$ -
		Total PP&E	**$ 52,958,978**			**$ 1,974,133**	**-$ 1,533,189**	**$ 53,399,922**	**-$ 27,845,387**			**-$ 1,213,224**	**$ 1,531,400**	**-$ 27,527,212**	**$ 25,872,710**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable [6]													
		Total										**-$ 1,213,224**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*
Transportation
Stores Equipment
Net Depreciation -$ 1,213,224

Table 2-11 - Fixed Asset Continuity Schedule as at December 31, 2014, MIFRS

Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS
Year 2014

			Cost						Accumulated Depreciation						
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**			**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**			**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 740,843			$ 146,486		$ 887,329	-$ 329,145			-$ 137,287		-$ 466,432	$ 420,897
CEC	1612	Land Rights (Formally known as Account 1806)	$ 70,296					$ 70,296	-$ 60,271			-$ 640		-$ 60,911	$ 9,385
N/A	1805	Land	$ 158,686					$ 158,686	$ -					$ -	$ 158,686
47	1808	Buildings	$ 96,568					$ 96,568	-$ 61,229			-$ 1,236		-$ 62,465	$ 34,103
13	1810	Leasehold Improvements	$ -					$ -	$ -					$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 467,359					$ 467,359	-$ 52,704			-$ 14,857		-$ 67,561	$ 399,798
47	1820	Distribution Station Equipment <50 kV	$ 4,026,866					$ 4,026,866	-$ 2,431,769			-$ 76,134		-$ 2,507,903	$ 1,518,963
47	1825	Storage Battery Equipment	$ -					$ -	$ -					$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 7,988,660			$ 973,203		$ 8,961,863	-$ 1,315,292			-$ 157,676		-$ 1,472,968	$ 7,488,895
47	1835	Overhead Conductors & Devices	$ 12,923,619			$ 202,465		$ 13,126,084	-$ 8,428,520			-$ 126,520		-$ 8,555,040	$ 4,571,044
47	1840	Underground Conduit	$ 1,070,590			$ 72,305		$ 1,142,895	-$ 148,489			-$ 20,866		-$ 169,355	$ 973,540
47	1845	Underground Conductors & Devices	$ 12,539,410			$ 280,038		$ 12,819,448	-$ 7,662,507			-$ 227,357		-$ 7,889,864	$ 4,929,584
47	1850	Line Transformers	$ 7,079,513			$ 319,776	-$ 49,635	$ 7,349,654	-$ 3,493,149			-$ 121,999	$ 43,340	-$ 3,571,808	$ 3,777,846
47	1855	Services (Overhead & Underground)	$ 726,195			$ 82,721		$ 808,916	-$ 138,212			-$ 18,005		-$ 156,217	$ 652,699
47	1860	Meters	$ 38,777					$ 38,777	-$ 38,777					-$ 38,777	$ -
47	1860	Meters (Smart Meters)	$ 2,965,244			$ 63,482		$ 3,028,726	-$ 762,278			-$ 199,799		-$ 962,077	$ 2,066,649
N/A	1865	Other Installations on Customer Premises	$ -					$ -	$ -					$ -	$ -
N/A	1905	Land	$ -					$ -	$ -					$ -	$ -
47	1908	Buildings & Fixtures	$ 2,503,254			$ 33,433		$ 2,536,687	-$ 1,088,695			-$ 70,862		-$ 1,159,557	$ 1,377,130
13	1910	Leasehold Improvements	$ -					$ -	$ -					$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 102,748				-$ 12,302	$ 90,446	-$ 67,544			-$ 8,924	$ 12,302	-$ 64,166	$ 26,280
8	1915	Office Furniture & Equipment (5 years)	$ -					$ -	$ -					$ -	$ -
10	1920	Computer Equipment - Hardware	$ 146,372			$ 118,498	-$ 80,441	$ 184,429	-$ 109,337			-$ 32,764	$ 80,441	-$ 61,660	$ 122,769
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -					$ -	$ -					$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -					$ -	$ -					$ -	$ -
10	1930	Transportation Equipment	$ 1,584,212			$ 88,771		$ 1,672,983	-$ 1,062,765			-$ 57,223		-$ 1,119,988	$ 552,995
8	1935	Stores Equipment	$ 30,023					$ 30,023	-$ 28,612			-$ 707		-$ 29,319	$ 704
8	1940	Tools, Shop & Garage Equipment	$ 79,681			$ 5,980	-$ 2,618	$ 83,043	-$ 58,792			-$ 8,786	$ 2,618	-$ 64,960	$ 18,083
8	1945	Measurement & Testing Equipment	$ 20,451					$ 20,451	-$ 14,131			-$ 1,146		-$ 15,277	$ 5,174
8	1950	Power Operated Equipment	$ -					$ -	$ -					$ -	$ -
8	1955	Communications Equipment	$ 225,965			$ 72,266		$ 298,231	-$ 109,241			-$ 22,394		-$ 131,635	$ 166,596
8	1955	Communication Equipment (Smart Meters)	$ -					$ -	$ -					$ -	$ -
8	1960	Miscellaneous Equipment	$ 315,235					$ 315,235	-$ 92,679			-$ 11,128		-$ 103,807	$ 211,428
47	1970	Load Management Controls Customer Premises	$ -					$ -	$ -					$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -					$ -	$ -					$ -	$ -
47	1980	System Supervisor Equipment	$ 687,996					$ 687,996	-$ 491,479			-$ 35,802		-$ 527,281	$ 160,715
47	1985	Miscellaneous Fixed Assets	$ -					$ -	$ -					$ -	$ -
47	1990	Other Tangible Property	$ -					$ -	$ -					$ -	$ -
47	1995	Contributions & Grants	-$ 3,188,642			-$ 178,205		-$ 3,366,847	$ 518,406			$ 98,797		$ 617,203	-$ 2,749,644
47	2440	Deferred Revenue[5]	$ -					$ -	$ -					$ -	$ -
		Sub-Total	**$ 53,399,922**			**$ 2,281,218**	**-$ 144,997**	**$ 55,536,143**	**-$ 27,527,212**			**-$ 1,253,315**	**$ 138,702**	**-$ 28,641,825**	**$ 26,894,319**
		Less Socialized Renewable Energy Generation Investments (input as negative)						$ -						$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)						$ -						$ -	$ -
		Total PP&E	**$ 53,399,922**			**$ 2,281,218**	**-$ 144,997**	**$ 55,536,143**	**-$ 27,527,212**			**-$ 1,253,315**	**$ 138,702**	**-$ 28,641,825**	**$ 26,894,319**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]													
		Total										**-$ 1,253,315**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*
Transportation
Stores Equipment
Net Depreciation -$ 1,253,315

Table 2-12 - Fixed Asset Continuity Schedule as at December 31, 2015, MIFRS

Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS
Year 2015

			Cost						Accumulated Depreciation						
CCA Class [2]	OEB Account [3]	Description [3]	Opening Balance	Pole Line Generation Adjustment	Contributed Capital Adjustment	Additions [4]	Disposals [6]	Closing Balance	Opening Balance	Pole Line Generation Adjustment	Contributed Capital Adjustment	Additions	Disposals [6]	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 887,329			$ 10,640		$ 897,969	-$ 466,432			-$ 107,665		-$ 574,097	$ 323,872
CEC	1612	Land Rights (Formally known as Account 1806)	$ 70,296					$ 70,296	-$ 60,911			-$ 640		-$ 61,551	$ 8,745
N/A	1805	Land	$ 158,686					$ 158,686	$ -					$ -	$ 158,686
47	1808	Buildings	$ 96,568					$ 96,568	-$ 62,465			-$ 1,236		-$ 63,701	$ 32,867
13	1810	Leasehold Improvements	$ -					$ -	$ -					$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 467,359					$ 467,359	-$ 67,561			-$ 14,857		-$ 82,418	$ 384,941
47	1820	Distribution Station Equipment <50 kV	$ 4,026,866			$ 137,899		$ 4,164,765	-$ 2,507,903			-$ 89,148		-$ 2,597,051	$ 1,567,714
47	1825	Storage Battery Equipment	$ -					$ -	$ -					$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 8,961,863	-$ 88,852	-$ 304,761	$ 715,872	-$ 921	$ 9,283,201	-$ 1,472,968	$ 889	$ 45,290	-$ 167,017	$ 183	-$ 1,593,623	$ 7,689,578
47	1835	Overhead Conductors & Devices	$ 13,126,084			$ 291,539		$ 13,417,623	-$ 8,555,040			-$ 131,460		-$ 8,686,500	$ 4,731,123
47	1840	Underground Conduit	$ 1,142,895			$ 175,209		$ 1,318,104	-$ 169,355			-$ 23,341		-$ 192,696	$ 1,125,408
47	1845	Underground Conductors & Devices	$ 12,819,448		-$ 2,144,360	$ 518,127		$ 11,193,215	-$ 7,889,864		$ 444,741	-$ 167,769		-$ 7,612,892	$ 3,580,323
47	1850	Line Transformers	$ 7,349,654		-$ 736,211	$ 348,934	-$ 20,940	$ 6,941,437	-$ 3,571,808		$ 124,462	-$ 112,667	$ 11,847	-$ 3,548,166	$ 3,393,271
47	1855	Services (Overhead & Underground)	$ 808,916			$ 51,055		$ 859,971	-$ 156,217			-$ 19,677		-$ 175,894	$ 684,077
47	1860	Meters	$ 38,777					$ 38,777	-$ 38,777					-$ 38,777	$ -
47	1860	Meters (Smart Meters)	$ 3,028,726		-$ 3,310	$ 50,858	-$ 59,324	$ 3,016,950	-$ 962,077		$ 331	-$ 203,390	$ 24,776	-$ 1,140,360	$ 1,876,590
N/A	1865	Other Installations on Customer Premises	$ -					$ -	$ -					$ -	$ -
N/A	1905	Land	$ -					$ -	$ -					$ -	$ -
47	1908	Buildings & Fixtures	$ 2,536,687			$ 18,710		$ 2,555,397	-$ 1,159,557			-$ 72,466		-$ 1,232,023	$ 1,323,374
13	1910	Leasehold Improvements	$ -					$ -	$ -					$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 90,446					$ 90,446	-$ 64,166			-$ 8,540		-$ 72,706	$ 17,740
8	1915	Office Furniture & Equipment (5 years)	$ -					$ -	$ -					$ -	$ -
10	1920	Computer Equipment - Hardware	$ 184,429			$ 67,324		$ 251,753	-$ 61,660			-$ 46,697		-$ 108,357	$ 143,396
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -					$ -	$ -					$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -					$ -	$ -					$ -	$ -
10	1930	Transportation Equipment	$ 1,672,983			$ 31,498		$ 1,704,481	-$ 1,119,988			-$ 63,281		-$ 1,183,269	$ 521,212
8	1935	Stores Equipment	$ 30,023					$ 30,023	-$ 29,319			-$ 704		-$ 30,023	$ -
8	1940	Tools, Shop & Garage Equipment	$ 83,043					$ 83,043	-$ 64,960			-$ 5,878		-$ 70,838	$ 12,205
8	1945	Measurement & Testing Equipment	$ 20,451					$ 20,451	-$ 15,277			-$ 771		-$ 16,048	$ 4,403
8	1950	Power Operated Equipment	$ -					$ -	$ -					$ -	$ -
8	1955	Communications Equipment	$ 298,231					$ 298,231	-$ 131,635			-$ 28,678		-$ 160,313	$ 137,918
8	1955	Communication Equipment (Smart Meters)	$ -					$ -	$ -					$ -	$ -
8	1960	Miscellaneous Equipment	$ 315,235					$ 315,235	-$ 103,807			-$ 11,128		-$ 114,935	$ 200,300
47	1970	Load Management Controls Customer Premises	$ -					$ -	$ -					$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -					$ -	$ -					$ -	$ -
47	1980	System Supervisor Equipment	$ 687,996			$ 88,737		$ 776,733	-$ 527,281			-$ 36,802		-$ 564,083	$ 212,650
47	1985	Miscellaneous Fixed Assets	$ -					$ -	$ -					$ -	$ -
47	1990	Other Tangible Property	$ -					$ -	$ -					$ -	$ -
47	1995/2440	Contributions & Grants/Deferred Revenue	-$ 3,366,847	$ 88,852	$ 3,188,642	-$ 421,828		-$ 511,181	$ 617,203	-$ 889	-$ 614,824	$ 9,603		$ 11,093	-$ 500,088
47	2440	Deferred Revenue[5]	$ -					$ -	$ -					$ -	$ -
		Sub-Total	**$ 55,536,143**	**$ -**	**$ -**	**$ 2,084,574**	**-$ 81,185**	**$ 57,539,532**	**-$ 28,641,825**	**$ -**	**$ -**	**-$ 1,304,209**	**$ 36,806**	**-$ 29,909,231**	**$ 27,630,302**
		Less Socialized Renewable Energy Generation Investments (input as negative)						$ -						$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)						$ -						$ -	$ -
		Total PP&E	**$ 55,536,143**	**$ -**	**$ -**	**$ 2,084,574**	**-$ 81,185**	**$ 57,539,532**	**-$ 28,641,825**	**$ -**	**$ -**	**-$ 1,304,209**	**$ 36,806**	**-$ 29,909,231**	**$ 27,630,302**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]													
		Total										**-$ 1,304,209**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*
Transportation
Stores Equipment
Net Depreciation -$ 1,304,209

Table 2-13 - Fixed Asset Continuity Schedule as at December 31, 2016, MIFRS

Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS
Year 2016

			Cost						Accumulated Depreciation						
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**		**Deferred Revenue**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**		**Deferred Revenue**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 897,969			$ 100,490		$ 998,459	-$ 574,097			-$ 105,364		-$ 679,461	$ 318,998
CEC	1612	Land Rights (Formally known as Account 1806)	$ 70,296					$ 70,296	-$ 61,551			-$ 640		-$ 62,191	$ 8,105
N/A	1805	Land	$ 158,686					$ 158,686	$ -					$ -	$ 158,686
47	1808	Buildings	$ 96,568					$ 96,568	-$ 63,701			-$ 1,236		-$ 64,937	$ 31,631
13	1810	Leasehold Improvements	$ -					$ -	$ -					$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 467,359					$ 467,359	-$ 82,418			-$ 14,857		-$ 97,275	$ 370,084
47	1820	Distribution Station Equipment <50 kV	$ 4,164,765			$ 200,000		$ 4,364,765	-$ 2,597,051			-$ 82,986		-$ 2,680,037	$ 1,684,728
47	1825	Storage Battery Equipment	$ -					$ -	$ -					$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 9,283,201			$ 768,000		$ 10,051,201	-$ 1,593,623			-$ 181,838		-$ 1,775,461	$ 8,275,740
47	1835	Overhead Conductors & Devices	$ 13,417,623			$ 120,000		$ 13,537,623	-$ 8,686,500			-$ 135,576		-$ 8,822,076	$ 4,715,547
47	1840	Underground Conduit	$ 1,318,104			$ 165,000		$ 1,483,104	-$ 192,696			-$ 26,743		-$ 219,439	$ 1,263,665
47	1845	Underground Conductors & Devices	$ 11,193,215			$ 271,000		$ 11,464,215	-$ 7,612,892			-$ 180,921		-$ 7,793,813	$ 3,670,402
47	1850	Line Transformers	$ 6,941,437			$ 259,000		$ 7,200,437	-$ 3,548,166			-$ 119,921		-$ 3,668,087	$ 3,532,350
47	1855	Services (Overhead & Underground)	$ 859,971			$ 40,000		$ 899,971	-$ 175,894			-$ 20,815		-$ 196,709	$ 703,262
47	1860	Meters	$ 38,777					$ 38,777	-$ 38,777					-$ 38,777	$ -
47	1860	Meters (Smart Meters)	$ 3,016,950			$ 60,000	-$ 60,000	$ 3,016,950	-$ 1,140,360			-$ 203,126	$ 30,680	-$ 1,312,806	$ 1,704,144
N/A	1865	Other Installations on Customer Premises	$ -					$ -	$ -					$ -	$ -
N/A	1905	Land	$ -					$ -	$ -					$ -	$ -
47	1908	Buildings & Fixtures	$ 2,555,397			$ 70,000		$ 2,625,397	-$ 1,232,023			-$ 76,902		-$ 1,308,925	$ 1,316,472
13	1910	Leasehold Improvements	$ -					$ -	$ -					$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 90,446					$ 90,446	-$ 72,706			-$ 5,675		-$ 78,381	$ 12,065
8	1915	Office Furniture & Equipment (5 years)	$ -					$ -	$ -					$ -	$ -
10	1920	Computer Equipment - Hardware	$ 251,753			$ 25,000	-$ 12,400	$ 264,353	-$ 108,357			-$ 52,839	$ 12,400	-$ 148,796	$ 115,557
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -					$ -	$ -					$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -					$ -	$ -					$ -	$ -
10	1930	Transportation Equipment	$ 1,704,481			$ 754,100	-$ 274,552	$ 2,184,029	-$ 1,183,269			-$ 86,155	$ 269,903	-$ 999,521	$ 1,184,508
8	1935	Stores Equipment	$ 30,023					$ 30,023	-$ 30,023					-$ 30,023	$ -
8	1940	Tools, Shop & Garage Equipment	$ 83,043			$ 5,500		$ 88,543	-$ 70,838			-$ 5,381		-$ 76,219	$ 12,324
8	1945	Measurement & Testing Equipment	$ 20,451					$ 20,451	-$ 16,048			-$ 771		-$ 16,819	$ 3,632
8	1950	Power Operated Equipment	$ -					$ -	$ -					$ -	$ -
8	1955	Communications Equipment	$ 298,231					$ 298,231	-$ 160,313			-$ 28,678		-$ 188,991	$ 109,240
8	1955	Communication Equipment (Smart Meters)	$ -					$ -	$ -					$ -	$ -
8	1960	Miscellaneous Equipment	$ 315,235					$ 315,235	-$ 114,935			-$ 11,128		-$ 126,063	$ 189,172
47	1970	Load Management Controls Customer Premises	$ -					$ -	$ -					$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -					$ -	$ -					$ -	$ -
47	1980	System Supervisor Equipment	$ 776,733					$ 776,733	-$ 564,083			-$ 42,184		-$ 606,267	$ 170,466
47	1985	Miscellaneous Fixed Assets	$ -					$ -	$ -					$ -	$ -
47	1990	Other Tangible Property	$ -					$ -	$ -					$ -	$ -
47	1995/2440	Contributions & Grants/Deferred Revenue	-$ 511,181		$ 511,181			$ -	$ 11,093		-$ 11,093			$ -	$ -
47	2440	Deferred Revenue[5]	$ -		-$ 511,181	-$ 53,000		-$ 564,181	$ -		$ 11,093	$ 17,086		$ 28,179	-$ 536,002
		Sub-Total	**$ 57,539,532**	**$ -**	**$ -**	**$ 2,785,090**	**-$ 346,952**	**$ 59,977,670**	**-$ 29,909,231**	**$ -**	**$ -**	**-$ 1,366,650**	**$ 312,983**	**-$ 30,962,898**	**$ 29,014,773**
		Less Socialized Renewable Energy Generation Investments (input as negative)						$ -						$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)						$ -						$ -	$ -
		Total PP&E	**$ 57,539,532**	**$ -**	**$ -**	**$ 2,785,090**	**-$ 346,952**	**$ 59,977,670**	**-$ 29,909,231**	**$ -**	**$ -**	**-$ 1,366,650**	**$ 312,983**	**-$ 30,962,898**	**$ 29,014,773**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]													
		Total										**-$ 1,366,650**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*
Transportation
Stores Equipment
Net Depreciation -$ 1,366,650

Table 2-14 - Fixed Asset Continuity Schedule as at December 31, 2017, MIFRS

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS
Year 2017

			Cost						Accumulated Depreciation						
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**			**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**			**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 998,459			$ 40,000		$ 1,038,459	-$ 679,461			-$ 92,996		-$ 772,457	$ 266,002
CEC	1612	Land Rights (Formally known as Account 1806)	$ 70,296					$ 70,296	-$ 62,191			-$ 640		-$ 62,831	$ 7,465
N/A	1805	Land	$ 158,686					$ 158,686	$ -					$ -	$ 158,686
47	1808	Buildings	$ 96,568					$ 96,568	-$ 64,937			-$ 1,236		-$ 66,173	$ 30,395
13	1810	Leasehold Improvements	$ -					$ -	$ -					$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 467,359					$ 467,359	-$ 97,275			-$ 14,857		-$ 112,132	$ 355,227
47	1820	Distribution Station Equipment <50 kV	$ 4,364,765			$ 170,000		$ 4,534,765	-$ 2,680,037			-$ 88,934		-$ 2,768,971	$ 1,765,794
47	1825	Storage Battery Equipment	$ -					$ -	$ -					$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 10,051,201			$ 673,986		$ 10,725,187	-$ 1,775,461			-$ 196,258		-$ 1,971,719	$ 8,753,468
47	1835	Overhead Conductors & Devices	$ 13,537,623			$ 115,000		$ 13,652,623	-$ 8,822,076			-$ 137,926		-$ 8,960,002	$ 4,692,621
47	1840	Underground Conduit	$ 1,483,104			$ 225,000		$ 1,708,104	-$ 219,439			-$ 30,643		-$ 250,082	$ 1,458,022
47	1845	Underground Conductors & Devices	$ 11,464,215			$ 330,000		$ 11,794,215	-$ 7,793,813			-$ 190,937		-$ 7,984,750	$ 3,809,465
47	1850	Line Transformers	$ 7,200,437			$ 435,000		$ 7,635,437	-$ 3,668,087			-$ 128,596		-$ 3,796,683	$ 3,838,754
47	1855	Services (Overhead & Underground)	$ 899,971			$ 40,000		$ 939,971	-$ 196,709			-$ 21,815		-$ 218,524	$ 721,447
47	1860	Meters	$ 38,777					$ 38,777	-$ 38,777					-$ 38,777	$ -
47	1860	Meters (Smart Meters)	$ 3,016,950			$ 100,000	-$ 60,000	$ 3,056,950	-$ 1,312,806			-$ 204,635	$ 34,680	-$ 1,482,761	$ 1,574,189
N/A	1865	Other Installations on Customer Premises	$ -					$ -	$ -					$ -	$ -
N/A	1905	Land	$ -					$ -	$ -					$ -	$ -
47	1908	Buildings & Fixtures	$ 2,625,397			$ 125,000		$ 2,750,397	-$ 1,308,925			-$ 68,738		-$ 1,377,663	$ 1,372,734
13	1910	Leasehold Improvements	$ -					$ -	$ -					$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 90,446					$ 90,446	-$ 78,381			-$ 3,896		-$ 82,277	$ 8,169
8	1915	Office Furniture & Equipment (5 years)	$ -					$ -	$ -					$ -	$ -
10	1920	Computer Equipment - Hardware	$ 264,353			$ 25,000		$ 289,353	-$ 148,796			-$ 55,555		-$ 204,351	$ 85,002
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -					$ -	$ -					$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -					$ -	$ -					$ -	$ -
10	1930	Transportation Equipment	$ 2,184,029			$ 70,000	-$ 35,423	$ 2,218,606	-$ 999,521			-$ 114,183	$ 35,423	-$ 1,078,281	$ 1,140,325
8	1935	Stores Equipment	$ 30,023					$ 30,023	-$ 30,023					-$ 30,023	$ -
8	1940	Tools, Shop & Garage Equipment	$ 88,543			$ 5,000		$ 93,543	-$ 76,219			-$ 5,401		-$ 81,620	$ 11,923
8	1945	Measurement & Testing Equipment	$ 20,451					$ 20,451	-$ 16,819			-$ 771		-$ 17,590	$ 2,861
8	1950	Power Operated Equipment	$ -					$ -	$ -					$ -	$ -
8	1955	Communications Equipment	$ 298,231					$ 298,231	-$ 188,991			-$ 28,678		-$ 217,669	$ 80,562
8	1955	Communication Equipment (Smart Meters)	$ -					$ -	$ -					$ -	$ -
8	1960	Miscellaneous Equipment	$ 315,235					$ 315,235	-$ 126,063			-$ 11,128		-$ 137,191	$ 178,044
47	1970	Load Management Controls Customer Premises	$ -					$ -	$ -					$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -					$ -	$ -					$ -	$ -
47	1980	System Supervisor Equipment	$ 776,733			$ 110,000	-$ 50,000	$ 836,733	-$ 606,267			-$ 50,560	$ 50,000	-$ 606,827	$ 229,906
47	1985	Miscellaneous Fixed Assets	$ -					$ -	$ -					$ -	$ -
47	1990	Other Tangible Property	$ -					$ -	$ -					$ -	$ -
47	1995/2440	Contributions & Grants/Deferred Revenue	$ -					$ -	$ -					$ -	$ -
47	2440	Deferred Revenue[5]	-$ 564,181			-$ 50,000		-$ 614,181	$ 28,179			$ 18,783		$ 46,962	-$ 567,219
		Sub-Total	**$ 59,977,670**	**$ -**	**$ -**	**$ 2,413,986**	**-$ 145,423**	**$ 62,246,233**	**-$ 30,962,898**	**$ -**	**$ -**	**-$ 1,429,600**	**$ 120,103**	**-$ 32,272,395**	**$ 29,973,839**
		Less Socialized Renewable Energy Generation Investments (input as negative)						$ -						$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)						$ -						$ -	$ -
		Total PP&E	**$ 59,977,670**	**$ -**	**$ -**	**$ 2,413,986**	**-$ 145,423**	**$ 62,246,233**	**-$ 30,962,898**	**$ -**	**$ -**	**-$ 1,429,600**	**$ 120,103**	**-$ 32,272,395**	**$ 29,973,839**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]													
		Total										**-$ 1,429,600**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*
Transportation
Stores Equipment
Net Depreciation -$ 1,429,600

As explained above, with the adoption of IFRS, customer contributions are no longer recorded in Account 1995 Contributions & Grants, but are recorded in Account 2440, Deferred Revenue. Historical contributions (as of January 1, 2014) are netted against the assets they relate to and have the same amortization period. There is no impact on depreciation expenses as a result of these transactions. For purposes of cost allocation and continuity within this application, WHESC has included all contributed capital including contributions forecast for the 2016 Bridge Year and the 2017 Test Year in Account 1995 and a breakdown of this account is provided in Table 2-15 below. The figures contained in Table 2-15 match those included in Table 2-9 and Table 2-12 above.

Table 2-15 – Account 1995 Breakdown

Accounting 1995/2440 Breakdown	Cost			Accumulated Depreciation			Net Book Value
	Opening	Additions	Closing	Opening	Additions	Closing	
Account 1995 Balance - December 31, 2014	**-3,188,642**	**-178,205**	**-3,366,847**	**518,406**	**98,797**	**617,204**	**-2,749,643**
January 1, 2014 Balance to Account 1830		304,761			-45,290		
January 1, 2014 Balance to Account 1845		2,144,360			-444,741		
January 1, 2014 Balance to Account 1850		736,211			-124,462		
January 1, 2014 Balance to Account 1860		3,310			-331		
Reverse 2014 Entry Capital Renewable Expansion		88,852			-889		
2015 Contributed Capital Transactions		-421,828			9,603	0	
Account 2440 Balance - December 31, 2015	**-3,366,847**	**2,855,666**	**-511,181**	**617,204**	**-606,110**	**11,094**	**-500,087**
2014 Capital Additions and 1.5 Yrs Depreciation		-178,205			5,364		
Reverse 2014 Entry Capital Renewable Expansion		88,852			-889		
2015 Capital Additions and 0.5 Yrs Depreciation		-421,828			6,619		
Account 2440 Balance - December 31, 2015	**0**	**-511,181**	**-511,181**	**0**	**11,094**	**11,094**	**-500,087**

2.2.1.2 GROSS ASSETS – PROPERTY PLANT & EQUIPMENT & ACCUMULATED DEPRECIATION

BREAKDOWN BY FUNCTION

Table 2-16 below categorizes WHESC's assets into four categories; distribution plant, general plant, contributions and grants, and WIP. In accordance with the Uniform System of Accounts ("USoA"), WHESC has included gross assets as follows:

- Distribution plant asset accounts include USoA 1805 to 1865 - this account includes assets such as substation equipment, poles, wires, transformers and meters;
- General plant asset accounts include USoA 1905 to 1990 and USoA 1611 - this account includes assets such as buildings, computer software and hardware, transportation equipment, and tools;
- Contributions and grants includes USoA account 1995/2440 – this account includes all contributions in aid of capital that WHESC has received or forecasted to be received as per the Distribution System Code ("DSC"); and

- WIP – this account includes all costs related to assets that are not considered in-service as of December 31st of the applicable fiscal year. Costs are transferred out of WIP and into the appropriate category above once designated in-service in the field.

Table 2-16 – Gross Asset Breakdown by Function

Description	2013 Board Approved	2013 Actual	2014 Actual	2015 Actual	2016 Bridge Year	2017 Test Year
Reporting Basis	**RCGAAP**	**RCGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Distribution Plant	49,261,879	50,151,783	52,096,138	51,026,952	52,849,952	54,878,938
General Plant	7,676,230	6,436,780	6,806,853	7,023,762	7,691,900	7,981,477
Contributions and Grants	-2,133,600	-3,188,642	-3,366,847	-511,181	-564,181	-614,181
Total Excluding WIP	**54,804,509**	**53,399,921**	**55,536,144**	**57,539,533**	**59,977,671**	**62,246,234**
WIP	0	137,172	55,500	153,290	0	0
Total Including WIP	**54,804,509**	**53,537,093**	**55,591,644**	**57,692,823**	**59,977,671**	**62,246,234**

DETAILED BREAKDOWN BY MAJOR PLANT ACCOUNT

Table 2-17 below provides a detailed breakdown by major account for each functionalized plant item. Each plant item is accompanied by a description in accordance with the Board's USoA, including the 2017 Test Year. WHESC has also included a breakdown of accumulated amortization in the same format in Table 2-18.

Table 2-17 - Gross Assets - Detailed Breakdown by Major Plant Function

Description	2013 Board Approved	2013 Actual	Variance from 2013 Board Approved	2014 Actual	Variance from 2013 Actual	2015 Actual	Variance from 2014 Actual	2016 Bridge Year	Variance from 2015 Actual	2017 Test Year	Variance from 2016 Bridge
Reporting Basis	**RCGAAP**	**RCGAAP**	**RCGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Land & Buildings											
1805 - Land	158,686	158,686	0	158,686	0	158,686	0	158,686	0	158,686	0
1806/1612 - Land Rights	70,296	70,296	0	70,296	0	70,296	0	70,296	0	70,296	0
1808 - Buildings	96,567	96,568	1	96,568	0	96,568	0	96,568	0	96,568	0
Sub-total Land & Buildings	**325,549**	**325,550**	**1**	**325,550**	**0**	**325,550**	**0**	**325,550**	**0**	**325,550**	**0**
Transmission & Distribution Stations											
1815 - Transformer Station Equipment >50 kV	467,359	467,359	0	467,359	0	467,359	0	467,359	0	467,359	0
1820 - Distribution Station Equipment < 50 kV	4,041,746	4,026,866	-14,880	4,026,866	0	4,164,765	137,899	4,364,765	200,000	4,534,765	170,000
Sub-total Transmission & Distribution Stations	**4,509,105**	**4,494,225**	**-14,880**	**4,494,225**	**0**	**4,632,124**	**137,899**	**4,832,124**	**200,000**	**5,002,124**	**170,000**
Poles & Wires											
1830 - Poles, Towers & Fixtures	7,645,522	7,988,660	343,138	8,961,863	973,203	9,283,201	321,338	10,051,201	768,000	10,725,187	673,986
1835 - Overhead Conductors & Devices	13,028,309	12,923,620	-104,689	13,126,085	202,465	13,417,624	291,539	13,537,624	120,000	13,652,624	115,000
1840 - Underground Conduit	1,021,854	1,070,590	48,736	1,142,895	72,305	1,318,104	175,209	1,483,104	165,000	1,708,104	225,000
1845 - Underground Conductors & Devices	11,821,995	12,539,410	717,415	12,819,448	280,038	11,193,215	-1,626,233	11,464,215	271,000	11,794,215	330,000
Sub-total Poles & Wires	**33,517,680**	**34,522,280**	**1,004,600**	**36,050,291**	**1,528,011**	**35,212,144**	**-838,147**	**36,536,144**	**1,324,000**	**37,880,130**	**1,343,986**
Line Transformers											
1850 - Line Transformers	7,143,533	7,079,513	-64,020	7,349,654	270,141	6,941,437	-408,217	7,200,437	259,000	7,635,437	435,000
Sub-total Line Transformers	**7,143,533**	**7,079,513**	**-64,020**	**7,349,654**	**270,141**	**6,941,437**	**-408,217**	**7,200,437**	**259,000**	**7,635,437**	**435,000**
Service & Meters											
1855 - Services Overhead & Underground	716,473	726,195	9,722	808,916	82,721	859,971	51,055	899,971	40,000	939,971	40,000
1860 - Meters	224,125	38,777	-185,348	38,777	0	38,777	0	38,777	0	38,777	0
1860 - Meters (Smart Meters)	2,817,384	2,965,243	147,859	3,028,725	63,482	3,016,949	-11,776	3,016,949	0	3,056,949	40,000
1865 - Leased Property Customer Premises	8,010	0	-8,010	0	0	0	0	0	0	0	0
Sub-total Service & Meters	**3,765,992**	**3,730,215**	**-35,777**	**3,876,418**	**146,203**	**3,915,697**	**39,279**	**3,955,697**	**40,000**	**4,035,697**	**80,000**
Buildings & Fixtures											
1908 - Buildings & Fixtures	2,464,785	2,503,254	38,469	2,536,687	33,433	2,555,397	18,710	2,625,397	70,000	2,750,397	125,000
Sub-total Service & Meters	**2,464,785**	**2,503,254**	**38,469**	**2,536,687**	**33,433**	**2,555,397**	**18,710**	**2,625,397**	**70,000**	**2,750,397**	**125,000**
IT Assets											
1920 - Computer Equipment	368,608	146,372	-222,236	184,429	38,057	251,753	67,324	264,353	12,600	289,353	25,000
1925/1611 - Computer Software	1,158,905	740,844	-418,061	887,330	146,486	897,970	10,640	998,460	100,490	1,038,460	40,000
Sub-total IT Assets	**1,527,513**	**887,216**	**-640,297**	**1,071,759**	**184,543**	**1,149,723**	**77,964**	**1,262,813**	**113,090**	**1,327,813**	**65,000**
Equipment											
1915 - Office Furniture & Equipment	107,819	102,748	-5,071	90,446	-12,302	90,446	0	90,446	0	90,446	0
1930 - Transportation Equipment	1,583,764	1,584,212	448	1,672,983	88,771	1,704,481	31,498	2,184,029	479,548	2,218,606	34,577
1935 - Stores Equipment	30,023	30,023	0	30,023	0	30,023	0	30,023	0	30,023	0
1940 - Tools, Shop & Garage Equipment	132,950	79,681	-53,269	83,043	3,362	83,043	0	88,543	5,500	93,543	5,000
1945 - Measurement & Testing Equipment	20,391	20,451	60	20,451	0	20,451	0	20,451	0	20,451	0
1955 - Communications Equipment	279,005	225,965	-53,040	298,231	72,266	298,231	0	298,231	0	298,231	0
1960 - Miscellaneous Equipment	315,235	315,235	0	315,235	0	315,235	0	315,235	0	315,235	0
Sub-total Service & Meters	**2,469,187**	**2,358,315**	**-110,872**	**2,510,412**	**152,097**	**2,541,910**	**31,498**	**3,026,958**	**485,048**	**3,066,535**	**39,577**
Other Distribution Assets											
1980 - System Supervisor Equipment	1,214,745	687,995	-526,750	687,995	0	776,732	88,737	776,732	0	836,732	60,000
1995 - Contributions & Grants	-2,133,600	-3,188,642	-1,055,042	-3,366,847	-178,205	0	3,366,847	0	0	0	0
2440 - Deferred Revenue	0	0	0	0	0	-511,181	-511,181	-564,181	-53,000	-614,181	-50,000
Sub-total Other Distribution Assets	**-918,855**	**-2,500,647**	**-1,581,792**	**-2,678,852**	**-178,205**	**265,551**	**2,944,403**	**212,551**	**-53,000**	**222,551**	**10,000**
Gross Assets for Rate Base	**54,804,489**	**53,399,921**	**-1,404,568**	**55,536,144**	**2,136,223**	**57,539,533**	**2,003,389**	**59,977,671**	**2,438,138**	**62,246,234**	**2,268,563**
WIP											
2055 - Construction Work in Process Electric	0	137,172	137,172	55,500	-81,672	153,290	97,790	0	-153,290	0	0
Sub-total WIP	**0**	**137,172**	**137,172**	**55,500**	**-81,672**	**153,290**	**97,790**	**0**	**-153,290**	**0**	**0**
Total Assets including WIP	**54,804,489**	**53,537,093**	**-1,267,396**	**55,591,644**	**2,054,551**	**57,692,823**	**2,101,179**	**59,977,671**	**2,284,848**	**62,246,234**	**2,268,563**

Table 2-18 – Accumulated Amortization - Detailed Breakdown by Major Plant Function

Description	2013 Board Approved	2013 Actual	Variance from 2013 Board Approved	2014 Actual	Variance from 2013 Actual	2015 Actual	Variance from 2014 Actual	2016 Bridge Year	Variance from 2015 Actual	2017 Test Year	Variance from 2016 Bridge
Reporting Basis	**RCGAAP**	**RCGAAP**	**RCGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Land & Buildings											
1805 - Land	0	0	0	0	0	0	0	0	0	0	0
1806/1612 - Land Rights	60,271	60,271	0	60,911	640	61,551	640	62,191	640	62,831	640
1808 - Buildings	61,227	61,229	2	62,465	1,236	63,701	1,236	64,937	1,236	66,173	1,236
Sub-total Land & Buildings	**121,498**	**121,500**	**2**	**123,376**	**1,876**	**125,252**	**1,876**	**127,128**	**1,876**	**129,004**	**1,876**
Transmission & Distribution Stations											
1815 - Transformer Station Equipment >50 kV	52,704	52,704	0	67,561	14,857	82,418	14,857	97,275	14,857	112,132	14,857
1820 - Distribution Station Equipment < 50 kV	2,614,582	2,431,769	-182,813	2,507,903	76,134	2,597,051	89,148	2,680,037	82,986	2,768,971	88,934
Sub-total Transmission & Distribution Stations	**2,667,286**	**2,484,473**	**-182,813**	**2,575,464**	**90,991**	**2,679,469**	**104,005**	**2,777,312**	**97,843**	**2,881,103**	**103,791**
Poles & Wires											
1830 - Poles, Towers & Fixtures	1,308,236	1,315,292	7,056	1,472,968	157,676	1,593,623	120,655	1,775,461	181,838	1,971,719	196,258
1835 - Overhead Conductors & Devices	8,432,490	8,428,520	-3,970	8,555,040	126,520	8,686,500	131,460	8,822,076	135,576	8,960,002	137,926
1840 - Underground Conduit	147,783	148,489	706	169,355	20,866	192,696	23,341	219,439	26,743	250,082	30,643
1845 - Underground Conductors & Devices	7,652,965	7,662,507	9,542	7,889,864	227,357	7,612,892	-276,972	7,793,813	180,921	7,984,750	190,937
Sub-total Poles & Wires	**17,541,474**	**17,554,808**	**13,334**	**18,087,227**	**532,419**	**18,085,711**	**-1,516**	**18,610,789**	**525,078**	**19,166,553**	**555,764**
Line Transformers											
1850 - Line Transformers	3,532,788	3,493,149	-39,639	3,571,808	78,659	3,548,166	-23,642	3,668,087	119,921	3,796,683	128,596
Sub-total Line Transformers	**3,532,788**	**3,493,149**	**-39,639**	**3,571,808**	**78,659**	**3,548,166**	**-23,642**	**3,668,087**	**119,921**	**3,796,683**	**128,596**
Service & Meters											
1855 - Services Overhead & Underground	137,652	138,212	560	156,217	18,005	175,894	19,677	196,709	20,815	218,524	21,815
1860 - Meters	101,115	38,777	-62,338	38,777	0	38,777	0	38,777	0	38,777	0
1860 - Meters (Smart Meters)	757,145	762,278	5,133	962,077	199,799	1,140,360	178,283	1,312,805	172,445	1,482,760	169,955
1865 - Leased Property Customer Premises	8,010	0	-8,010	0	0	0	0	0	0	0	0
Sub-total Service & Meters	**1,003,922**	**939,267**	**-64,655**	**1,157,071**	**217,804**	**1,355,031**	**197,960**	**1,548,291**	**193,260**	**1,740,061**	**191,770**
Buildings & Fixtures											
1908 - Buildings & Fixtures	1,082,635	1,088,695	6,060	1,159,557	70,862	1,232,023	72,466	1,308,925	76,902	1,377,663	68,738
Sub-total Service & Meters	**1,082,635**	**1,088,695**	**6,060**	**1,159,557**	**70,862**	**1,232,023**	**72,466**	**1,308,925**	**76,902**	**1,377,663**	**68,738**
IT Assets											
1920 - Computer Equipment	290,821	109,337	-181,484	61,660	-47,677	108,357	46,697	148,796	40,439	204,351	55,555
1925/1611 - Computer Software	724,562	329,146	-395,416	466,433	137,287	574,098	107,665	679,462	105,364	772,458	92,996
Sub-total IT Assets	**1,015,383**	**438,483**	**-576,900**	**528,093**	**89,610**	**682,455**	**154,362**	**828,258**	**145,803**	**976,809**	**148,551**
Equipment											
1915 - Office Furniture & Equipment	68,445	67,544	-901	64,166	-3,378	72,706	8,540	78,381	5,675	82,277	3,896
1930 - Transportation Equipment	1,062,750	1,062,765	15	1,119,988	57,223	1,183,269	63,281	999,521	-183,748	1,078,281	78,760
1935 - Stores Equipment	28,611	28,612	1	29,319	707	30,023	704	30,023	0	30,023	0
1940 - Tools, Shop & Garage Equipment	96,258	58,792	-37,466	64,960	6,168	70,838	5,878	76,219	5,381	81,620	5,401
1945 - Measurement & Testing Equipment	18,213	14,131	-4,082	15,277	1,146	16,048	771	16,819	771	17,590	771
1955 - Communications Equipment	164,648	109,241	-55,407	131,635	22,394	160,313	28,678	188,991	28,678	217,669	28,678
1960 - Miscellaneous Equipment	92,680	92,679	-1	103,807	11,128	114,935	11,128	126,063	11,128	137,191	11,128
Sub-total Service & Meters	**1,531,605**	**1,433,764**	**-97,841**	**1,529,152**	**95,388**	**1,648,132**	**118,980**	**1,516,017**	**-132,115**	**1,644,651**	**128,634**
Other Distribution Assets											
1980 - System Supervisor Equipment	959,414	491,479	-467,935	527,281	35,802	564,083	36,802	606,267	42,184	606,827	560
1995 - Contributions & Grants	-489,475	-518,406	-28,931	-617,203	-98,797	0	617,203	0	0	0	0
2440 - Deferred Revenue	0	0	0	0	0	-11,093	-11,093	-28,179	-17,086	-46,962	-18,783
Sub-total Other Distribution Assets	**469,939**	**-26,927**	**-496,866**	**-89,922**	**-62,995**	**552,990**	**642,912**	**578,088**	**25,098**	**559,865**	**-18,223**
Gross Assets for Rate Base	**28,966,530**	**27,527,212**	**-1,439,318**	**28,641,826**	**1,114,614**	**29,909,229**	**1,267,403**	**30,962,895**	**1,053,666**	**32,272,392**	**1,309,497**
WIP											
2055 - Construction Work in Process Electric	0	0	0	0	0	0	0	0	0	0	0
Sub-total WIP	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Total Assets including WIP	**28,966,530**	**27,527,212**	**-1,439,318**	**28,641,826**	**1,114,614**	**29,909,229**	**1,267,403**	**30,962,895**	**1,053,666**	**32,272,392**	**1,309,497**

VARIANCE ANALYSIS ON GROSS ASSETS

Table 2-19 below provides the same level of detail as Table 2-17, however, for the purposes of the variance analysis assets are categorized as Distribution Assets and General Plant and explanations on variances over WHESC's materiality threshold are explained following the table.

Table 2-19 – Variance on Gross Assets

Description	2013 Board Approved	2013 Actual	Variance from 2013 Board Approved	2014 Actual	Variance from 2013 Actual	2015 Actual	Variance from 2014 Actual	2016 Bridge Year	Variance from 2015 Actual	2017 Test Year	Variance from 2016 Bridge
Reporting Basis	**RCGAAP**	**RCGAAP**	**RCGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Distribution Assets											
1805 - Land	158,686	158,686	0	158,686	0	158,686	0	158,686	0	158,686	0
1806/1612 - Land Rights	70,296	70,296	0	70,296	0	70,296	0	70,296	0	70,296	0
1808 - Buildings	96,567	96,568	1	96,568	0	96,568	0	96,568	0	96,568	0
1815 - Transformer Station Equipment >50 kV	467,359	467,359	0	467,359	0	467,359	0	467,359	0	467,359	0
1820 - Distribution Station Equipment < 50 kV	4,041,746	4,026,866	-14,880	4,026,866	0	4,164,765	137,899	4,364,765	200,000	4,534,765	170,000
1830 - Poles, Towers & Fixtures	7,645,522	7,988,660	343,138	8,961,863	973,203	9,283,201	321,338	10,051,201	768,000	10,725,187	673,986
1835 - Overhead Conductors & Devices	13,028,309	12,923,620	-104,689	13,126,085	202,465	13,417,624	291,539	13,537,624	120,000	13,652,624	115,000
1840 - Underground Conduit	1,021,854	1,070,590	48,736	1,142,895	72,305	1,318,104	175,209	1,483,104	165,000	1,708,104	225,000
1845 - Underground Conductors & Devices	11,821,995	12,539,410	717,415	12,819,448	280,038	11,193,215	-1,626,233	11,464,215	271,000	11,794,215	330,000
1850 - Line Transformers	7,143,533	7,079,513	-64,020	7,349,654	270,141	6,941,437	-408,217	7,200,437	259,000	7,635,437	435,000
1855 - Services Overhead & Underground	716,473	726,195	9,722	808,916	82,721	859,971	51,055	899,971	40,000	939,971	40,000
1860 - Meters	224,125	38,777	-185,348	38,777	0	38,777	0	38,777	0	38,777	0
1860 - Meters (Smart Meters)	2,817,384	2,965,243	147,859	3,028,725	63,482	3,016,949	-11,776	3,016,949	0	3,056,949	40,000
1865 - Leased Property Customer Premises	8,010	0	-8,010	0	0	0	0	0	0	0	0
1995 - Contributions & Grants	-2,133,600	-3,188,642	-1,055,042	-3,366,847	-178,205	0	3,366,847	0	0	0	0
2440 - Deferred Revenue	0	0	0	0	0	-511,181	-511,181	-564,181	-53,000	-614,181	-50,000
Sub-total Distribution Assets	**47,128,259**	**46,963,141**	**-165,118**	**48,729,291**	**1,766,150**	**50,515,771**	**1,786,480**	**52,285,771**	**1,770,000**	**54,264,757**	**1,978,986**
General Plant											
1908 - Buildings & Fixtures	2,464,785	2,503,254	38,469	2,536,687	33,433	2,555,397	18,710	2,625,397	70,000	2,750,397	125,000
1920 - Computer Equipment	368,608	146,372	-222,236	184,429	38,057	251,753	67,324	264,353	12,600	289,353	25,000
1925/1611 - Computer Software	1,158,905	740,844	-418,061	887,330	146,486	897,970	10,640	998,460	100,490	1,038,460	40,000
1915 - Office Furniture & Equipment	107,819	102,748	-5,071	90,446	-12,302	90,446	0	90,446	0	90,446	0
1930 - Transportation Equipment	1,583,764	1,584,212	448	1,672,983	88,771	1,704,481	31,498	2,184,029	479,548	2,218,606	34,577
1935 - Stores Equipment	30,023	30,023	0	30,023	0	30,023	0	30,023	0	30,023	0
1940 - Tools, Shop & Garage Equipment	132,950	79,681	-53,269	83,043	3,362	83,043	0	88,543	5,500	93,543	5,000
1945 - Measurement & Testing Equipment	20,391	20,451	60	20,451	0	20,451	0	20,451	0	20,451	0
1955 - Communications Equipment	279,005	225,965	-53,040	298,231	72,266	298,231	0	298,231	0	298,231	0
1960 - Miscellaneous Equipment	315,235	315,235	0	315,235	0	315,235	0	315,235	0	315,235	0
1980 - System Supervisor Equipment	1,214,745	687,995	-526,750	687,995	0	776,732	88,737	776,732	0	836,732	60,000
Sub-total General Plant	**7,676,230**	**6,436,780**	**-1,239,450**	**6,806,853**	**370,073**	**7,023,762**	**216,909**	**7,691,900**	**668,138**	**7,981,477**	**289,577**
Gross Assets for Rate Base	**54,804,489**	**53,399,921**	**-1,404,568**	**55,536,144**	**2,136,223**	**57,539,533**	**2,003,389**	**59,977,671**	**2,438,138**	**62,246,234**	**2,268,563**
WIP											
2055 - Construction Work in Process Electric	0	137,172	137,172	55,500	-81,672	153,290	97,790	0	-153,290	0	0
Sub-total WIP	**0**	**137,172**	**137,172**	**55,500**	**-81,672**	**153,290**	**97,790**	**0**	**-153,290**	**0**	**0**
Total Assets including WIP	**54,804,489**	**53,537,093**	**-1,267,396**	**55,591,644**	**2,054,551**	**57,692,823**	**2,101,179**	**59,977,671**	**2,284,848**	**62,246,234**	**2,268,563**

2013 Board Approved vs. 2013 Actual:

Analysis of Gross Book Value 2013 Board Approved versus 2013 Actual is comprised of variances in capital spending, and write-offs. Average Net Book Value for Rate Bate is $25,464,079 for 2013 Board Approved versus $25,493,150 for 2013 Actual as can be seen in Table 2-1 above. This represents a difference of only $29,071 which is less than the materiality threshold. Actual capital expenditures in 2013 were 1,974,132 versus Board Approved of $1,976,365. Actual Depreciation in 2013 was $1,213,224 versus Board Approved of $1,228,565 (before 1576 adjustment). The majority of differences in Gross Book Value between 2013 Board Approved and 2013 Actual relates to assets being removed from both Gross Book Value and Accumulated Depreciation in preparation for the conversion to IFRS. 2013 Board Approved Disposals totaled $132,851 versus 2013 actual of $1,533,188. The entries made in 2013 would have no impact on rate base as these assets were for the most part fully depreciated (difference of $1,788 between Gross Assets and Accumulated Depreciation).

- Distribution Assets – ($165,118)

The majority of this variance is related to 2013 Actual asset write offs of $306,088 versus no amounts included for write off in 2013 Board Approved totals. 2013 Board Approved Capital Contributions were forecasted by job type, however actual contributions made by WHESC are in accordance with the DSC and the provisions of WHESC's Conditions of Service and vary by individual job. This results in differences between assets categories which for the most part offset. WHESC uses the economic evaluation methodology from the DSC to determine the level of capital contribution for each project.

General Assets - ($1,239,450)

The majority of this variance is related to 2013 Actual asset write offs of $1,227,100 versus $132,851 amounts included for write off in 2013 Board Approved totals.

2014 Actual vs. 2013 Actual:

- Distribution Assets - $1,766,150

Distribution assets are higher than the 2013 Actuals by $1,766,150. In 2014, WHESC continued its overhead and underground line renewal programs. Overhead line renewals total $1,008,927 with two major projects. The first is a rebuild of a 27.6 kV line on Major Street at a total cost of $323,827. The second is a system conversion from 4.16 kV to 27.6 kV at Division/Burger which is located in an older area of downtown Welland at a cost of $295,502. Underground renewals totaled $536,326 with the majority related to an older residential neighborhood on Greystone. Total costs were $380,376 and included a conversion from 2.4 kV to 16 kV.

- General Assets - $370,073

General assets increased over 2013 Actuals by $370,073 in 2014. In 2014, Computer Hardware purchases totaled $112,624 with an emphasis on internal server replacements including the engineering server which hosts WHESC's GIS software and data. Vehicle additions and replacements totaled $88,771 in 2014. A used back yard digger and trailer were purchased to perform line repairs/replacements in areas where access is limited for heavy equipment at a total cost of $32,500. There were two rebuilds of trucks in an attempt to extend their useful lives by five years. A sub-frame rebuild to a 14 year old double bucket truck cost $23,648 and this truck will remain in service thru the 2017 Test Year. A rebuilt engine was installed at a cost of $9,296 in a 26 year old digger/derrick truck which is used in new construction projects. However, this truck will be replaced in 2016 due to continued breakdowns/safety issues and difficulty in finding replacement parts because of it age.

2015 Actual vs. 2014 Actual:

- Distribution Assets - $1,786,480

Distribution assets are higher than the 2014 Actuals by $1,786,480. In 2015, WHESC began a program of upgrading its substation assets with expenditures of $137,899. No significant expenditures on substations had been made since 2012. This program will be phased over the duration of this COS rate application and involves transformer and switchgear replacements. Line renewals continued in 2015 with overhead expenditures of $794,499 and underground expenditures of $574,446. Major overhead rebuilds include the completion of the Orchard/Wright/Deere street rebuild $175,959 and the first phase of the Hellems/Dorothy/Park street rebuild $269,045. The Humberstone/Townline tunnel 27.6 kV rebuild at $345,567 represents the majority of the underground renewals.

- General Assets - $216,909

General assets increased over 2014 Actuals by $216,909 in 2015 and included miscellaneous computer hardware and software replacements and upgrades. The major project addition was the completion of the SCADA ICCP software program at a cost of $83,411. This amount includes $55,550 which was included in Construction in Process (WIP) at the end of 2014. A new service van was purchased at a cost of $27,099 replacing a 14 year old truck. A new double bucket truck was ordered in 2015 with a required deposit of $117,800. This amount is included in WIP at the end of 2015. This vehicle replaces a 1998 vintage truck at a total cost of $364,100.

2016 Bridge vs. 2015 Actual:

- Distribution Assets - $1,770,000

Distribution assets will increase by $1,770,000 over 2015 Actuals. In the 2016 Bridge Year, WHESC will spend approximately $200,000 on substation renewal with switchgear and primary cable replacements at MS#7. A total of $1,273,000 will be spent on overhead/underground line renewal projects. This includes the completion of the Hellems/Dorothy/Park street overhead rebuild at $300,000 and the first phase of the Church/Niagara street overhead rebuild/conversion at $450,000. Underground renewals include the first phase of the Silvan/Newleaf rebuild/conversion.

- General Assets - $668,138

General assets will increase by $668,138 over 2015 actuals. The majority of the increase is related to the purchase of two vehicles. As mentioned previously, a new double bucket truck has been put into service in 2016 at a total cost of $364,100. Also discussed previously was the replacement of the large digger/derrick truck which in 2016 will have 28 years of service. Total cost of the new vehicle is $315,000. As a result of upgrades to its vehicle fleet WHESC has determined that it will reduce its vehicle maintenance staff from 2 to 1. This strategic reduction will be made to offset the addition of a certified engineer as part of succession planning without adding additional personnel. The 2016 Bridge Year also includes a $70,000 replacement of the service center fire alarm system. WHESC is committed to remaining in its existing facilities for the foreseeable future. However, this will require phased in improvements to the existing building and grounds over the five year period of this 2017 COS Rate Application.

2017 Test vs. 2016 Bridge:

- Distribution Assets - $1,978,986

Distribution assets will increase by $1,978,986 over the 2016 Bridge Year. Substation renewal costs of $170,000 includes transformer/primary cabling replacement at MS#14 and transformer replacement at MS#8. Overhead/Underground line renewals total $1,454,485 and is comprised of $749,485 overhead and $705,000 underground. Major projects include $300,000 for the completion of the Church/Niagara overhead renewal, $250,000 for the completion of the Wellington Street/East Main conversion, and $280,000 on phase two of the Silvan/Newleaf rebuild/conversion.

- General Assets - $289,577

General assets will increase by $289,577 over the 2016 Bridge Year. The major expenditure relates to the first phase of the parking lot replacement at $100,000. SCADA SmartVu software will be replaced at a cost of $50,000 as the existing software will no longer be supported. There are no significant additions to either computer hardware/software or vehicles in the 2017 Test Year. WHESC will make strategic investments to maintain/upgrade its CIS/Financials/Document Storage/GIS/SCADA software systems and networks as required during the term of this COS Rate Application. WHESC has also not included MIST meter replacements in the 2017 Test Year. The current OEB approved deferral account will be used for these mandated changes and will be dealt upon the completion of the program in a future rate application as was the case with smart meters.

ASSET DISPOSALS

Asset disposals have been included in Table 2-10 thru Table 2-14. Account 1575 has been used to reflect the difference between Gross Assets and Accumulated Depreciation values in relation to the early disposition of smart meters in account 1860 for 2015 Actuals ($34,548) and the 2016 Bridge Year ($29,320) and poles in 1830 in 2015 Actuals ($738). This account was previously a pooled asset category which has been revised under IFRS. There were no premature disposition of assets in 2014 as a result of restatement upon conversion to IFRS January 1, 2015. WHESC can confirm for the Board that asset disposals in all years have been removed from Rate Base. However, WHESC has not adjusted depreciation expense in the 2017 Test Year for the cost related to early disposition of assets previously pooled. As discussed in Exhibit 3 and in Exhibit 6, WHESC has included this expense as an adjustment to account 4355 Other Revenue. WHESC expects to have early retirement of assets throughout the period covered by the COS rate application.

SUMMARY OF ADVANCE CAPITAL MODULE/INCREMENTAL CAPITAL MODULE ADJUSTMENT

WHESC confirms that it has not applied for nor received any ACM/ICM adjustments as part of a previous IRM application.

RECONCILIATON OF CONTINUITY STATEMENTS TO CALCULATED DEPRECIATION EXPENSES

WHESC confirms that the depreciation expenses in the fixed asset continuity statements reconcile to the calculated depreciation expenses under Exhibit 4 – Operating Costs and are presented by account. As such there are no reconciling items between the fixed asset continuity statements in this Exhibit and the calculated depreciation expense in Exhibit 4.

2.2.1.3 ALLOWANCE FOR WORKING CAPITAL

OVERVIEW

The Filing Requirements permit applicants to take one of two approaches for the calculation of the allowance for working capital; the 7.5% Default Allowance Approach or the filing of a lead/lag study. Using the Default Allowance Approach, the working capital allowance is calculated to be 7.5% of the sum of Cost of Power ("COP") and Controllable Expenses (Operations, Maintenance, Billing and Collecting, Community Relations, Administration and General). WHESC was required to perform a lead/lag study as part of the settlement agreement in its 2013 COS Rate Application EB-2012-0173. However, WHESC filed a Motion to Review and Vary the decision in the 2013 COS Rate Application on April 7, 2016 to remove the requirement to conduct a lead/lag study. The motion was filed "With Consent" of the intervenors in EB-2012-0173 and would require that WHESC use the default working capital percentage of 7.5% in the 2017 COS Rate Application. The Board assigned case number EB-2016-0147 to this filing and on May 19, 2016 the Board issued its Decision and Vary Order eliminating the requirement for WHESC to conduct a lead/lag study for this rate application.

As a result, the working capital allowance for the 2017 Test Year is based upon 7.5% of the sum of the Cost of Power ("COP") and Controllable Expenses. In calculating the working capital allowance for 2013 to 2015 actual and for the 2016 Bridge Year, WHESC used a working capital allowance of 12%. The 12% represents the working capital allowance in the settlement agreement in WHESC's 2013 Board Approved COS Rate Application.

Table 2-20 provides a summary of WHESC's COP and Controllable Expenses used to the calculate working capital allowance for 2013 Board Approved, 2013 Actual, 2014 Actual, 2015 Actual, 2016 Bridge Year and the 2017 Test Year.

Table 2-20 - Summary of Working Capital Allowance

Description	2013 Board Approved	2013 Actual	2014 Actual	2015 Actual	2016 Bridge Year	2017 Test Year
Cost of Power Expenses	**43,394,903**	**41,761,439**	**43,111,545**	**43,174,574**	**46,376,611**	**46,574,530**
Controllable Expenses						
Distribution Expenses Operations	1,392,257	1,232,459	1,275,287	1,320,244	1,401,297	1,508,493
Distribution Expenses Maintenance	1,621,552	1,653,693	1,651,437	1,834,314	1,854,122	1,884,210
Billing and Collecting	1,407,275	1,379,546	1,591,426	1,382,233	1,475,391	1,539,473
Commuinty Relations	134,249	116,716	89,463	128,286	137,204	144,123
Administrative and General Expenses	1,803,667	1,735,439	1,599,129	1,639,861	1,797,772	1,910,708
Donations Leap	11,000	11,150	11,250	11,500	11,750	12,900
Taxes Other than Income Taxes	0	64,457	0	0	0	0
Total Controllable Expenses	**6,370,000**	**6,193,460**	**6,217,992**	**6,316,438**	**6,677,536**	**6,999,907**
Working Capital	**49,764,903**	**47,954,899**	**49,329,537**	**49,491,012**	**53,054,147**	**53,574,437**
Working Capital Allowance Rates	12.0%	12.0%	12.0%	12.0%	12.0%	7.5%
Working Capital Allowance	**5,971,788**	**5,754,588**	**5,919,544**	**5,938,921**	**6,366,498**	**4,018,083**

As shown in Table 2-20, the 2017 working capital allowance has decreased $1,953,705 or 33% in comparison to the 2013 Board Approved Year. The change between the 2017 Test Year and 2013 Board Approved Year is a result of increased costs of power and increased controllable expenses, offset by the decrease in the percentage rate applied in the computation of the working capital allowance from 12% to 7.5%. Table 2-21 provides a summary of the changes between the 2017 Test Year and 2013 Board Approved working capital allowance.

Table 2-21 - Summary of Changes in Working Capital Allowance

Description	2013 Board Approved	2017 Test Year	Change	Working Capital Allowance Factor	Working Capital Allowance
Cost of Power Expenses	43,394,903	46,574,530	3,179,627	7.5%	238,472
Total Controllable Expenses	6,370,000	6,999,907	629,907	7.5%	47,243
Working Capital	**49,764,903**	**53,574,437**	**3,809,534**		**285,715**
COP and Controllable Expenses		53,574,437		12.0%	6,428,932
		53,574,437		7.5%	4,018,083
Decrease in Working Capital Allowance					**-2,410,850**
Net Change Working Capital Allowance					**-2,125,135**

Approximately 83% of the working capital increase of $3,809,715, which translates to an increased working capital allowance for rate base purposes of $285,715, is related to cost of power. The balance of the increase is 17% and is related to increases in Controllable OM&A expenses over the 2013 Board-Approved amounts. Details on the expenses can be found in Exhibit 4 – Operating Costs.

COST OF POWER CALCULATIONS

WHESC has calculated COP for the 2017 Test Year based upon the 2017 load forecast, adjusted for the impact of Conservation and Demand Management activities and in accordance with the Board's filing requirements. A summary of the total COP expenses is provided in Table 2-22.

Table 2-22 - Summary of Total Cost of Power Expenses

Description	2013 Board Approved	2013 Actual	2014 Actual	2015 Actual	2016 Bridge Year	2017 Test Year
Power Purchased	35,112,552	34,193,388	35,660,450	36,786,385	39,394,405	39,611,228
Wholesale Market Service/Rural Rate Assistance	2,820,807	2,173,493	2,174,837	1,394,481	1,755,685	1,764,623
IESO Smart Meter Charge	0	141,119	207,091	209,653	214,381	216,381
Network Charges	3,159,964	2,960,588	2,890,346	2,703,150	2,554,261	2,543,534
Connection Charges	2,301,580	2,292,851	2,178,821	2,080,905	2,063,746	2,042,624
Ontario Electricity Support Program	0	0	0	0	394,133	396,140
Total Cost of Power Expenses	**43,394,903**	**41,761,439**	**43,111,545**	**43,174,574**	**46,376,611**	**46,574,531**

Commodity Prices

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

The RPP and non-RPP price was obtained from the Regulated Price Plan Price Report for the period of May 1, 2016 through April 30, 2017 published by the OEB April 14, 2016. For the purposes of calculating the 2017 Test Year, WHESC has used an estimate of $0.11141 per kWh for RPP customers. For non-RPP customers, WHESC has used $0.10772/kWh which includes $0.01686 per kWh for the Wholesale Electricity Price and $0.09086 per kWh for Global Adjustment charges.

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

Regulatory Charges

The Wholesale Market Service ("WMS") Charges for the 2017 Test Year were calculated based on the OEB Decision and Rate Order issued on November 19, 2015 (EB-2015-0294). The Decision and Rate Order sets the Wholesale Market Service Rate (WMSR) at $0.36/kwh, the Rural Rate Protection Charge (RRPC) at $0.13/kwh, and the new Ontario Electricity Support Program Charge (OESP) at $0.11/kwh. These rates were applied to the forecasted power purchases for the 2017 Test Year.

Network and Connection Charges

WHESC incurs Network and Connection charges from the IESO. For the purposes of determining the cost of each for the 2017 Test Year, WHESC determined the kW billed by IESO for 2015 actual Network and Connection costs. The 2015 kW was then utilized to estimate the monthly Network and Connection costs for the 2017 Test Year by applying the forecasted kW by the January 1, 2016 Uniform Transmission Rates (UTR) as approved by the Board (EB-2015-0031). WHESC understands that the transmission costs will be updated to reflect any new rates that may become available prior to the approval of its application.

Low Voltage Charges

WHESC does not incur low voltage charges from Hydro One.

Smart Meter Entity Charges

The Smart Meter Entity costs are calculated based on the rate of $0.788 per month for each Residential and General Service < 50 kW customer approved by the Board on March 28, 2013.

Table 2-23 provides a summary of the COP calculation for the 2017 Test Year.

Table 2-23 - Cost of Power Calculation

Details	Metric	2017 Forecast kWh/kW	Loss Factor Proposed	2017 Uplifted kWh	2016 Rates	2017 Cost of Power
Electricity - Commodity RPP						
Residential	kWh	151,960,484	1.0476	159,193,803	0.11141	17,735,782
General Service < 50kW	kWh	46,716,421	1.0476	48,940,123	0.11141	5,452,419
General Service 50 to 4,999 kW	kWh	11,534,576	1.0457	12,061,624	0.11141	1,343,786
Direct Market Participant	kWh	0	1.0476	0	0.11141	0
Street Lighting	kWh	0	1.0476	0	0.11141	0
Sentinel Lighting	kWh	730,655	1.0476	765,434	0.11141	85,277
Unmetered Scattered Load	kWh	770,610	1.0476	807,291	0.11141	89,940
Total RPP		**211,712,745**		**221,768,274**		**24,707,203**
Electricity - Commodity Non-RPP						
Residential	kWh	9,091,026	1.0476	9,523,759	0.10772	1,025,899
General Service < 50kW	kWh	7,942,259	1.0476	8,320,311	0.10772	896,264
General Service 50 to 4,999 kW	kWh	113,773,167	1.0456	118,965,385	0.10772	12,814,951
Direct Market Participant	kWh	3,358,021	1.0476	3,517,863	0.00000	0
Street Lighting	kWh	1,282,067	1.0476	1,343,093	0.10772	144,678
Sentinel Lighting	kWh	23,309	1.0476	24,419	0.10772	2,630
Unmetered Scattered Load	kWh	173,703	1.0476	181,971	0.10772	19,602
Total Non-RPP		**135,643,553**		**141,876,799**		**14,904,025**
Total Power USoA 4705		**347,356,298**		**363,645,073**		**39,611,227**
Wholesale Market Service						
Residential	kWh	161,051,510	1.0476	168,717,562	0.00360	607,383
General Service < 50kW	kWh	54,658,680	1.0476	57,260,433	0.00360	206,138
General Service 50 to 4,999 kW	kWh	125,307,743	1.0456	131,027,009	0.00360	471,697
Direct Market Participant	kWh	3,358,021	1.0476	3,517,863	0.00000	0
Street Lighting	kWh	1,282,067	1.0476	1,343,093	0.00360	4,835
Sentinel Lighting	kWh	753,964	1.0476	789,853	0.00360	2,843
Unmetered Scattered Load	kWh	944,313	1.0476	989,262	0.00360	3,561
Total Wholesale Market Service Charge		**347,356,298**		**363,645,073**		**1,296,458**
Rural Rate Protection						
Residential	kWh	161,051,510	1.0476	168,717,562	0.00130	219,333
General Service < 50kW	kWh	54,658,680	1.0476	57,260,433	0.00130	74,439
General Service 50 to 4,999 kW	kWh	125,307,743	1.0456	131,027,009	0.00130	170,335
Direct Market Participant	kWh	3,358,021	1.0476	3,517,863	0.00000	0
Street Lighting	kWh	1,282,067	1.0476	1,343,093	0.00130	1,746
Sentinel Lighting	kWh	753,964	1.0476	789,853	0.00130	1,027
Unmetered Scattered Load	kWh	944,313	1.0476	989,262	0.00130	1,286
Total Rural Rate Protection		**347,356,298**		**363,645,073**		**468,165**
Ontario Electricity Support Program						
Residential	kWh	161,051,510	1.0476	168,717,562	0.00110	185,589
General Service < 50kW	kWh	54,658,680	1.0476	57,260,433	0.00110	62,986
General Service 50 to 4,999 kW	kWh	125,307,743	1.0456	131,027,009	0.00110	144,130
Direct Market Participant	kWh	3,358,021	1.0476	3,517,863	0.00000	0
Street Lighting	kWh	1,282,067	1.0476	1,343,093	0.00110	1,477
Sentinel Lighting	kWh	753,964	1.0476	789,853	0.00110	869
Unmetered Scattered Load	kWh	944,313	1.0476	989,262	0.00110	1,088
Total Ontario Electricity Support Program		**347,356,298**		**363,645,073**		**396,140**
Total WMS/RPP/OESP USoA 4708						**2,160,763**
Transmission Network						
Residential	kWh	161,051,510	1.0476	168,717,562	0.00770	1,299,125
General Service < 50kW	kWh	54,658,680	1.0476	57,260,433	0.00680	389,371
General Service 50 to 4,999 kW	kW	362,937	1.0000	362,937	2.31440	839,981
Street Lighting	kW	1,771	1.0000	1,771	2.16230	3,829
Sentinel Lighting	kW	2,077	1.0000	2,077	2.16700	4,501
Unmetered Scattered Load	kWh	944,313	1.0476	989,262	0.00680	6,727
Total Transmission Network UsoA 4714						**2,543,534**
Transmission Connection						
Residential	kWh	161,051,510	1.0476	168,717,562	0.00600	1,012,305
General Service < 50kW	kWh	54,658,680	1.0476	57,260,433	0.00510	292,028
General Service 50 to 4,999 kW	kW	362,937	1.0000	362,937	1.99480	723,987
Street Lighting	kW	3,560	1.0000	3,560	1.64120	5,843
Sentinel Lighting	kW	2,077	1.0000	2,077	1.64480	3,416
Unmetered Scattered Load	kWh	944,313	1.0476	989,262	0.00510	5,045
Total Transmission Connection UsoA 4716						**2,042,624**
Smart Meter Entity Charge						
Residential	Customers	21,042	12.0000	252,504	0.79000	199,478
General Service < 50kW	Customers	1,783	12.0000	21,396	0.79000	16,903
Total Smart Meter Entity UsoA 4751						**216,381**
Total Cost of Power						**46,574,531**

2.2.1.4 TREATMENT OF STRANDED ASSETS RELATED TO SMART METER DEPLOYMENT

WHESC disposed of Stranded Assets Related to Smart Meter Deployment in its 2013 COS Rate Application by way of a four year rate rider. The rate rider expires on April 30, 2017 and any residual balances relating to Stranded Assets Related to Smart Meter Deployment will be disposed of in a future rate application.

2.2.2 CAPITAL EXPENDITURES

Please note that when the term "Capital Expenditures" is used, WHESC will identify the treatment of Work-In Process (WIP). For the most part, the DSP and tables relating to the DSP, include work in process amounts. WHESC will identify the expenditures in WIP at the end of each calendar year as required. Work in Process has been excluded from any tables relating to Rate Base calculations.

2.2.2.1 PLANNING

In accordance with the Filing Requirements, WHESC is filing its consolidated 2017-2021 DSP as a stand-alone document which includes all elements of the DSP as Appendix 2-A of this Exhibit. Capital Expenditures within the DSP include capital expenditures related to Work in Process. WHESC has organized the information contained in the DSP using the headings indicated in Chapter Five of the Board's *Filing Requirements for Electricity Distribution and Transmission Applications*, *Consolidated Distribution System Plan Filing Requirements.* The DSP incorporates matters pertaining to asset management, regional planning, and renewable energy generation.

All categories of system investments, including System Renewal, System Access, System Service, and General Plant have been addressed and consolidated in WHESC's capital expenditure plan. WHESC has provided historical spending by material capital project in the categories mentioned for 2013 Actual, 2014 Actual, 2015 Actual, 2016 Bridge and 2017 Test Year. WHESC has assigned all historical and future construction projects to the new categories as required by the Board. Planned capital expenditures have been leveled to address pacing and affordability.

Based on the evaluation of the distribution system WHESC is not proposing any capital investments for capacity upgrades to accommodate applications for the connection of renewable energy generation plants for the 2017 Test Year to 2021 which represents the periods covered by the DSP.

Regional Planning/Planning Horizon

WHESC has adopted a 5 year planning horizon in its DSP.

Regional Planning is discussed in section 5.2.2b of WHESC's DSP in Appendix 2-A attached. WHESC has no embedded distributors within its service territory and is not embedded in another LDCs service territory. WHESC receives transmitted power thru one HONI owned and operated TS ("Transformer Station"). As detailed in WHESC's DSP, discussions with the Regional Planning Working Group – Niagara Study Team has determined that there is no requirement for further coordinated Regional Planning at this time. As a result, there are no capital expenditures related to regional planning within WHESC's forecasted five year capital plan.

WHECS works closely with the City of Welland and the Regional Municipality of Niagara thru the Public Utilities Coordinating Committee. Regional/Municipal planning is detailed in section 5.2.2b of WHECS's DSP attached in Appendix 2-A. Discussions at this committee reveal future plans throughout the Region of Niagara which may impact future capital spending. For the most part, road widening projects have had limited impact on WHECS capital spending. There are no known regional or municipal projects which would have a material impact on WHECS's capital spending from 2017 – 2021.

2.2.2.2 REQUIRED INFORMATION

SUMMARY OF CAPITAL EXPENDITURES

Table 2-24 below provides a summary of historical capital expenditures for the past four historical years, 2012 through 2015, projections for the 2016 Bridge Year and 2017 Test Year, as well as projections for the period 2018 through 2021. This table is consistent with Board Appendix 2-AB. WHESC has made its best efforts to categorize historical projects into the DSP categories. In 2012, WHESC received approval for the disposition and recovery of its smart meter costs. As this was a distinct, discrete one-time project, WHESC has not included these costs in the capital expenditure table. The annual capital expenditures include all new spending in the fiscal period. Costs for projects that are considered WIP at the end of a fiscal year are captured in the year spent, not the year the asset is transferred into service. The variance between the annual capital expenditure totals in Table 2-24 and the total 'additions' in the continuity schedules Tables 2-10 thru 2-14 are those applicable to WIP. Tables 2-5 thru 2-9 are presented on a before WIP and after WIP. The amounts in Table 2-24 will match the amounts after WIP.

Table 2-24 – Capital Expenditure Summary – 2012-2021

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

First year of Forecast Period: *2017*

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2012			2013			2014			2015			2016			2017	2018	2019	2020	2021
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	*$ '000*		%	*$ '000*		%	*$ '000*		%	*$ '000*		%	*$ '000*				
System Access		225,766	--	135,000	85,482	-36.7%		111,353	--		94,079	--	147,000	147,000	0.0%	204,501	250,000	250,000	190,000	150,000
System Renewal		1,233,301	--	1,334,200	1,504,700	12.8%		1,710,305	--		1,773,585	--	1,683,000	1,683,000	0.0%	1,834,485	1,495,000	1,775,000	1,920,000	1,770,000
System Service		8,300	--	35,000	4,047	-88.4%		55,500	--		33,237	--	-	-	--	110,000	260,000	35,000	35,000	35,000
General Plant		417,631	--	472,165	517,076	9.5%		322,389	--		281,463	--	801,800	801,800	0.0%	265,000	305,000	400,000	295,000	525,000
TOTAL EXPENDITURE	1,887,015	1,884,998	-0.1%	1,976,365	2,111,305	6.8%	2,002,500	2,199,547	9.8%	2,027,500	2,182,364	7.6%	2,631,800	2,631,800	0.0%	2,413,986	2,310,000	2,460,000	2,440,000	2,480,000
System O&M		$2,978,610	--	$3,013,809	$2,886,152	-4.2%		$2,926,724	--		$3,154,558	--	$3,255,419	$3,255,419	0.0%	$3,392,703				

Notes to the Table:

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

2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year): 0

Explanatory Notes on Variances (complete only if applicable)

Notes on shifts in forecast vs. historical budgets by category

The Budget amounts from 2013 to 2015 represents the total capital from the Asset Management Plan included in the 2013 Cost of Service Application ("COS"). As no Distribution System Plan was included in the 2013 COS there is no breakout available by category for the budget from 2012 to 2015. The Budget for 2012 represents the final amount approved in the 2013 Cost of Service Rate Application as detailed in the final Chapter 2 Appendices 2012 Continuity MIFRS.

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

Actual capital expenditures exceeded plan from 5% to 10% per year over the 2013 to 2015 period. Actuals are within the plus/minus 10% target WHESC has determined for Capital Expenditures. General Plant increased significantly in the 2016 Bridge Year as a result of the purchase of two new trucks at a cost of approximatley $650K.

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

As shown in Table 2-24, WHESC's main infrastructure focus is on renewal; this has been the driver of historical spending and is the driver of future spending.

VARIANCE OF YEAR OVER YEAR CATEGORY SPENDING

An analysis of year over year trending for historical costs within the DSP categories is as follows.

- **2013 Actual vs. 2012 Actual**

Table 2-25A – 2013 Actual vs. 2012 Actual

Description	2012 Actual	2013 Actual	Variance from 2012 Actual
System Access	225,766	85,482	-140,284
System Renewal	1,233,301	1,504,700	271,399
System Service	8,300	4,047	-4,253
General Plant	417,631	517,076	99,445
Total Capital Expenditures	**1,884,998**	**2,111,305**	**226,307**

System Access – Expenditures in 2012 included a road widening project of $287,848 offset by a Capital Contribution from the Region of Niagara of ($124,159). There were no major road widening projects in 2013. As a result, System Access spending is reduced in 2013 Actual compared to 2012 Actual.

System Renewal - There isn't one particular aspect that drives the variance, but instead a difference in the types of projects resulting in the small variance of $271,399. Reductions in Substation Renewal compared to 2012 are offset by additional overhead/underground line renewal projects in 2013.

System Service – This variance is below the materiality threshold variance.

General Plant – The variance was primarily driven by a large truck replacement in 2013 of $325,615. This was offset by a reduction in capital spending on Buildings and grounds compared to 2012 of ($290,340). Major renovations to the front office and conference room occurred in 2012.

- **2014 Actual vs. 2013 Actual**

Table 2-25B – 2014 Actual vs. 2013 Actual

Description	2013 Actual	2014 Actual	Variance from 2013 Actual
System Access	85,482	111,353	25,871
System Renewal	1,504,700	1,710,305	205,605
System Service	4,047	55,500	51,453
General Plant	517,076	322,389	-194,687
Total Capital Expenditures	**2,111,305**	**2,199,547**	**88,242**

System Access - The variance is below the materiality threshold.

System Renewal - There isn't one particular aspect that drives the variance, but instead a difference in the types of projects resulting in the small variance of $205,605. Overhead/Underground line renewal and conversion projects continue to be the main emphasis of capital spending.

System Service – This variance is the result of the purchase of SCADA ICCP software. This project remained in Work in Process for rate making purposes until 2015 when the software installation and modifications were completed and is currently fully operational. This software provides a direct link to the Crowland TS and provides more operating functionality than the existing Remote Terminal Unit (RTU) which is no longer used. WHESC can now perform functions related to distribution activities that previously had to be done via phone with Hydro One.

General Plant – The reduction is for the most part related to the purchase of the large truck replacement in 2013.

- **2015 Actual vs. 2014 Actual**

Table 2-25C – 2015 Actual vs. 2014 Actual

Description	2014 Actual	2015 Actual	Variance from 2014 Actual
System Access	111,353	94,079	-17,274
System Renewal	1,710,305	1,773,585	63,280
System Service	55,500	33,237	-22,263
General Plant	322,389	281,463	-40,926
Total Capital Expenditures	**2,199,547**	**2,182,364**	**-17,183**

System Access - The variance is below the materiality threshold.

System Renewal - There isn't one particular aspect that drives the variance, but instead a difference in the types of projects resulting in the small variance of $63,280. Overhead/Underground line renewal and conversion projects continue to be the main emphasis of capital spending. The substation renewal program accounted for the majority of the variance as a result of an increase over 2014 of $137,899. Substation renewal will continue from the 2016 Bridge Year going forward.

System Service - The variance is below the materiality threshold.

General Plant – The variance is below the materiality threshold but is for the most related to reductions in Computer Hardware/Software compared to 2014.

- **2016 Forecast vs. 2015 Actual**

Table 2-25D – 2016 Forecast vs. 2015 Actual

Description	2015 Actual	2016 Bridge Year	Variance from 2015 Actual
System Access	94,079	147,000	52,921
System Renewal	1,773,585	1,683,000	-90,585
System Service	33,237	0	-33,237
General Plant	281,463	801,800	520,337
Total Capital Expenditures	**2,182,364**	**2,631,800**	**449,436**

System Access - The variance is below the materiality threshold.

System Renewal - There isn't one particular aspect that drives the variance, but instead a difference in the types of projects resulting in the small variance of ($90,585). Overhead/Underground line renewal and conversion projects continue to be the main emphasis of capital spending.

System Service - The variance is below the materiality threshold.

General Plant – The increase in General Plant capital spending is the replacement of two large trucks. The first is a 2016 International Bucket Truck for $364,100 of which $117,800 was included in 2015 WIP for rate base purposes. This vehicle replaces an 18 year old truck (1998) currently in service. The second truck is a Digger/Derrick used in plant construction at a total cost of $315,000. This vehicle replaces a 28 year old truck (1988) for which parts are difficult to locate. Loss of this vehicle would significantly impact plant construction activity and result in the increased use of contractors.

- **2017 Forecast vs. 2016 Forecast**

Table 2-25E – 2017 Forecast vs. 2016 Forecast

Description	2016 Bridge Year	2017 Test Year	Variance from 2016 Bridge
System Access	147,000	204,501	57,501
System Renewal	1,683,000	1,834,485	151,485
System Service	0	110,000	110,000
General Plant	801,800	265,000	-536,800
Total Capital Expenditures	**2,631,800**	**2,413,986**	**-217,814**

System Access – The increase in System Access capital spending is related to smart meter replacements as a result of the start of testing. The initial seal period for smart meters installed in 2009 will expire in 2019. Measurement Canada expects utilities to pre-sample their meter population prior to applying for a final extension period. The new sampling procedure will require additional smart meter stock and possible additional operating costs.

System Renewal - There isn't one particular aspect that drives the variance, but instead a difference in the types of projects resulting in the small variance of $151,485. Overhead/Underground line renewal and conversion projects continue to be the main emphasis of capital spending along with substation renewal.

System Service - The variance is attributable to the installation of a SCADA Radio System totaling $60,000. The second is for the purchase of new SCADA operating system software at a cost of $50,000 which will be fully functional in 2017. The current software will no longer be supported by the current vendor after 2017.

General Plant – Capital spending compared to 2016 Bridge Year is down significantly as 2016 had two major vehicle purchases. The 2017 Test Year marks the start of a program to improve Building Facilities & Grounds with repaving the service center parking lot. This project will be phased in over two years. There are no significant investments planned for CIS/Financial computer software in either of the 2016 Bridge or 2017 Test Years.

- **2018 – 2021 Trending**

Table 2-25F – 2018 – 2021 Trending

Description	2018 Forecast	2019 Forecast	2020 Forecast	2021 Forecast
System Access	250,000	250,000	190,000	150,000
System Renewal	1,495,000	1,775,000	1,920,000	1,770,000
System Service	260,000	35,000	35,000	35,000
General Plant	305,000	400,000	295,000	525,000
Total Capital Expenditures	**2,310,000**	**2,460,000**	**2,440,000**	**2,480,000**

System Access - forecasted expenditures in the System Access category is for the most part comprised of New Overhead Services, Contributed Capital, and Meters. New Overhead Services of $40,000 and Contributed Capital of $50,000 are based on historical expenditures. Meters include both smart meters ($60,000 to $100,000 per year) and MIST Meters at $60,000 in both 2018 and 2019. The MIST meter replacement program has been mandated by the OEB and all existing non-interval GS>50 meters will be replaced by the end of 2019 resulting in a reduction in spending in 2020 and 2021. The smart meters spending includes both growth, testing program requirements, and early retirements. The MIST meter replacements have been mandated by the OEB.

System Renewal - as indicated previously these expenditures are comprised for the most part of substation renewals and overhead/underground renewals. WHESC has adopted a strict discipline to pace these expenditures in a manner that balances reliability and affordability, while also leaving some flexibility for unexpected growth in projects or emergency rebuilds.

System Service – the increase in System Service capital expenditures in 2018 is related to RTU Relay replacements at two substations. WHESC has been experiencing operational issues with the relays at these substations which are from the same manufacturer and same vintage. Although WHESC has made repairs to extend their useful lives, further delay in replacement could cause significant reliability issues.

General Plant - expenditures show spikes in capital spending in 2019 and 2021. A new service center roof is currently being planned for replacement in 2019. After updating its vehicle fleet in 2016, WHESC has only minor vehicle replacements in 2018 and 2019. There are currently two larger trucks which will require replacement over the next five years. A vintage year 2000 bucket truck will be purchased beginning with a deposit in 2020 and completion in 2021 at a cost of $370,000. A smaller digger/derrick vintage 1990 will be replaced in 2022 which will require a deposit estimated at $120,000 in 2021.

CAPITAL PROJECT SUMMARY

Tables 2-26 A-D provide a summary of all capital projects for the years 2012 through 2015, the 2016 Bridge Year and the 2017 Test Year. WHESC has a materiality threshold of $53,000. Individual projects below the materiality threshold have been grouped together as miscellaneous within the applicable capital expenditure category. WHESC's DSP, found in Appendix 2-A, provides capital project summaries with a full description and justification of expenditures above $53,000 listed in Tables 2-26 A-D for the 2017 Test Year in Appendix 5-D. Table 2-26 A-D is consistent with the Board's Appendix 2-AA Capital Projects Table and reconciles to Table 2-24 above.

Table 2-26A – Capital Projects Systems Access – Appendix 2-AA

Projects	2012 Revised	2013 Revised	2014	2015	2016 Bridge Year	2017 Test Year	2018 Forecast	2019 Forecast	2020 Forecast	2021 Forecast
Reporting Basis	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Access										
Municipal Relocations										
Woodlawn Road Widening Rice to First Avenue	287,848									
Contributed Capital Region of Niagara - Woodlawn	-124,159									
Wellington Street Road Widening				32,821						
Contributed Capital City of Welland - Wellington					-3,000					
System Expansion - Generation						14,501				
Sub-Total Municipal Relocations	**163,689**	**0**	**0**	**32,821**	**-3,000**	**14,501**	**0**	**0**	**0**	**0**
Customer Connections										
New Overhead/Underground Service Connections	**39,404**	**9,908**	**40,922**	**42,577**	**40,000**	**40,000**	**40,000**	**40,000**	**40,000**	**40,000**
Expansions (Subdivisions)										
Clare Estates 1	9,160									
Elmwood Estates	28,368									
Hunter's Pointe - Galloway	26,515									
Hunter's Pointe - Block 150	2,316									
Shipview Court	10,175									
Webber Estates		28,503								
Blue Rive Estates		16,214								
Hunter's Pointe - Masters		9,864								
Hunter's Pointe - Highlands		14,820								
Coyle Creek 2 & 3			6,800							
Pine Creek			6,919							
Clare Estates 2			1,902							
Coyle Creek 4			8,112							
Tetherwood 2			6,583							
Michael Drive				4,230						
Clare Estates 3				10,068						
Lochness North 1				10,112						
Sub Total Subdivisions - Plan	**76,534**	**69,401**	**30,316**	**24,410**	**50,000**	**50,000**	**50,000**	**50,000**	**50,000**	**50,000**
Expansions (Transformers/Meters)										
Contributed Capital Sale of Transformers/Meters	**-74,519**	**-59,359**	**-29,240**	**-56,586**	**0**	**0**	**0**	**0**	**0**	**0**
Retail Meters										
Smart Meters	17,202	65,532	63,482	50,857	60,000	100,000	100,000	100,000	100,000	60,000
Communication Equipment - Metro Collector	3,456									
Computer Equipment - Smart Meter Diagnostics			5,873							
MIST Meter Replacements							60,000	60,000		
Sub-Total Retail Meters	**20,658**	**65,532**	**69,355**	**50,857**	**60,000**	**100,000**	**160,000**	**160,000**	**100,000**	**60,000**
Sub-Total System Access	**225,766**	**85,482**	**111,353**	**94,079**	**147,000**	**204,501**	**250,000**	**250,000**	**190,000**	**150,000**

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Table 2-26B – Capital Projects System Renewal – Appendix 2-AA

Projects	2012 Revised	2013 Revised	2014	2015	2016 Bridge Year	2017 Test Year	2018 Forecast	2019 Forecast	2020 Forecast	2021 Forecast
Reporting Basis	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Renewal Projects										
Substation Renewal										
MS 3 Battery Charger Replacement				8,227						
MS 4 Primary Cabling		3,532								
MS 5 Fencing	6,627									
MS 5 HV Switchgear - 5T2	46,065									
MS 5 HV Switchgear - 5T1				51,032						
MS 6 Transformer & Primary Cabling	100,995									
MS 7 Switchgear & Primary Cabling	828				200,000					
MS 8 Transformer/Switchgear/Primary Cabling						50,000	100,000	100,000		
MS 9 Switchgear & Primary Cabling								50,000	50,000	100,000
MS 10 HV Switchgear & Primary Cabling							125,000			
MS 12 Transformer & Primary Cabling	47,270			30,290						
MS 14 Transformer/Switchgear/Primary Cabling				48,350		120,000				
Sub-Total Substation Renewal	**201,785**	**3,532**	**0**	**137,899**	**200,000**	**170,000**	**225,000**	**150,000**	**50,000**	**100,000**
Overhead Line Renewal										
Pole Replacement 4.16kV First Ave-College Park to Woodland	37,692									
Pole Replacement 4.16kV Summitt Ave	17,011									
Aqueduct Area 4.16kV Rebuild-Birch,Cedar,Beechwood	73,440									
Pole Replacement 4.16kV Market Square	17,473									
Regent Street Rebuild/Conversion 2.4kV to 16kV	292,255									
Mayfair Estates Rebuild/Conversion 2.4kV to 16kV	69,810									
Niagara Street South of Quaker Rebuild/Conversion 4.16kV to 27.6kV	33,324									
Plymouth Road-St. Mary's School Rebuild/Conversion 4.16kV to 27.6kV	25,473									
Netherby Road @ Townline Tunnel Rebuild/Conversion 2.4kV to 16kV	17,375	20,185								
Maple,Bald,Denistoun,Hooker Rebuild/Conversion 4.16kV to 27.6kV	193,692	2,992								
PCB Transformer Replacements	13,660	51,238								
Cohoe Street 4.16kV Rebuild		12,538								
Pine Street 4.16kV Rebuild		28,469								
Circuit North of Crowland TS 27.6kV Rebuild		12,305								
Pole Replacement 4.16kV Woodview Estates-Trent Avenue		29,178								
Garner Avenue 4.16kV Rebuild		83,995	4,318							
Fitch Street-First Ave to Prince Charles Rebuild/Conversion 2.4kV to 16kV		31,326								
Wilton & Riverside Rebuild/Conversion 4.16kV to 27.6kV		262,157								
McCormick & Dufferin Rebuild/Conversion 2.4kV to 16kV		66,862								
Cady Street Rebuild/Conversion 2.4kV to 16kV		22,122								
Southworth Rebuild/Conversion 4.16kV to 27.6kV		335,986								
Lancaster Drive Rebuild/Conversion 4.16kV to 27.6kV		54,193								
Major Street 27.6kV Rebuild			323,827							
Division & Burger Rebuild/Conversion 4.16kV to 27.6kV			295,502							
Bald St West and Denistoun Rebuild/Conversion 2.4kV to 16kV			32,978							
Clare Avenue & Woodlawn Rebuild/Conversion 4.16kV to 27.6kV			112,907							
Harriet Street Rebuild/Conversion 2.4kV to 16kV			27,181							
Wallace Avenue Rebuild/Conversion 2.4kV to 16kV			45,980							
James Street 4.16kV Rebuild			5,393	13,477						
Orchard,Wright,Deere Rebuild/Conversion 2.4kV to 16kV			156,366	175,959						
Lincoln,Wilton,Riverside Rebuild/Conversion 4.16kV to 27.6kV			4,475	61,145						
Grange Avenue 4.16kV Rebuild				37,806						
Southworth Rebuild 8F3 Feeder				69,369						
Fitch Street & Westdale Rebuild/Conversion 2.4kV to 16kV				70,026						
Hellems Ave-King Street Conversion 4.16kV to 27.6kV				97,672						
Hellems Ave- Dorothy to Park Rebuild/Conversion 4.16kV to 27.6kV				269,045	300,000					
Fitch Street @ MS7 4.17/27.6kV Rebuild to accommodate upgrade					75,000					
Lincoln Street east of Denistoun 27.6kV Rebuild					50,000					
Church St/Niagara Street Rebuild/Conversion 4.16kV to 27.6kV					450,000	300,000				
Wellington Street-East Main to Eastdale Rebuild/Conversion 4.16kV to 27.6kV					88,000	250,000				
Bradley Ave 4.16kV Rebuild to accommodate Robert St U/G						49,485				
Ross Street/Kennedy Street Rebuild/Conversion 4.16kV to 27.6kV						150,000	100,000			
Ontario Road Corridor to Canal Rebuild/Conversion 4.16kV to 27.6kV							300,000			
Lincoln Street-Coventry to Schoelfield Rebuild/Conversion 4.16kV to 27.6kV								440,000		
Duncan Street-Hagar to East Main Rebuild/Conversion 4.16kV to 27.6kV								300,000	320,000	
Clare-Thorold to Steven Rebuild/Conversion 4.16kV to 27.6kV									100,000	
Dorothy Street-River Road to Ross St Rebuild/Conversion 2.4kV to 16kV									100,000	
Denistoun Street-Hooker to Welland River Rebuild/Conversion 4.16kV to 27.6kV									250,000	
Myrtle Avenue Rebuild/Conversion 4.16kV to 27.6kV									165,000	
Rusholme Road 27.6kV Rebuild										150,000
Classic/Lewis Street Rebuild/Conversion 2.4kV to 16kV										350,000
King Street-Lincoln to Regent Rebuild/Conversion 4.16kV to 27.6kV										300,000
Hellems Ave-Park to Lincoln Rebuild/Conversion 4.16kV to 27.6kV										310,000
Sub-Total Overhead Line Renewal	**791,205**	**1,013,546**	**1,008,927**	**794,499**	**963,000**	**749,485**	**400,000**	**740,000**	**935,000**	**1,110,000**

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Table 2-26B – Capital Projects System Renewal – Appendix 2-AA Cont'd

Projects	2012 Revised	2013 Revised	2014	2015	2016 Bridge Year	2017 Test Year	2018 Forecast	2019 Forecast	2020 Forecast	2021 Forecast
Reporting Basis	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Renewal Projects										
Underground Line Renewal										
Preston Place 4.16kV Rebuild	23,178									
Whiteoak Cr 4.16kV Rebuild	21,629									
McComb 4.16kV Rebuild	79,076	5,503								
Oak Street Rebuild/Conversion 2.4kV to 16kV	21,791	45,650								
Ontario Road Canal Crossing-Backup Cable		20,075								
Woodlawn/Lincoln/Division Canal Crossing-Backup Cable		41,856								
Preston,Wiltshire,McColl 4.16kV Rebuild		171,993								
Graystone Area Rebuild/Conversion 2.4kV to 16kV		17,970	380,376	54,285						
Clairmount/Bettes Rebuild/Conversion 2.4kV to 16kV		30,590	31,397							
Birch & Linwood Rebuild/Conversion 2.4kV to 16kV			38,603							
Rice Road Rebuild/Conversion 4.16kV to 27.6kV			85,950	17,256						
Humberstone/Townline Tunnel 27.6 kV Rebuild				345,567						
Regatta Drive-Primary Loop 2.4kV Rebuild				23,771						
Wilson Road to New Seniors Residence Rebuild/Conversion 4.16kV to 27.6kV				133,567						
Woodington/Champlain 2.4kV Rebuild					100,000					
Silvan/Newleaf Phase 1 Rebuild/Conversion 2.4kV to 16kV					210,000					
Maureen Ave 2.4kV Rebuild						125,000				
Riverview Drive Rebuild/Conversion 4.16kV to 27.6kV						150,000				
Robert Street Rebuild/Conversion 2.4kV to 16kV						150,000				
Silvan/Newleaf Phase 2 Rebuild/Conversion 2.4kV to 16kV						280,000				
Royal Oak 2.4kV Rebuild							160,000			
Page Drive-Whiteoak Cr 2.4kV Rebuild							250,000			
Loyalist/Lisa/Jennifer Rebuild/Conversion 2.4kV to 16kV							300,000			
Glenayr/McGill 2.4kV Rebuild								300,000		
Glen Park Drive/Court Rebuild/Conversion 2.4kV to 16kV								300,000		
Centennial Drive Rebuild/Conversion 2.4kV to 16kV								125,000		
Rolling Acres 2.4kV Rebuild									200,000	
Bridlewood/Chapel Hill Rebuild/Conversion 2.4kV to 16kV									300,000	
Apple/Brant Rebuild/Conversion 2.4kV to 16kV									125,000	
Erin & Steven Rebuild/Conversion 2.4kV to 16kV									150,000	150,000
Nottingham Ave 2.4kV Rebuild										250,000
Sub-Total Underground Line Renewal	**145,674**	**333,637**	**536,326**	**574,446**	**310,000**	**705,000**	**710,000**	**725,000**	**775,000**	**400,000**
Miscellaneous Renewal										
Miscellaneous Pole Replacements	78,259	89,289	107,968	101,094	100,000	100,000	50,000	50,000	50,000	50,000
Miscellaneous Transformer Replacements	27,771	81,026	39,399	73,031	50,000	50,000	50,000	50,000	50,000	50,000
Transformers New Developments	74,519	59,359	29,240	56,586	0	0	0	0	0	0
Change in Transformer Inventory	-128,126	-117,628	-43,991	36,030	0	0	0	0	0	0
Miscellaneous Underground Rebuild	30,926	582	32,436	0	30,000	30,000	30,000	30,000	30,000	30,000
Miscellaneous Overhead Primary	11,288	41,357	0	0	30,000	30,000	30,000	30,000	30,000	30,000
Sub-Total Miscellaneous Renewal	**94,637**	**153,985**	**165,052**	**266,741**	**210,000**	**210,000**	**160,000**	**160,000**	**160,000**	**160,000**
Sub-Total System Renewal Projects	**1,233,301**	**1,504,700**	**1,710,305**	**1,773,585**	**1,683,000**	**1,834,485**	**1,495,000**	**1,775,000**	**1,920,000**	**1,770,000**

Table 2-26C – Capital Projects System Service – Appendix 2-AA

Projects	2012 Revised	2013 Revised	2014	2015	2016 Bridge Year	2017 Test Year	2018 Forecast	2019 Forecast	2020 Forecast	2021 Forecast
Reporting Basis	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Service										
Scada/Substation System Service										
Scada Switches/Remote Fault Indicators/Radio Systems	8,300	4,047		5,326		60,000	35,000	35,000	35,000	35,000
MS1 - RTU/Relay Replacements							100,000			
MS5 - RTU/Relay Replacements							75,000			
Scada SmartVU/Server Upgrade						50,000	50,000			
Scada Software ICCP			55,500	27,911						
Sub-Total System Service	**8,300**	**4,047**	**55,500**	**33,237**	**0**	**110,000**	**260,000**	**35,000**	**35,000**	**35,000**

Table 2-26D – Capital Projects General Plant – Appendix 2-AA

Projects	2012 Revised	2013 Revised	2014	2015	2016 Bridge Year	2017 Test Year	2018 Forecast	2019 Forecast	2020 Forecast	2021 Forecast
Reporting Basis	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
General Plant										
Furniture & Equipment										
Furniture & Equipment	**11,025**	**1,403**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Computer Hardware										
Computer Equipment Miscellaneous	13,289	14,809	14,064	42,657	25,000	25,000	25,000	25,000	25,000	25,000
Computer Equipment FileNexus Test Server			7,645							
Computer Equipment HP Scanners (4)			6,536							
Computer Equipment Cisco Firewall			9,705							
Computer Equipment Server/Lan/Battery Backup			45,922							
Computer Equipment Engineering Server			13,353							
Computer Equipment Engineering Plotter			7,839							
Computer Equipment Mcare Tablets (4)			7,560	8,984						
Computer Equipment Backup Server from Tape to Disk				15,683						
Sub-Total Computer Equipment	**13,289**	**14,809**	**112,624**	**67,324**	**25,000**	**25,000**	**25,000**	**25,000**	**25,000**	**25,000**
Computer Software										
Computer Software Northstar Customer Connect	11,250		3,750							
Computer Software Northstar CIS Version 6.4			42,844	-3,427						
Computer Software Northstar CIS Automation Platform				8,400						
Computer Software Northstar CIS Cognos License				5,667						
Computer Software Cayenta Financials Implementation	58,433									
Computer Software Cayenta Financials Fixed Assets Module/Upgrade				35,490	25,000					
Computer Software Spidaweb	4,411									
Computer Software Autocad	4,620									
Computer Software FileNexus Document Storage License/Modules		68,401	31,492							
Computer Software FileNexus Customer Online Forms					40,000	40,000				
Computer Software Multispeak Outage Manager		16,621								
Sub Total Computer Software - Plan	**78,714**	**85,022**	**78,086**	**46,130**	**65,000**	**40,000**	**50,000**	**50,000**	**50,000**	**50,000**
Communication Equipment										
Communication Equipment - New Phone System	**0**	**68,771**	**3,495**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Measurement & Testing Equipment										
Measurement & Testing Equipment	**2,996**	**-711**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Tools										
Tools	**0**	**0**	**5,980**	**0**	**5,500**	**5,000**	**5,000**	**5,000**	**5,000**	**5,000**
Automotive Equipment & Vehicles										
2013 Freightliner Double Bucket Truck		325,615								
2005 Backyard Digger & Trailer Used			32,500							
2014 Brooks Brothers Pole Trailer			23,327							
Rebuild GMC Digger Derrick Rebuild Motor (Truck 31 - 1988)			9,296							
Rebuild International Single Bucket Truck Sub frame (Truck 11 - 2000)			23,648							
2015 Nissan Van (Truck 8 - 2001)				27,099						
2015 Dump Trailer				4,400						
2016 International Double Bucket Truck (Truck 9 - 1998)				117,800	246,300					
2016 3/4 Ton Pickup Truck (Truck 3 - 1995)					40,000					
2016 1/2 Ton Pickup Truck (Truck 1 - 2000)					35,000					
2016 International Digger Derrick (Truck 31 - 1988)					315,000					
2017 1/2 Ton Pickup Truck (Truck 36 - 2000)						35,000				
2017 1/2 Ton Pickup Truck (Truck 37 - 2000)						35,000				
2018 3/4 Ton Pickup Truck (Truck 24 - 1997)							50,000			
2018 Forklift Replacement (Truck 43 - 2002)							50,000			
2019 3/4 Ton Pickup Truck (Truck 42 - 2005)								45,000		
2021 International Bucket Truck (Truck 11 - 2000)									120,000	250,000
2020 Passenger Van (Truck 41 - 2005)									30,000	
2020 Utility Van (Truck 44 - 2007)									40,000	
2021 3/4 Ton Pickup Truck (Truck 51 - 2010)										50,000
2022 International Digger Derrick (Truck 18 - 1990)										120,000
Sub Total Automotive Equipment & Vehicles	**0**	**325,615**	**88,771**	**149,299**	**636,300**	**70,000**	**100,000**	**45,000**	**190,000**	**420,000**
Buildings & Grounds										
Roof Replacement Administrative Office - Board Room Area	19,453									
Main Office & Conference Room Renovations	157,810									
Atrium Replacement/New Customer Service Area	134,344									
Building Renovations - Ladies Washrooms		22,167								
Building Renovations - Men's Washrooms			33,433							
Building Upgrades PDB Shed				3,425						
Building Upgrades A/C Multizone				15,285						
Building Upgrades Fire Alarm System					70,000					
Building Upgrades Stair Lift to Lower Level						25,000				
Service Centre Parking Lot Repaving						100,000	100,000			
Building Upgrades - Plan							25,000	25,000	25,000	25,000
Service Centre Roof Replacement								250,000		
Sub-Total Buildings & Grounds	**311,607**	**22,167**	**33,433**	**18,710**	**70,000**	**125,000**	**125,000**	**275,000**	**25,000**	**25,000**
Renewables - Non Rate Regulated										
Renewable Generation Microfits	**81,719**	**-1,958**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Sub-Total General Plant	**499,350**	**515,118**	**322,389**	**281,463**	**801,800**	**265,000**	**305,000**	**400,000**	**295,000**	**525,000**
Total Before Renewable & Non-Rate Regulated	**1,966,717**	**2,109,347**	**2,199,547**	**2,182,364**	**2,631,800**	**2,413,986**	**2,310,000**	**2,460,000**	**2,440,000**	**2,480,000**
Less Renewable Generation Microfits	**-81,719**	**1,958**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Total Regulated	**1,884,998**	**2,111,305**	**2,199,547**	**2,182,364**	**2,631,800**	**2,413,986**	**2,310,000**	**2,460,000**	**2,440,000**	**2,480,000**

CAPITAL PROJECT VARIANCE – 2013 BOARD APPROVED VS. 2013 ACTUAL

Table 2-27 provides a summary of 2013 actual project costs compared to 2013 Board-Approved projected costs. An explanation of the material variances follows.

Table 2-27 – 2013 Capital Projects vs. 2013 Board Approved Projects

Description	2013 Board Approved	2013 Actual	Variance from 2013 Board Approved
System Access	135,000	85,482	-49,518
System Renewal	1,334,200	1,504,700	170,500
System Service	35,000	4,047	-30,953
General Plant	472,165	517,076	44,911
Total Capital Expenditures	**1,976,365**	**2,111,305**	**134,940**

With the exception of System Renewal, the variance in all categories are below the materiality threshold. Due to lower than anticipated System Service spending on Scada switches, WHESC focused on completing additional System Renewal work during the 2013 year that otherwise needed to get done. The additional General Plant spending was related to the unplanned purchase of electronic document storage software.

TREATMENT OF PROJECTS

Life Cycle Greater than One Year

WHESC's accounting policy is to include projects in fixed assets when they are placed into service. Capital projects which are not yet completed are included in WIP. Capital projects with a life cycle greater than one year will be carried over from one year to the next in WIP. Once completed, expenditures are removed from WIP and capitalized to fixed assets at which point they begin depreciating. For the most part WIP would consist of items with long lead times and is mostly confined to General Plant expenditures. This would include vehicles which require deposits in one year with receipt in the following year. Software purchases also require deposits and installation/modifications/training before old systems are deemed redundant and the new systems are in place. This would typically happen with upgrades to major software systems such as the CIS and Financials.

Treatment of Cost of Funds

WHESC's accounting policy is to expense borrowing costs. It does not capitalize interest on capital projects unless they meet the IFRS criteria of a qualifying asset which is defined in the Board's Report of the Board EB-2008-0408 Transition to International Financial Reporting Standards, June 28, 2009 as "an asset that necessarily takes a substantial period of time to get ready for its intended use or sale." WHESC does not have any capitalized borrowing costs forecast in the 2016 Bridge Year or 2017 Test Year and has not previously capitalized any borrowing costs.

COMPONETS OF OTHER CAPITAL EXPENDITURES

WHESC does not have other capital expenditures forecast in the 2016 Bridge Year or 2017 Test Year, such as non-distribution activities, for which it needs to provide components. WHESC currently has previous expenditures relating to generation which have been removed from rate base for rate setting purposes. Revenues and expenses associated with these assets have not been included in both the 2016 Bridge Year and 2017 Test Year.

EFFICIENCIES REALIZED DUE TO DEPLOYMENT OF SMART METERS AND RELATED TECHNOLOGIES

WHESC has used the information provided from smart meters in two separate areas. The first is in Engineering where the data is used to better analyze loading resulting in reduced capacity requirements of transformers and conductors. The second area is related to outage management. WHESC has integrated smart meter alarm functionality with the outage management system. This provides more detailed information in support of the Scada System to allow staff to reduce response and restoration times for outages. Additional time is spent reviewing smart meter performance (intervals sent) as compared to conventional meters. This impacts both duties performed by meter technicians and billing personnel.

RATE-FUNDED ACTIVITIES TO DEFER DISTRIBUTION INFRASTRUCTURE

WHESC currently does not have any funding in rates for CDM programs over and above those established in cooperation with the IESO. In the early 2000's there was a point at which the current TS (HONI) was approaching capacity and discussions had occurred between WHESC and HONI as to the options available. However, WHESC has lost three large use customers since that time which had combined demand of approximately 25MW. This reduction in demand and the addition of a 10MW solar generation site has reduced demand on the TS by approximately 25%. As a result, the requirement for a significant capital investment for which WHESC would be required to make a capital contribution has been deferred. WHESC believes its current CDM activities have also contributed to the significant reduction in total system

demand and that no additional funding from its customers for CDM spending beyond IESO programs are currently required.

2.2.2.3 CAPITALIZATION POLICY

CAPITALIZATION POLICY OVERVIEW

WHESC's current capitalization policies and principles are based on IFRS, and guidelines set out by the Ontario Energy Board, where applicable. WHESC converted to IFRS January 1, 2015 and as such the capitalization policy in effect for the 2016 Bridge Year and 2017 Test Year is compliant with MIFRS.

WHESC reviewed its capitalization policy in anticipation of transitioning to IFRS; componentization of assets, depreciation changes and overheads were the focus of the review. In parallel with this analysis, the capitalization policy was also reviewed in light of the July 17, 2012 Board letter indicating that changes to depreciation expense and capitalization policies were permitted in 2012. WHESC elected to make these changes in 2012 as a substantial amount of work had gone into the analysis for componentization and depreciation changes. The changes were also recognized in WHESC's 2013 COS Rate Application. The only change not recognized in the 2013 COS Rate Application was the elimination of the pooling of assets methodology under IFRS. WHESC has used account 1575 to capture the impact of these changes in the 2014 Actual (Nil), 2015 Actual, and 2016 Bridge Year. Asset categories which are no longer subject to pooling of assets will continue to result in early retirement losses in the 2017 Test year and other years covered by this 2017 COS Rate Application. As a result, WHESC has requested an amount be included in revenue requirement to cover these expected losses.

WHESC confirms that the changes to its capitalization policy are consistent with the Board's regulatory accounting policies as set out for MIFRS as contained in the *Report of the Board, Transition to International Financial Reporting Standards*, EB-2008-0408, the Kinectrics Report, and the APH, effective January 1, 2012. WHESC's external auditors have also deemed WHESC's capitalization policy, including the overhead policy, to align with IFRS standards. WHESC can also confirm for the Board that it has not made any change to these policies since the 2013 COS Rate Application.

PP&E include expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes the cost of materials, direct labor and other costs directly attributable to bringing the asset to a working condition for its intended use.

Assets with a cost in excess of $1,000 expected to provide future economic benefit greater than one year will be capitalized. Expenditures that create a physical betterment or improvement of an asset will be capitalized.

Guidelines for Capitalization

Capital Assets include property, plant, and equipment that are held for use in the production or supply of goods and services and provide a benefit lasting beyond one year. Capital expenditures also include the improvement or "betterment" of existing assets. Intangible assets are also considered capital assets and are defined as assets that lack physical substance. They include goodwill, patents, copyrights and computer software.

Betterment - a "betterment" is a cost which enhances the service potential of a capital asset and/or increases its value, and is therefore capitalized. A betterment includes expenditures which increase the capacity of the asset, lower associated operating costs of the asset, improve the quality of output or extend the asset's useful life. A betterment does not include general maintenance-related actions that seek to sustain an asset's current value.

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

Capitalization by Component

When parts or components of an item of property, plant and equipment have different useful lives, they are accounted for as individual items (major components) of property, plant and equipment. Component costs must be significant in relation to the total cost of the item and depreciated separately over the component's useful life. Components are those which: a) are significant in relation to the total cost of the item and b) have different depreciation methods or useful life.

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

Depreciation

Depreciation is recognized on a straight-line basis over the estimated useful life of each significant identifiable component of an item of property, plant and equipment. Land is not depreciated. Construction in progress assets are not depreciated until the project is complete and in service.

WHESC has used the Typical Useful Life provided in the Kinectrics Report as its basis for assigning the estimated service life to assets. Any asset with deviations between WHESC's Useful Life and the

Kinectric's Report Useful Life Range have been identified and detailed in Exhibit 4 Table 4-25. Depreciation of an asset begins in the year when it is available for use, i.e. when it is in the location and condition necessary for it to be capable of operating in the manner intended. For rate setting purposes, in the first year of service, depreciation is calculated using the ½ year rule. Depreciation of an asset ceases when the asset is retired from active use, sold or is fully depreciated. WHESC calculates a full year of depreciation in the year in which an asset is retired from active use, sold or becomes fully depreciated.

Overhead Policy

WHESC's overhead policy has been reviewed by both its external auditors (Deloitte) and the consulting services branch of an independent audit firm (KPMG) and has been deemed IFRS compliant.

As previously discussed, WHESC has reviewed and changed its overhead policy, including the capitalization component, to follow a more direct allocation of costs. WHESC does not capitalize general administrative costs related to Administration, HR or Finance.

Included in WHESC's labor costs are those costs that are generally considered labor 'burden'. WHESC's burden costs include vacation, statutory holidays, sick time, CPP, EI, OMERS contributions, health care and other employee benefits. It should be noted that WHESC does not include Post Retirement Benefit Plan expenses in the capitalized burden rates. Burden rates are forecasted and are set-up in WHESC's payroll system accordingly. Through the timesheet process, employees track their hours by work order which designates whether the work is expensed or capitalized. Labor costs, including burden, are then directly charged to specific project by employee based on the work executed in the field.

The overhead policy addresses what WHESC considers four service departments; the Stores department, the Service Centre (which includes facility costs), the Engineering department, and the Garage department (vehicle costs excluding depreciation). Stores costs are allocated out to Operations & Maintenance Accounts and intercompany/third party billings. No Stores overhead costs are allocated to capital expenditures. Service Center costs are allocated out based on square footage to all departments. No service center costs end up capitalized as a result of this allocation process. Engineering costs are allocated out to Operations & Maintenance Accounts and intercompany/third party billings. No engineering overhead costs are allocated to capital expenditures. Engineers will complete time sheets and record direct hours to capital projects as required. For the 2017 Test year these charges including labor burden total $24,905 and are not a material portion of capital expenditures in a year. Vehicle costs are allocated to Operations & Maintenance Accounts, Billing & Customer Service Accounts, and intercompany/third party billings. No overhead, labor costs, materials and supplies, or depreciation related to vehicles are allocated to capital expenditures.

Facility (Service Centre) - the costs to operate the building are charged out to the various functional departments based on the square footage of each department. These costs are included in Operations & Maintenance, Billing and Collecting, and Administrative expenses. No amounts are included in capital expenditures. Any variances at year end (over/under absorbed) are charged or credited to Operations & Maintenance accounts. For the most part these year-end variances are not material.

Inventory and Purchasing (Stores) – the costs of this function are related to managing the warehouse and all inventory processing. As part of the budget process, WHESC determines the material that is forecasted to flow through the warehouse related to Operations & Maintenance and intercompany/third party billings. An overhead rate is determined as a % of total material costs. No Stores overhead costs are included in capital expenditures. Any variances at year end (over/under absorbed) are charged or credited to Operations & Maintenance accounts. For the most part these year-end variances are not material.

Fleet Costs (Garage) - these costs include the costs associated with maintaining WHESC's fleet of pick-up trucks, bucket trucks with aerial devices, and trailers. These costs include mechanics labor, fuel costs, repairs, parts, insurance, and all other items of expense necessary to keep the fleet in service. A fleet rate is determined on an annual basis for each vehicle group by estimating the run time of each category of vehicle and allocating the costs accordingly. Vehicle costs are charged on an hourly basis to Operations & Maintenance Accounts, Billing & Customer Service Accounts, and intercompany/third party billings. No fleet costs are charged to capital expenditures. Any variances at year end (over/under absorbed) are charge or credited to Operations & Maintenance accounts. For the most part these year-end variances are not material.

Engineering - the Engineering budget is comprised of both labor and expenses. Unless directly chargeable to a capital project or intercompany/third party billings, all Engineering time is charged to the Engineering Department. These labor charges and expenses are allocated to Operations & Maintenance accounts based upon direct labor charges of line and field staff.

Operations & Maintenance (Line & Field Staff) – Employees allocate their time directly to O&M and capital through the timesheet process by work order. These charges would then include a percentage amount for payroll burdens as described previously. In addition, amounts allocated to O&M accounts include engineering overhead as described above. Amounts charged to capital work orders include only direct labor and payroll burdens and exclude engineering overhead.

Billing & Collecting-Community Relations – Employees allocate their time directly to accounts through the timesheet process. These charges would then include a percentage amount for payroll burdens as

described previously. No engineering overheads are included in these accounts and no personnel in these departments charge their time to capital expenditures.

Administrative & General – Employees allocate their time directly to accounts through the timesheet process. These charges would then include a percentage amount for payroll burdens as described previously. No engineering overheads are included in these accounts and no personnel in these departments charge their time to capital expenditures. There are no overhead amounts related to Administrative Expenses charged to capital expenditures.

CHANGES TO CAPITALIZATION POLICY

No changes have been made to WHESC's capitalization policy since the last rebasing application in 2013. However, there have been two changes relating to fixed assets as a result of adopting IFRS effective January 1, 2015. The first is the elimination of pooling of assets and the second is Customer Contributions. The impact of these changes is discussed below.

Overhead Policy Changes

No changes to capitalized overhead policy since WHESC's 2013 COS Rate Application.

Componentization and Depreciation Changes

No changes to asset componentization and asset depreciation policies since WHESC's 2013 COS Rate Application.

Pooling of Assets

Under IFRS pooling of assets was discontinued effective January 1, 2015 with changes retroactive to January 1, 2014. WHESC had no early retirement of assets due to the elimination of pooled assets for 2014. However, as previously discussed WHESC has recognized early retirement of assets previously pooled in 2015 Actual, 2016 Bridge Year, and 2017 Test Year. Differences between gross assets and accumulated depreciation have been charged to account 1575 prior to the 2017 Test Year for disposition. For the 2017 Test, these differences have been charged to Other Income Account 4355 and included in revenue requirement. All assets taken out of service have been removed from rate base.

Customer Contributions Changes

Under CGAAP, WHESC recorded customer contributions as an offset to the cost of capital assets and amortized accordingly. Under MIFRS, WHESC cannot capitalize these customer contributions as part of its net capital assets, but instead will classify the contributions as a deferred revenue liability and amortize

the costs to revenue over the life of the asset the contribution relates to. For rate setting purposes and forecasts included in this rate application, these costs are included as an offset to rate base and the related amortized revenue as an offset to depreciation expense. Differences between 2014/2015 Financial Statements and OEB reporting for the corresponding periods are discussed in Exhibit 1.

Historical Contributed Capital and Accumulated Depreciation to December 31, 2013 has been reallocated and netted against the specific PP&E asset they relate to. These changes are outlined in Table 2-12 above. The adjustment entry nets to zero and has no impact on rate base. Capital contributions and accumulated depreciation since January 1, 2014 are reflected in account 2440 Deferred Revenue, however, both are included in the Fixed Asset Continuity Schedules and within the Rate Base calculation. Please see Table 2-15 - Account 1995/2440 Breakdown for the reconciliation between financial statement reporting and rate setting classification.

2.2.2.4 CAPITALIZATION OF OVERHEAD

OVERVIEW

As discussed above in the “Capitalization Policy Overview” section, no changes have been made to capitalization of overheads policies since the 2013 COS Rate Application. WHESC only capitalizes direct labor and burdens of line and field staff based on time card entries to capital work orders. No stores overhead, engineering overhead, administrative overhead, or vehicle costs are capitalized.

Table 2-28 provided below, which is consistent with Board Appendix 2-D, has been completed to show WHESC’s OM&A costs prior to the allocation of direct wages and burden to capital projects. These amounts are also detailed in Board Appendix 2-K Employee Costs.

Table 2-28 – Summary of Capitalized Overheads

Appendix 2-D
Overhead Expense

Applicants are to provide a breakdown of OM&A before capitalization in the below table. OM&A before capitalization may be broken down by cost center, program, drivers or another format best suited to focus on capitalized vs. uncapitalized OM&A.

OM&A Before Capitalization	2013 Historical Year	2014 Historical Year	2015 Historical Year	2016 Bridge Year	2017 Test Year
Operations & Maintenance Before Capitalization	$ 3,335,150	$ 3,367,809	$ 3,632,276	$ 3,753,795	$ 3,911,353
Billing and Collecting	$ 1,379,546	$ 1,591,426	$ 1,382,233	$ 1,475,391	$ 1,539,473
Community Relations	$ 116,716	$ 89,463	$ 128,286	$ 137,204	$ 144,123
Administrative & General	$ 1,811,046	$ 1,610,379	$ 1,651,361	$ 1,809,522	$ 1,923,608
Total OM&A Before Capitalization (B)	$ 6,642,458	$ 6,659,077	$ 6,794,156	$ 7,175,912	$ 7,518,557

Applicants are to provide a breakdown of capitalized OM&A in the below table. Capitalized OM&A may be broken down using the categories listed in the table below if possible. Otherwise, applicants are to provide its own break down of capitalized OM&A.

Capitalized OM&A	2013 Historical Year	2014 Historical Year	2015 Historical Year	2016 Bridge Year	2017 Test Year	Directly Attributable? (Yes/No)	Explanation for Change in Overhead Capitalized
direct employee wages & benefits	$ 448,998	$ 441,085	$ 477,718	$ 498,376	$ 518,650	Yes	2013 COS Reflected changes.
costs of site preparation							No stores, engineering, administration overheads
initial delivery and handling costs							are capitalized.
costs of testing whether the asset is functioning properly							No vehicle costs or depreciation are capitalized
professional fees							
costs of opening a new facility							
costs of introducing a new product or service (including costs of advertising and promotional activities)							
costs of conducting business in a new location or with a new class of customer (including costs of staff training)							
administration and other general overhead costs							
Insert description of additional item(s) and new rows if needed							
Total Capitalized OM&A (A)	$ 448,998	$ 441,085	$ 477,718	$ 498,376	$ 518,650		
% of Capitalized OM&A (=A/B)	7%	7%	7%	7%	7%		

BURDEN RATES

WHESC currently has only one overhead burden which is capitalized which is labor burden. These costs are directly allocated to capital through a burden rate in the payroll system. The current rate labor burden rate is 50% of direct labor costs. This rate is adjusted only when a significant change in labor burden to total wages occurs. No change has been made to this percentage since the 2013 COS Rate Application.

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

Based on the evaluation of the distribution system to accept green energy generation connections WHESC is not proposing any capital investments for capacity upgrades to accommodate applications for the connection of renewable energy generation plants for the 2017 Test Year.

Section 2.2.2.5 of the Board's 2016 Filing Requirements states: *"The applicant must provide a proposal to divide the costs of eligible investments between the distributor's ratepayers and all Ontario ratepayers per O.Reg. 330/09, taking into account the OEB's Report on the Framework for Determining Direct Benefits (EB-2009-0349) (the "Direct Benefits Report")."*

WHESC has reflected the following proposed treatment for eligible investments of connecting qualifying generation facilities in this application:

- WHESC invested in one qualifying expansion project in 2014 in the amount of $88,852.

- In the Board's model 17% of the expansion costs are directly attributable to WHESC's customers. WHESC has included the Direct Benefit portion as December 31, 2016 of $14,501 (17%) in its 2017 Capital Expenditures. This will allow WHESC to recover depreciation and returns on the 17% Direct Benefit portion in revenue requirement.

- Board Appendix 2-FC is provided in Table 2-29 below. As per instructions in Appendix 2-FC WHESC has entered rates of return from the 2013 COS Rate Application as this expansion took place in 2014.

- WHESC is requesting in this Application the Board's approval for WHESC to obtain payment from the IESO for Ratepayer Protection under O. Reg. 330/09 in the amount of $5,172 annually by payment of $431 monthly, the 2017 Test Year Provincial Rate Protection Amount as calculated by the Board's Appendix 2-FC.

- Board Appendix 2-FC shows cumulative costs and returns to December 31, 2016 related to this expenditure of $1,666 Direct Benefit and $8,136 Provincial Benefit. WHESC is requesting recovery of $8,136 relating to the Provincial Benefit costs and returns to December 31, 2016 by way of a one-time payment. WHESC believes this one-time payment is necessary to collect the Provincial Benefit portion prior to the 2017 Test Year.

Table 2-29 Appendix 2-FC

Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount

		2013			2014			2015			2016			2017 Test Year		
			Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial
		Total	17%	83%	Total	17%	83%	Total	17%	83%	Total	17%	83%	Total	17%	83%
Net Fixed Assets (average)		$ -	$ -	$ -	$ 43,982	$ 7,477	$ 36,505	$ 87,075	$ 14,803	$ 72,272	$ 85,298	$ 14,501	$ 70,797	$ 83,521	$ 14,199	$ 69,322
Incremental OM&A (on-going, N/A for Provincial Recovery)		$0	$ -	$ -	$0	$ -		$0	$ -		$0	$ -		$0	$ -	
Incremental OM&A (start-up, applicable for Provincial Recovery)		$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
WCA	12%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base			$ -	$ -		$ 7,477	$ 36,505		$ 14,803	$ 72,272		$ 14,501	$ 70,797		$ 14,199	$ 69,322
Deemed ST Debt	4%		$ -	$ -		$ 299	$ 1,460		$ 592	$ 2,891		$ 580	$ 2,832		$ 568	$ 2,773
Deemed LT Debt	56%		$ -	$ -		$ 4,187	$ 20,443		$ 8,290	$ 40,472		$ 8,120	$ 39,646		$ 7,951	$ 38,821
Deemed Equity	40%		$ -	$ -		$ 2,991	$ 14,602		$ 5,921	$ 28,909		$ 5,800	$ 28,319		$ 5,679	$ 27,729
ST Interest	2.08%		$ -	$ -		$ 6	$ 30		$ 12	$ 60		$ 12	$ 59		$ 12	$ 58
LT Interest	3.78%		$ -	$ -		$ 158	$ 773		$ 313	$ 1,530		$ 307	$ 1,499		$ 301	$ 1,467
ROE	8.93%		$ -	$ -		$ 267	$ 1,304		$ 529	$ 2,582		$ 518	$ 2,529		$ 507	$ 2,476
Cost of Capital Total			$ -	$ -		$ 432	$ 2,107		$ 854	$ 4,172		$ 837	$ 4,086		$ 820	$ 4,001
OM&A			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Amortization		$ -	$ -	$ -	$ 889	$ 151	$ 737	$ 2,666	$ 453	$ 2,212	$ 4,443	$ 755	$ 3,687	$ 1,777	$ 302	$ 1,475
Grossed-up PILs			$ -	$ -		-$ 67	-$ 328		-$ 64	-$ 314		$ 74	$ 363		-$ 62	-$ 304
Revenue Requirement			$ -	$ -		$ 516	$ 2,517		$ 1,243	$ 6,070		$ 1,666	$ 8,136		$ 1,059	$ 5,172
Provincial Rate Protection				$ -			$ 2,517			$ 6,070			$ 8,136			$ 5,172
Monthly Amount Paid by IESO				$ -			$ 210			$ 506			$ 678			$ 431

Note 1: The difference between the actual costs of approved eligible investments and revenue received from the IESO should be recorded in a variance account. The Board may provide regulatory accounting guidance regarding a variance account either in an individual proceeding or on a generic basis.
Note 2: For the 2016 Test Year, Costs and Revenues of the Direct Benefit are to be included in the test year applicant Rate Base and Revenues.

PILs Calculation

Income Tax	2013		2014		2015		2016		2017 Test Year	
	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial
Net Income - ROE on Rate Base	$ -	$ -	$ 267	$ 1,304	$ 529	$ 2,582	$ 518	$ 2,529	$ 507	$ 2,476
Amortization (17% DB and 83% P)	$ -	$ -	$ 151	$ 737	$ 453	$ 2,212	$ 755	$ 3,687	$ 302	$ 1,475
CCA (17% DB and 83% P)	$ -	$ -	-$ 604	-$ 2,950	-$ 1,160	-$ 5,664	-$ 1,067	-$ 5,211	-$ 982	-$ 4,794
Taxable income	$ -	$ -	-$ 186	-$ 908	-$ 178	-$ 870	$ 206	$ 1,006	-$ 173	-$ 843
Tax Rate (to be entered)	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
Income Taxes Payable	$ -	$ -	-$ 49.31	-$ 240.74	-$ 47.21	-$ 230.50	$ 54.58	$ 266.47	-$ 45.74	-$ 223.31
Gross Up										
Income Taxes Payable	$ -	$ -	-$ 67.09	-$ 327.54	-$ 64.23	-$ 313.60	$ 74.26	$ 362.55	-$ 62.23	-$ 303.83
Grossed Up PILs	$ -	$ -	-$ 67	-$ 328	-$ 64	-$ 314	$ 74	$ 363	-$ 62	-$ 304

Net Fixed Assets		2011	2012	2013	2014	2015	2016	2017	2018	2019
Enter applicable amortization in years:	50									
Opening Gross Fixed Assets			$ -	$ 88,852	$ 88,852	$ 88,852	$ 88,852	$ 88,852	$ 88,852	$ 88,852
Gross Capital Additions		$ -	$ 88,852	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Gross Fixed Assets		$ -	$ 88,852	$ 88,852	$ 88,852	$ 88,852	$ 88,852	$ 88,852	$ 88,852	$ 88,852
Opening Accumulated Amortization			$ -	$ 889	$ 2,666	$ 4,443	$ 6,220	$ 7,997	$ 9,774	$ 11,551
Current Year Amortization (before additions)			$ -	$ 1,777	$ 1,777	$ 1,777	$ 1,777	$ 1,777	$ 1,777	$ 1,777
Additions (half year)		$ -	$ 889	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Accumulated Amortization		$ -	$ 889	$ 2,666	$ 4,443	$ 6,220	$ 7,997	$ 9,774	$ 11,551	$ 13,328
Opening Net Fixed Assets		$ -	$ -	$ 87,963	$ 86,186	$ 84,409	$ 82,632	$ 80,855	$ 79,078	$ 77,301
Closing Net Fixed Assets		$ -	$ 87,963	$ 86,186	$ 84,409	$ 82,632	$ 80,855	$ 79,078	$ 77,301	$ 75,524
Average Net Fixed Assets		$ -	$ 43,982	$ 87,075	$ 85,298	$ 83,521	$ 81,744	$ 79,967	$ 78,190	$ 76,413

UCC for PILs Calculation

		2014	2014	2014	2014	2015	2016	2017	2018	2019
Opening UCC			$ -	$ 85,298	$ 78,474	$ 72,196	$ 66,420	$ 61,107	$ 56,218	$ 51,721
Capital Additions (from Appendix 2-FA)		$ -	$ 88,852	$ -	$ -	$ -	$ -	$ -	$ -	$ -
UCC Before Half Year Rule		$ -	$ 88,852	$ 85,298	$ 78,474	$ 72,196	$ 66,420	$ 61,107	$ 56,218	$ 51,721
Half Year Rule (1/2 Additions - Disposals)		$ -	$ 44,426	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Reduced UCC		$ -	$ 44,426	$ 85,298	$ 78,474	$ 72,196	$ 66,420	$ 61,107	$ 56,218	$ 51,721
CCA Rate Class (to be entered)	47	47	47	47	47	47	47	47	47	47
CCA Rate (to be entered)	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
CCA		$ -	$ 3,554	$ 6,824	$ 6,278	$ 5,776	$ 5,314	$ 4,889	$ 4,497	$ 4,138
Closing UCC		$ -	$ 85,298	$ 78,474	$ 72,196	$ 66,420	$ 61,107	$ 56,218	$ 51,721	$ 47,583

2.2.2.6 NEW POLICY OPTIONS FOR THE FUNDING OF CAPITAL

On September 18, 2014, the Board released *Report of the Board New Policy Options for the Funding of Capital Investments: The Advanced Capital Module* and in it the Board has established the following mechanism to assist distributors in aligning capital expenditure timing and prioritization with rate predictability and smoothing:

> The review and approval of business cases for incremental capital requests that are subject to the criteria of materiality, need and prudence are advanced to coincide with the distributor's cost of service application. To distinguish this from the Incremental Capital Module ("ICM"), this new mechanism will be named the Advanced Capital Module (or "ACM").
>
> Advancing the reviews of eligible discrete capital projects, included as part of a distributor's Distribution System Plan and scheduled to go into service during the IR term, is expected to facilitate enhanced pacing and smoothing of rate impacts, as the distributor, the Board and other stakeholders will be examining the capital projects over the five-year horizon of the DSP.

WHESC does not have any discrete capital projects within the five-year horizon that it believes would require this new policy option. The capital investment required by WHESC from 2017 through 2021 is relatively flat and WHESC believes it can be managed through the rates proposed within this application.

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

WHESC has not applied for approval of ACM or ICM Assets and therefore has no such assets added to its rate base.

2.2.2.8 SERVICE QUALITY AND RELIABILITY PERFORMANCE

WHESC follows the Board's Reporting and Record Keeping Requirements Guideline to report its service quality indicators annually. In accordance with the Filing Requirements, Table 2-30 is provided below and is consistent with Board Appendix 2-G, Service Quality Indicators. The table provides the performance measurements for the last five (5) historical years – 2011 through 2015.

Table 2-30 – Service Quality and Reliability Performance

Appendix 2-G
Service Reliability and Quality Indicators
2011 - 2015

Service Reliability

Index	Including outages caused by loss of supply					Excluding outages caused by loss of supply					Excluding Major Event Days				
	2011	2012	2013	2014	2015	2011	2012	2013	2014	2015	2011	2012	2013	2014	2015
SAIDI	2.840	1.260	4.990	1.530	1.950	2.840	1.260	4.860	1.530	1.740	1.660	1.260	0.980	1.530	1.740
SAIFI	1.920	1.330	3.600	1.760	1.680	1.920	1.330	2.340	1.760	1.390	1.290	1.330	1.140	1.760	1.390

5 Year Historical Average

SAIDI				2.514				2.446		1.434
SAIFI				2.058				1.748		1.382

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

Service Quality

Indicator	OEB Minimum Standard	2011	2012	2013	2014	2015
Low Voltage Connections	90.0%	100.0%	100.0%	100.0%	94.0%	100.0%
High Voltage Connections	90.0%	N/A	N/A	N/A	N/A	N/A
Telephone Accessibility	65.0%	99.9%	98.4%	99.0%	96.9%	98.5%
Appointments Met	90.0%	99.7%	99.7%	99.4%	99.7%	98.5%
Written Response to Enquires	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Emergency Urban Response	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Emergency Rural Response	80.0%	N/A	N/A	N/A	N/A	N/A
Telephone Call Abandon Rate	10.0%	1.4%	1.5%	1.7%	2.4%	0.9%
Appointment Scheduling	90.0%	100.0%	100.0%	99.8%	95.5%	94.0%
Rescheduling a Missed Appointment	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Reconnection Performance Standard	85.0%	100.0%	100.0%	100.0%	100.0%	100.0%

WHESC can confirm for the Board that the data presented in Table 2-30 is consistent with the scorecard which is presented in Exhibit 1 of this application. WHESC continues to exceed Electricity Service Quality Requirements (ESQRs) as set out in Chapter 7 of the Distribution Code. As an example, 2015 Billing Accuracy at 99.99% exceeds the OEB target of 98.0% which in WHESC's view is of great importance to customers. The one metric which has shown a material drop in performance is Appointment Scheduling and is related to locate scheduling. Locate requests within WHESC's territory have increased significantly since 2013, particularly between the months of May to August. WHESC has worked with its service provider to ensure they have adequate staffing to meet demand levels. Performance from May, 2016 to August, 2016 improved to 98.6%.

SAIDI and SAIFI for 2015 were also well within the targets set for WHESC. However, both of these indices were impacted by "Major Event Days" in 2011 and 2013 as can be seen in Table 2-30 above. In the 2011 year, WHESC's service territory was impacted by two major weather events. The first was a significant wind storm on April 28, 2011 and the second, a severe lightning storm on September 4th. In 2013, WHESC was impacted by the ice storm which occurred in December which caused significant damage to distribution systems throughout southern Ontario.

Appendix 2-A: Distribution System Plan

Welland Hydro
ELECTRIC SYSTEM CORP.
POWERING WELLAND'S FUTURE

Distribution System Plan

2017 Test Year

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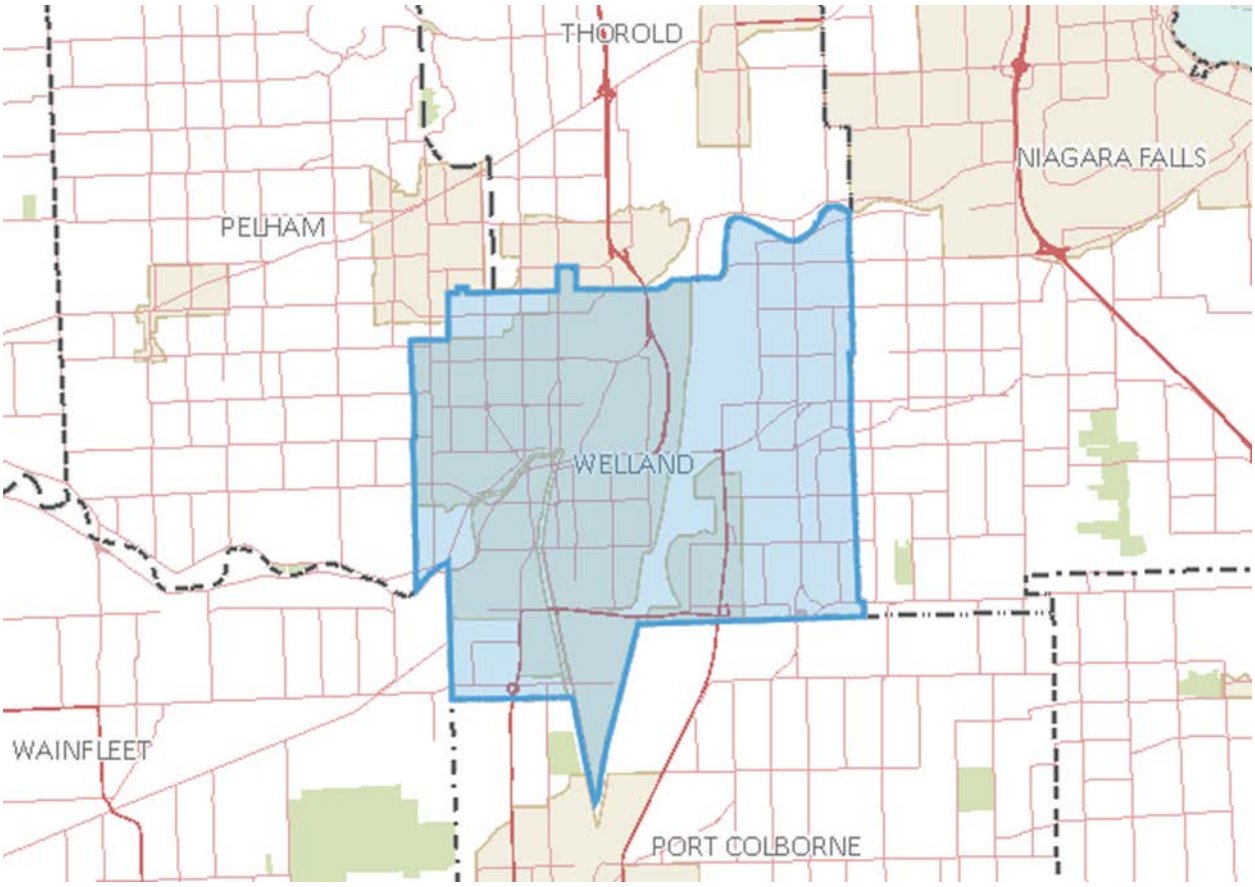
5.0 Introduction

Welland Hydro-Electric System Corp. ("**WHESC**") 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 March 28, 2013 ("the **Filing Requirements**") as part of its 2017 Cost of Service Application (the "**Application**").

WHESC has been distributing electricity to customers within the City of Welland for over one hundred years. WHESC had 22,666 customers as of the end of 2015, including over 20,700 residential customers, with a service territory of 81 square kilometers. Neighboring utilities include Niagara Peninsula Energy, Canadian Niagara Power, and Hydro One. Figure 5-1 below illustrates WHESC's service territory boundaries.

Figure 5-1: Map depicting WHESC's service area boundaries



WHESC owns, maintains and operates approximately 338 km of overhead primary distribution feeders and 142 km of underground primary distribution circuits. WHESC receives power from one Transformer Station that is owned and operated by Hydro One. The station provides eight 27.6kV feeder breakers to distribute power throughout the city via WHESC's 27.6 kV distribution system. In the past these eight feeders were treated more

as subtransmission circuits with only Municipal Substations and Large Commercial and Industrial Customers being directly connected.

Originally there were fourteen Municipal Substations owned by WHESC that transformed power down to 4.16 kV, but one substation was decommissioned over the historical period due to the ongoing voltage conversion program. The locations of the thirteen in-service Municipal Substations are depicted in Figure 5- 2.

Known for its steel, automotive and textile industries, manufacturing had a big influence on the shaping of the City of Welland. However, WHESC's Industrial & Commercial Sector has experienced negative growth in the past few years including the loss of the last remaining large use customer in 2014. Recently, General Electric announced a major investment of $165 million U.S. in a state of the art "brilliant" manufacturing facility in the City of Welland which is scheduled for completion in 2018. The new plant touted as the first "brilliant" manufacturing facility in Canada will be able to operate both on and off the grid. Developments are underway to further promote local economic development and possible spin off industries. As a result, WHESC has made investment plans, as part of this DSP, to maintain and upgrade its distribution system to allow it to continue to provide reliable high quality power to existing and future customers. This commitment to customers is reflected in WHESC's Vision and Mission as outlined below.

Our Vision

Welland Hydro will remain a community-owned asset and continue to collaborate with others, embracing best practices to implement appropriate product and service innovations in a timely manner within an ever-changing provincial policy environment.

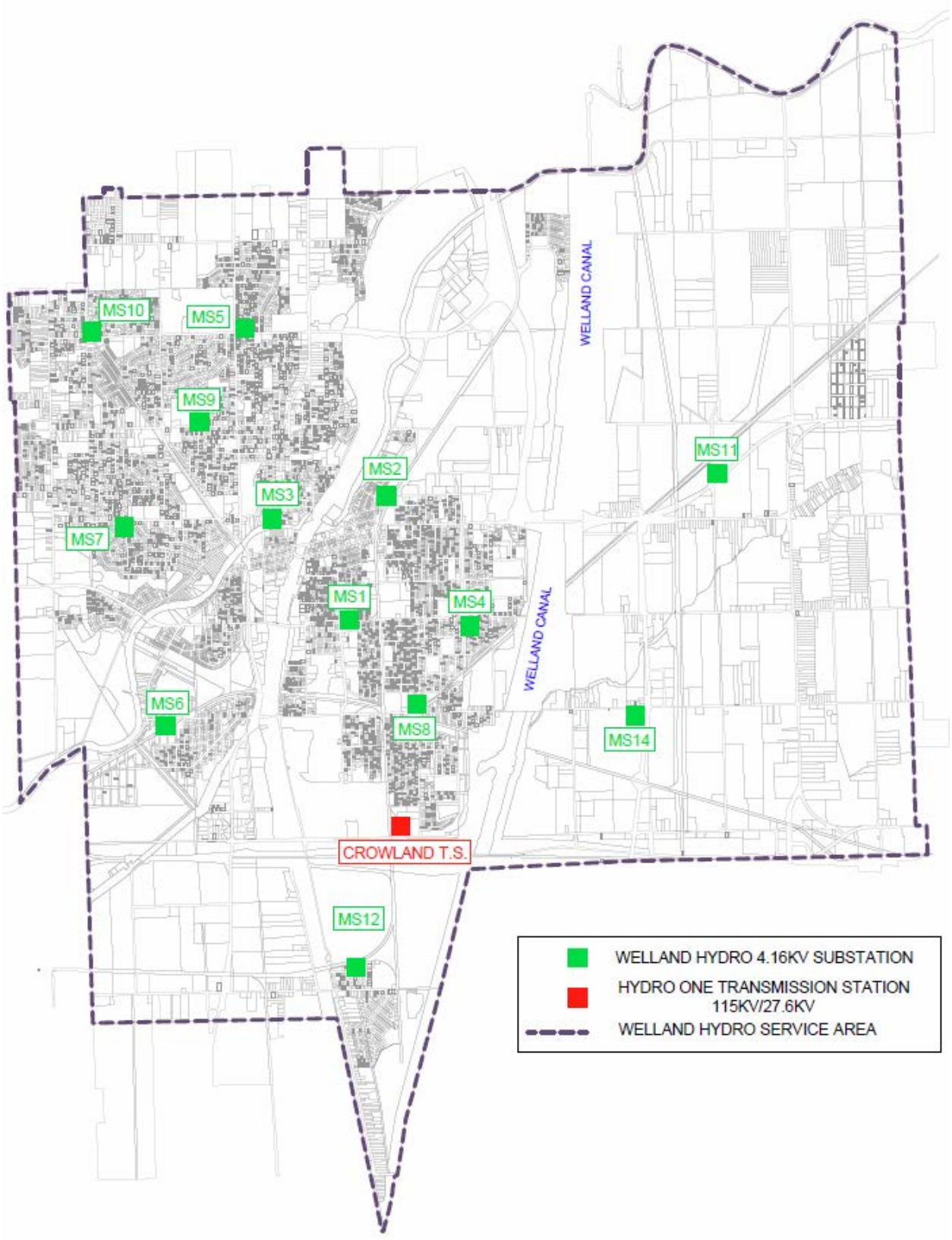
Our Mission

Welland Hydro is a community-owned asset whose team of highly skilled professionals are committed to distributing safe, reliable power and generating renewable energy that enhances the quality of life in Welland.

This DSP was prepared to provide to the OEB and all interested stakeholders:

- An overview of WHESC's asset planning objectives and goals;
- A review of WHESC's asset-related operational performance in the five-year historical period;
- A preview of WHESC's planned expenditures for the forecast period that illustrates WHESC's plan for further-improving its asset-related performance to the four outcomes established by the OEB; and
- A detailed justification of WHESC's planned capital expenditures in the 2017 Test Year.

Figure 5- 2: Map depicting the location of WHESC's thirteen Municipal Substations



An integrated approach was taken for investment planning on WHESC's distribution system. All investments have been planned and optimized together, including for example:

- System renewal and expansion;
- Renewable generation connections;
- Customer connections and regulatory requirements;
- System growth and planning criteria:
- General plant in support of daily operations; and
- Regionally planned infrastructure.

This allows WHESC to develop a DSP that allocates its resources in an optimal way to achieve cost-effective planning over the planning horizon of five years starting in the Test Year, which is 2017 in the case of the Application.

Employing this longer term approach requires WHESC to consider future customer needs and any required changes to its distribution system in advance, thereby enhancing WHESC's ability to plan ahead and respond to evolving needs of customers in a timely manner while managing and levelling the impacts of these expenditures on consumer rates.

On October 18, 2012, the Ontario Energy Board released its Report, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach (the "**RRFE**"). Taking a performance-based approach for regulating electricity distributors under the RRFE, the OEB has established four performance outcomes to be achieved by electricity distributors:

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

This is WHESC's first Application under the RRFE.

5.1 General and Administrative Matters

The form and the content of these filing requirements reflect the Board's conclusions in relation to distribution infrastructure planning. These filing requirements introduce a standard approach to a distributor's filings of asset management and capital expenditure plan information in support of a rate application. As detailed in section 5.2, distributors filing a corporate 'Asset Management Plan' are expected to include and clearly identify in their filings the information set out in these filing requirements, and to use the terminology and formats set out in these filing requirements.

WHESC has prepared this DSP for the Application using headings in the terminology of and formats set out in the Filing Requirements.

5.1.1 Investment Categories

A distributor's investment projects and activities should be grouped for filing purposes into one of the four investment categories listed below, based on the 'trigger' driver of the expenditure, examples of which are provided on Table 1.

- ***System access investments are modifications (including asset relocation) to a distributor's distribution system a distributor is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via the distribution system***
- ***System renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services.***
- ***System service investments are modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements***
- ***General plant investments are modifications, replacements or additions to a distributor'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***

A project or activity involving two or more 'drivers' associated with different categories should be placed in the category corresponding to the 'trigger' driver. For example, a project triggered by the need to replace end of service life components in a distribution station should be considered a 'system renewal investment, even if in anticipation of future system requirements (a ' system service ' driver) the project includes assets rated for a higher voltage and/or capable of handling reverse flows. Note, however (as detailed in section 5.4.5), information on all drivers of a given project or activity should be used to justify proposed capital investments.

In the Filing Requirements, the OEB has specified the investment categories to be used by distributors in their filings. WHESC has identified each investment category, the key drivers that are applicable in its case, and listed at a program category level, a representative example of the applicable projects/activities presented in this DSP based on the 'trigger' driver of the expenditure. The result of this is summarized in Table 5-1 below. Each

program category has been expanded in greater detail in subsequent sections of the DSP that details specific projects within each program category.

Table 5-1: Summary of WHESC's investment drivers

	OEB Example Drivers	OEB Example Projects/Activities	WHESC Drivers	WHESC Program Categories
System Access	Customer Service Request	New customer connections. Modifications to existing customer connections. Expansion for customer connections or property developments.	Customer Service Requests	Customer Connections Expansions (Subdivisions) Expansions (Transformers/Meters)
	Other 3rd party infrastructure development requirements	System modifications for property or infrastructure development (e.g. relocating pole lines for road widening).	Other 3rd party infrastructure development requirements	Municipal Relocations
	Mandated Service Obligations (Distribution System Code, Conditions of Service, etc.	Metering. Long Term Load Transfer.	Mandated Service Obligations	Retail Meters
System Renewal	Assets/asset systems at end of service life due to: -failure -failure risk -substandard performance -high performance risk -functional -obsolescence	Programs to refurbish/replace assets or asset systems; (e.g.. poles, conductor, physical plant, relays, switchgear, transformer, other equipment).	Assets/asset systems at end of service life due to failure or failure risk. Distribution loss reduction. SAIDI/SAIFI.	Substation Renewal Overhead Line Renewal Underground Line Renewal Miscellaneous
System Service	System operations objectives -Safety -Reliability -Power Quality -Other performance/functionality	Protection & control upgrade; (e.g. reclosers, relays). Automation by device type/function. SCADA.	System operations objectives: Safety Reliability Power Quality Other performance/ functionality SAIDI/SAIFI	SCADA Enhancements Substation System Enhancements
General Plant	System capital investment support System maintenance support Business operations efficiency Non-system physical support	Structures & depreciable improvements. Equipment and tools. Finance & Admin/Billing Software Systems.	System capital investment support System maintenance support Business operations efficiency Non-system physical support	Furniture & Equipment Computer Hardware Computer Software Communication Equipment Measurement & Testing Equipment Tools Automotive Equipment & Vehicles Buildings & Grounds Renewables

5.1.2 Investments Related to Renewable Energy

Under the renewed regulatory framework, a distributor's investments to accommodate and connect renewable energy generation (i.e. REG investments) are integral to its DS Plan, which includes all costs to connect renewable generation facilities that will be the responsibility of the distributor under the DSC, and are therefore eligible for recovery through the provincial cost recovery mechanism set out in section 79.1 of the OEB Act.

WHESC acknowledges its responsibility to ensure that its distribution system has, and will continue to have, the ability to connect renewable energy generation ("**REG**") facilities. The four projects that have been awarded in WHESC's territory under the FIT4 program do not require any significant system modifications or expansions to connect the new facilities.

5.1.3 Timing of Filing

All distributors are required to file a DS Plan as specified here when filing a cost of service application for the rebasing of their rates under the 4th Generation IR or a Custom IR application. Distributors proposing to use the 'Annual IR Index' method for 2014 rates are not required to use Chapter 5 when filing an application. However, any distributor using the 'Annual IR Index' method must make a Chapter 5 filing within five years of the date of the most recent Board decision approving their rates in a cost of service proceeding; and is required to do so at five year intervals thereafter while using the Annual IR Index method. The Board may also require a DS Plan to be filed in relation to leave to construct, Incremental Capital Module or Z –factor applications.

This DSP is filed as part of WHESC's Application.

5.1.4 Planning in Consultation with Third Parties

5.1.4.1 Regional Planning and Consultations

Prior to filing a DS Plan and at a time and in a manner to be determined in consultation with the participants in a Regional Planning Process, a distributor must:

1. Provide regionally interconnected distributors (including host and /or embedded where applicable), the transmitter to which the distributor is connected and the OPA (where applicable) with information on:

- ***forecast load at existing (and proposed, if any) points of interconnection;***
- ***forecast renewable generation connections and any planned network investments to accommodate the connections;***
- ***investments involving smart grid equipment and/or systems that could have an impact on the operation of assets serving the regionally interconnected utilities; and***
- ***the results of projects or activities involving the study or demonstration of innovative processes, services, business models, or technologies; and on the projects or activities of this nature planned by the distributor over the forecast period.***

2. Consult with regionally interconnected distributors (including host and embedded where applicable) and transmitter(s) to which the distributor is connected in preparing their DS Plan.

WHESC provided system load and load forecast data to Hydro One during the Regional Planning Process ("RPP"). A description of these consultation processes and findings are provided in Appendix 5-A. WHESC has provided the IESO with information on connected renewable generation projects and a forecast of expected future connections (see Appendix 5-B for WHESC's submission to the IESO). The IESO has reviewed WHESC's information and has responded formally by letter of comment. The IESO letter of comment is provided in Appendix 5-C. WHESC does not have any smart grid projects planned for the test year or any projects that would affect the limited number of interconnections with neighbouring utilities. WHESC, along with neighbouring

utilities, municipalities and Regional Government continue to meet regularly to share information and coordinate efforts where possible.

5.1.4.2 Renewable Energy Generation Investments

Prior to filing a DS Plan, a distributor must:

1. Not less than 60 days (where REG investments are contemplated; 30 days otherwise) in advance of the date the distributor needs to receive the OPA letter for inclusion in an application, a distributor must submit information to the OPA in relation to the REG investments identified in their DS Plan and request in writing that the OPA provide a letter commenting on the information by a date that conforms to the distributor's filing timetable.

2. The Board expects that the 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.***

The Board may postpone processing an application where a comment letter from the OPA has not been filed in accordance with this requirement.

It is mandated by the OEB that all distributors submit information to the IESO in relation to the REG investments identified in their DSP and request in writing that the IESO provide a letter commenting on the REG Plan, no less than 30 days in advance of filing the DSP where the distributor is not requesting investments related to REG projects.

WHESC submitted the required information to the IESO (this is attached as Appendix 5-B). The IESO Letter of Comment has been received and is included in Appendix 5-C.

5.1.5 Performance Reporting

A distributor is to provide information on its performance in relation to its DS Plan as set out in section 5.2.3, including information on the achievement of the operational or other objectives targeted by investments the costs for which were approved in a previous application(s). Through its RRR filing, a distributor is also required to report annually on its performance, including in relation to reliability and any Performance Scorecard metrics established by the Board, including metrics related to asset management and capital expenditure planning as applicable.

To facilitate performance monitoring and utility benchmarking, the OEB employs a balanced scorecard approach that translates the four RRFE performance outcomes into a set of measures that can be monitored and compared.

WHESC uses the performance scorecard metrics shown in Table 5-3 established by the OEB to continuously monitor its achievement in relation to the four performance outcomes and reports its performance to the OEB as required.

5.2 Distribution System Plans

Distributors are encouraged to organize the required information using the section headings indicated. If a distributor's application uses alternative section headings and/or arranges the information in a different order, the distributor shall demonstrate that these requirements are met by providing a table that clearly cross-references the headings/subheadings used in the application as filed to the section headings/subheadings indicated below.

The DSP was developed in compliance with the Filing Requirements to ensure all key elements are included. Information in this report is organized using the section headings indicated in the Filing Requirements.

5.2.1 Distribution System Plan Overview

This section provides the Board and stakeholders with a high level overview of the information filed in the DS Plan, including but not limited to

- ***a) 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***
- ***b) the sources of cost savings expected to be achieved over the forecast period through good planning and DS Plan execution***
- ***c) the period covered by the DS Plan (historical and forecast years);***
- ***d) 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?);***
- ***e) 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 ; and***
- ***f) 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.***

Prior to filing, care should be taken to ensure that summary information is consistent with the detailed information filed in the following sections and elsewhere in the application.

A summary of **WHESC's** expenditures for the proposed capital investments in the 2017 Test Year in each of the investment categories are briefly discussed below:

1. System Access

   System Access investments account for just under 10% of the capital expenditures for 2017. The investments in System Access are in response to customer requests for connections. **WHESC** must complete requested connections in order to remain compliant with regulations. The estimated expenditures for this category is based on investment from previous years, taking into consideration forecasted developments in the service area.

2. System Renewal

   System Renewal projects make up the largest category of investments for 2017 and account for over 72% of total capital expenditures. Projects in this category consist of the replacement of distribution assets. Applying **WHESC's** asset management process, **WHESC** has determined many of these assets are in poor condition and susceptible to failure in the near term if not replaced. System renewal investments also address reliability and, where practical, voltage conversions which have greatly contributed to **WHESC's** reduced loss factor in 2017. The reduction in the loss factor from past conversion projects is expected to generate savings in customer's power and power related billings of approximately $250,000 in the 2017 Test Year.

3. System Service

   System Service expenditures account for a small portion of the overall allocation of capital investment. The amount invested in this category in 2017 is largely composed of the replacement of current SCADA software and related communication equipment. SCADA investments are required to maintain system efficiency, reliability, and support in responding to certain power disruption events.

4. General Plant

   General plant expenditures account for just over 10% of capital expenditures for 2017. The amount invested in this category in the Test Year is largely composed of expenditures related to maintaining buildings and grounds at WHESC's current service center. These upgrades to facilities are required to ensure the current facilities meet the needs of WHESC and its customers for years to come.

5.2.1a Key Elements of the DSP

All categories of system investments, including System Renewal, System Access, System Service, and General Plant have been addressed and consolidated in the Capital Expenditure Summary. In Table 5-2 the summary of the forecast spending for each of the investment categories is presented for the years 2017 through 2021.

Table 5-2: Capital expenditures over the forecast period

OEB Investment Category	Forecast Period 2017	2018	2019	2020	2021	Average Annual Investment 2017-2021	% of Annual Investment 2017-2021
System Access	204,501	250,000	250,000	190,000	150,000	208,900	8.6 %
System Renewal	1,834,485	1,495,000	1,775,000	1,920,000	1,770,000	1,758,897	72.7 %
System Service	110,000	260,000	35,000	35,000	35,000	95,000	3.9 %
General Plant	265,000	305,000	400,000	295,000	525,000	358,000	14.8 %
Totals	2,413,986	2,310,000	2,460,000	2,440,000	2,480,000	2,420,797	

The investment drivers over the forecast period are as follows:

System Access

System Access investments are modifications to the existing system that will allow WHESC to provide customers access to its electricity services. These investments are often triggered by customer requests and are completed to fulfill WHESC's service obligations. Forecasting is based on load growth estimates; in the current economic climate there is minimal work in this area.

Regular meter work, new customer connections and commercial MIST meter installations will continue into the forecast period. Plant relocations, due to municipal road widenings are not expected to have significant budget impact. Meter pre-sampling and final sampling for meter seal extensions are expected to have a minor additional cost impacts in years 2017 through 2020.

System Renewal

System Renewal investments involve the replacement or refurbishment of system assets to maintain the system's ability to provide reliable electricity services to customers. As assets become aged and reach end of life, these investments are necessary to rectify and maintain the overall asset condition at an acceptable level to prevent decline in system reliability and mitigate safety risk to staff and the public.

As seen in Table 5-2 above, System Renewal represents approximately 73% of the Capital Budget based on the asset replacement requirements over the forecast period. Both overhead and underground system rebuilds offer the opportunity in many areas to incorporate voltage conversions, during the design and construction stages, resulting in reduced system losses. Pacing of asset replacement in the forecast period is expected to remain consistent with the historical period.

System Service

System Service investments include new assets or upgrades to systems, impacting system reliability. These projects are driven by required upgrades to support systems including Supervisory Control and Data Acquisition ("**SCADA**"). Additional projects include systems that support SCADA. The communication system upgrades,

scheduled for the Test Year, will provide continued support to the SCADA system and drive cost efficiency. Future projects include protection and control upgrades at Municipal Substations.

General Plant

General Plant investments are made to maintain assets that are not part of the distribution system, but are used to support day to day business and operational activities. The average annual expenditure in this investment category over the forecast period is $358,000 per year, or 14.8% of the total budget. The main expenditures in this category during the Test Year and over the forecast period are with respect to land and buildings.

5.2.1b Sources of Cost Savings

WHESC has introduced many programs over the past few years to improve efficiency, to contain cost, and to mitigate future cost increases.

Enhanced Pole Testing/Treatment

WHESC is required to visibly inspect one third of its distribution assets each year. WHESC has divided its service territory into nine distinct areas for its system maintenance activities. Each year three of the areas are selected for the pole inspection program which includes all of the normal visual and sounding tests. Each year, one of these three areas is selected for a comprehensive pole inspection program. In addition to the normal inspections mentioned above, the comprehensive inspection determines the poles external and internal condition at and below the ground level through the process of core drilling. Following the drilling process, the bored hole is filled with boron and plugged to extend the life of the asset.

Shared Services – Joint Facilities Use

WHESC shared some services with the municipality to achieve cost saving synergies, such as the joint use of WHESC's office for the municipal services, which is a Revenue Offset.

Shared Services – Software Solutions

WHESC is a member of UCS, a nine-member consortium of electrical utility companies that achieves cost synergies through sharing various software solutions, including the Northstar Customer Information System ("**CIS**"), financial analysis software, Customer Connect (access to Time-of-Use data), and FileNexus (document storage). The UCS members share maintenance costs for the software solutions and jointly employ a senior billing analyst, who tests new software updates and monitors changing requirements from the IESO, Meter Data Management and Repository ("**MDM/R**"), and new billing credit initiatives under the Ontario Electricity Support Program ("**OESP**").

Shared Services – CDM Materials

WHESC shares achieved cost synergies in its CDM program roll-outs through collaboration and sharing of materials with neighbouring utilities such as information booklets and playing card hand-outs.

Shared Services – Standardized Designs

WHESC is a member of the Utilities Standard Forum ("**USF**"), which is a large group of Ontario LDCs formed to create standards and share services promoting operational efficiency. As a member, WHESC has access to standardized designs and Bills of Materials, reducing project design and engineering costs.

Cooperative Purchasing

WHESC is a member of Grid Smart City, which is presently considering options to engage in cooperative purchasing that, if successful, would reduce WHESC's costs of materials. Furthermore, if this venture is successful, additional cost saving opportunities will be explored in the future.

Outsourcing – Underground Locates

WHESC began outsourcing underground locates to complete the high volume of requests received in the timelines dictated by the Distribution System Code. This decision allowed WHESC to achieve cost savings through avoidance of hiring additional staff. Yearly locate costs depend on the volume of requests received that year.

Mobile Applications

WHESC has developed programs to collect in field data on mobile computer devices. Data collected includes information and photographs of asset conditions through assessments and details on new plant installed both overhead and underground. The data collected is wirelessly uploaded into the Geospatial Information System eliminating both paperwork and risk of data entry error.

Substation Rebuilds

Where practical, WHESC has implemented a new substation design that uses a standard layout and common components, providing inter-changeability of components during unplanned events, resulting in operational efficiencies and reduced stock requirements.

Distribution System Losses

As part of the System Renewal plan voltage conversions are implemented where practical, driving cost savings through reduced system losses. The long term benefits of the voltage conversion will be the eventual elimination of spare inventory for the 4.16 kV system and reduced OM&A and capital investments in Municipal Substations due to their eventual elimination. These cost savings are expected to exceed the increased capital cost of a system built to a higher voltage level.

Outage Management

WHESC's distribution system is monitored and controlled in many locations using a Survalent SCADA system. In 2015 an alarm annunciation system was added to prioritize alarms and notify staff of outage details, via cellular communications, thereby improving response time.

In addition, WHESC's engineering staff installed software and programs to develop an Outage Management System using the GIS and the Smart Metering Network alarm messaging system. Outages of individual meters can be viewed both in the control room and off site using smart devices. The data, which supports the SCADA system, provides additional granularity resulting in quicker response times during power interruptions.

Focused Services

To reduce its system O&M costs over the forecast period and focus on its core services, WHESC will transition from two to one vehicle mechanics.

5.2.1c Period covered by the DSP

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

5.2.1d Vintage of the Information on Investment Drivers

Information contained in this DSP is considered current as of the end of 2015.

5.2.1e Important Changes to the Asset Management Process

As this is the first DSP to be filed by WHESC, there are no specific updates to any previous plan.

Although WHESC has been following its asset management plan as developed in the historical period, year-over-year it has consistently added operational data to its GIS to further enhance it analytic abilities. Process improvements for data collection into the GIS are also taking place thru mobile devices in the field improving accuracy and timeliness of updates. Enhancements have been made to the predictive maintenance program such as comprehensive pole inspections and corona/arch flash testing. WHESC has also taken advantage of information from the smart meter network and CIS platform to perform load analysis on transformers.

In addition, WHESC is participating in a USF working group to develop a standard set of guidelines and rules for performing asset condition assessments, resulting in the development of health indices for typical LDC assets. These guidelines and rules are expected to be incorporated into future asset management practices.

5.2.1f Aspects Contingent on the Outcome of Ongoing Activities

The level of actual investments in the System Access category is contingent upon Municipal or Regional government plans for roadway alterations and is typically not brought to the public utilities coordinating committee well in advance of the proposed construction schedule. Hence, there are no known projects at this time for the test and forecast periods.

There are no known activities determined by Regional Planning process to be completed in the Test Year or forecast period and WHESC has no Long Term Load Transfer customers to transfer to adjacent utilities to meet an OEB directive.

5.2.2 Coordinated Planning with Third Parties

To demonstrate that a distributor has met the Board's expectations in relation to coordinating infrastructure planning with customers, the transmitter, other distributors and/or the OPA or other third parties where appropriate, a distributor must provide:

a) 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.***

b) 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.***

c) 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.

5.2.2a Stakeholder Consultations

To meet the OEB's expectations with respect to coordinated planning with third parties, WHESC has initiated or participated in the following consultation processes with major stakeholders:

- Customers
- Municipal and regional governments
- Neighbouring LDCs
- The IESO

5.2.2a.1 Customer Consultations

As part of the rate application and DSP, WHESC engaged Innovative Research Group Inc. ("**INNOVATIVE**") to help design, collect feedback and document its customer engagement and consultation process. The consultation was designed to engage various rate classes and collect feedback on preferences and priorities as they relate to WHESC's rate application review and determination of capital spending priorities. The consultation was initiated by WHESC and encompassed three core elements of customer engagement:

- General Service and residential consultation groups
- Large customer validation interviews
- Random telephone surveys

General Service and Residential Consultation Groups

This qualitative phase of the consultation was designed to educate customers, assess their preferences and priorities, gauge reaction to proposed rate changes, and ultimately help inform the quantitative phases of the consultation. The groups were randomly recruited from WHESC residential and GS<50 customers. A workbook was provided to participants containing information on the provincial and local electricity system, WHESC's proposed capital and operating expenditures to maintain system reliability, and the rate impact for each of the respective rate classes.

Large Customer Validation Interviews

A number of key accounts and GS>50 customers were consulted in the development of the proposed DSP (see "Meetings with GS>50 customers" below). INNOVATIVE followed up with telephone interviews to validate the process and to verify that WHESC provided them with the information they needed to provide informed feedback on the proposed plan.

Random Telephone Surveys

INNOVATIVE conducted telephone surveys using a random sample of residential and GS<50 customers to provide a quantitative assessment of key aspects of the DSP.

The main findings of these three customer consultation processes was the acceptance of WHESC's DSP as laid out in this document. The full report can be found in Exhibit 1 Appendix 1-G.

Additional Customer Consultations

In addition to these consultations highlighted in the INNOVATIVE report, WHESC has engaged in the following consultations:

- Scattered load customer rate impact meetings
- City of Welland corporate calls for commercial customers
- Meetings with GS>50 customers
- CDM focus group meetings (IESO)
- 2015 residential customer focus group (WHESC)
- Hope Centre meetings (LEAP and OESP agency)

Scattered Load Customer Rate Impact Meetings

WHESC initiated meetings with the City of Welland and the Region of Niagara to discuss scattered load rates per the Application and their prospective bill impacts. No other participants attended these meetings. The Region of Niagara advised that their scattered load payments have very little impact on their costs, while the City of Welland was also advised of the prospective rate impacts. These meetings did not have any further impact on the DSP.

City of Welland Corporate Calls for Commercial Customers

WHESC is part of the City of Welland team which meets with individual commercial customers (12-16) once each year from 2014 to 2016. These meetings were initiated by the office of the Welland Economic Development Commission and also include the Chamber of Commerce. Customers identified issues with respect to momentary outages, power equality, e-billing, global adjustment classes, electricity usage, and CDM. All of the concerns were addressed in follow-up meetings with customers. These meetings provide an opportunity for customers to share their future plans such as expansion and for WHESC to include in Distribution System Planning if required. An example of actions taken by WHESC as a result of these meetings was the early construction of the Humberstone/Townline tunnel distribution feeder in 2015 to support economic development.

In response to customer concerns for power quality, a metric for tracking power quality complaints was established for this DSP (see Section 5.2.3 – Performance Measurement for Continuous Improvement); although capital expenditures to address power quality have not been planned over the forecast period since all of the concerns have been resolved.

Meetings with GS>50 Customers

WHESC initiated meetings with two GS>50 customers (no other participants): one to assist with power quality issues and the other to advise on options for Class A or Class B status. In both cases, WHESC met the

customer's needs and expectations and no investments into WHESC's distribution system have been planned as a result of these meetings. As mentioned above, WHESC has established a metric to track power quality complaints. These discussions had no direct impact on the DSP.

CDM Focus Group Meetings (IESO)

The IESO initiated focus group meetings for residential customers, commercial customers, and contractors from within WHESC's service area regarding CDM saveONenergy programs. IESO and WHESC staff attended these meeting along with consultants hired by the IESO. Residential and commercial customers advised that they complete CDM projects as a concern for the environment. Customer are aware of CDM programs, believe they will reduce consumption, but probably only maintain cost as rates are increasing. Customers believe electricity cost is expensive and cannot afford a lot of increases to their electricity bills. Customers would like to see higher incentives for CDM programs.

WHESC markets CDM programs to its customers through newspaper and social media and completes incentives applications for customers when required. Customer Connect is used to assist customers with understanding Time of Use rate impacts. In response to customer concern for electricity rates, WHESC has proposed an investment intensity that balances meeting the needs of the system with keeping rates competitive.

These meetings had no direct impact on the DSP.

2015 Residential Customer Focus Group Meetings (WHESC)

Prior to the focus group meetings conducted by INNOVATIVE (see above), WHESC initiated and conducted focus group meetings with residential customers in 2015. Customers specified that their greatest needs from WHESC are accurate bills, pre-authorized payment options, communication by telephone, and reliable power; however, they do not want higher electricity rates.

WHESC tracks billing accuracy and targets an accuracy greater than 98% as per the Distribution System Code. WHESC developed an online pre-authorized payment system portal now used by customers. Automated calls are made for any planned or emergency outages and 48-hour calls for non-payment issues. WHESC is currently updating its Customer Connect to enhance its online site (presently in the testing phase). WHESC is also developing an outage management map for mobile devices. In response to customer concerns for electricity rates, WHESC has proposed an investment intensity that balances meeting the needs of the system with keeping rates competitive.

WHESC has included Computer Software-Customer Online Forms as part of DSP capital expenditures in 2016/2017 as a result of this focus group meeting.

Hope Centre Meetings (LEAP and OESP Agency)

WHESC initiated meetings with the Hope Centre executive director and staff to review issues with LEAP, OESP, low income customers, and senior citizens. Customers are concerned with high costs and want access to

information online. Customers are having some difficulty understanding the OESP and seniors are sometimes too proud to come to the Hope Centre for assistance. WHESC then teamed up with the Hope Centre to host two separate events to register and explain LEAP, OESP, and Customer Connect to customers.

These meetings and events have had no further impact on the DSP.

5.2.2a.2 Municipal & Regional Government Consultations

The majority of WHESC's consultation is with the Municipality of the City of Welland and the Niagara Region through the Public Utilities Coordinating Committee, the Economic Development Commission, and the Sustainable Energy Committee. These consultations assist WHESC in determining other capital investments due to third party infrastructure development requirements.

In particular, coordinated planning is conducted through the Public Utilities Coordinating Committee to:

- Integrate regional plans into WHESC's distribution system planning process to ensure that any distribution requirements identified during the Regional Planning Process are included in the DSP; and
- Align WHESC's DSP with planning at the regional level to achieve planning efficiency in the long term.

Neither the City nor the Region have planned capital projects over the forecast period that would require WHESC to relocate its poles occupying the Right-of-Way; therefore, WHESC has not budgeted capital expenditures in the System Access category to meet these needs.

5.2.2a.3 Neighbouring Utility Consultations

WHESC meets with neighbouring utilities on an as-needed basis to coordinate projects such as the common smart metering platform that was deployed in 2009. For the purpose of this DSP, there have been no significant meetings with neighbouring utilities outside of the Regional Planning Process and, therefore, no impact on the DSP. The Regional Planning Process is discussed in Section 5.2.2b below.

5.2.2a.4 Transmitter Consultations (Hydro One)

Outside of the Regional Planning Process, WHESC receives updates from its transmitter Hydro One on an annual basis regarding scheduled capital works and planned outages in the Niagara Region. This information is used by WHESC to coordinate its own planned outages to minimize the impact to customers. This has not had any material impact on the DSP.

WHESC and Hydro One engage in two-way communication: load and generation forecasts are provided by WHESC to Hydro One on an annual basis and Hydro One advises of any capacity constraints. Information on the ability of Hydro One's upstream system to accommodate new REG connections is used in performing the system capability assessment for REG (Section 5.4.3).

The Regional Planning Process is discussed in Section 5.2.2b below.

5.2.2a.5 IESO Consultations

WHESC coordinated with the IESO to jointly consult customers through CDM Focus Group Meetings (see 5.2.2a.1 – Customer Consultations). Consultations with the IESO also took place through the Regional Planning Process as discussed in Section 5.2.2b below.

In preparing this DSP WHESC prepared and submitted an REG Investment Plan to the IESO and received a Letter of Comment in response. Further details are provided in Section 5.2.2c below.

5.2.2b Regional Planning Process

Integrated Regional Resource Planning was triggered in response to the OEB's Regional Infrastructure Planning process approved in August, 2013. The Niagara Region is in Group 3 and planning commenced on 15 October 2015 and was completed 30 April 2016. Hydro One took the lead role in the process and participants included WHESC, the IESO, and other local LDCs including:

- Niagara Peninsula Energy;
- Niagara on the Lake Hydro;
- Canadian Niagara Power; and
- Horizon Utilities

The Needs Assessment Report concluded that no further regional coordination or planning is required and the region will be reassessed within five years as part of the next planning cycle. The full report can be found in Appendix 5-A.

5.2.2c IESO Comment Letter

WHESC prepared and submitted an REG investment plan to the IESO and received a Letter of Comment in response from the IESO. The IESO confirmed that WHESC's information on REG connections is consistent with that of the IESO and that the Regional Planning Needs Assessment Report indicates that the Regional Planning Process for the Niagara region is complete and will be undertaken again when the next five-year planning cycle commences. WHESC's REG investment plan (based on Section 5.4.3 of this DSP) has been included as Appendix 5-B and the full letter of comment can be found in Appendix 5-C.

5.2.3 Performance Measurement for Continuous Improvement

As mentioned in section 5.0, good distributor planning is an essential element of the Board's performance-based rate-setting approaches. The Board understands that distributors often use certain qualitative assessments and/or quantitative metrics to monitor the quality of their planning process, the efficiency with which their plans are

implemented, and /or the extent to which their planning objectives are met. The Board expects that this information is used to improve continuously a distributor's asset management and capital expenditure planning processes.

a) 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.***

b) provide a summary of performance and performance trends over the historical period using the methods and measures (metric s/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.

c) 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.

5.2.3a Definition of Measures

WHESC uses a set of performance measures to continuously monitor and evaluate its achievement with respect to the four performance outcomes established by the OEB, particularly in respect to the Electricity Distributors Scorecard. Most of these measurements are required by the OEB for DSP filing. Regardless of the requirement, these measurements are recorded as they are considered meaningful to WHESC. These measures not only allow WHESC to capture deviations in its own performance from year to year, but also provide a means to compare its performance with other Ontario LDCs.

A summary of these performance measures detailed in the Scorecard are outlined in Table 5-3 below.

Table 5-3: Performance metrics on the OEB's Electricity Distributor Scorecard

Performance Outcomes	Performance Categories	Measures
Customer Focus	Service Quality	New Residential/Small Business Services Connected On Time
		Scheduled Appointments Met On Time
		Telephone Calls Answered On Time
	Customer Satisfaction	First Contact Resolution
		Billing Accuracy
		Customer Satisfaction Survey Results
	Customer Bill Impacts	Percentage Average Total Bill Impact
	Power Quality	Number of Unresolved Power Quality Complaints
Operational Effectiveness	Safety	Public Safety
		Electrical Safety Authority (**ESA**) Audits
		Serious Electrical Incident Index
	System Reliability	SAIDI
		SAIFI
		CAIDI
	DSP Implementation Progress	Actual vs. planned project costs
		Actual vs. planned annual spending
		Percentage of projects completed in the budget year
	Cost Control	Efficiency Assessment
		Total Cost per Customer
		Total Cost per km
Public Policy Responsiveness	CDM Program Achievements	Net Annual Peak Energy Savings
Financial Performance	Financial Ratios	Liquidity: Current Ratio
		Leverage: Total Debt to Equity Ratio
		Profitability: Achieved Regulated Returned on Equity

In addition to these metrics listed on the OEB's Distributor Scorecard, the Filing Requirements also address asset and/or system operations performance. Existing scorecard safety metrics would overlap with this category and WHESC is proposing to also track distribution losses to monitor asset/system operations performance.

Table 5-4: Proposed metrics for asset and/or system operations performance

Performance Outcomes	Performance Categories	Measures	Motivation
Asset and/or System Operations Performance	Distribution Losses	Percentage Line Loss	Corporate

5.2.3a.1 Service Quality

New Residential/Small Business Services Connected on Time

The utility must connect a new service for a customer within five business days 90% of the time, unless the customer agrees to a later date. This timeline depends on the customer meeting specific requirements ahead of time (such as ESA authorization received by WHESC and all WHESC service connection requirements have been met by the customer). WHESC's target for this metric is to achieve 90% or greater in a given year, as mandated by the OEB.

Scheduled Appointments Met On Time

For appointments during the utility's regular business hours, the utility must offer a window of time that is not more than four hours long and must arrive within that window 90% of the time. WHESC's target for this metric is to achieve 90% or greater in a given year, as mandated by the OEB.

Telephone Calls Answered on Time

For calls during the utility's regular business hours, the utility staff must answer calls within 30 seconds of receiving the call. WHESC's target for this metric is to achieve 65% or greater in a given year, as mandated by the OEB.

5.2.3a.2 Customer Satisfaction

First Contact Resolution

First Contact Resolution measurements have not been previously defined across the industry. The OEB has instructed all electricity distributors to review and develop measurements in these areas.

First Contact Resolution requires front line staff to be prepared to respond to customer issues effectively, accurately and to the complete satisfaction of the customer. WHESC staff need to be well trained to develop expertise in the ability to listen and communicate with customers. Empowered to assist customers, staff have quick access to information customers require to address customer concerns, needs, and preferences. As part of the 2015 Customer Satisfaction Survey (telephone survey), 406 customers were asked if they contacted WHESC by phone or in person and were asked about the following six aspects of their most recent experience with a representative from WHESC:

- Information- quality of information provided
- Staff attitude- level of courtesy
- Professionalism- knowledge of staff
- Delivery- helpfulness of staff

- Timeliness- length of time it took to get information requested by the customer
- Accessibility

Based on its Customer Satisfaction Survey, WHESC has selected the metric for First Contact Resolution as the percentage of customers that are "very or fairly satisfied with most recent telephone or in-person experience". WHESC's target for this metric is to achieve 80% or greater in a given year.

Billing Accuracy

As per the Distribution System Code, an accurate bill must contain correct customer information, correct meter readings, and correct rates that result in an accurately calculated bill. WHESC's target for this metric is to achieve 99.5% or greater, which is higher than mandated by the OEB.

Customer Satisfaction Survey Results

WHESC engaged a third party to conduct a Customer Satisfaction Survey in 2015. The Customer Satisfaction Survey provided information that identifies areas to improve customer service at all levels and departments within WHESC. The Customer Satisfaction Survey was a telephone survey of 406 customers who were asked questions on a wide range of topics, including: social media, overall satisfaction with WHESC, reliability, customer service, outages, billing, corporate image, customer expectations, and customer needs. WHESC used the results of the information to develop processes, explore different technologies and develop plans through Customer Service team meetings to identify and meet customers' expectations.

WHESC's 2015 Customer Satisfaction Survey results contain a number of measures of customer satisfaction. In its Scorecard, WHESC reports the percentage of customers who are "very or fairly satisfied" with WHESC. The target for this metric is to achieve 90% or greater in a given year.

Another measure developed by the third party survey provider, is a "Customer Satisfaction Survey Report Card" that measures utilities against their peers across Ontario on customer care, company image, and management operations. The scorecard provides an overall letter grade (A,B,C, etc.) for WHESC that accounts for these three facets of customer satisfaction. WHESC's target is to achieve a letter grade of "A" or better.

5.2.3a.3 Customer Bill Impacts

In preparing this application, WHESC has considered the impacts on its customers, with a goal of minimizing those impacts. Incorporated in the overall monthly bill impact is the effect of the following major components of the electricity bill:

- Distribution rates (monthly service charge and volumetric rates)
- Disposition of deferral and variance accounts
- Revised Retail Transmission rates

- Wholesale Marker Service rates
- Loss Factors

Percentage Bill Impact

The percentage average total bill impact considers the percentage year-over-year increase by customer class based on an assumed consumption volume. The percentage impact is calculated per sub-total A of the Tariff Schedule and for the total bill. WHESC aims to keep its rates competitive. As per the OEB rule for rate mitigation, WHESC targets no total bill impact exceeding 10%.

5.2.3a.4 Power Quality

WHESC follows the CSA/CAN3-C235 standard for voltage variation limits at a customer's service entrance.

Number of Unresolved Power Quality Complaints

In response to a customer power quality concern, where the utilization of electricity adversely affects the performance of electrical equipment, WHESC will perform an investigation to attempt to identify the underlying cause. If the issue is deemed to originate on the utility side of the demarcation point, WHESC will take appropriate action to mitigate the problem. WHESC proposes to track the number of unresolved power quality complaints as its metric for tracking power quality with a target of 0 unresolved power quality complaints each year.

5.2.3a.5 Safety

Public Awareness of Electrical Safety

WHESC completed its first Public Electrical Safety Survey in 2015. Public awareness of electrical safety is measured as the percentage of customer/contractors that have good knowledge and have received some information pertaining to the six core electrical safety questions. WHESC's target for this metric is to achieve 80% or greater.

Compliance with Ontario Regulation 22/04

The metric measuring Ontario Regulation 22/04 assesses an LDC's compliance with the ESA's standard for safety performance based on requirements for the design, construction, and maintenance of electrical distribution systems. The audit consists of a review of the Declaration of Compliance, Due Diligence inspections, Public Safety Concerns, and Compliance Investigations. WHESC's targets to always be in compliance with Ontario Regulation 22/04.

Serious Electrical Incident Index

The Serious Electrical Incident Index is measured as the number of serious electrical incidents resulting in death or critical injury and the rate of lost-time injuries. WHESC treats safety of its employees, contractors and the

general public as a number one priority and strives to maintain zero injuries for both the number of serious incidents and the rate of lost-time injuries.

5.2.3a.6 System Reliability

System reliability is key component of the OEB's RRFE. Although the OEB's Electricity Distributor's Scorecard categorizes system reliability under operational effectiveness, this measure is largely reflective of customer oriented performance as also indicated in the Filing Requirements.

The Filing Requirements lists three metrics that distributors must track: System Average Interruption Duration Index ("**SAIDI**"), System Average Interruption Frequency Index ("**SAIFI**"), and Customer Average Interruption Duration Index ("**CAIDI**").

SAIDI

Recovering from power outages as quickly as possible is valued by customers. SAIDI is used to measure the average number of hours that power to a customer is interrupted. SAIDI is equal to the sum of all interruption durations divided by the total number of customers served. SAIDI is calculated both including and excluding loss of supply. WHESC targets a SAIDI of 2.0 or less.

SAIFI

SAIFI measures the number of outages (greater than one minute) seen by a typical customer throughout the year. SAIFI is calculated by dividing the total number of customer interruptions by the total number of customers served. As with SAIDI, SAIFI is calculated both including and excluding loss of supply. WHESC's target for this metric is 1.8 or less.

CAIDI

Similar to SAIDI, CAIDI measures the typical interruption time per outage. It is calculated by dividing the total number of customer interruption hours by the total number of customer interruptions (i.e. dividing SAIDI by SAIFI). CAIDI was removed from the OEB's Electricity Distributor's Scorecard in 2014, but the Filing Requirements mandates CAIDI reporting; therefore, WHESC has included CAIDI as a metric, measured both including and excluding loss of supply. WHESC's target for this metric is 2.0 or less.

5.2.3a.7 DSP Implementation Progress

To measure cost efficiency and effectiveness with respect to planning quality and DSP implementation, WHESC is proposing to track three metrics:

- Actual vs. planned cost of work completed;
- Actual vs. planned annual spend; and
- Percentage of projects completed within the budget year.

Actual vs. Planned Cost of Work Completed

The intent of this metric is to measure WHESC's planning quality for budgeted projects (not including programs without defined scopes). WHESC targets +/- 10% spending on each project relative to the budgeted amount.

Actual vs. Planned Annual Spend

The intent of this metric is to measure WHESC's overall planning quality with respect to its overall budget. WHESC targets +/- 10% spending each year relative to the total budgeted amount.

Percentage of Projects Completed within the Budget Year

Planned projects may be deferred if urgent, unforeseen work materializes during the year. WHESC targets at least 80% of projects/programs to be completed in the year they were budgeted.

5.2.3a.8 Cost Control

Efficiency Assessment

Total costs for Ontario's LDCs are evaluated by the Pacific Economics Group on behalf of the OEB to produce a single efficiency ranking. LDCs are divided into five groups based on the magnitude of the difference between their respective individual actual and predicted costs. WHESC's target is remain in Group 2 (actual costs 10% to 25% below predicted costs).

Total Cost per Customer

Total cost per customer is calculated as the sum of capital and operating, maintenance, and administration ("**OM&A**") costs divided by the total number of customers. WHESC's targets a 2.5% yearly increase in this measure.

Total Cost per km of Line

This measure divides the total cost (sum of capital and OM&A) by the total primary circuit kilometres maintained WHESC. WHESC targets a 2.5% yearly increase in this measure.

5.2.3a.9 CDM Program Achievements

WHESC began implementing CDM programs under the IESO's new Conservation First Framework in October 2015. Under the new Framework spanning 2015 to 2020, WHESC was assigned a target of 25.5 GWh in energy savings by 2020. Based on the recent Achievable Potential Study completed by the IESO, WHESC is expecting that target to be adjusted to 20.5 GWh.

Net Annual Peak Energy Savings

WHESC tracks its CDM program achievements as the percentage of the assigned total net annual peak energy savings and is targeting to achieve one sixth of the total each year up to 2020. The Conservation First Framework does not extend into 2021, therefore no target has been set for that year.

Table 5-5: Annual CDM program achievement targets

Year	2015	2016	2017	2018	2019	2020
Target Net Annual Peak Energy Savings (Percentage of Assigned Total)	16.7%	33.3%	50.0%	66.7%	83.3%	100.0%

5.2.3a.10 Financial Ratios

Liquidity: Current Ratio

Liquidity is calculated as the current ratio of assets to liabilities. As an indicator of financial health, a current ratio that is greater than 1 is considered good as it indicates that the company can pay its short term debts and financial obligations; therefore, WHESC targets its current ratio to be greater than 1.

Leverage: Total Debt to Equity Ratio

The debt to equity ratio is calculated including short-term and long-term debt, as specified by the OEB. The OEB has set a deemed capital structure of 60% debt and 40% equity for LDCs in Ontario. This deemed structure assumes a debt to equity ratio of 1.5 (60/40). A debt to equity ratio of more than 1.5 indicates that a distributor is more highly leveraged than the deemed capital structure. Therefore, WHESC targets its total debt to equity ratio to be less than 1.5.

WHESC's 2015 leverage ratio of 0.84 indicates that it is currently operating with less actual debt than deemed debt. For an LDC, it is imperative to be able to fund capital expenditures to maintain the reliability of the distribution system. WHESC's current and forecasted capital expenditures exceeds depreciation amounts. The excess in capital spending over deprecation is currently being funded thru cash reserves. Maintaining WHESC's current profitability levels and current dividend policy are necessary to ensure that sufficient profits are generated and retained so that debt/equity ratios are not negatively impacted.

Profitability: Regulatory Return on Equity

The OEB allows a distributor to earn within +/- 3% of its deemed return on equity. When a distributor performs outside of this range, the actual performance may trigger a regulatory review of the distributor by the OEB. Therefore, WHESC targets its return on equity to be within +/- 3% of the value deemed by the OEB.

5.2.3a.11 Distribution Losses

To measure its asset and/or systems operations performance, WHESC is proposing to track distribution losses as the percentage line loss each year.

Percentage Line Loss

Although line losses are often driven by factors outside of a utility's controls such as outside temperature, WHESC will track its percentage line loss each year to assess system performance trends. WHESC targets the five-year average not to exceed the five-year average of its Rate Filing Application.

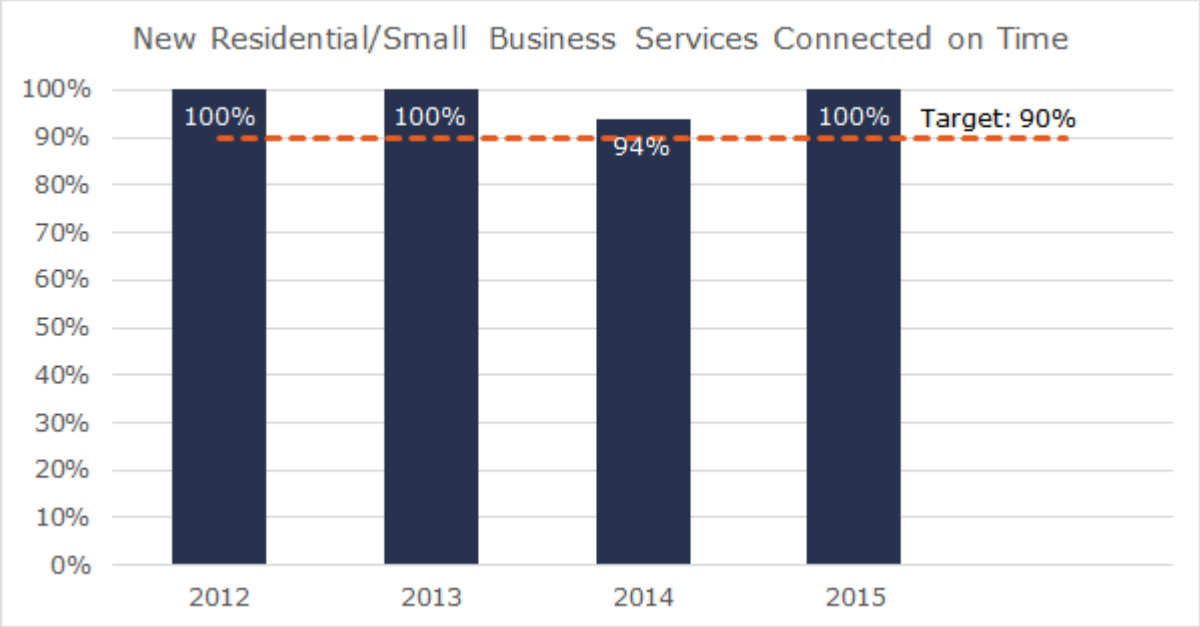
5.2.3b Historical Performance

5.2.3b.1 Service Quality

New Residential/Small Business Services Connected on Time

In 2015, WHESC connected approximately 237 new residential and small business customers to the distribution system within the five-day timeline as prescribed. WHESC has exceeded the 90% target in each year of the historical period as shown in Figure 5-3.

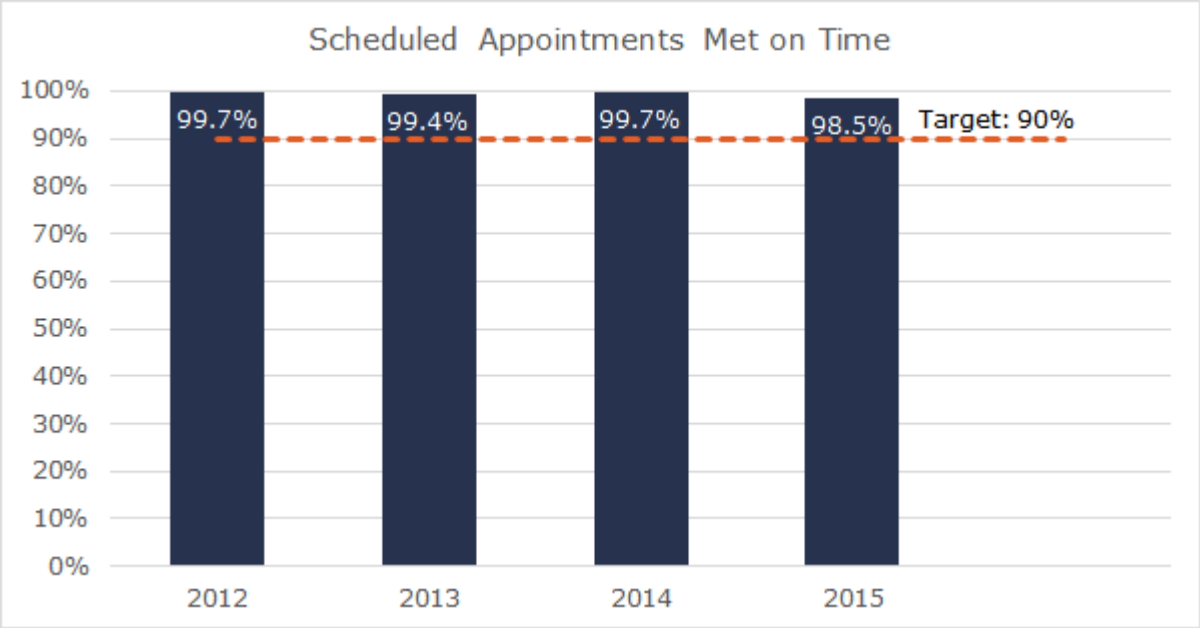
Figure 5-3: Percentage of new residential/small business services connected on time over the historical period



Scheduled Appointments Met On Time

WHESC scheduled 1347 appointments with customers in 2015. As depicted in Figure 5-4, WHESC exceeded the target in each year of the historical period.

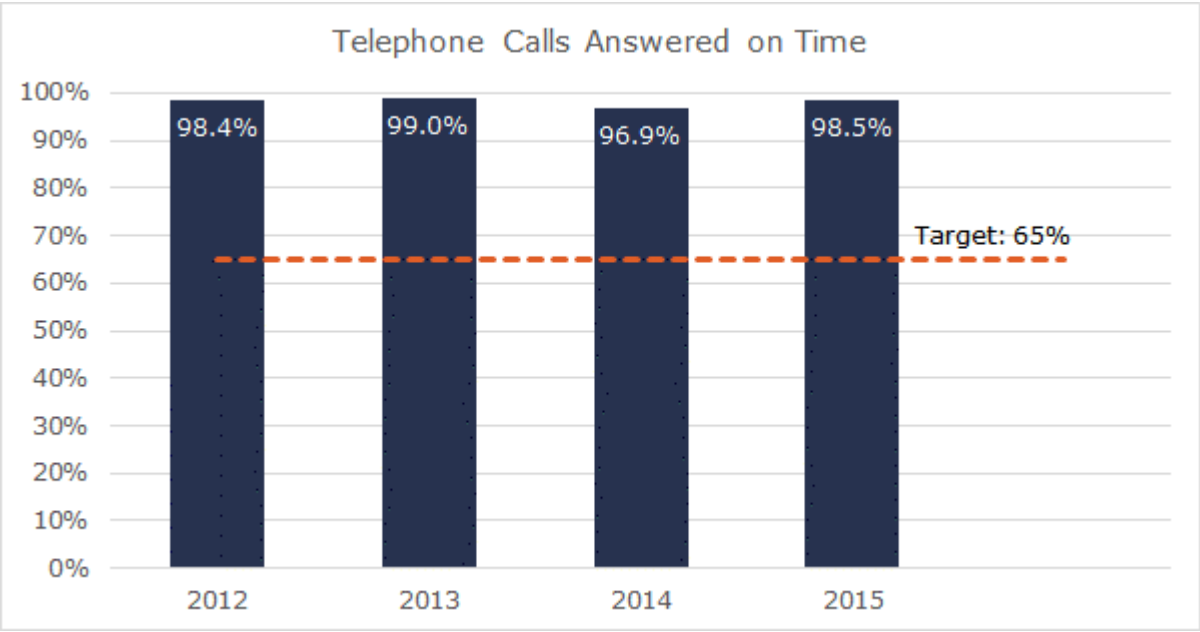
Figure 5-4: Percentage of scheduled appointments met on time over the historical period



Telephone Calls Answered on Time

In 2015, WHESC contact centre representatives answered 31,980. WHESC has achieved well above the 65% target for this metric each year of the historical period.

Figure 5-5: Percentage of telephone calls answered on time over the historical period

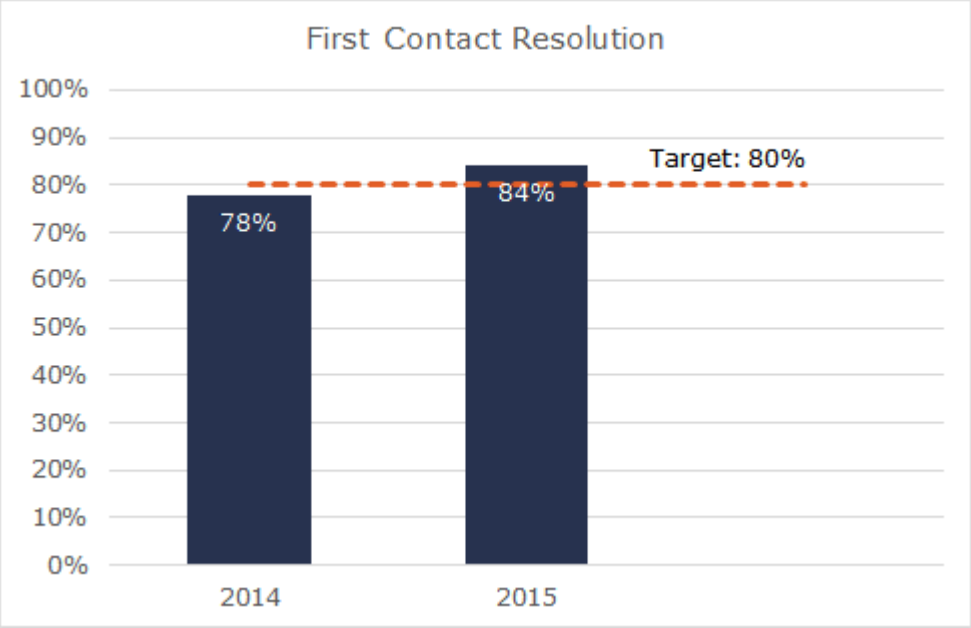


5.2.3b.2 Customer Satisfaction

First Contact Resolution

WHESC has historical data on first contact resolution based on the customer survey results for 2014 and 2015 (measured as the percentage of customers "very or fairly satisfied with most recent telephone or in-person experience"). In 2014 this percentage was 78%, which is below the targeted 80%, and in 2015 this score improved to 84%.

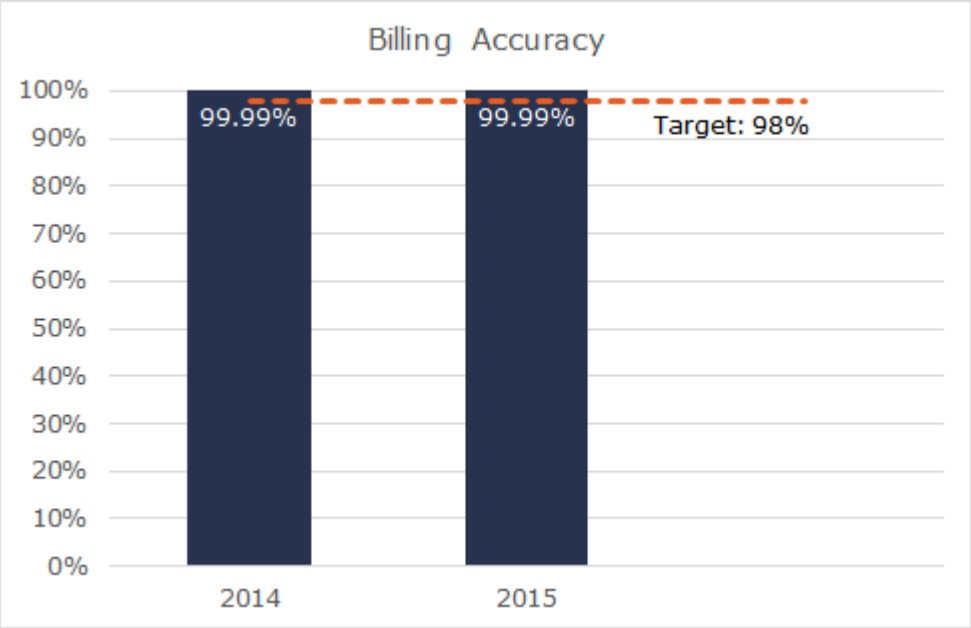
Figure 5-6: First contact resolution performance over the historical period



Billing Accuracy

WHESC on average issues more than 275,000 invoices in a given year. The metric for billing accuracy was introduced by the OEB in 2014 and was not tracked in prior years. WHESC achieved a billing accuracy of 99.9% for the years 2014 and 2015, exceeding its target of 98%.

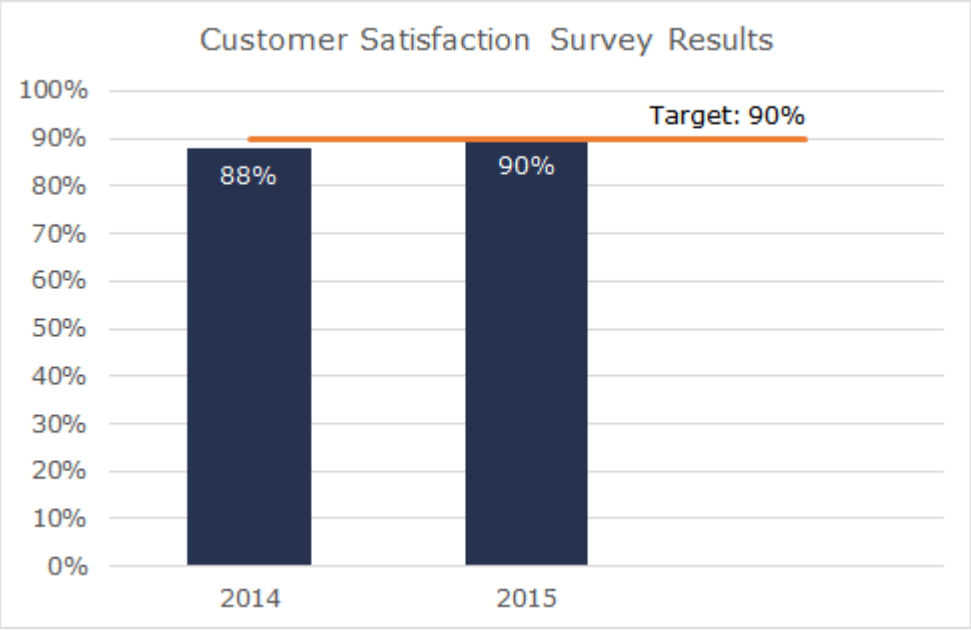
Figure 5-7: Billing accuracy over the historical period



Customer Satisfaction Survey Results

The percentage of customers who are "very or fairly satisfied" with WHESC was 88% in 2014, below the 90% target, but increased to 90% in 2015. Furthermore, WHESC achieved its target on its most recent "Customer Satisfaction Survey Report Card" by scoring an "A", exceeding the average score of LDCs in Ontario ("B+").

Figure 5-8: Customer satisfaction survey results over the historical period



5.2.3b.3 Customer Bill Impacts

Percentage Bill Impact

Bill impacts resulting only from distribution cost changes as per sub-total A of the Tariff Schedule and Bill Impacts spreadsheet model are detailed in Table 5-6, while total bill impacts are detailed in Table 5-7. For each rate class, the total bill impact is below 10% per WHESC's target.

Table 5-6: Percentage bill impact in the Test Year for sub-total A

Rate Class/Description	kWh	kW	Current Distribution Charge Subtotal A	Proposed Distribution Charge Subtotal A	$ Change	% Change
Residential – TOU	750		$27.14	$29.42	$2.28	8.40%
Residential 10th Percentile – TOU	308		$22.49	$26.01	$3.52	15.65%
General Service Less Than 50kW	2,000		$46.91	$51.85	$4.94	10.53%
General Service 50 to 4,999 kW Non-RPP	32,400	60	$429.50	$526.63	$97.13	22.61%
General Service 50 to 4,999 kW Non-RPP	1,091,088	3,268	$6,666.59	$8,525.98	$1,859.39	27.89%
Unmetered Scattered Load	150		$13.13	$11.84	-$1.29	-9.82%
Sentinel Lighting	120	0.3	$4.51	$6.44	$1.93	42.79%
Street Lighting	16	0.044	$2.36	$0.76	-$1.60	-67.80%

Table 5-7: Percentage bill impact for the total bill in the Test Year

Rate Class/Description	kWh	kW	Current Total Bill	Proposed Total Bill	$ Change	% Change
Residential – TOU	750		$147.42	$149.45	$2.03	1.38%
Residential 10th Percentile - TOU	308		$74.06	$77.81	$3.75	5.06%
General Service Less Than 50kW	2,000		$373.93	$378.93	$5.00	1.34%
General Service 50 to 4,999 kW Non-RPP	32,400	60	$5,387.41	$5,537.79	$150.38	2.79%
General Service 50 to 4,999 kW Non-RPP	1,091,088	3,268	$179,351.62	$181,663.22	$2,311.60	1.29%
Unmetered Scattered Load	150		$39.10	$37.53	-$1.57	-4.02%
Sentinel Lighting	120	0.3	$24.16	$26.24	$2.08	8.61%
Street Lighting	16	0.044	$5.41	$3.60	-$1.81	-33.46%

5.2.3b.4 Power Quality

WHESC has 0 unresolved power quality complaints and has therefore achieved its target.

Table 5-8: Number of unresolved power quality complaints

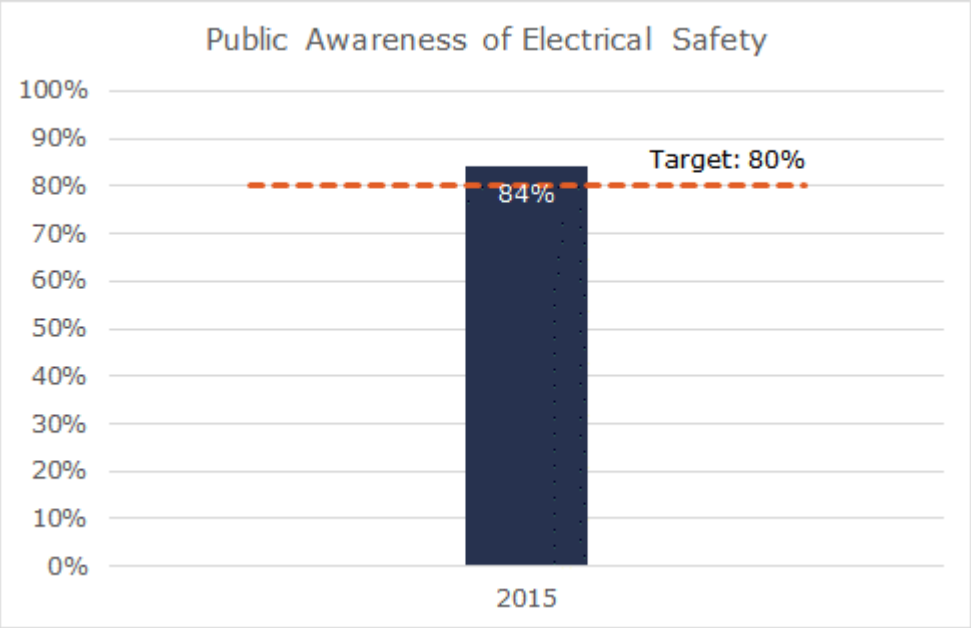
Year	2012	2013	2014	2015
Number of unresolved power quality complaints	0	0	0	0

5.2.3b.5 Safety

Public Awareness of Electrical Safety

WHESC completed its first Public Electrical Safety Survey in 2015. The results indicate that a significant number of customers/contractors (84%) have a good knowledge or have received some information pertaining to the six core measurement questions, which exceeds WHESC's 80% target.

Figure 5-9: Public Electrical Safety Survey results



Compliance with Ontario Regulation 22/04

Over the past four years, WHESC was independently audited and found to be in compliance with Ontario Regulation 22/04.

Table 5-9: Results of Ontario Regulation 22/04 compliance audits

Year	2012	2013	2014	2015
Level of Compliance with Ontario Regulation 22/04	Compliant	Compliant	Compliant	Compliant

Serious Electrical Incident Index

WHESC has had no serious electrical incidents resulting in death or critical injury over the historical period and zero lost-time injuries as a result of a serious electrical incident. Table 5-10 summarizes WHESC's performance.

Table 5-10: Historical safety performance

Year	2012	2013	2014	2015
Number of serious electrical incidents	0	0	0	0
Lost-time injury rate	0	0	0	0

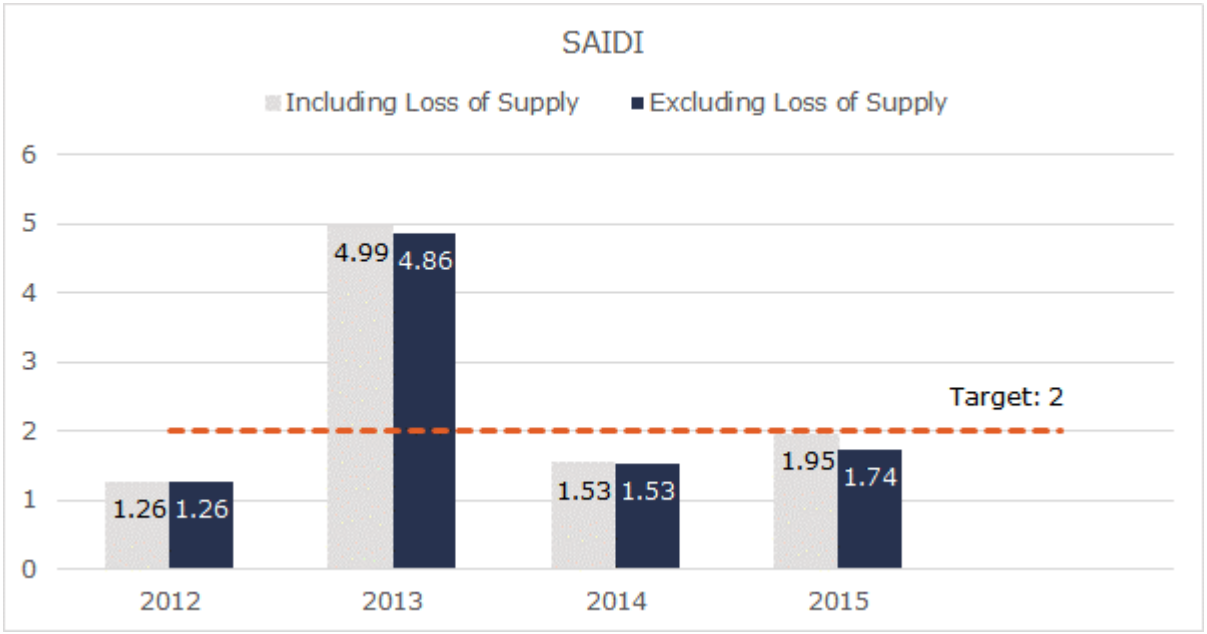
5.2.3b.6 System Reliability

System reliability indices are subject to significant year-over-year volatility experienced due to major weather events. WHESC's historical performance in SAIDI, SAIFI, and CAIDI are summarized below.

SAIDI

WHESC's SAIDI performance from 2012 to 2015 is depicted in Figure 5-10. The ice storm of 2013 resulted in SAIDI well above its target. For the other historical years, WHESC achieved better than its targeted value for SAIDI including and excluding loss of supply.

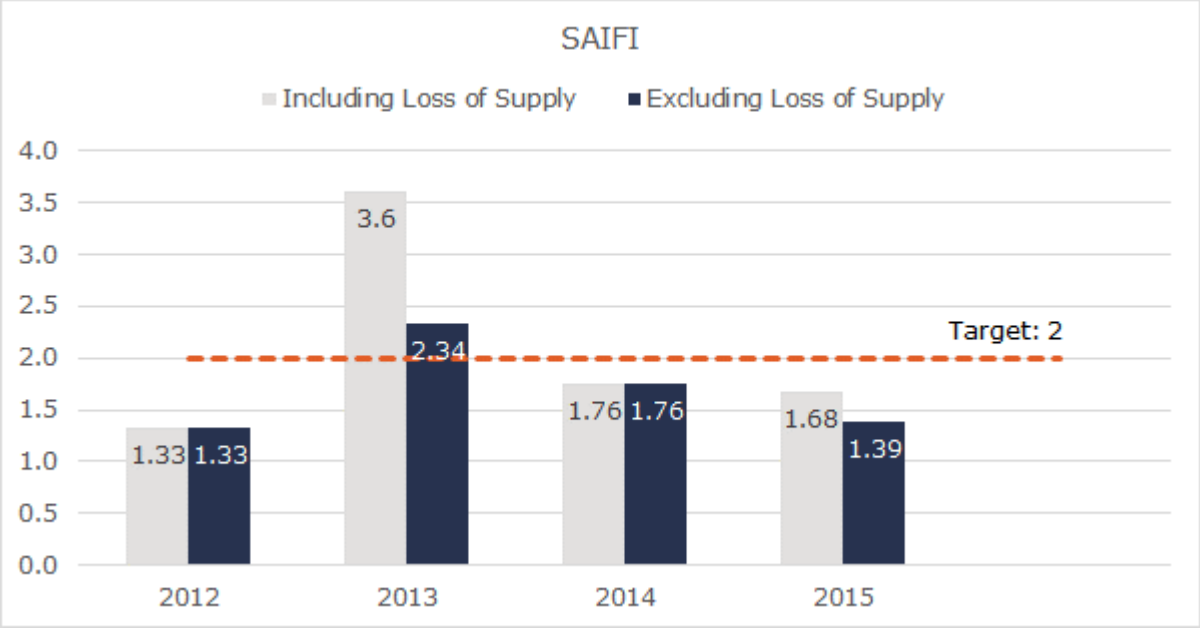
Figure 5-10: Historical SAIDI performance



SAIFI

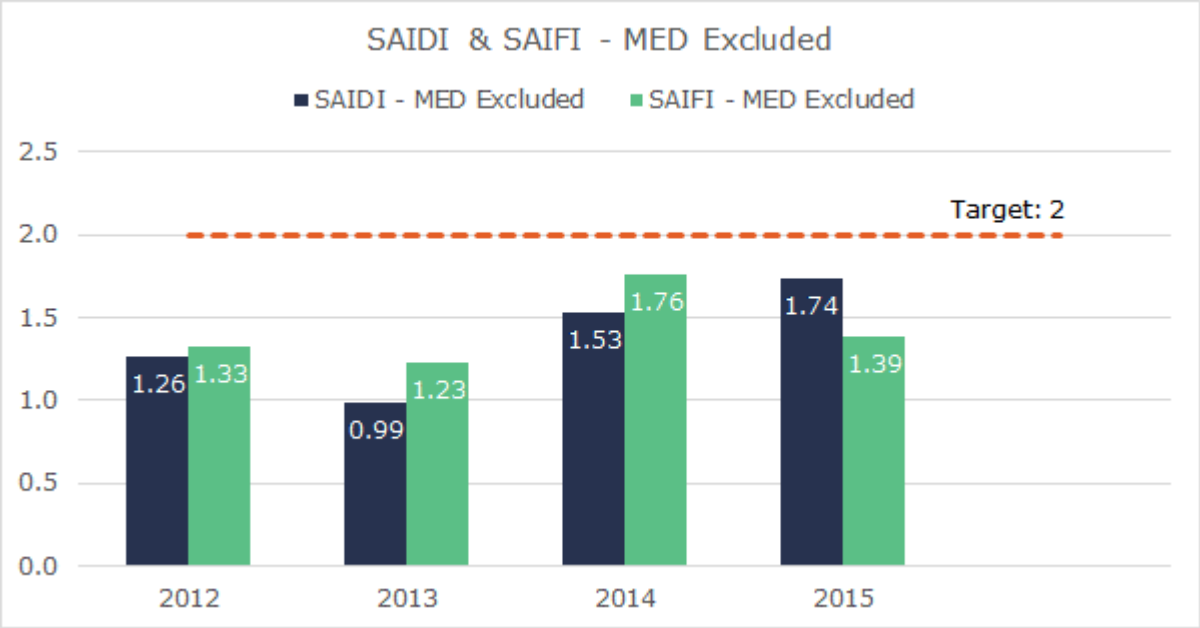
WHESC's SAIFI performance from 2012 to 2015 is depicted in Figure 5-11. The ice storm of 2013 resulted in SAIFI above its target. For the other historical years, WHESC achieved better than its targeted value for SAIFI including and excluding loss of supply.

Figure 5-11: Historical SAIFI performance



Both SAIDI and SAIFI were abnormally high in 2013 due to the ice storm affecting much of southern Ontario. Such events, when the service area systematically experiences significant outages, are typically categorized as "Major Event Days" ("**MED**"). WHESC calculated SAIDI and SAIFI each year excluding MED and, as shown in Figure 5-12, both SAIDI and SAIFI fall below the respective targets of 2.0 and 1.80 each year when the MED are excluded.

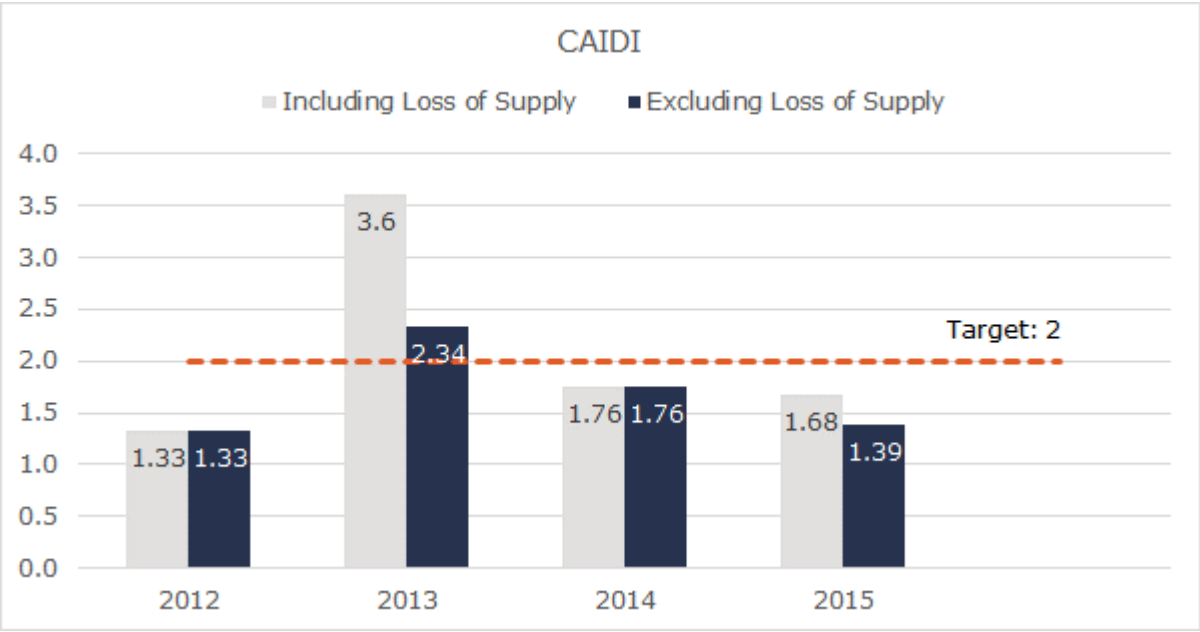
Figure 5-12: Historical SAIDI and SAIFI performance – MED excluded



CAIDI

Figure 5-13 depicts WHESC's CAIDI performance for the years 2012 through 2015, which is below the target each year except 2013 when WHESC was affected by an ice storm causing long duration outages.

Figure 5-13: Historical CAIDI performance



Cause of Outages

Figure 5-14 through Figure 5-17 depict the customer interruption hours by Cause Code for the years 2012 to 2015. During 2012, the majority of the outages (70%) were attributed to adverse weather, with a meaningful portion (17%) attributed to defective equipment. 2013 had a similar percentage of outages caused by adverse weather (73%), but defective equipment had less of an impact (7%), while scheduled outages accounted for 15% of the customer interruption hours. In 2014, 59% of the outages were due to adverse weather, 21% were scheduled outages, 12% were caused by defective equipment, and 6% were caused by foreign interference. In 2015 WHESC experienced an unusually high number of defective equipment outages, which accounted for 71% of the customer interruption hours; while 11% came from loss of supply, 8% were due to adverse weather, and 8% were scheduled outages.

The defective equipment outages were further analyzed and a summary of the results is presented in Figure 5-18. Most of the defective equipment outages in 2015 can be attributed to three insulator failures. One of the failures was on a multi-circuit pole and resulted in 12,600 customer interruption hours. Other outages were also caused by switches, underground cables, and tension sleeves.

Figure 5-14: Customer interruption hours by Cause Code – 2012

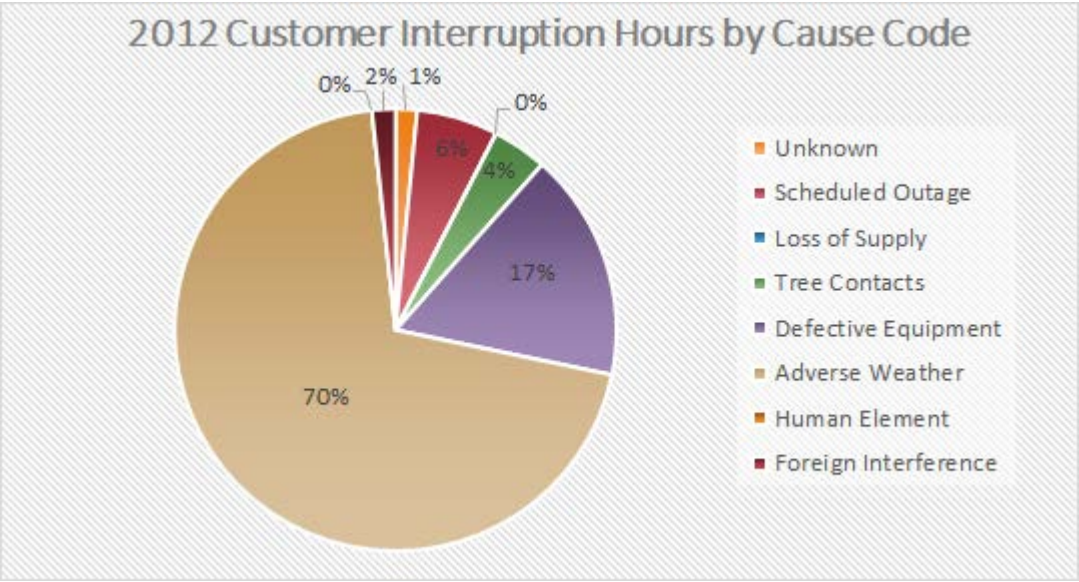


Figure 5-15: Customer interruption hours by Cause Code – 2013

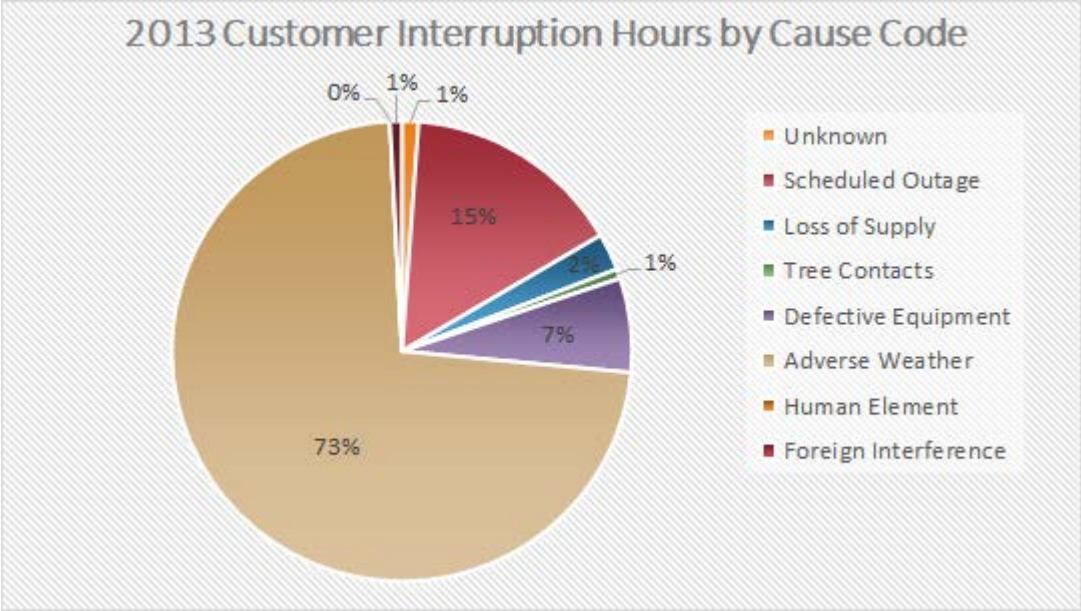


Figure 5-16: Customer interruption hours by Cause Code – 2014

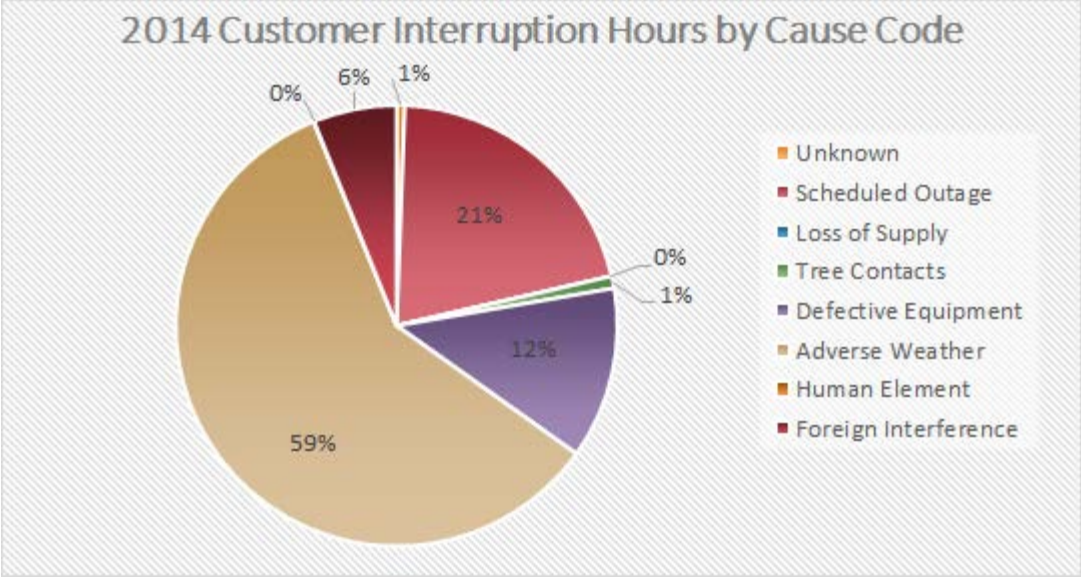


Figure 5-17: Customer interruption hours by Cause Code – 2015

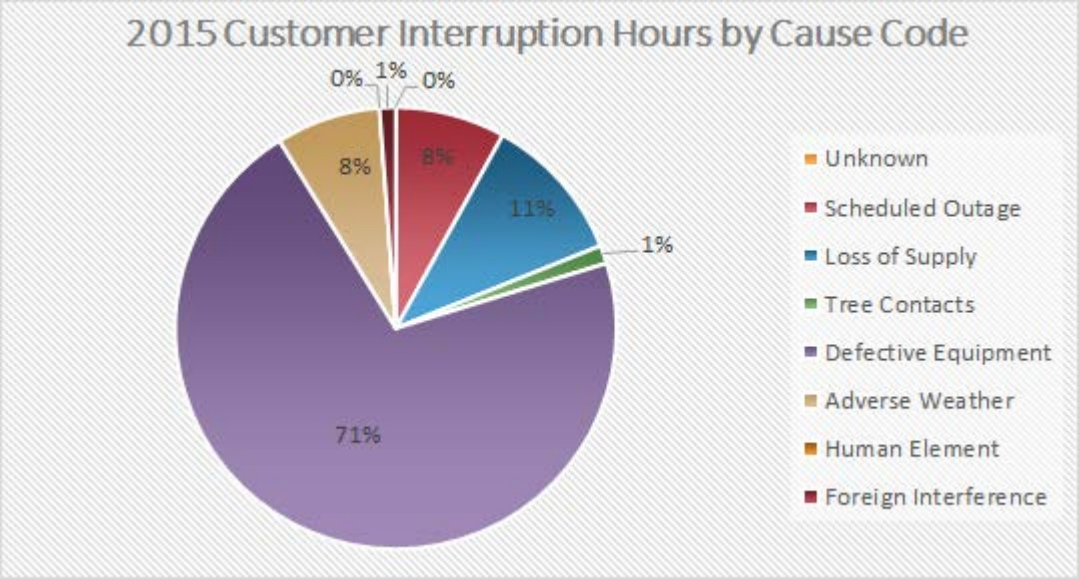
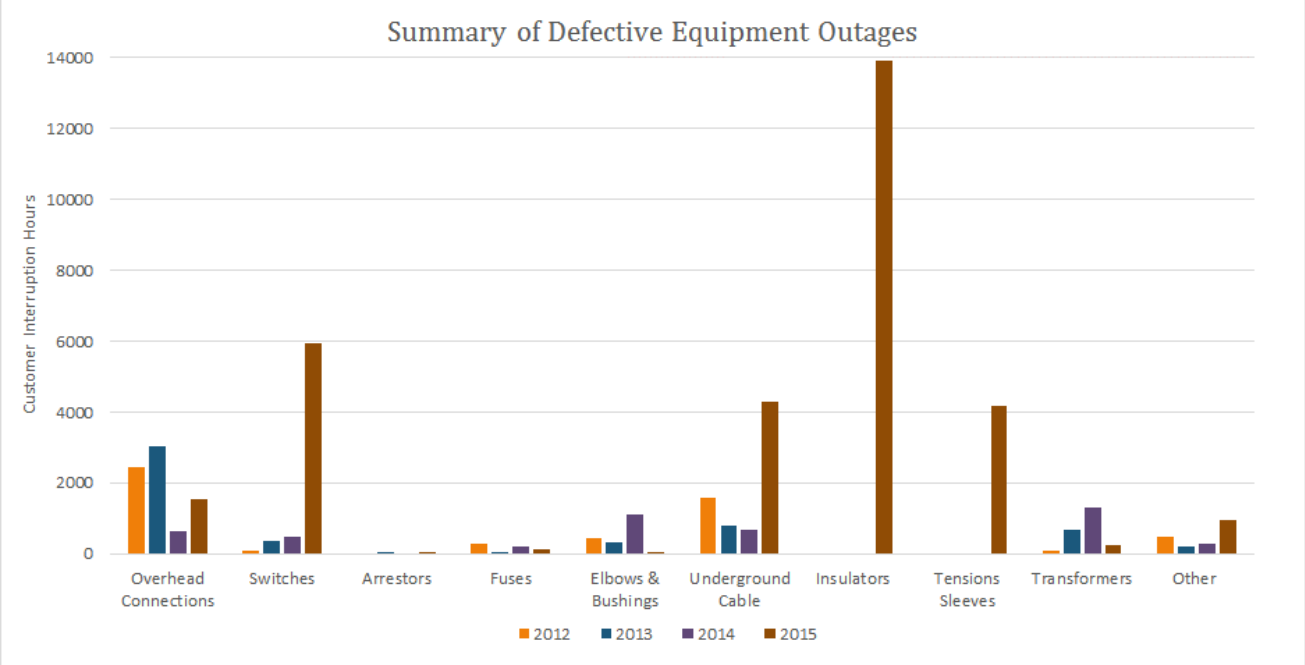


Figure 5-18: Summary of defective equipment outages



5.2.3b.7 DSP Implementation Progress

As this is WHESC's first DSP, there is no historical DSP implementation progress to report.

5.2.3b.8 Cost Control

Efficiency Assessment

WHESC was assessed to be in the second efficiency group (actual costs 10% to 25% below predicted costs) for each year of the historical period, thus achieving its target. The 2015 assessment places WHESC within the top twenty electricity distributors in all of Ontario for cost efficiency. Performance in 2015 showed actual costs 18.7% below predicted. This increased WHESC's three year average performance from 14.3% below expected costs in 2014 to 17.0% below expected costs in 2015. The improved performance reflects WHESC's commitment to finding continuous improvements throughout all processes.

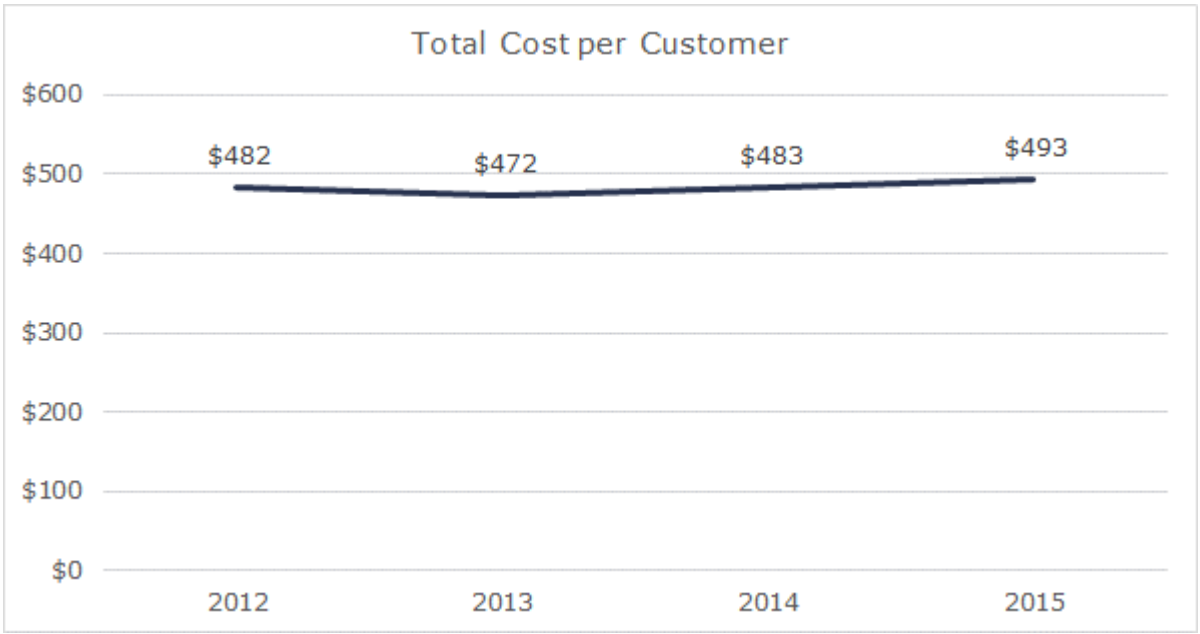
Table 5-11: Results of the efficiency assessment

Year	2012	2013	2014	2015
Efficiency assessment results	Group 2	Group 2	Group 2	Group 2

Total Cost per Customer

Results for 2015 at $493 per customer represents a 2.1% increase over 2014 results, below the 2.5% target. These results can be impacted by one off costs such as emergency repairs and regulatory costs on a year by year basis. A comparison of 2015 cost per customer to 2012 results, shows a 2.3% increase over three years, corresponding to a 0.8% increase per year.

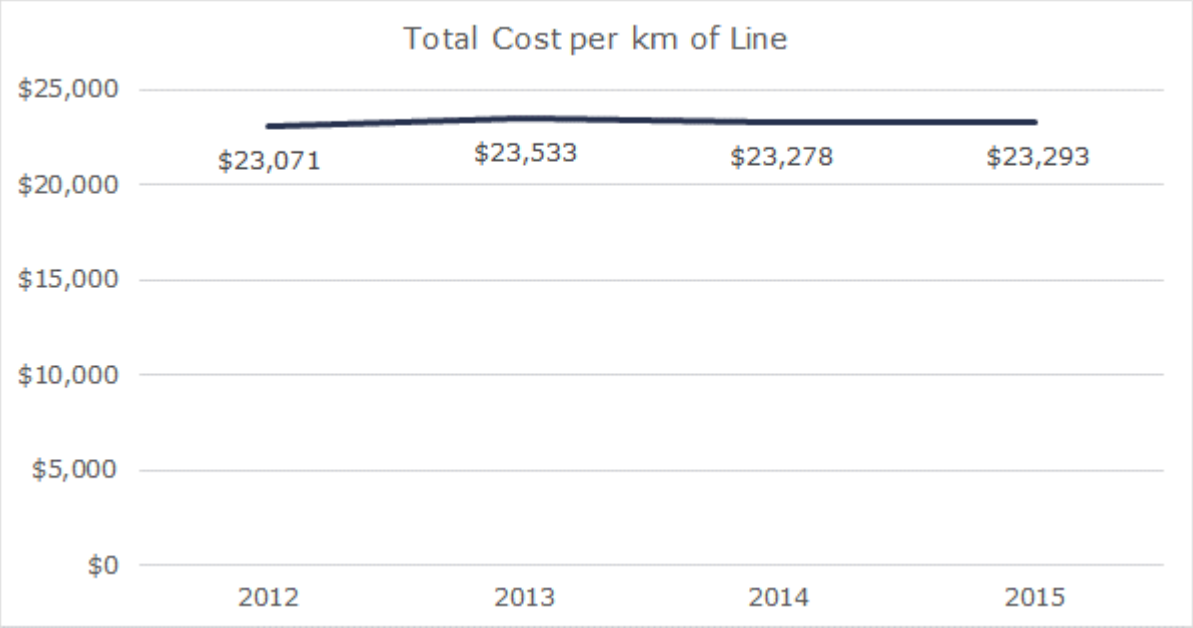
Figure 5-19: Total cost per customer over the historical period



Total Cost per km of Line

Actual cost per km of line serviced by WHESC in 2015 remained flat compared to 2014. Since 2012, total cost per km of line have increased by 1.0% over the three-year period, corresponding to an average increase of 0.3% per year, well below the target.

Figure 5-20: Total cost per km of line over the historical period



5.2.3b.9 CDM Program Achievement

Net Annual Peak Energy Savings

WHESC began the Conservation First Framework in October 2015 and continues to build momentum from the Commercial Sector. WHESC has achieved 6.78% of its net annual peak energy savings target under the Conservation First Framework. The recently completed Achievable Potential Study, completed by the IESO, indicates that the original assigned target should be lowered by 5 GWh, which, if considered for adjustment at the mid-term review, would change WHESC's achieved net energy savings for 2015 to 8.48%.

Figure 5-21: Percentage of net annual peak energy savings target achieved

Year	2015	2016	2017	2018	2019	2020
Target	16.7%	33.3%	50.0%	66.7%	83.3%	100.0%
Achieved	6.78%					

Whole Home Residential and small Business Lighting Programs will be launched by the IESO to enhance savings in 2016 and 2017. Furthermore, WHESC has a large streetlight conversion project that began in 2015

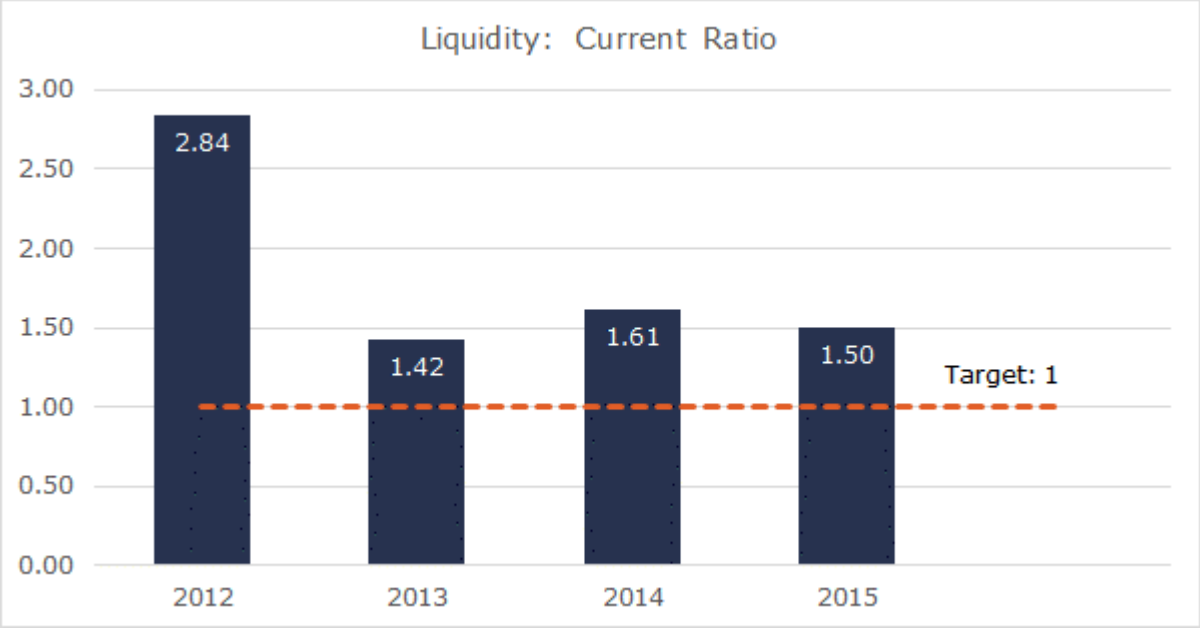
and is scheduled for completion in 2016 and completion of this project will have a significant impact on the savings achieved in 2016.

5.2.3b.10 Financial Ratios

Liquidity

WHESC has consistently had a current ratio greater than 1. The majority of current assets is related to receivables and unbilled revenues whereas current liabilities are for the most part related to amounts owed to the IESO for power purchased. There was no significant change with this ratio in 2015 compared to 2014.

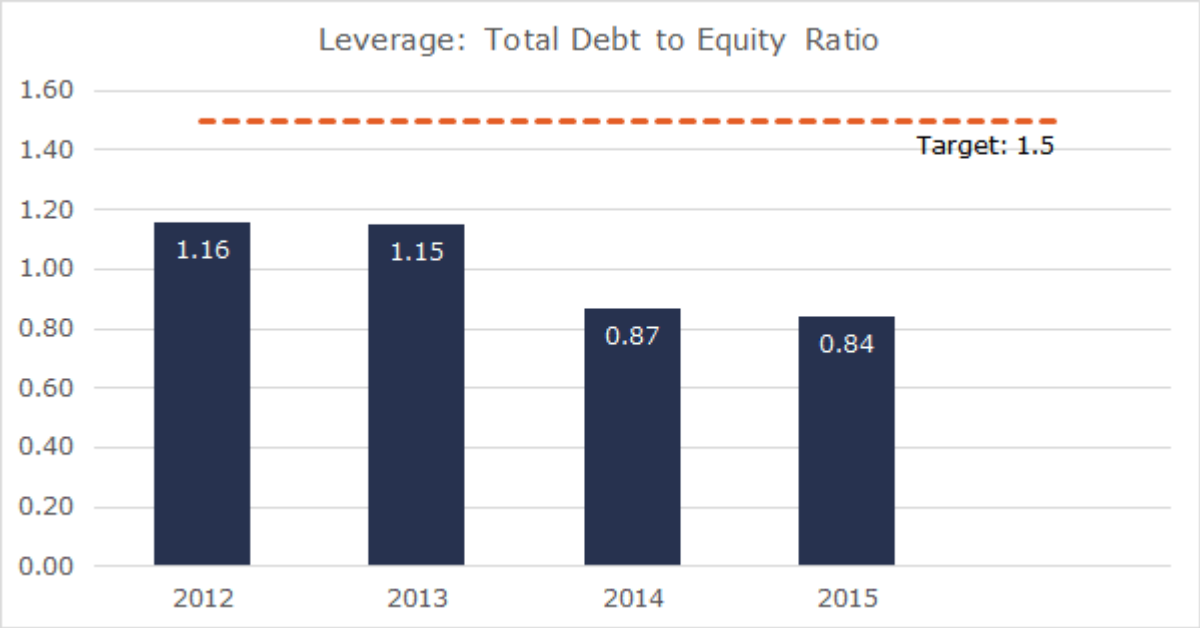
Figure 5-22: Historical liquidity



Leverage: Total Debt to Equity Ratio

WHESC's 2015 leverage ratio of 0.84 indicates that it is currently operating with less actual debt than deemed debt, and has been below the target each year of the historical period. For an LDC, it is imperative to be able to fund capital expenditures to maintain the reliability of the distribution system. WHESC's current and forecasted capital expenditures exceeds depreciation amounts. The excess in capital spending over deprecation is currently being funded thru cash reserves. Maintaining WHESC's current profitability levels and current dividend policy are necessary to ensure that sufficient profits are generated and retained so that debt/equity ratios are not negatively impacted.

Figure 5-23: Historical debt to equity ratio



Profitability: Regulatory Return on Equity

Over the historical period, WHESC's achieved return on equity has been within 3% of the value included in rates, as per its target. WHESC's current distribution rates were approved by the OEB and include an expected (deemed) regulatory return of 8.93%. WHESC's achieved return in 2015 was 8.72%, slightly below its deemed rate of return of 8.93% but well within the +/- 3% allowed by the OEB. Capital expenditures in 2015 continued to exceed depreciation levels and has increased the deemed equity year over year contributing to the slightly lower return rate. WHESC has also produced sustainable OM&A savings during the past few years that have contributed to maintaining its deemed rate of return at regulatory returns in 2015.

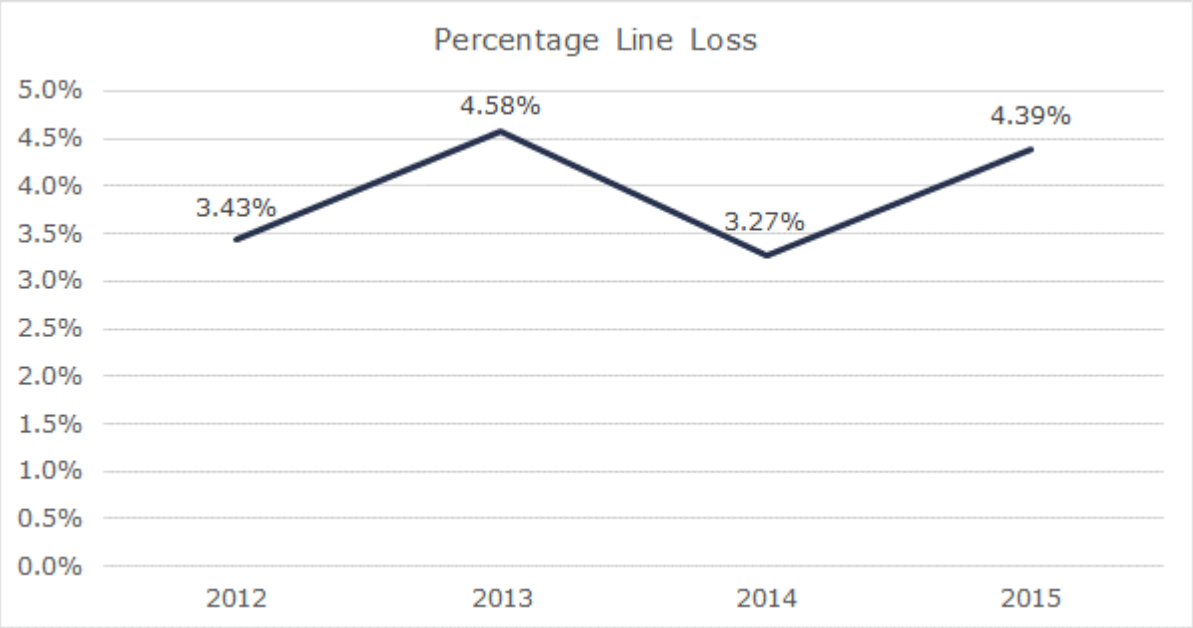
Table 5-12: Historical deemed and achieved return on equity

Year	2012	2013	2014	2015
Deemed Return on Equity	8.01%	8.93%	8.93%	8.93%
Achieved Return on Equity	6.73%	10.5%	9.98%	8.72%

5.2.3c.11 Distribution Losses

As shown in Figure 5-24, the percentage line loss fluctuates between years due to factors outside of WHESC's control, such as ambient temperature. The percentage line loss was 4.39% in 2015, which is higher than 2014, but lower than the previous three-year high of 4.58%.

Figure 5-24: Historical percentage line loss



5.2.3c Effects on the DSP

5.2.3c.1 Service Quality

WHESC's service quality metrics have all historically been above target and WHESC expects to maintain this performance. These results have not had any effect on the DSP.

5.2.3c.2 Customer Satisfaction

As per its corporate vision, WHESC has a high standards for customer satisfaction. WHESC's DSP is in tune with customer preferences and needs, which are a reliable source of electricity at a reasonable price. WHESC has planned a number of investments in the System Renewal category to replace assets at the end of their service life and System Service investments into SCADA technology. These investments are expected to maintain system reliability at an acceptable level, while keeping rate increases reasonable and within customers' expectations. Indeed WHESC's customer engagement (see Section 5.4.2d) confirmed that the level of proposed rates was reasonable and supported by WHESC's customers.

5.2.3c.3 Customer Bill Impacts

All of WHESC's investments have been planned, paced, and prioritized with customer bill impacts in mind. Projects have been deferred to limit the bill impact to the amount proposed in this DSP, in order to keep rate increases reasonable and within customers' expectations. As stated above, WHESC's customers agree with the reasonableness of the proposed rates and generally support the rate increase.

5.2.3c.4 Power Quality

Table 5-8 shows that there are no unresolved power quality complaints and, therefore, WHESC has not proposed any investments to address power quality. WHESC will continue to operate its system within the voltage limits prescribed in the CSA/CAN3-C235 and will work with customers to identify and resolve any issues that may arise in the future.

5.2.3c.5 Safety

WHESC's performance in safety measures indicate no deficiencies. WHESC will continue to promote electrical safety in the community through the use of elementary school safety programs and a variety of electrical safety radio campaigns. WHESC will continue to comply with Ontario Regulation 22/04 and will continue to engage in safe work practices. Projects in the System Renewal category, especially Miscellaneous Pole Replacements and Miscellaneous Transformer Replacements, replace end-of-life assets which would otherwise pose a safety risk without proper investment.

5.2.3c.6 System Reliability

WHESC has achieved better reliability than targeted each year since 2014. Continued investment is required into WHESC's system in order to maintain reliability at present levels and meet future targets. Investment in the System Renewal category are designed to replace assets at their end-of-life in order to maintain system reliability. SCADA investments in the System Service have been planned to improve the operability of WHESC's system and are expected to reduce outage durations. Asset maintenance programs and other programs such as vegetation control will continue to maintain system reliability. New maintenance programs, capital spending, and outage management system initiatives will continue to be evaluated with the goal of continuous improvements. Indices are reviewed regularly to identify negative trends in feeder performance.

Figure 5-17 and Figure 5-18 indicate that defective equipment outages caused a significant number of customer interruption hours in 2015. Much of this can be attributed to insulator failures and WHESC implemented a program to replace multiple porcelain clamp-type insulators. Switches and underground cables are also a critical contributors to defective equipment outages. Overhead rebuild projects in the System Renewal category and SCADA investments in the System Service category all replace switches and are driven by reliability. Underground rebuilds are designed to maintain system reliability by replacing end-of-life cables and the number of failures of a cable segment is one of the inputs to selecting and prioritizing underground rebuild projects.

5.2.3c.7 DSP Implementation Progress

The DSP has been carefully planned such that the targets in DSP implementation progress targets can be met.

5.2.3c.8 Cost Control

WHESC has met all of its targets in cost control. A number of cost saving measures listed in Section 5.2.1b have been adopted to reduce customer bill impacts, and WHESC is constantly looking for ways to improve its

operational efficiency. WHESC will continue to implement productivity and improvement initiatives as well as continuing to "level" capital replacement spending programs. WHESC is committed to service both new and existing customers at reasonable costs while maintaining or improving reliability.

5.2.3c.9 CDM Program Achievements

WHESC has planned various CDM program roll-outs and initiatives in order to meet its CDM target, including some on-going projects, but this has not affected the DSP.

5.2.3c.10 Financial Ratios

WHESC's capital expenditure planning process considers its financial ratios in order to ensure the financial stability of the organization.

5.2.3c.11 Distribution Losses

Whenever planning an overhead or underground rebuild project, WHESC considers whether the area can be converted from 4.16 kV to 27.6 kV and projects are scored higher if the area can be converted. Several of the projects planned over the forecast period are conversions. Replacements of substation and distribution transformers, which often reduce losses since the new transformers meet the latest energy efficiency standards, have also been planned over the forecast period.

5.3 Asset Management Process

As noted in the Introduction, a distributor's asset management process is the systematic approach used to plan and optimize ongoing capital and operating and maintenance expenditures on its distribution system and general plant. The purpose of the information requirements set out in this section 5.3 is to provide the Board and stakeholders with an understanding of the distributor's asset management process, and the direct links between the process and the expenditure decisions that comprise the distributor's capital investment plan.

5.3.1 Asset Management Process Overview

This section provides the Board and stakeholders with a high level overview of the information filed on a distributor's asset management process, including key elements of the process that have informed the preparation of the distributor's capital expenditure plan and therefore are referred to in response to requirements for more detailed information supporting the overall capital expenditure plan, budget allocations to categories of investments, or material projects/activities proposed for recovery in rates. The information provided should include but need not be limited to:

a) 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;

b) 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.***

Use of a flowchart illustration accompanied by explanatory text is recommended.

5.3.1a Asset Management Objectives and Related Corporate Goals.

WHESC operates using the following fundamental asset management objectives when prioritizing OM&A and Capital Expenditures:

1. Address health & safety issues.
2. Address environmental risk.
3. Meet regulatory and legal obligations (including system reliability).
4. Replace end-of-life plant.
5. Improve operational efficiency.
6. Mitigate rate impact to customers.

Table 5-13 below indicates the relationship between the RRFE outcomes and WHESC's corporate goals, asset management objectives, and project ranking criteria.

Table 5-13: Linkage of WHESC's asset management objectives to its corporate goals

RRFE Outcome	Corporate Goal	Asset Management Objective	Ranking
Customer Focus	Providing value to customers	Improve Operational Efficiency	High
Operational Effectiveness	Reliability and resilience	Replace end of life plant	High
		Address Environmental Risk	High
		Address worker Health & Safety Risks	High
		Meet OEB Reliability obligations	Mandatory
Financial Performance	Financial Integrity within OEB tolerances	Improve Operational Efficiency	High
		Meet Legal Obligations	Mandatory
	Balanced approach to capital spending	Mitigate rate impact to customers	High
Public Policy Responsiveness	Public Policy Compliance	Address Public Safety	High
		Meet OEB RRR requirements	Mandatory

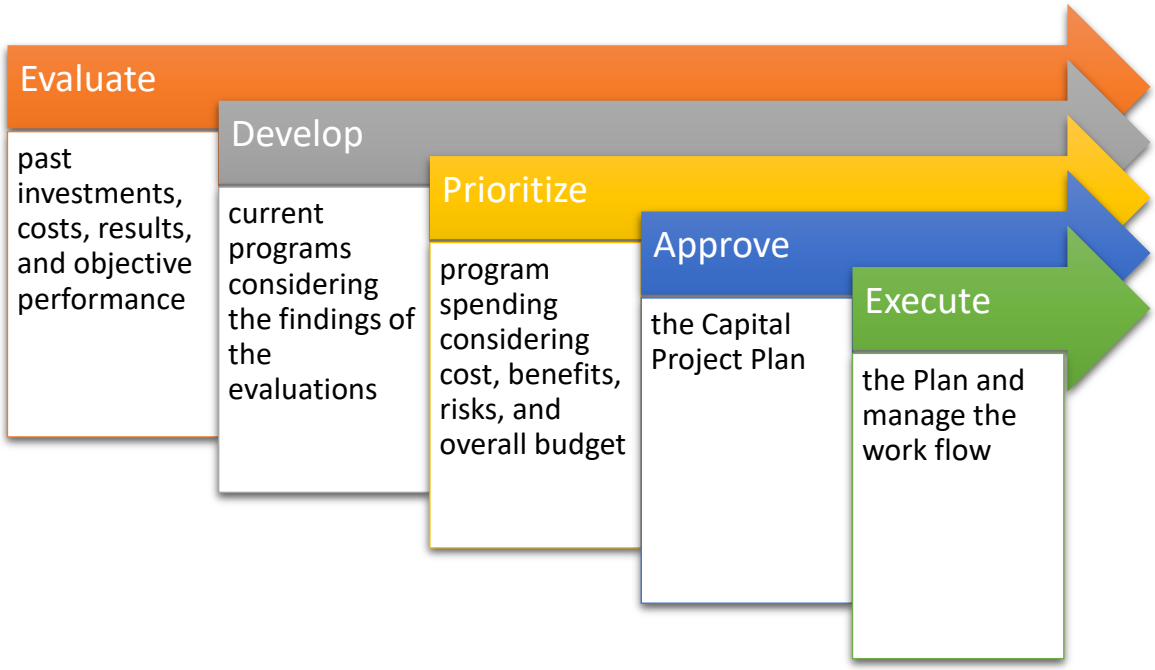
5.3.1b Asset Management Process

The Asset Management Process is used to analyze WHESC's system assets and general plant, in order to determine the optimal amount of capital and maintenance work required to meet the asset management objectives (Figure 5-25 below). WHESC's asset management process follows good utility practices within its inspection and maintenance programs and its approach to documentation and data analysis, managing information and development of the capital and operations and maintenance budgets. Implementation of this asset management process allows for an organized program for inspection, assessment, and remediation of assets within the overhead distribution system, underground distribution system, and substations.

Figure 5-25: WHESC's asset management objectives drives its asset management process

The overall asset management process is driven by the six asset management objectives. It includes steps to ensure that, year over year, asset information, evaluation criteria, and costing methods remain current. In order to achieve this, WHESC follows the five steps shown in Figure 5-26.

Figure 5-26: WHESC's steps to select, prioritize, and pace investments

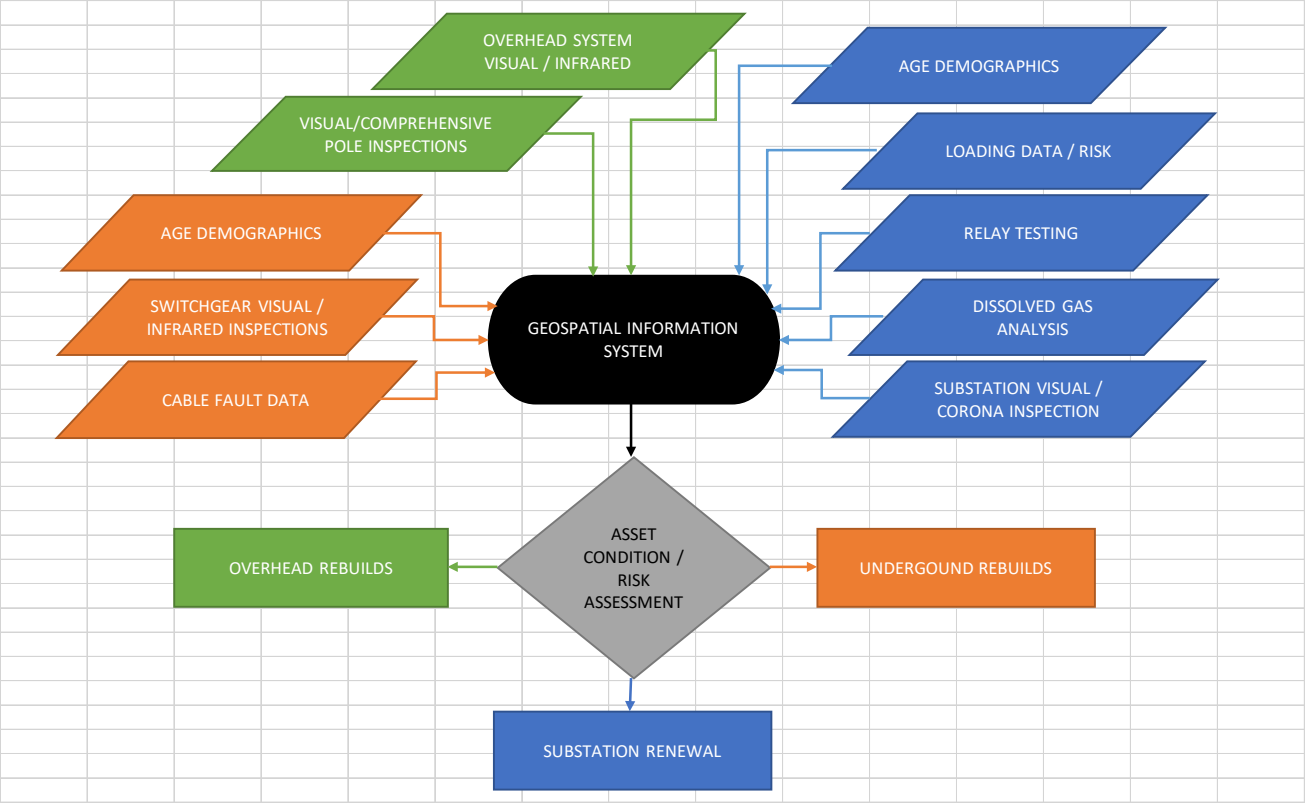


Progress is constantly monitored to ensure that program goals, such as timelines and project budgets are met. Deviations are monitored and approved, and the results of the deviations are collected to aid in the final evaluation of the project before the next cycle begins.

WHESC does not have a formal Asset Condition Assessment process at this time. WHESC plans to incorporate a USF developed program and standards when available. The results of the system inspections and assessments have been combined with both historical performance and age assessments to provide the tools to make prudent decisions on prioritization for the replacement of assets. Both data analytics and graphical analytics are tools that have been utilized to demonstrate a clear and consistent approach to assessing and scheduling for the replacement of assets.

WHESC's asset management process, including inputs and outputs used to identify and select investments has been illustrated in the flowchart in Figure 5-27 and is described in further detail below. For information on project prioritization and pacing, see Section 5.4.2c – Project Prioritization.

Figure 5-27: Inputs/outputs of the asset management process used to identify and select projects



WHESC manages the following major groups of assets, which are each assessed according to unique criteria, relying on critical information stored in its Geo-spatial Information System ("**GIS**"):

- Municipal Substations
- Poles
- Distribution transformers
- High Voltage Switchgear
- Underground Primary Cable
- Fleet
- Land & Buildings
- Supervisory Control and Data Acquisition ("**SCADA**")

Municipal Substations

Substations are scheduled to be replaced based on age demographics, performance data, annual test results, and criticality. More specifically, the following data are analyzed and used in the asset replacement decision making process:

Loading: Monthly Loading Reports are reviewed annually. It is preferable to keep overall station loading at an optimal level that allows flexibility for power restoration should any one single station be forced out of service. This concept also reduces temporary station overloading to a minimum, potentially extending the in service life of the equipment.

Age: Typically the older the transformer and related equipment, the higher the priority.

Load Risk: Transformers servicing larger quantities of customers, commercial or industrial customers or high priority customers will be considered for additional priority in ranking.

Physical Condition: The potential risk of any abnormal physical conditions is considered during the ranking.

Transformer Oil Analysis: Dissolved Gas Analysis ("**DGA**") is used to determine the overall internal condition of the transformer and quantifying the results, in a determination of the estimated reasonable end of useful life. Recommendations for remediating anomalies or concerns identified during transformer oil analysis as presented to WHESC may include no action/observing, re-testing or replacing, for example. WHESC generally follows the recommendations and implements those condition-based maintenance recommendations or capital expenditures and within the recommended timeline.

Relay Testing: During relay testing, critical deficiencies are reported immediately and WHESC endeavors to remediate immediately. Non-critical deficiencies are subsequently remediated through condition-based maintenance. In each case the remediation is documented in a relay and breaker maintenance record and in the SCADA system records for that station.

Corona and Arcing Detection: Corona and arcing detection is primarily used to pinpoint sources of partial discharge and identify probable faulty components or components in deteriorating stages. The presence of corona discharge may also indicate impending failure of insulating materials that can cause flashovers and outages. After Corona testing any non-critical deficiencies or concerns that have been identified (either related to corona discharge or other) are reported to WHESC for remediation.

Performing all of the above functions promotes efficiency and costs savings resulting from maximizing the useful life of the equipment and having sound data to determine the reasonable amount/size of equipment required when planning for equipment replacement at the useful end of life for existing assets.

Poles

Poles are scheduled for replacement based on condition assessments of the pole, an overall condition assessment of the distribution system that is supported by the poles, and other system requirements. When poles are scheduled for replacement, additional pole height requirements for future expansions or conversions is considered to reduce future costs.

Poles are assessed through systematic inspection and testing programs. All assessments are gathered and analyzed to ensure that the data is complete, accurate and consistent. The result allows for the scoring and ranking of all projects within the five-year capital asset replacement window. Projects meeting the materiality threshold are identified individually in the capital plan and the remaining projects are captured in the miscellaneous and overhead categories.

Where deficiencies or concerns exist, a copy of the pole picture, comments, and an overview of the deficiency and/or concern is forwarded to WHESC Line Department. A Journeyman Lineman performs an additional inspection, particularly with items that present imminent failure or pose a risk to health, safety, the environment, reliability or WHESC legal or regulatory obligations. Such critical, high-priority deficiencies are addressed immediately. Non-critical deficiencies, defined as all other deficiencies or concerns, are addressed after high-priority items and through condition-based maintenance or are directed into a capital program, such as a rebuild, if applicable.

Poles are replaced during overhead rebuilds, as well as WHESC's pole replacement program. Although the number of poles replaced per year depends on the capital program being executed and the results of the pole assessments, WHESC tries to balance its approach, using a planned and paced process, to the total number of poles replaced on an annual basis.

Distribution Transformers

Distribution transformers are assessed through visual and infrared inspections. WHESC-owned transformers that service large or sensitive customers also undergo DGA. Distribution transformers are generally run to failure, but may also be replaced sooner if there is a system benefit such as a reduction of system losses through

voltage conversion. Age of assets is tracked to forecast potential future increases in the amount of transformers that may require replacement.

In 2007, WHESC began collecting oil samples from overhead and underground transformers manufactured prior to 1986 to determine the amount of polychlorinated biphenyls ("**PCB**"s). PCBs, a common dielectric and coolant fluid, are toxic compounds classified as a persistent organic pollutant. As such, the Government of Canada has established PCB Regulations that came into force in 2008 and have since been amended and in force in March, 2010. The PCB Regulations allow for the use of transformers with less than 50mg/kg. However, the PCB Regulations require transformers to be removed from service with concentrations greater than 50mg/kg, according to a schedule based on concentration and location of the transformer. WHESC has complied and continues to comply with the regulations and as of December 31, 2014 all known PCB contaminated transformers have been removed from WHESC's system.

High Voltage Switchgear

High voltage switchgear are assessed considering age, inspection results, performance, and criticality to determine when the units have reached end-of-life and require replacement. Critical deficiencies identified during inspection of the switchgear units, such as missing or damaged penta-head bolts, are documented and also immediately remedied during inspection, provided materials are on hand at such time.

Underground Cables

Cable replacement is dictated by performance, age, criticality, and system benefits such as reduction of system losses through voltage conversion. The age of assets is tracked to forecast potential future increases in the amount of cabling that may require replacement.

If an outage is caused by a primary or secondary underground cable failure, an Underground Fault Record is recorded in the GIS, along with the cable age. This data is used for assessing cable performance and prioritizing replacements.

Figure 5-28: Example of a primary cable fault depiction in the GIS

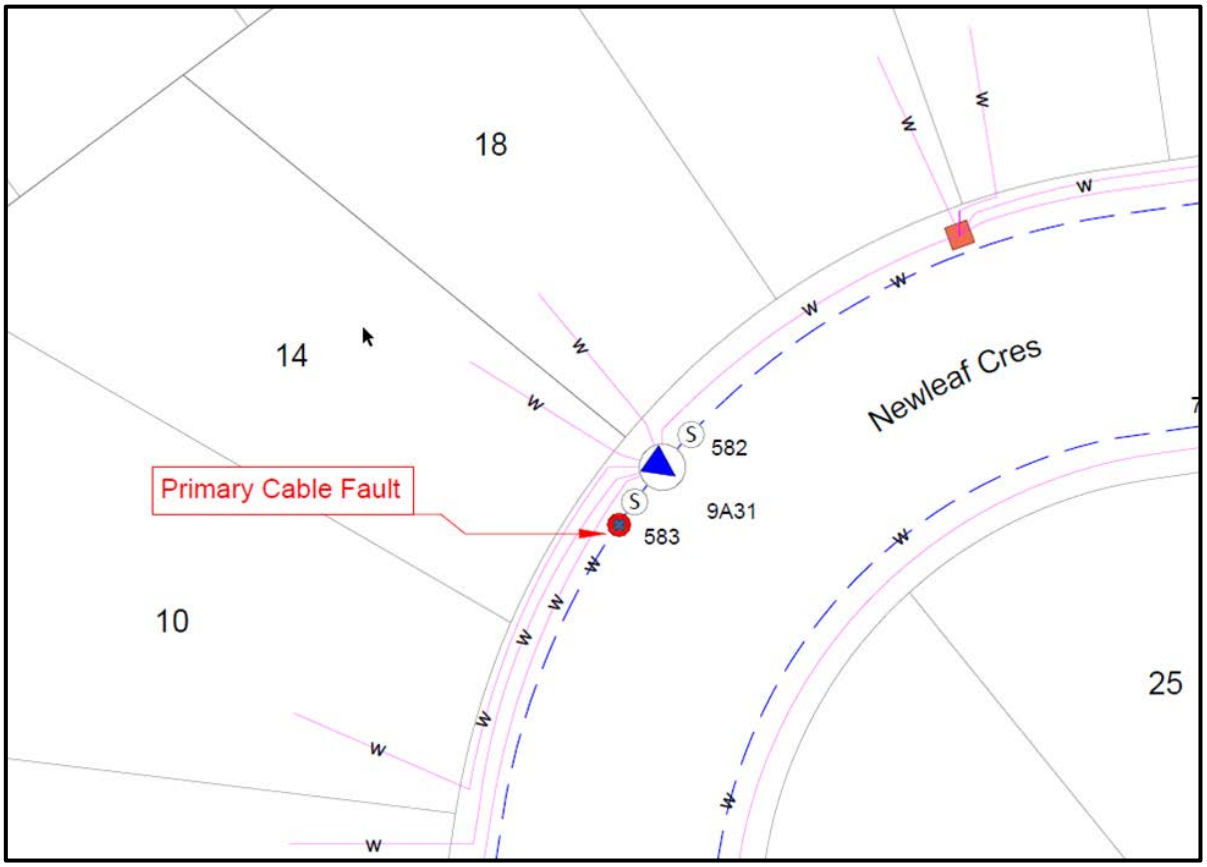
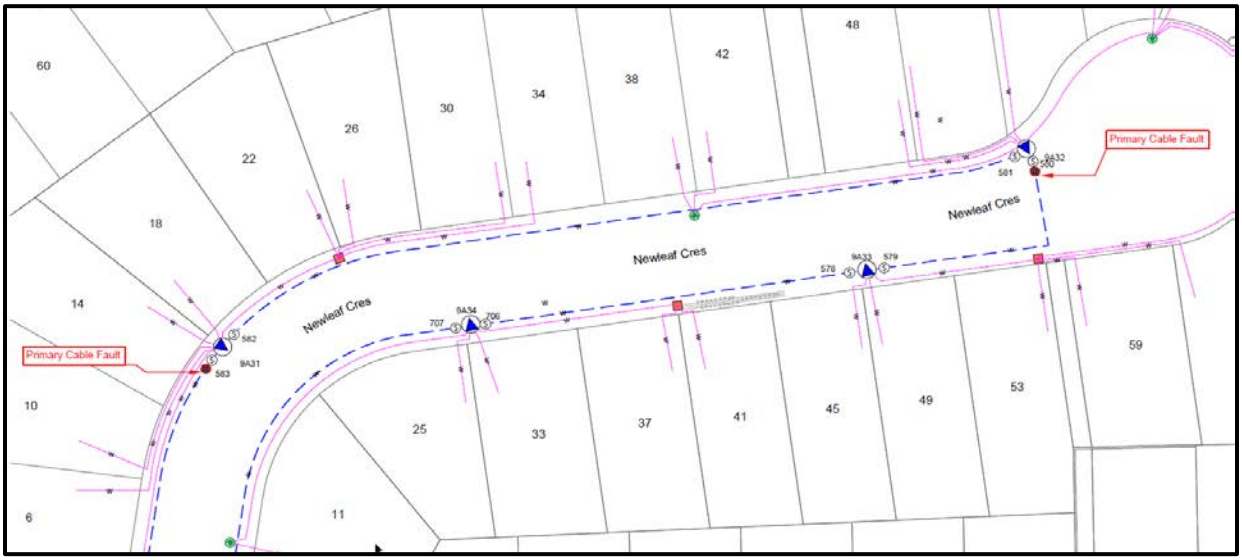
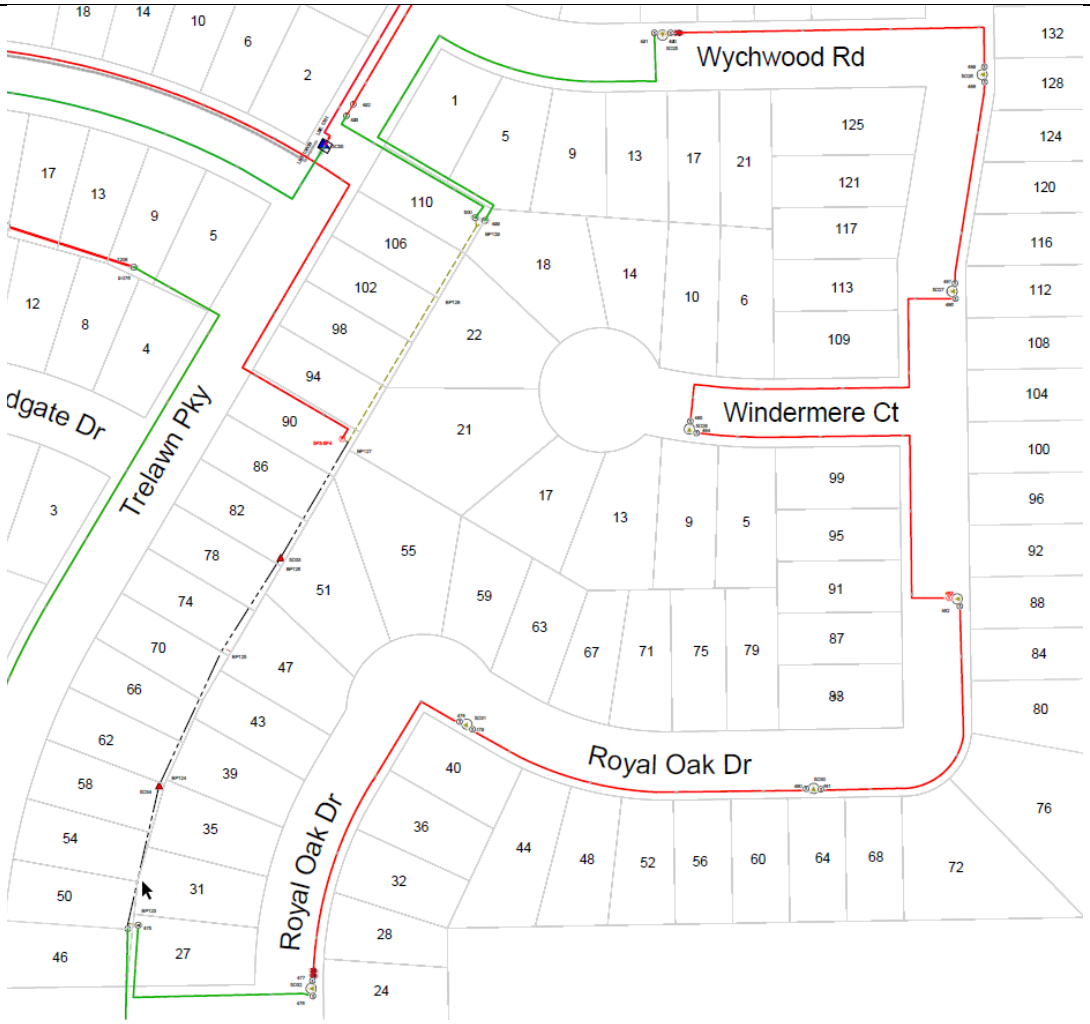


Figure 5-29: Multiple cable faults depicted in the GIS



WHESC's GIS also stores cable age information that is used for project planning purposes, as depicted in Figure 5-30.

Figure 5-30: Cable age depicted in WHESC's GIS



Cable Age: (Solid coloured lines)
Green: 1988 to Present
Yellow: 1977 to 1987
Red: Up to 1976

The reliability data along with cable age is collected and presented graphically and in table format to assess and score projects for capital planning. Cable performance can vary and cables are left in service as long as possible to prevent unnecessary spending.

Land & Buildings

WHESC's building assets include one service centre and three municipal substation buildings, of which the service centre is the most significant asset. It was constructed in 1969 and has the following size characteristics:

- Property size: 8 acres
- Asphalt area: 100,000 square feet
- Office Space: 18,000 square feet
- Stores: 7,000 square feet
- Garage: 20,000 square feet

WHESC has invested money and will continue to invest money in a prudent manner to keep the facility operational without unnecessary cost increases to its customers.

Fleet

WHESC's fleet includes single and double bucket trucks, diggers, pickup trucks, vans and other associated equipment. Condition assessments and records of vehicles maintenance costs are used to assist in determining the end of useful life of a vehicle. Vehicles are replaced based on safety, maintenance costs, and performance. Consideration is also given to the gains in safety and performance due to technological advancements in new vehicles.

Vehicles that are used for the higher risk work, namely bucket trucks, are given additional safety assessment rankings based on the type of high risk work they are used for and tend to be replaced sooner than the other large digger trucks. However, all vehicles remain in service as long as possible to reduce overall capital replacement costs.

Regular maintenance extends vehicle life. Vehicles are typically replaced using the guidelines presented in Table 5-14.

Table 5-14: Vehicle replacement guidelines based on age

Vehicle Type	Typical Useful Life
Small vehicles; pickup trucks and vans	10 to 12 years
Large vehicle; bucket and digger trucks	15 years
Trailers and other equipment:	20 years

SCADA

WHESC installed its first SCADA system in the late 1980's. The 1990's saw the majority of SCADA asset installs. The final configuration allowed the control room to retrieve data, block reclosing devices and operate switching devices at approximately 38 locations within WHESC's 4.16kV and 27.6kV distribution systems.

SCADA devices are fully depreciated after 20 years and SCADA software 5 years. Remote Terminal Unit ("**RTU**") replacements are dictated by performance. In planning for RTU replacements, if station relays are Intelligent Electronic Devices, consideration is given to re-engineer the installation with the intention of eliminating the RTU in its entirety, thereby saving costs.

SCADA communication continues to be an operating cost consideration. Currently, WHESC uses a combination phone lines, wireless radio systems and cellular devices to communicate to in field devices. Projects are underway to test additional wireless systems and data concentrators with the intention of reducing the amount of communication lines and systems.

5.3.2 Overview of Assets Managed

Appropriate regulatory assessment of DS Plans requires an understanding of the scope and depth of the assets managed by a distributor. Distributors vary in terms of the types of assets managed (e.g. some own high voltage equipment; others do not). Detailed characteristics and data on the assets covered by the asset management process are to be filed, including but not necessarily limited to

a) 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;

b) 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;

c) 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; and

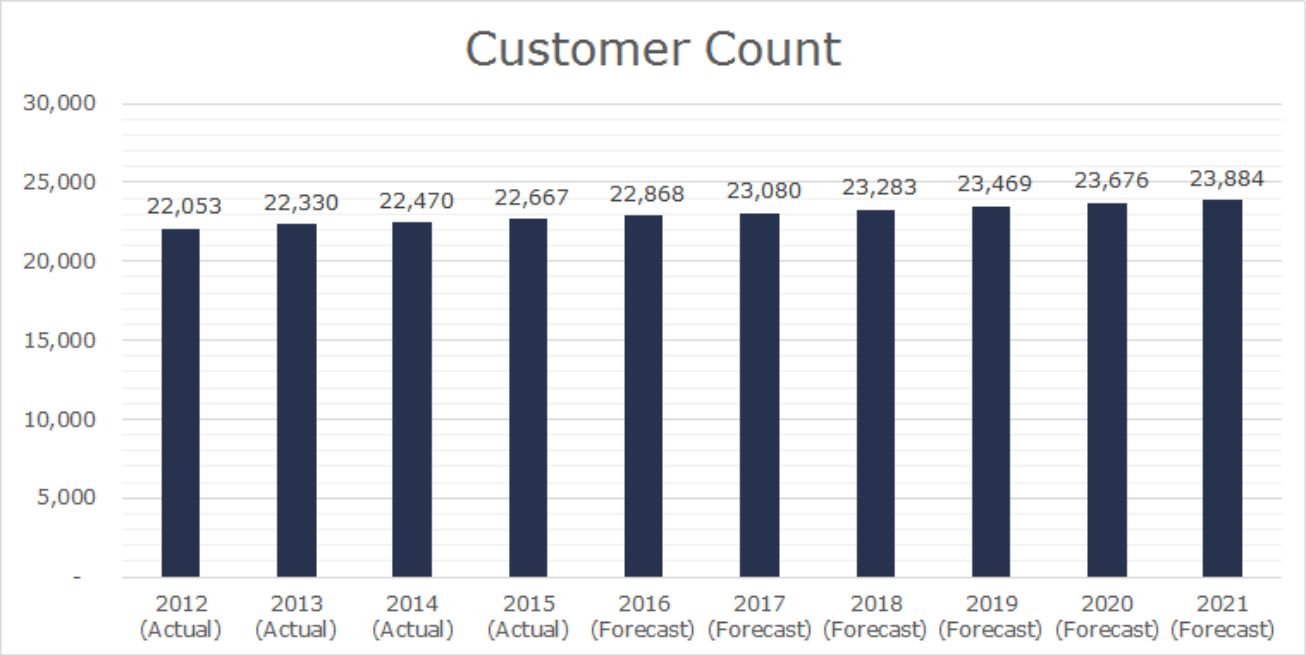
d) an assessment of the degree to which the capacity of existing system assets is utilized relative to planning criteria, referencing the distributor's asset related objectives and targets

- ***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.***

5.3.2a Distribution Service Area

WHESC serves 22,666 customers based on 2015 year-end customer counts, including over 20,700 residential customers. Its service territory covers 81 square kilometres, two-thirds of which is classified as urban and the remaining is classified as rural. Figure 5-31 depicts the historical year-end customer counts and the forecast counts up to 2021. WHESC has been in a period of stagnant economic growth and its Industrial & Commercial Sector has experienced negative growth in the past few years including the loss of the last remaining large use customer in 2014.

Figure 5-31: Actual year-end and forecast customer counts



Located in southern Ontario, WHESC is exposed to severe weather events such as severe wind storms that occurred in 2011 and the ice storm of 2013. WHESC's system is composed of approximately 70% overhead conductors and 30% underground cables.

Based on the forecast growth and service area developments, WHESC has created its metering budgets in System Access category and there is no need to install additional capacity at WHESC's Municipal Substations. Instead, WHESC will focus on replacing end-of-life assets while maintaining a level approach to capital spending.

5.3.2b Distribution System Configuration

WHESC receives power from one Transformer Station that is owned and operated by Hydro One. The station provides eight 27.6 kV feeder breakers to distribute power throughout the city via WHESC's 27.6 kV distribution system. The 27.6kV feeders also provide power to WHESC's thirteen Municipal Substations that step power down to 4.16 kV. Total load on the 4.16kV system continues to decrease, year over year, through end of life asset replacement programs that include voltage conversion. Tables 5-15 A-C below provides details on the significant components of WHECS's distribution system.

Table 5-15A: WHESC's Municipal Substation Capacity/Loading

Municipal Substations	Total Capacity	Total Load (2015)
13	73.9 MW	43.9 MW

Table 5-15B: WHESC's Overhead/Underground Primary Circuity

Operating Voltage	Overhead Primary Circuitry	Underground Primary Circuitry	Number of Feeders
4.16kV	206 km	79 km	43
27.6KV	132 km	63 km	8

Table 5-15C: WHESC's Overhead/Underground Secondary Circuity

Operating Voltage	Overhead Circuitry	Underground Circuitry
<750 volts	436 km	338 km

5.3.2c Distribution System Asset Information

The main categories of distribution assets managed by WHESC are:

- Municipal Substations
- Poles
- Distribution transformers
- High Voltage Switchgear
- Underground Primary Cable

As previously mentioned, WHESC does not have a formal Asset Condition Assessment process at this time, but will roll out the methodology developed by USF in the near future. The results of the system inspections and assessments have been combined with both historical performance and age assessments to provide the tools to make prudent decisions on prioritization for the replacement of assets. Information on asset age and other pertinent information is presented in the succeeding subsections, as compiled at the end of 2015.

5.3.2c.1 Municipal Substations

WHESC currently owns and operates thirteen Municipal Substations. The stations transform the voltage from 27.6kV to 4.16kV and vary in sizes from 3 to 10 MVA. The overall useful life of the substation is contingent upon the useful lives of its constituent components. WHESC finds that the typical useful life of the substation is most related to the useful lives of the transformer and switchgear. This typically places the useful life in the range of 30 to 60 years. Proper maintenance based inspections and equipment testing typically minimizes age effects for asset life, promoting efficiency and cost savings. Historically, transformers being replaced, on average, have been in service for 50 to 60 years.

WHESC owns fourteen transformers at its thirteen Municipal Substations and two large distribution transformers servicing high-demand customers. Table 5-16 summarizes the in-service date, transformer size, 2015 peak load, and tap settings for each of these transformers. The table also includes the in-service dates for the high voltage ("**HV**") and low voltage ("**LV**") switchgear, and primary, secondary, and feeder cables.

Table 5-16: Municipal Substation and large transformer assessment

H:\DrawBase Drawings\dra\Substations\Mixed Dwgs\Substation Transformation Information Cad 398 Rev 8

	M.S. #	TX MAKE	SERIAL #	TX YEAR BUILT	TX SIZE	LOADING 2015	TAPS	TAP	HV Switchgear	LV Switchgear	Indoor outdoor	Primary Cables Year	Secondary Cables Year	Feeder Cables Year	Notes:
	1T1	Ferranti Packard	1704201001	1994	10000	6118	100% to 95% in 2.5% steps	2	1999	1994	Outdoor	1994	1994	1994	RELAY UPGRADES 2013–2017
	2T1	Moloney	202053–1	2007	3000	1752	105% to 95% in 2.5% steps	100%	N/A	2008	Outdoor	2008	2008	2008	Load reduction 2014–2016
	3T1	Westinghouse	A3S6683	1982	7500	5719	28.29 to 25.53 in 2.5% steps	3 (97.5%)	1983	1983	Outdoor	N/A	N/A	1983	3F4 cables replaced 2004
	4T1	Northen Transformer	01–1623	2001	8000	5871	27.6 to 24.8 in 2.5% steps	2	2003	2003	Outdoor	2003	2003	2003	
	5T1	Moloney	297811	1977	5000	1980	27.6 to 24.8 in 2.5% steps	3	1996	1996	Outdoor	1996	1996	1996	
	5T2	Moloney	T5971–1	2007	3000	2900	4 AN 12 BN	100%	N/A	1996	Outdoor	2016	2016	1996	
	6T1	Moloney	204291–1	2012	3000	1903	105% to 95% in 2.5% steps	100%	N/A	1979	Outdoor	2012	2012	1979	SOLID STATE FEEDER RELAY
4	7T1	CGE	285507	1964	5000	3323	27.6 to 24.8 in 2.5% steps	2	1964	REBUILT 2016	Indoor	1992	2011	2016	SOLID STATE RELAYS
2	8T1	CGE	286100	1966	5000	2219	27.6 to 24.8 in 2.5% steps	?	1966	1966	Outdoor	N/A	1991	1966	8F1/8F3–1985 2014–2017 LOAD REDUCTION 2018 REBUILD
3	9T1	CGE	287474	1969	5000	3777	27.6 to 24.8 in 2.5% steps	2	1969	1969	Indoor	1969 ?	1969 ?	1969 ?	9F1–1992
	10T1	Moloney	3662–1/ 9101–1	1992	8000 10666	5148	27.6 to 24.8 in 2.5% steps	3	2016	1978	Indoor	1978	1992	1978	LOAD REDUCTIONS 2014–2018 SWITCHGEAR 2016
	11T1	Moloney	204291–2	2012	3000	1129	105% to 95% in 2.5% steps	100%	N/A	2007	Outdoor	2007	2007	2007	
	12T1	Moloney	206608–1	2015	3000	1460	27.6 to 24.8 in 2.5% steps	1 (27.6%)	N/A	1998	Outdoor	2015	2015	1998	2015 NEW PRIMARY & SECONDARY
1	14T1	CGE	285005	1963	5400	640	?	2	1963	1963	Indoor	N/A	N/A	1984	2017 REBUILD
	20S18D (C–132)	Westinghouse	A31S0894	1977	3000	?	?	?	1977	N/A	Outdoor	N/A	N/A	2003	
	20S28D (C–131)	Westinghouse	B31S0959	1977	2000	?	?	?	2007	N/A	Outdoor	N/A	N/A	2007	

Total 4KV LOADING = 43939

1. Replace all station assets – 2017
2. Replace all station assets – 2018
3. Upgrade LV Gear & Feeder cables – 2019
   Replace transformer & HV Cables – 2022
4. Replace transformer – 2020

Marked in Red Ink – Replacement within 1 to 5 years
Marked in Yellow Ink – Replacement within 6 to 15 years
Marked in Green Ink – Replacement greater than 15 years

Original DWG # 249 was renamed & replaced by Cad 398

KB	KB	KB	KB	KB	KB	KB	KB	KB
SP	SP	SP	SP	SP	SP	SP	SP	SP
8 REV. July/2016	7 REV. Sept/2014	6 REV. July/2014	5 REV. Dec 2012	4 REV. MAR/2011	3 REV. JULY/2005	2 REV. DEC/2002	1 REV. NOV/2000	

WELLAND HYDRO ELECTRIC SYSTEM CORP.

SUBSTATION INFORMATION

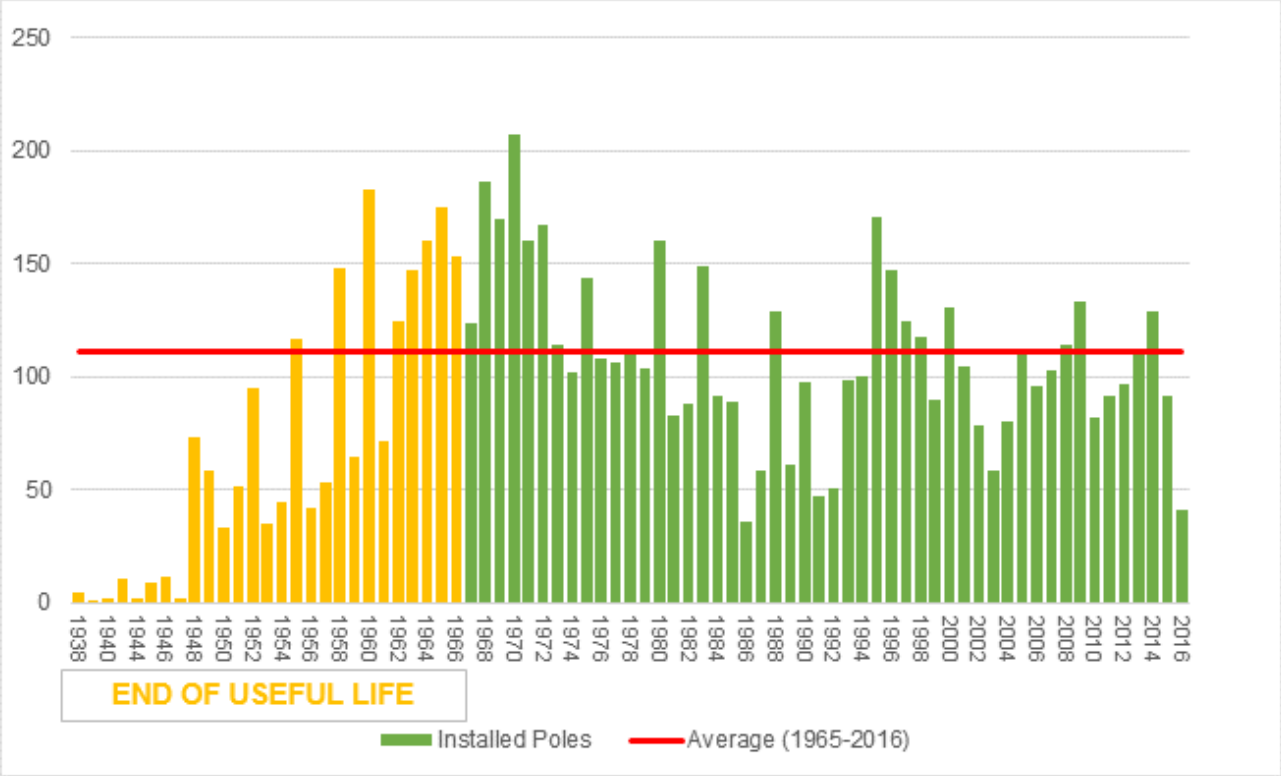
Drawn:Salvatore Pino | CHECKED: KB | PASSED: LP

DWG NO CAD 398 | DATE DEC 11, 2002 | SCALE 1 : 1

5.3.2c.2 Poles

WHESC owns approximately 8,000 wood poles. Poles are fully depreciated after 50 years but can last many years longer depending on many factors including material, treatment and environmental conditions. Figure 5-32 below illustrates the number of poles currently in service, the quantity for each year, and the average age of poles currently in service.

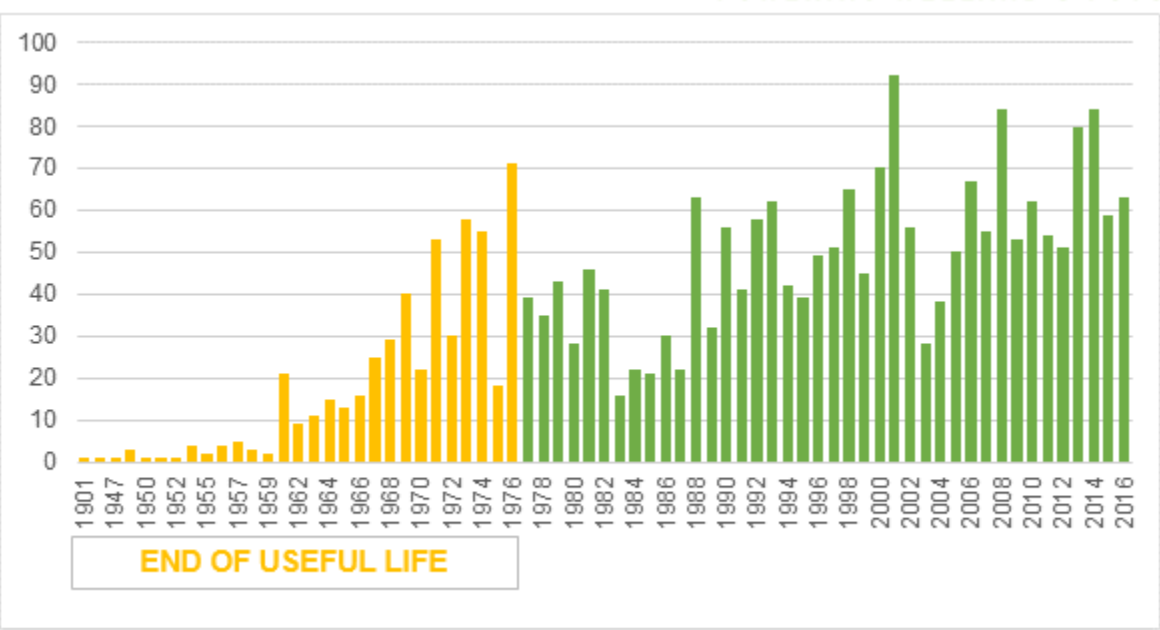
Figure 5-32: In-service dates of wood poles



5.3.2c.3 Distribution Transformers

WHESC owns approximately 2,300 distribution transformers ranging in size from 5 to 1500 kVA. Transformers are fully depreciated after 40 years but are replaced immediately on failure or typically if they have any deficiencies that introduce risk. Figure 5-33 illustrates the number of transformers in service and the quantity installed each year.

Figure 5-33: In-service dates of distribution transformers



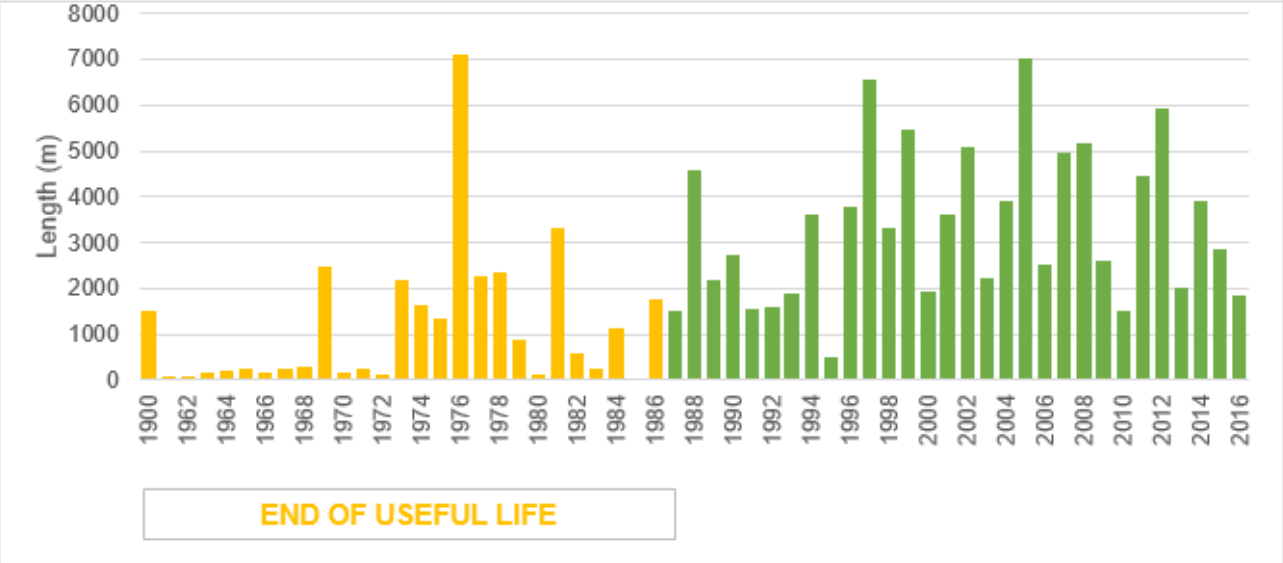
5.3.2c.4 High Voltage Switchgear

WHESC owns seventeen 27.6 kV pad-mounted switchgear units in the system, all of which have been installed within the last twenty years. The units are fully depreciated after 35 years.

5.3.2c.5 Underground Primary Cable

WHESC owns approximately 142 km of primary underground cable. Although the asset is fully depreciated after thirty years, WHESC has primary cable in service that is greater than 40 years old. Figure 5-34 illustrates the amount of cable in service and the quantity installed each year.

Figure 5-34: In-service dates of primary underground cable



5.3.2d System Utilization

WHESC's system utilization was assessed based on the capacity of the Transformer Station, the 27.6 kV and 4.16 kV feeders, and Municipal Substations to maintain existing service and provide future connections for load and generation customers.

Transformer Station

WHESC does not own the Transformer Station that supplies its service territory; however, it has been determined through data collection and Regional Planning, that the Transformer Station is expected to have adequate capacity for future load and generation connections.

27.6 kV and 4.16 kV Feeders

WHESC monitors peak loads on both the 27.6 kV and 4.16 kV distribution feeders. Based on expected minimal growth, there are no feeder constraints requiring significant capital investment during the forecast period.

Municipal Substations

Table 5-16 in Section 5.3.2c.1 presented the 2015 peak load for each Municipal Substation and Table 5-17 presents the summed peak load and capacity for the 13 Municipal Substations. Municipal Substations have no capacity issues and it is preferred that all new loads and generation connect directly to the 27.6kV feeders.

Table 5-17: Total capacity and 2015 peak load of WHESC's Municipal Substations

Number of Municipal Substations	Total Capacity	Total Load (2015)	Load as % of Capacity
13	73.9 MW	43.9 MW	59%

5.3.3 Asset Lifecycle Optimization Policies and Practices

An understanding of a distributor's asset lifecycle optimization policies and practices will support the regulatory assessment of system renewal investments and decisions to refurbish rather than replace system assets. Information provided should be sufficient to show the trade-off between spending on new capital (i.e. replacement) and life-extending refurbishment, and should include but need not be limited to:

a) 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).***

b) 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.

5.3.3a Asset Lifecycle Optimization Policies and Practices

WHESC optimizes asset lifecycles by performing inspections to monitor the health of distribution system assets. The practice includes performing preventative maintenance where necessary and financially prudent, or proactively replacing key assets at end of life.

5.3.3a.1 Asset Replacement/Refurbishment Policies

Assets, for which replacement of the asset or reconstruction of the surrounding system is identified as the most ideal solution, will be replaced. For assets where replacement is not deemed to be the ideal approach, WHESC's will attempt to economically extend the assets life. Asset replacement is levelled to minimize capital spending peaks and valleys. The levelled replacement schedule is used in the project prioritization and selection process to identify the optimal assets that should be replaced and to remain within budget limits.

Assets may be replaced as a result of failure or in response to a trouble call. Assets that cannot be repaired, or repairs determined to not be financially prudent, will be replaced. The impact of replacement and repair decisions on Operating and Maintenance ("**O&M**") costs is considered during the project selection and prioritization process. All applicable asset management objectives and related RRFE outcomes are considered when evaluating and scoring projects.

To further reduce costs, WHESC assesses whether assets removed from the field can be returned to its warehouse rather than scrapped based on its Material Returns Policy.

5.3.3a.2 Maintenance Planning Criteria and Assumptions

WHESC plans maintenance and inspection activities on an annual basis. Budgets for maintenance activities are informed by historical costs for repairing various asset types, as well as historical inspection costs. WHESC has recognized the benefits of various maintenance practices for improving reliability, reducing costly emergency expenditures and to preserving the integrity of its distribution system and has therefore implemented predictive, preventive, and condition-based maintenance practices, to varying degrees. These practices are defined and as follows:

- **Predictive Maintenance:** activities that detect changes in the physical condition of equipment (signs of failure) in order to execute appropriate maintenance (e.g. condition-based maintenance) or capital planning. Predictive Maintenance activities include thermographic infrared inspections, transformer dissolved gas analysis, comprehensive pole inspections, relay testing, and corona/arcing detection. All vehicles receive annual safety inspections. In addition, all aerial fleet vehicles undergo annual dielectric testing. The backup generator is tested monthly for functionality and receives an annual load test.

- **Preventive Maintenance:** maintenance performed at predetermined intervals or according to prescribed criteria and intended to reduce the probability of failure. Preventive Maintenance activities include vegetation management, visual pole/transformer inspections, and high voltage switchgear dry ice cleaning.

- **Condition-Based Maintenance:** maintenance performed after indication of impending failure or degradation in performance or condition of the asset. Condition-based maintenance serves to

eliminate opportunity of breakdowns and reduce deviations from optimum asset performance. Condition-Based Maintenance involves repair and or replacement of defective components.

All information reported from the above maintenance activities are retained in the GIS and available for future review or verification if required.

WHESC's system of prioritizing deficiencies identified through inspection and some maintenance practices (e.g. infrared thermography) allows for timely and appropriate corrective action. Critical deficiencies (posing a threat to health, safety, the environment or regulatory obligations) are remediated expeditiously, often at the time or just following inspection. If remediation cannot be performed at such time (due to material lead times, locates, etc.), the asset is temporarily secured. Non-critical deficiency remediation follows; however, if the concern or deficiency may be resolved through a capital project (such as a pole line rebuild), then the deficiency is monitored until such time or address if it becomes higher priority.

5.3.3a.3 Inspection and Maintenance Policies

WHESC's O&M programs are designed to follow the guidelines set out in the OEB's Appendix C of the Distribution System Code for the inspection and maintenance of all key distribution system assets. The programs are reviewed annually to best align with capital programs. Inspection of key assets is paramount to the prioritization of O&M and capital spending. The outcome of the inspection process results in a recommendation to replace, repair or leave as is, allowing WHESC to optimize system renewal investment impact.

Municipal Substations

Substations are inspected monthly by qualified staff. The inspection incorporates an assessment of the following:

- Feeder Readings
  - Amperage on each phase
  - Voltage on each phase
  - Counter Reading
- Substation Monthly Readings
  - Total KWH
  - Maximum KW
  - Maximum KVA
- Transformers
  - Temperature
  - Oil Level
  - Leaks
- Vegetation
- Electrical Panel
- Receptacles and Light Switches
- Indoor & Outdoor Lighting Fixtures
- Battery Chargers and Batteries
- RTUs
- Cooling Fans
- Sump Pump
- Baseboard Heaters
- Station Lights
- Grounding
- Station Security
  - Fence
  - Signs

DGA is performed annually for power transformers at each of WHESC's thirteen Municipal Substations. Oil samples obtained by a contractor annually are subsequently sent to a laboratory for testing; the results of

individual transformer oil analysis are provided to WHESC. The lab provides a report of the results, highlighting any anomalies/concerns that may exist and corresponding recommendations for remediation. Lab results are also compiled electronically into a database that provides historical test results for each transformer such that results may be compared and analyzed year-to-year. Condition-based maintenance may result from the DGA results.

Testing of both electrical and mechanical relays is performed on a three-year cyclical basis by a qualified contractor at each of the Municipal Substations. WHESC provides the relay settings to the contractor and relies on the contractor's expertise in performing the testing. Condition-based maintenance may result from the relay testing.

High Voltage substation equipment is tested each year using both infrared thermography and an ultrasonic system to detect corona discharge. Corona discharge is caused by corrosive materials that reduce the life of various asset components, but in particular insulating materials. The presence of corona discharge may also indicate impending failure of insulating materials that can cause flashovers and outages. Testing is performed by a qualified contractor who is accompanied by a Welland Hydro Journeyman Lineman to provide access to the Municipal Stations. During testing, the Journeyman Lineman is also performing a secondary inspection, observing any non-corona related deficiencies. After Corona testing any non-critical deficiencies or concerns that have been identified (either related to corona discharge or other) are reported to WHESC for remediation. A report is then created summarizing the station and concern, together with pictures, and is subsequently provided with a work order to the Line Department.

Overhead Systems

Poles and pole hardware are inspected on a three-year rotating cycle. Once every nine years the pole also undergoes a comprehensive assessment that includes the testing and analysis of the poles internal condition above, at and below ground level. Where deficiencies or concerns exist, a copy of the pole picture, comments, and an overview of the deficiency and/or concern is forwarded to WHESC's Line Department. A Journeyman Lineman performs an additional inspection, particularly with items that present imminent failure or pose a risk to health, safety, the environment, reliability or WHESC's legal or regulatory obligations. Such critical, high-priority deficiencies are addressed immediately. Non-critical deficiencies, defined as all other deficiencies or concerns, are addressed after high-priority items and through condition-based maintenance or are directed into a capital program, such as a rebuild, if applicable.

Thermographic infrared inspection is an integral component of WHESC's predictive maintenance practice for assessing distribution transformers and overhead switches. Distribution transformers are inspected for deficiencies such as rusted or leaking transformers. Overhead switches and other protective devices are inspected for deficiencies such as loose, flashed or old switches, each of which may deteriorate the condition of the asset, pose a risk to safety, or reduce reliability of the overhead distribution system. Condition-based maintenance to remediate critical deficiencies are performed immediately following identification. Similarly, non-critical deficiencies are remediated through asset repair or replacement.

WHESC hires a qualified contractor to perform tree trimming on a three-year cycle. There are occasions for which vegetation management is required outside of the predetermined intervals, such as following a storm or in response to customer requests for tree or limb removal in proximity to power lines.

Underground Systems

Pole-Tran and pad-mount transformers are inspected on a two-year cycle during WHESC's thermographic imaging program. During the inspection, transformers are imaged to identify temperature variances, or 'hot spots'. Hot spots, representing deficiencies of the transformer or its peripheral attachments such as bushings, are categorized as minor, intermediate or severe, the latter of which is considered critical and represents a risk to health, safety, the environment or reliability. Each transformer is opened; a picture of the transformer is then taken, attributes confirmed and the transformer's condition is assessed for concerns or deficiencies. As deficiencies may not be identified by visual assessment alone thermal imaging is also performed. Deficiencies or concerns (critical and non-critical) identified through either process are documented as comments on the transformer check list.

During the inspection of Pole-Tran and pad-mount transformers, all identified deficiencies are documented on a transformer check list. Those deficiencies identified as critical (that is, presenting a risk to health, safety, the environment, or reliability) by the WHESC Journeyman Lineman are reported immediately; examples of critical deficiencies of underground transformers include missing locks or complete corrosion resulting in access to live parts. Condition-based maintenance of critical items is such that Welland Hydro attempts to repair the deficiency or replace the defective component (or unit) at the time of inspection to mitigate continued deterioration of the asset, its performance and prevent complete failure. Remediation may be subsequently noted on the transformer check list.

27.6 kV switchgear units are inspected and maintained on an annual basis, including dry ice cleaning. Dry-ice cleaning is performed for those PMH switchgear units identified as contaminated, or dirty, during visual inspection. Units that are exposed to dust, dirt or other contamination may be subject to dielectric breakdown which causes tracking and damage to the unit; the result may be an outage on the unit. During the inspection of these devices cosmetic deficiencies are also noted on the inspection forms. Cosmetic deficiencies may include fading or peeling paint, graffiti, minor or extensive rusting. Information is gathered and units requiring attention are sorted in order to address the most significant issues first. Critical deficiencies identified during inspection of PMH units, such as missing or damaged penta-head bolts, are documented and also immediately remedied during inspection, provided materials are on hand at such time.

Fleet

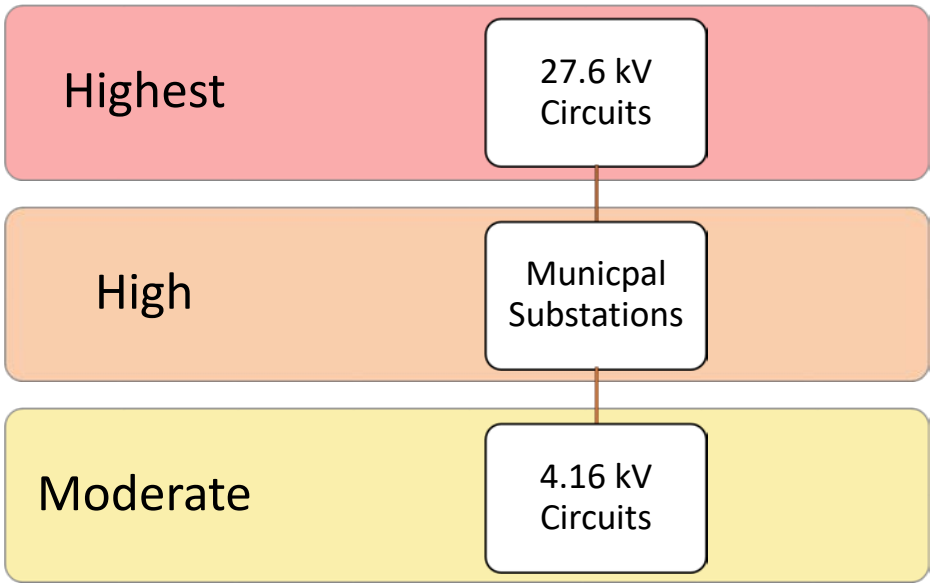
WHESC employs a certified vehicle mechanic who performs maintenance, inspections, and certifications of the fleet of vehicles.

5.3.3b Asset Life Cycle Risk Management

The assessment of risk begins with the inspection of assets. Assets are inspected and inspection data is loaded into the GIS. Inspection data, data from other analysis and asset performance data are used to estimate the probability of failure. The determination of the probability is determined solely on the use of historical data and experience (i.e. at this time, there is no formal process to derive a health index and associate a probability of failure). The consequences of failure are weighed against the impacts of such failure on worker and public safety, the environment, reliability, power quality and operational effectiveness. Risk is factored into the selection and prioritization of capital expenditures during the prioritization process. Projects of high risk are monitored and plans are created to either modify, maintain or replace the assets to reduce the risk to an acceptable level. Projects are selected and integrated into the capital budget based on the effectiveness of the investment. Projects having poor asset conditions and high risk are given high priority and typically cannot be deferred.

To manage risk over an asset's life cycle, investments are made as necessary to address imminent failure or concerns regarding health and safety, the environment, reliability, and/or regulatory/legal obligations. When addressing regulatory and legal obligations, regional, customer-driven and reliability related projects are also considered. Projects concerning reliability are further prioritized as follows:

Figure 5-35: Prioritization of projects concerning reliability



Within the process of prioritizing projects, WHESC evaluates the items above to determine if multiple priorities may be achieved within a single project. For example, WHESC may identify several projects, such as a substation with assets approaching end-of-life, rebuild of a portion of the 27.6kV system and maintenance to the 4.16kV system (a proactive measure dictated by potential safety and reliability issues going forward).

Overhead Systems

As introduced in Section 5.3.1b – Asset Management Process, WHESC selects and prioritizes investments into overhead systems based on the system voltage level, reliability (configuration and worker access), voltage conversion potential, connection of new customers, pole condition, and customer criticality.

Table 5-18 Selection and prioritization of overhead rebuild projects based on risk analyses

Project Number	Location	Job Description	Voltage	Score	Reliability	Score	Efficiency	Score	New	Score	Reliability	Score	Safety , Reliab.	Score	Customers	Score	Total	Budget	Year
			RRFE		Op. Eff.		Fin. Perf.		Customer Cust. Focus		Op. Eff.		Enviroment Public Policy		C/I/R Cust. Focus				
				1-5	Loop	0-5	Converted	0-5	Connection	0-5	Worker Access	0-5	Pole Condition	0-10	Criticality	0-5	Points		
1	Niagara/Church/Aqueduct	27.6kV Extension	27.6kV & 4.16kV	5	Yes	5	1000	5	No	0	Good	0	Poor	5	High	4	24	$750,000.00	2016/ 2017
2	Wellington Street	4.16kV Line Rebuild/27.6kV Extension	27.6kV & 4.16kV	5	Yes	5	500	3	School	5	Good	0	Fair	3	Medium	3	24	$338,000.00	2016/ 2017
3	Riverview Drive	2.4kV Rebuild & Conversion	2.4kV	4	No	0	400	3	No	0	Poor Access	3	Decayed	10	Low	0	20	$150,000.00	2017
4	Bradley Ave/Robert Street	27.6kV Conversion	27.6kV & 4.16kV	5	No	0	150	1	No	0	Feed to Robert	5	Poor	9	Low	0	20	$49,485.00	2017
5	Ross & Kennedy	16kV Extension	16kV	3	No	1	150	1	No	0	Good	0	Poor	10	Low	1	16	$250,000.00	2017/ 2018
6	Ontario Road - Corridor to Wellington	27.6kV & 4.16kV Rebuild	27.6kV & 4.16 kV	5	Existing	3	215	1	No	0	Good	0	Fair/Poor	3	High	4	16	$300,000.00	2018
7	Lincoln Street - Coventry to Scholfield	27.6kV Rebuild and Tower Removals	27.6kV & 4.16 kV	5	No	5	475	3	No	0	Good	0	Fair	3	Medium	3	19	$440,000.00	2019
8	Duncan - Hagar to East Main	27.6kV Extension	27.6kV & 4.16kV	5	No	2	800	4	No	0	Good	0	Poor	5	Low	2	18	$620,000.00	2019/ 2020
9	Denistoun Ave - Hooker to River	27.6kV Rebuild	27.6kV & 4.16kV	5	Existing	3	600	3	No	0	Good	0	Fair/Poor	3	Low	1	15	$250,000.00	2020
10	Myrtle Avenue	4.16kV Line Rebuild/27.6kV Extension	27.6kV & 4.16kV	5	Yes	5	150	1	No	0	Good	0	Fair/Poor	5	Low	1	17	$165,000.00	2020
11	Dorothy Street - Riverside to Ross	16kV Conversion	16kV	3	No	0	150	1	No	0	Fair - Trees	3	Poor	8	Low	0	15	$100,000.00	2020
12	Clare Avenue - Fitch to Erin	4.16kV Line Rebuild/27.6kV Extension	27.6kV & 4.16kV	5	Future	3	237	1	No	0	Good	0	Fair	3	Low	1	13	$100,000.00	2020
13	Hellems Ave/Park Street	27.6kV Overhead Extension	27.6kV & 4.16kV	5	Yes	3	180	1	No	0	Fair - Trees	3	Fair/Poor	5	Low	0	17	$310,000.00	2021
14	King Street - Lincoln to Regent	27.6kV Overhead Extension	27.6kV & 4.16kV	5	Duplicate	3	750	4	No	0	Good	0	Fair/Poor	3	Medium	3	18	$300,000.00	2021
15	Classic/Lewis	2.4kV Rebuild/Conversion	16kV	4	No	0	750	4	No	0	Good	0	Poor	10	Low	0	18	$350,000.00	2021
16	Rusholme Road - Ridge Road to CNR Tracks	27.6kV Rebuild	27.6kV	5	No	0	0	0	No	0	Good	0	Fair/Poor	3	High	4	12	$150,000.00	2021

Underground Systems

As introduced in Section 5.3.1b – Asset Management Process, WHESC selects and prioritizes investments into overhead systems based on cable age, number of faults, and the potential for voltage conversion.

Table 5-19: Selection and prioritization of underground rebuild projects based on risk analyses

Project #	Subdivision	Street	Install Date	Cable Faults	Circuit	Length (m)	KVA	Convert/ Re-Build	Cable Age Points	Cable Faults Points	R-B/C Points	Total Points	Budget	Year
1	Seaway Park Subdivision	Robert St	1975	2	8F1	165.67	150.0	Convert	1	6	6	13	$150,000	2017
1	Seaway Park Subdivision	Robert St	1975	0	8F1	163.12	150.0	Convert	1	0	6	7		
1	Seaway Park Subdivision	Robert St	1975	0	8F1	175.62	150.0	Convert	1	0	6	7		
1	Seaway Park Subdivision	Robert St	1975	0	8F1	186.24	150.0	Convert	1	0	6	7		
2	Bridlewood Subdivision - EXT 1	Silvan Dr	1976	2	10F3	65.65	525.0	Convert	1	6	6	13	$490,000	2016 - 2017
2	Bridlewood Subdivision - EXT 1	Silvan Dr	1976	1	10F3	74.75	525.0	Convert	1	3	6	10		
2	Bridlewood Subdivision - EXT 1	Silvan Dr	1976	0	10F3	36.19	525.0	Convert	1	0	6	7		
2	Bridlewood Subdivision - EXT 1	Silvan Dr	1976	0	10F3	57.07	525.0	Convert	1	0	6	7		
2	Bridlewood Subdivision - EXT 1	Silvan Dr	1976	0	10F3	64.47	525.0	Convert	1	0	6	7		
2	Bridlewood Subdivision - EXT 1	Silvan Dr	1976	0	10F3	69.05	525.0	Convert	1	0	6	7		
2	Bridlewood Subdivision - EXT 1	Silvan Dr	1976	0	10F3	70.74	525.0	Convert	1	0	6	7		
2	Bridlewood Subdivision - EXT 1	Silvan Dr	1976	0	10F3	70.79	525.0	Convert	1	0	6	7		
2	Bridlewood Subdivision - EXT 1	Silvan Dr	1976	0	10F3	70.83	525.0	Convert	1	0	6	7		
2	Bridlewood Subdivision - EXT 1	Silvan Dr	1976	0	10F3	71.48	525.0	Convert	1	0	6	7		
2	Bridlewood Subdivision - EXT 1	Silvan Dr	1976	0	10F3	74.79	525.0	Convert	1	0	6	7		
2	Bridlewood Subdivision - EXT 1	Silvan Dr	1976	0	10F3	99.05	525.0	Convert	1	0	6	7		
2	Woodfield Acres Subdivision	Cummington Pl	1976	0	10F3	45.81	187.5	Convert	1	0	6	7		
2	Woodfield Acres Subdivision	Cummington Pl	1976	1	10F3	130.2	187.5	Convert	1	3	6	10		
2	Woodfield Acres Subdivision	Leaside Dr/Meadowvale	1976	0	10F3	89.79	187.5	Convert	1	0	6	7		
2	Woodfield Acres Subdivision	Leaside	1976	0	10F3	178.47	187.5	Convert	1	0	6	7		
2	Woodfield Acres Subdivision	Meadowvale Pl	1976	0	10F3	36.69	187.5	Convert	1	0	6	7		
2	Woodfield Acres Subdivision	Leaside Dr	1976	0	10F3	90.82	75.0	Convert	1	0	6	7		
2	Woodfield Acres Subdivision	Leaside Dr	1976	0	10F3	100.55	75.0	Convert	1	0	6	7		
2	Woodfield Acres Subdivision	Leaside Dr	1976	0	10F3	167.53	75.0	Convert	1	0	6	7		
2	Woodfield Acres Subdivision	Leaside Dr	1976	1	9F1	148.48	250.0	Convert	1	3	6	10		
2	Woodfield Acres Subdivision	Leaside Dr/McCrae	1976	1	9F1	232.34	250.0	Convert	1	3	6	10		
2	Woodfield Acres Subdivision	McCrae Dr/Newleaf Cres	1976	1	9F1	169.66	250.0	Convert	1	3	6	10		
2	Woodfield Acres Subdivision	Newleaf Cres	1976	1	9F1	41.63	250.0	Convert	1	3	6	10		
2	Woodfield Acres Subdivision	McCrae Dr	1976	0	9F1	55.03	250.0	Convert	1	0	6	7		
2	Woodfield Acres Subdivision	Newleaf Cres	1976	0	9F1	60.38	250.0	Convert	1	0	6	7		
2	Woodfield Acres Subdivision	Newleaf Cres	1976	0	9F1	79.09	250.0	Convert	1	0	6	7		
2	Woodfield Acres Subdivision	Newleaf Cres	1976	0	9F1	133.55	250.0	Convert	1	0	6	7		
6	Glen Park Estates - EXT 1	Maureen Ave	1974	0	7F1	101.26	125.0	Re-Build	3	6	0	9	$125,000	2017
6	Glen Park Estates - EXT 1	Maureen Ave	1974	0	7F1	112.94	125.0	Re-Build	3	6	0	9		
6	Glen Park Estates - EXT 1	Maureen Ave	1974	0	7F1	183.23	125.0	Re-Build	3	6	0	9		
6	Glen Park Estates - EXT 1	Maureen Ave	1971	1	7F1	183.23	125.0	Re-Build	3	6	0	9		

Substations

Substation failures are much more extensive, costly and difficult to manage on an emergency basis and emergency expenditures (e.g. replacement costs) would likely be too high for a single year. As such, WHESC would assign a high priority to such a project and spread expenditures over several years. The project would then be considered with regards to achieving multiple objectives: replacing end-of-life plant and improving operational efficiency. Table 5-16 summarizes the risk analysis for substations.

5.4 Capital Expenditure Plan

A distributor's DS Plan details the programme of system investment decisions developed on the basis of information derived from its asset management and capital expenditure planning process. It is critical that investments, whether identified by category or by specific project, be justified in whole or in part by reference to specific aspects of that process. As noted above, a DS Plan must include information on prospective investments over a minimum five year forecast period, beginning with the test year (or initial test year if Customer IR filing), as well as information on investments – planned and actual – over the five year period prior to the initial year of the forecast period.

5.4.1 Summary

This section elicits key information about a distributor's capital expenditure plan including, by category (see section 5.1.1), significant projects and activities to be undertaken and their respective key drivers; the relationship between investments in each category and a distributor's objectives and targets; and the primary factors affecting the timing of investment in each category (or of projects within each category, if significant).

The following information should be provided:

a) 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';

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

c) 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;

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

e) 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;

f) 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;

g) 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;

h) 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.*

5.4.1a System Capability to Connect New Load or Generation

As per the assessment in Section 5.3.2d, WHESC has sufficient capacity to connect new load on its 27.6 kV feeders, Municipal Substations, and 4.16 kV feeders. In general, new load is connected directly to the 27.6 kV system whenever possible. The Transformer Station supplying, Crowland TS, is owned and operated by Hydro One and was also assessed to have sufficient capacity to connect new load. Therefore, WHESC has not planned any investments related to this driver

WHESC's system capacity assessment to accommodate new REG is presented in Section 5.4.3. Parallel to WHESC's policy of new load connections, new generation is connected to the 27.6 kV system whenever possible. Of the eight 27.6 kV feeders owned by WHESC, only one of these feeders is approaching its prescribed limit for the connection of REG projects. The remaining seven feeders have a limited amount of generation connected and, therefore, WHESC has not planned any investments related to this driver.

5.4.1b Summary of Annual Capital Expenditures

The total annual gross capital expenditures over the forecast period by investment category are presented below in Table 5-20. The overall spending increases slightly over the forecast period due to inflation; however, no material changes in investments are planned.

Table 5-20: Capital expenditures over the forecast period by investment category

Investment Category	Forecast Period				
	2017	2018	2019	2020	2021
System Access	$204,501	$250,000	$250,000	$190,000	$150,000
System Renewal	$1,834,485	$1,495,000	$1,775,000	$1,920,000	$1,770,000
System Service	$110,000	$260,000	$35,000	$35,000	$35,000
General Plant	$265,000	$305,000	$400,000	$295,000	$525,000
Total	$2,413,986	$2,310,000	$2,460,000	$2,440,000	$2,480,000

5.4.1c Asset Management and Capital Expenditures Planning

The following information provides a brief outline of the outputs of the asset management and capital expenditure planning process that have affected capital expenditures in the four main categories.

5.4.1c.1 System Access

System Access investments account for just under 9% of the capital expenditures for the test and forecast period. The estimated expenditures for this category are based on investments from previous years, taking into consideration forecasted developments in the service area. Forecasted growth is minimal resulting in this category representing a minimal portion of the plan. Investments in metering have been budgeted based on the forecast number of new connections, as well as the expected failure rate of the existing meters. No third party infrastructure development have been budgeted over the forecast period since neither the Municipality nor the Region have planned any road works requiring relocation of WHESC's plant.

5.4.1c.2 System Renewal

System Renewal projects make up the largest category of investments for the test and forecast period accounting for over 72% of total capital expenditures. Through the asset management process, WHESC has determined many of these assets are in poor condition and susceptible to failure in the near term if not replaced. This category represents the largest portion of the plan and addresses the two most important significant customer preferences noted in WHESC's customer engagement activities.

Municipal Substations

Investments in substations are driven by assets at the end of their service life. Investments are selected, ranked, and prioritized based on the condition of the assets, their maintainability and availability of spare parts, the redundancy of the substation, environmental impacts in case of a failure, the number of customers served, the criticality of the customers served, and other opportunities for cost savings. The possible decommissioning of the Municipal Substation is always considered as part of the planning process.

Overhead Systems

Investments in overhead systems are driven by assets at the end of their service life, namely poles and pole-mounted transformers. Poles and distribution transformers are replaced on their own through Miscellaneous Pole Replacements and Miscellaneous Transformer Replacements or through overhead rebuild. Miscellaneous replacements account for end-of-life poles and transformers in WHESC's system that cannot be grouped into an overhead rebuild.

As per WHESC's asset management and capital expenditure planning process, overhead rebuilds are scored based on their voltage, reliability benefits (circuit configuration and worker access), operational efficiency improvement due to voltage conversion, new customer connections (if a driver), customer criticality, and the condition of the poles.

Underground Systems

The replacement of pad-mounted and Pole-Tran transformers are included in the program for Miscellaneous Transformer Replacements, as well as underground rebuild. The five-year plan for

underground rebuilds assesses cable that would represent the oldest ten years of installed cable. Cable replacement priority must meet WHESC's six asset management objectives presented in Section 5.3.1a, plus, as a cost savings measure, be assessed by the following criteria:

- System voltage conversion potential
- Reliability
- Age

The most current cable replacement ranking is organized first by the cables in service from 1969 to 1976. Cables are organized by subdivision name and grouped with other stages of subdivisions that makes the most sense for achieving cost savings during asset replacement.

5.4.1c.3 System Service

System Service expenditures account for less than 4% of total capital expenditures for the test and forecast period. Activities in this category have been determined by asset condition assessment through historic performance and notifications from service providers recommending operating system replacements. The dual redundant control room server's hardware and software were last upgraded in 2007. At that time, the operating system was upgraded from VMS to Windows based. The next major upgrade will take place in 2017 and will include an operating system upgrade to SmartVU.

Replacement of SCADA switches, remote fault indicators, and radio systems are all categorized under System Service. Devices that have the highest probability of failure are targeted for replacement. New devices are also added to the system to improve WHESC's operational capabilities and reduce costs in the long term.

5.4.1c.4 General Plant

General plant investments account for just under 15% of the capital expenditures for the test and forecast period. Activities in this category comprise mostly of building investments to ensure continued use of the service center. Projects have been determined through inspection and historical performance of similar assets.

Land & Buildings

A project to replace 50% of the paved areas at WHESC's service center and correct drainage issues was previously deferred and is now planned for 2017. WHESC has been conducting minor repair to potholes and deteriorating asphalt over the past ten years.

Fleet

Condition assessments and records of vehicles maintenance costs are used to assist in determining the end of useful life of a vehicle. Vehicles are replaced based on safety, maintenance costs, and performance. Consideration is also given to the gains in safety and performance due to technological advancements in new vehicles.

5.4.1d Material Capital Expenditures

Table 5-21A below details all material capital projects planned for the Test Year, sorted by investment category.

Table 5-21A: Material capital expenditures in the Test Year by investment category

Project Activity By Investment Category	Above Materiality	Total Capital Cost
System Access		
Municpal Relocations		$14,501
New Overhead/Underground Service Connections		$40,000
Expansions Subdivsions		$50,000
Retail Meters	$100,000	$100,000
Subtotal System Access	**$100,000**	**$204,501**
System Renewal		
MS 8 Transformer/Switchgear/Primary Cabling	$50,000	$50,000
MS 14 Transformer/Switchgear/Primary Cabling	$120,000	$120,000
Church St/Niagara Street Rebuild/Conversion 4.16kV to 27.6kV	$300,000	$300,000
Wellington Street-East Main to Eastdale Rebuild/Conversion 4.16kV to 27.6kV	$250,000	$250,000
Bradley Ave 4.16kV Rebuiild to accommodate Robert St U/G		$49,485
Ross Street/Kennedy Street Rebuild/Conversion 4.16kV to 27.6kV	$150,000	$150,000
Maureen Ave 2.4kv Rebuild	$125,000	$125,000
Riverview Drive Rebuild/Conversion 4.16kV to 27.6kV	$150,000	$150,000
Robert Street Rebuild/Conversion 2.4kV to 16kV	$150,000	$150,000
Silvan/Newleaf Phase 2 Rebuild/Converesion 2.4kV to 16kV	$280,000	$280,000
Miscellaneous Pole Replacements	$100,000	$100,000
Miscellaneous Transformer Replacements	$50,000	$50,000
Miscellaneous Underground Rebuild		$30,000
Miscellaneous Overhead Primary		$30,000
Subtotal System Renewal	**$1,725,000**	**$1,834,485**
System Service		
Scada Switches/Remote Fault Indicators/Radio Systems	$60,000	$60,000
Scada SmartVU/Server Upgrade	$50,000	$50,000
Subtotal System Service	**$110,000**	**$110,000**
General Plant		
Computer Equipment		$25,000
Computer Software		$40,000
Tools		$5,000
2017 1/2 Ton Pickup Truck (Truck 36 - 2000)		$35,000
2017 1/2 Ton Pickup Truck (Truck 37 - 2000)		$35,000
Building Upgrades Stairlift to Lower Level		$25,000
Service Centre Parking Lot Repaving	$100,000	$100,000
Subtotal General Plant	**$100,000**	**$265,000**
Total Capital Spending	**$2,035,000**	**$2,413,986**

A description for projects above materiality can be found in Appendix 5-D.

5.4.1e Material Impact of IRRP/RIP on the DSP

As previously discussed, the Regional Planning exercise in the Niagara area has determined that no further planning is required at this time. The results of this exercise have resulted in there being no impact on WHESC's DSP.

5.4.1f Customer Preferences

As introduced in Section 5.2.2a.1 – Customer Consultations, INNOVATIVE was commissioned by WHESC to help the utility design, collect feedback and document its customer engagement and consultation process as part of the development of WHESC's Application. WHESC conducted telephone surveys of residential and general service customers, conducted focus group sessions with residential and general service groups and met with five customers in the greater than 50 kW rate class. WHESC informed customers of its DSP and the associated potential bill impacts in order to solicit informed feedback from its customers to shape DSP. Based on the information from the INNOVATIVE market research telephone surveys, group consultations, and large customer individual interviews, the majority of customers think the proposed DSP is reasonable and support the plan.

As a result of the surveys conducted in 2015 and 2016, WHESC has learned that its customer preferences are:

Residential Customer

- Value for Service Provided
- Current Reliability of Power Maintained
- Billing Accuracy
- Maintaining the current pace of replacing infrastructure

Business Customer

- Value for Service Provided
- Strong majority of customers are satisfied with current reliability of power, response times to outages, quality of power delivered
- Replacement of Equipment before breakdowns occur
- Most feel that the process of system renewal is on track and progressing at the right speed

Further analysis of customer opinions and preferences is provide in Section 5.4.2d Mechanisms Use to Engage Customers. The complete, third-party review by INNOVATIVE has been included in Exhibit 1 Appendix 1-G.

WHESC has factored these drivers into its DSP. Specifically, WHESC has maintained a levelled approach to total annual spending with a focus on System Renewal to maintain reliability. WHESC has taken a balanced and prudent approach to spending within the General Plant category to meet immediate and future requirements without impacting System Renewal and improving the overall quality of customer service.

5.4.1g Expected System Development over the Planning Horizon

Load and Customer Growth

WHESC expects the distribution system within its service territory to continue to follow historic activities from the last five years with approximately 1% load growth. The forecast customer counts were presented in Figure 5-31. As per Section 5.3.2d and 5.4.1a, load growth is not a significant investment driver over the forecast period; therefore, no expansions or major system upgrades have been planned to accommodate load growth.

Smart Grid Development

WHESC will continue to invest in smart meters over the forecast period. Existing SCADA assets will also require replacement through the forecast period including operating systems, hardware, switches and RTU's. Additional load and fault sensing systems will be added to the system; however, these investments are expected to be below the materiality threshold.

REG Accommodation

WHESC's distribution system has sufficient capacity to connect renewable energy projects, therefore, WHESC has not planned any capital investments to accommodate new REG connections over the next five years.

5.4.1h Projects Planned in Response to Customer Preferences, Technology, Innovation

Table 5-21B: Material capital expenditures in the Test Year

Response to Customer Preferences, Technology, and Innovation

Project Activity By Investment Category	Above Materiality	Customer Preference	Technology	Innovative Processes
System Access				
Retail Meters	$100,000	$100,000		
System Renewal				
MS 8 Transformer/Switchgear/Primary Cabling	$50,000	$50,000		
MS 14 Transformer/Switchgear/Primary Cabling	$120,000	$120,000		
Church St/Niagara Street Rebuild/Conversion 4.16kV to 27.6kV	$300,000	$300,000		
Wellington Street-East Main to Eastdale Rebuild/Conversion 4.16kV to 27.6kV	$250,000	$250,000		
Ross Street/Kennedy Street Rebuild/Conversion 4.16kV to 27.6kV	$150,000	$150,000		
Maureen Ave 2.4kv Rebuild	$125,000	$125,000		
Riverview Drive Rebuild/Conversion 4.16kV to 27.6kV	$150,000	$150,000		
Robert Street Rebuild/Conversion 2.4kV to 16kV	$150,000	$150,000		
Silvan/Newleaf Phase 2 Rebuild/Converesion 2.4kV to 16kV	$280,000	$280,000		
Miscellaneous Pole Replacements	$100,000	$100,000		
Miscellaneous Transformer Replacements	$50,000	$50,000		
System Service				
Scada Switches/Remote Fault Indicators/Radio Systems	$60,000			$60,000
Scada SmartVU/Server Upgrade	$50,000		$50,000	
General Plant				
Service Centre Parking Lot Repaving	$100,000	$100,000		
Total Capital Spending	**$2,035,000**	**$1,925,000**	**$50,000**	**$60,000**

Customer Preference

While WHESC engaged customers as a part of the planning process for this Distribution System Plan, no specific project was initiated solely as a result of customer preference. Rather, customer preferences with respect to capital expenditures were considered as part of the evaluation and prioritizing of projects with in the plan.

WHESC considers customer preference in prioritizing certain projects. In particular, System Access projects are typically customer driven and the utility is required to complete these projects which can include connecting new customers, connecting renewable generation, and accommodating municipally driven projects such as road widening. System Access projects are customer driven and therefore timelines are often determined by the customer and WHESC is expected to meet those timelines.

The results of WHESC's customer engagement activities revealed that customers prefer WHESC to balance system reliability with cost of service. As previously mentioned, approximately 73% of WHESC's capital spending program is allocated to System Renewal to replace end-of-life assets and maintain system reliability and power quality as preferred by customers.

For General Plant, WHESC has responded to customer preferences by minimizing expenditures relating billing systems (CIS) and website tools in the 2017 Test Year and for the balance of the periods covered by the DSP. WHESC will continue to explore opportunities to make online tools available to customers where they deliver customer value. WHESC's service centre was built in the late 1960's and is in need of repairs/upgrades. Given that a new service centre is cost prohibitive, WHESC has responded to customer preferences by taking a levelled approach to capital expenditures on buildings & grounds throughout the DSP forecast period.

Technology/Innovative Processes

WHESC capital expenditures as it relates to technology and innovative process are included in System Service. The first project is related to Scada Communication Systems whereby cellular modems and radio technology will be combined to create a more cost effective and responsive network. The second project relates to Scada Operating Software providing advanced functionality and ability to expand on outage management and power restoration opportunities.

WHESC has not planned any projects/activities related to the integration of distributed generation and complex loads.

5.4.2 Capital expenditure planning process overview

The information a distributor should provide includes, but need not be restricted to:

- ***a) 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;***
- ***b) 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;***
- ***c) 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);***
- ***d) 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; and***

e) 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).

5.4.2a Capital Expenditure Planning Objectives

The following information provides an overview of WHESC's capital expenditure planning process which includes details on planning objectives, planning criteria, and assumptions used in the development of the capital expenditure plan. The asset management process is the foundation to the DSP and the capital expenditure plan which helps align each to the overall corporate objectives. By following a strategic approach to the capital expenditure process WHESC achieves efficiencies in work practices and productivity along with creating and maintaining a distribution system capable of meeting the needs of existing and future customers and providing the highest level of customer value.

5.4.2a.1 Planning Objectives

A number of objectives and processes are followed while developing the capital expenditure plan in order for the end result of the plan to meet strategic priorities. WHESC's asset management objective is to identify and implement the appropriate timing of asset replacement in order to minimize risk and maintain system reliability. Asset management objectives are used to determine the priority of projects to ensure system integrity, to continue to provide reliable service to existing customers, and to make available assets for the connection of both new load customers and generators.

For each of the planning objectives listed below, its relationship to WHESC's asset management objectives (see Section 5.3.1a) is discussed).

1 Allocate investment to meet all Regulatory requirements. This relates to WHESC's second and third asset management objectives.

2 Allocate System Renewal investments adequate to maintain a safe and reliable distribution system. This relates to WHESC's first, third, and fourth asset management objectives

3 Allocate adequate investment to meet load and new load and REG connection requirements. This relates to WHESC's third asset management objective.

4 Allocate adequate investment in general plant assets to support investment initiatives. This relates to WHESC's fourth asset management objective.

5 Review overall expenditures and detail customer cost impact and adjust as required. This relates to WHESC's fifth and sixth asset management objectives.

5.4.2a.2 Planning Criteria

There are a number of important sets of criteria that are used to ensure that the level of investment is correct and targeted to the correct area. Key planning criteria that are utilized to support investment in the four categories are:

- Consultation with the City of Welland Economic Development Department.
- Consultation with Municipal and Regional governments through the public utility coordinating committee.
- Consultation with large industrial customers.
- Consultation with Hydro One.
- Asset condition assessment and performance results.
- System capacity assessments for both load and generation.
- Load forecasting using historical data.
- Other assessments related to general plant, fleet, IT and SCADA.

5.4.2a.3 Assumption Used

As part of the capital expenditure plan, there are a number of assumptions made to support the development of the plan including:

- The use of historical trends related to the System Access category.
- The validity of information being provided by existing and new customers.
- The historical impact and rate of CDM and DG projects.

5.4.2b Non Distribution System Alternatives

WHESC does not have a formal process of determining the effects of CDM and REG projects on the load forecast. The IESO's current Conservation First Framework focuses on energy conservation and does not consider the particulars of peak shaving, while REG is intermittent and cannot be relied on to trim peak demand without the use of energy storage. Since system capacity and operational constraints are usually determined by peak conditions, CDM and REG in their present regulatory states would have little effect. WHESC makes assumptions, based on historical information, on the potential for these programs to mitigate future costs related to increased capacity requirements. A more formal process will be considered in the future during the next wave of Regional Planning. However, a formal process at this time is not seen as necessary, due to slow growth and available Transformer Station capacity.

5.4.2c Project Prioritization Tools and Methods

5.4.2c.1 Project Identification and Selection

The following methods are used to identify and select projects for each investment category:

System Access

System Access projects are identified through customers contacting WHESC requesting new services or through requests from the Municipality of Region requesting relocation of WHESC owned assets. System access is budgeted based on historical data.

Budgeting for plant relocation requests is very difficult as the road authority may introduce a project to be completed in a budget year without prior notice or may change project schedules affecting the LDC. The Public Utility Coordinating Committee meets regularly to promote long term efficient project planning mitigating impact on asset owners. If an unknown project is introduced by the road authority, a project or projects with lower priorities are postponed to the following year, mitigating any customer bill impact issues.

System Renewal

System Renewal projects are identified using the asset condition assessment and the performance data relevant to the asset. There is no formal process to determine an asset Health Index. Rather WHESC scores projects based asset criteria such as age, condition, customer impact, safety and environmental. Criteria used for scoring underground distribution projects is more simplified and less subjective (see 5.3.3b – Asset Life Cycle Risk Management).

System Service

System Service projects are identified a number of methods or situations.

- **Asset Performance:** Devices such as SCADA switches, remote terminal units, and SCADA hardware are assessed by historical performance. Due to an acceptable level of risk associated with asset failure, projects are not normally scheduled until assets show signs of potential failure or as functionality of the devices degrade as individual associated components fail.
- **Software Requirements:** SCADA operating system needs are identified through vendor interaction providing information on new systems with enhanced features or simply by notification of system support expiry timelines.

General Plant

General Plant projects are identified using a combination of inspections, operating cost information, benefits of replacement and asset performance.

WHESC's fleet includes bucket trucks, digger derricks, pickup trucks, vans and various trailers. It is crucial that all vehicles are properly maintained and replaced in a timely manner. The following factors are considered to assess the need to replace a particular vehicle:

- Age, odometer read, PTO hours.
- Maintenance costs
- Annual and bi-annual vehicle inspection results.
- Benefits of new technology.
- Road Safety Regulations
- Crew needs
- Level of worker/public risk associated with failure.

As a guideline vehicle types are replaced under the following age guidelines:

- Small vehicles; Pickup Trucks and Vans – 10 to 12 years
- Large vehicle; Bucket and Digger Trucks – 15 Years
- Trailers and other equipment – 20 Years

Building investments are identified through inspections, asset performance, repair issues, and expert opinion. Investment levels are based on historical costs of projects of significance and can include paving, roofing, and heating and cooling. Investments are planned based on asset condition and its effect on daily operations. Expert opinion provides the information necessary to forecast when the asset will require replacement.

Information Technology investments are selected in order to maintain normal and emergency business operations. Timing of asset replacements is based on established life cycles of both hardware and software. Both hardware and software needs are determined by expert opinion and as identified individually by each department.

5.4.2c.2 Project Prioritization

Section 5.3.3b – Asset Life Cycle Risk Management introduced how WHESC uses the conclusions of risk analyses to select and prioritize capital expenditures within an investment category. To prioritize investments across its entire capital expenditure plan, WHESC evaluates them in terms of potential impacts to safety, regulatory compliance, load growth, reliability (accounting for probability and consequence of failure), and minimizing life cycle cost of ownership. Table 5-22 summarizes the numeric weights assigned to each of these decision criteria.

Table 5-22: Assigned weights to decision criteria

Criteria	Numeric Weight
Significant Potential for Safety Problem	10
Regulatory/Municipal Coordination	9
Load Growth	8
Reliability/Total Risk of Failure*	6
Minimum Life Cycle Cost of Ownership	5

*accounting for probability and consequence

Projects are scored in each of the five decision criteria. For consistency in scoring, WHESC has defined typical ranges of scores for some of its common types of projects. This system is summarized in Table 5-23, using score values between 0 and 10. Metering projects are a regulatory requirement and are typically prioritized before other projects, except for projects addressing safety. Projects to address load growth are also given high priority, but there are no load growth projects planned over the forecast period.

WHESC maintains a balanced approach to System Renewal spending, that is, both underground and overhead projects are included in each budget year and prioritized based on all other assets in a similar category. Underground rebuilds typically score higher than overhead rebuilds in reliability, while conversion projects score higher than like-for-like rebuilds since the eventual elimination of Municipal Substations decreases the long term cost of ownership. Once the projects have been ranked, the asset quantities and historical costs are used to determine budget costs. Projects are then included in the five-year capital plan as dictated by funding availability in the asset class.

Table 5-23: General scoring of projects by type

Project Type	Safety	Regulatory	Growth	Reliability	Cost
Reliability Lines Project	6 to 10			10	3 to 5
Reliability Transformer Project	6 to 10			2 to 4	3 to 5
Stations Reliability Project	6 to 10			10	3 to 5
Metering Project		10			
Growth Project			10		
U/G Rebuild and Conversion				6 to 8	6 to 8
O/H Rebuild and Conversion				4 to 6	6 to 8
Station Renewal				4 to 6	4 to 6
U/G Rebuild only				6 to 8	
O/H Rebuild only				4 to 6	
Vehicles	0 to 4				8 to 10
Land & Buildings	0 to 6				6 to 10
Hardware/Software		0 to 6			6 to 10

Municipal projects such as pole line relocation to accommodate road works are non-discretionary since WHESC's plant occupies the Right-of-Way. Customer-driven projects accommodate customer requests

for supply, typically by large commercial or industrial customers, and are also of high priority. The priority is driven by the regulatory requirement that new connections are completed within the expected connection window.

Using the assigned weights and criteria scores, the end result is a project score for each material project/program:

$$Project\ Score = \sum_{i=0}^{i=4} (Weight_i * Score_i)$$

Table 5-24 presents the project scores for each material project/program in the 2017 Test Year. Details on the scoring for each project/program are included in the Project Justification Forms (Appendix 5-D).

Table 5-24: Material project/program scores and rankings (in the Test Year)

Investment Category	Project/Activity	Capital Cost	Project Score	Project Rank
System Renewal	Miscellaneous Pole Replacements	$100,000	185	1
System Renewal	Miscellaneous Transformer Replacements	$50,000	149	2
System Access	Smart Meters	$100,000	90	3
System Renewal	Silvan/Newleaf Phase 2 Rebuild/Conversion 2.4kV TO 16Kv	$280,000	88	4
System Renewal	MS 14 Transformer/Switchgear/Primary Cabling Replacement	$120,000	85	5
System Renewal	Robert Street Rebuild/Conversion 2.4kV to 16kV	$150,000	77	6
System Renewal	Church Street/Niagara Street Rebuild/Conversion 4.16kV to 27.6kV	$300,000	76	7
System Renewal	Wellington Street-East Main to Eastdale Rebuild/Conversion 4.16kV to 27.6kV	$250,000	76	7
System Renewal	MS 8 Transformer	$50,000	66	9
System Renewal	Riverview Drive Rebuild/Conversion 4.16kV to 27.6kV	$150,000	65	10
System Service	SCADA SmartVU/Server Upgrade	$50,000	61	11
General Plant	Service Centre Parking Lot Paving	$100,000	60	12
System Renewal	Ross Street/Kennedy Street Rebuild/Conversion 4.16kV to 27.6kV	$150,000	54	13
System Renewal	Maureen Ave 2.4kV Rebuild	$125,000	48	14
System Service	SCADA Switches/Remote Fault Indicators/Radio Systems	$60,000	40	15

5.4.2c.3 Project Pacing

Project pacing is based on the analysis of customer bill impacts. The results of WHESC's customer survey indicated that the cost of electricity is significant to WHESC's customers; therefore, project and program spending over the forecast period has been designed with rate impacts in mind. Projects are paced based

on their ranking per WHESC's project prioritization process. If there is an urgent need to complete a project during the budget year that was not budgeted – for example a road widening – WHESC would defer a lesser priority project as ranked by its prioritization process.

5.4.2d Mechanisms Used to Engage Customers

5.4.2d.1 General Service and Residential Customer Focus Groups

As introduced in Section 5.2.2a.1 – Customer Consultations and 5.4.1f – Customer Preferences, WHESC and INNOVATIVE developed a workbook to use to engage with customers in the Consultations Groups and the workbook had five distinct chapters:

1. **What is this Consultation About?** The purpose of the section was to inform readers of where this consultation fits in the context of electricity planning in Ontario.

2. **Electricity 101**: This section described how Ontario's electricity system works and the players involved in operating and regulating the electricity system as it relates to Welland Hydro's customers.

3. **Welland Hydro's Distribution System Today**: This section detailed the structure and key elements of Welland Hydro's distribution system.

4. **Pressures on the Distribution System**: This section described the various challenges facing Welland Hydro's distribution system and provided an overview of recent and current initiatives to manage these challenges. This section also included information on cost drivers, how the utility works to find efficiencies and costs savings, and provided an overview of both historical and forecasted capital and operating spending between 2012 and 2021.

5. **What will Welland Hydro's Plan Cost Customers?** This section detailed the estimated bill impact of the plan on the average customer in the rebase year and provided forecasted bill impacts for the following four years.

Another key part of the workbook were the questions completed by the customers that highlighted customer value choices of the following topics:

- What should the balance be between system reliability and rate impact?
- What should Welland Hydro's priority be when planning its level of investment in replacing aging infrastructure?
- How important is system modernization to customers?
- Should Welland Hydro be playing a bigger role in CDM program delivery?

- Should Welland Hydro invest in discretionary programs to help digitize the customer experience?

The final question of the workbook asked about the cost of the plan and outcomes it planned to achieve and the customers were given the following options:

- The rate increase is reasonable and I support it
- I don't like it, but I think the rate increase is necessary
- The rate increase is unreasonable and I oppose it
- Don't know

Sixteen customers participated in the Consultation Groups, which were the qualitative stage of the engagement process. Overall, both General Service and Residential participants are satisfied with the service Welland Hydro provides. All General Service focus group participants were either somewhat or very satisfied, as were residential participants save one who was somewhat dissatisfied. In both groups, satisfaction was tied to power quality issues, such as blips and surges, and customer service experiences.

Proposed Plan and Rate Impact

All participants felt that Welland Hydro is doing at least a good job when it comes to planning for the future. Ultimately, all but one participant supported the proposed rate increase. Three felt the rate increase is reasonable, and supported it outright, while five felt that, while they don't like it, they think the proposed increase is necessary.

The INNOVATIVE report is included in Exhibit 1 Appendix 1-G for further reference.

5.4.2d.2 Large Customer Validation Interviews

Overall, the key account customers interviewed by Innovative are satisfied with the consultation process and the job Welland Hydro has done in communicating the proposed Distribution System Investment Plan. Most feel the process of system renewal is on track and progressing at the right speed. Furthermore, customers felt they had the opportunity to raise concerns and ask questions during the meeting with Welland Hydro. Most key accounts understand the rate increase, think it is reasonable and support the plan. However, the industrial customer interviewed expressed concern and opposes the rate increase.

5.4.2d.3 Random Telephone Survey

As previously introduced in Section 5.2.2a.1 – Customer Consultations and Section 5.4.1f – Customer Preferences, WHESC teamed up with INNOVATIVE to conduct a telephone survey of residential and GS<50 customers in order to quantify their needs and preferences. 501 residential customers and 25 GS<50 customers who responded to the quantitative stage where we documented the incidence of *needs* and *preferences* across the customer population.

Continued Delivery of High Quality Services

Almost all Welland Hydro customers are satisfied with the job the utility is doing at running the electricity distribution system. This pattern was consistent across all rate classes in all phases of the customer consultation. However some customers commented lower rates, improved customer communication and improved power quality and reliability could further enhance services.

Reliability of Service

In regard to the number and length of power outages 19% of WHESC customers think they should spend what is needed to reduce the number of power outages while 50% think they should spend what is needed to maintain the current number of outages and 69% think WHESC should spend what is needed to reduce or maintain the length of power outages.

Customer Service, Communication, and E-billing

- A strong majority of residential customers feel satisfied with either their customer service (68%) or their communications materials from Welland Hydro (73%).
- 3-in-4 (76%) think Welland Hydro is doing a good job in communication to its customers regarding consumption management.
- Over half (56%) of residential customers are not interested in changing to e-billing. Among those who are interested, a third (33%) claim to have not heard or thought about it.

System Challenges and Priorities

- The majority (54%) of residential customers feel that Welland Hydro should invest what it takes to replace the system's aging infrastructure to maintain system reliability.
- The run-to-failure approach is not supported by residential customers. Two-thirds (65%) of residential customers would prefer to replace equipment before it breaks down vs. waiting for its full value (26%).
- Residential customers prefer that Welland Hydro has the equipment and tools they need to manage the system (62%) over making do with the infrastructure it already has (32%).
- More than 8-in-10 (82%) acknowledge the importance of investing now in modernizing the grid, even though there are other areas that require investment.

Affordable Electricity and Service

It is true that many customers are feeling a "financial pinch" when it comes to their electricity bills. However, WHESC customers feel they are well served by the electricity system in Ontario.

Customer Reaction to Rate Increase

Based on the results from the telephone survey customers feel that although they do not like a rate increase they believe the rate increase is necessary and reasonable, and they support it.

5.4.2e Method and Criteria used to Prioritize REG Investments

WHESC does not expect any distribution system investments over the forecast period as a result of REG connection requirements.

5.4.3 System Capability Assessment for REG

This section provides information on the capability of a distributor's distribution system to accommodate REG, including a summary of the distributor's load and renewable energy generation connection forecast by feeder/substation (where applicable); and information identifying specific network locations where constraints are expected to emerge due to forecast changes in load and/or connected renewable generation capacity.

In relation to renewable or other distributed energy generation connections, the information that must be considered by a distributor and documented in an application (where applicable) includes:

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

b) 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 in formation 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);

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

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

e) constraints for an embedded distributor that may result from the connections.

5.4.3a Applications for REG

By the end of June 2016, WHESC had connected seven Feed In Tariff ("**FIT**") and 78 microFIT projects of renewable energy generators ranging in size up to 10,000 kW, with the majority of microFIT installations being approximately 10 kW. The projects are summarized in Table 5-25.

Table 5-25: Existing FIT and microFIT connections

Year	microFIT		FIT	
	Connections	kW	Connections	kW
2010	2	20	0	0
2011	8	72	0	0
2012	12	100	2	350
2013	16	160	2	500
2014	10	90	3	11,000
2015	17	170	0	0
2016 (up to June)	13	130	0	0

5.4.3b Number of REG connections anticipated

Four 500 kW projects have been awarded under the FIT4 program. WHESC expects that fewer projects will be awarded in WHESC's service territory under the FIT5 program.

WHESC is already seeing a decline in the number of microFIT applications and expects this trend to continue through the forecast period.

5.4.3c&d Capacity and Constraints affecting REG

The distribution system, with its combination of voltage levels and Municipal Stations, has sufficient transformation capacity to accommodate any load or generation expected over the period covered by the **DSP**. Aside from one of the 27.6kV distribution feeders (see Table 5-26) below, all remaining feeders are minimally utilized and have no constraints that would prevent the connection of REG. Upstream capability, namely the Hydro One TS and transmission system, to accommodate new load and generation are through the Regional Planning Process. Currently, as determined by Hydro One, there are no generation connection limitations.

Table 5-26: Generation connection capacity by feeder

	WHESC Feeders - Crowland TS							
	M14	M15	M16	M17	M18	M19	M20	M22
Loading								
Voltage (kV)	27.6	27.6	27.6	27.6	27.6	27.6	27.6	27.6
Average Loading (A)	223	202	187	152	331	36	218	47
Average Loading (%)	37	34	31	25	55	6	36	8
Peak Loading (A)	364	293	277	156	546	36	331	36
Peak Loading (%)	61	49	46	26	91	6	55	6
Generation (kW)								
Max Capacity (kW)	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000
Generation Connected (kW)	211.8	79.37	126.93	11155	434.14	0	585	0
Remain Generation Capacity (kW)	18788.2	18920.63	1873.07	7845	18565.86	19,000	18415	19,000

5.4.3e Embedded Distribution Constraints

There are no embedded distributors in WHESC's service area.

5.4.4 Capital Expenditure Summary

The purpose of the information filed under this section is to provide the Board and stakeholders with a 'snapshot' of a distributor's capital expenditures over a 10 year period, including five historical years and five forecast years. Note that where a distributor's internal investment planning framework does not align with the investment categories defined here, best efforts are expected to 'map' investments to these categories.

Despite the 'multi -purpose' character of a project or activity, for 'summary' purposes the entire costs of individual projects or activities are to be allocated to one of the four investment categories on the basis of the primary (i.e. initial or 'trigger') driver of the investment. Note, however, that for material projects, a distributor must estimate and allocate costs to the relevant investment categories when providing information to justify the investment, as this assists in understanding the relationship between the costs and benefits attributable to each driver underlying the investment. In any event, the categorization of an individual project or activity for the purposes of these filing requirements should not in any way affect the proper apportionment of project costs as per the DSC.

Table 2 illustrates how information filed under this section includes a distributor's actual and forecast (i.e. proposed) capital expenditures over the historical and forecast periods. System operations and maintenance (O&M) costs are also shown to reflect the potential impact, if any, of capital expenditures on routine system O&M.

Note that 'Plan' expenditures over the historical period refer to a distributor's previous plan for capital expenditures after adjustments (if any) occasioned by the Board's decision on the relevant prior application.

Brief explanatory notes should be provided to explain the factor(s) and/or circumstances underlying marked changes in the share of total investment represented by a given investment category over the forecast period relative to 'actual' spending over the historical period. For example, a large expenditure over a relatively short period for a
'one- off' project (e.g. a distribution station) can cause a temporary 'step change' in category C spending compared to the trend in actual expenditures over the historical period.

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.***

Table 5-27 provides a snapshot of WHESC's capital expenditures over a ten-year period, including four historical years, the estimated 2016 Bridge Year, the 2017 estimated Test Year, and four additional forecast years.

Table 5-27: Expenditure summary over the historical and forecast periods

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

First year of Forecast Period: *2017*

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2012			2013			2014			2015			2016			2017	2018	2019	2020	2021
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access		225,766	--	135,000	85,482	-36.7%		111,353	--		94,079	--	147,000	147,000	0.0%	204,501	250,000	250,000	190,000	150,000
System Renewal		1,233,301	--	1,334,200	1,504,700	12.8%		1,710,305	--		1,773,585	--	1,683,000	1,683,000	0.0%	1,834,485	1,495,000	1,775,000	1,920,000	1,770,000
System Service		8,300	--	35,000	4,047	-88.4%		55,500	--		33,237	--	-	-	--	110,000	260,000	35,000	35,000	35,000
General Plant		417,631	--	472,165	517,076	9.5%		322,389	--		281,463	--	801,800	801,800	0.0%	265,000	305,000	400,000	295,000	525,000
TOTAL EXPENDITURE	1,887,015	1,884,998	-0.1%	1,976,365	2,111,305	6.8%	2,002,500	2,199,547	9.8%	2,027,500	2,182,364	7.6%	2,631,800	2,631,800	0.0%	2,413,986	2,310,000	2,460,000	2,440,000	2,480,000
System O&M		$2,978,610	--	$3,013,809	$2,886,152	-4.2%		$2,926,724	--		$3,154,558	--	$3,255,419	$3,255,419	0.0%	$3,392,703	$3,460,557	$3,529,768	$3,600,364	$3,672,371

Notes to the Table:

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

2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' 0

Explanatory Notes on Variances (complete only if applicable)

Notes on shifts in forecast vs. historical budgets by category

The Budget amounts from 2013 to 2015 represents the total capital from the Asset Management Plan included in the 2013 Cost of Service Application ("COS"). As no Distribution System Plan was included in the 2013 COS there is no breakout available by category for the budget from 2012 to 2015. The Budget for 2012 represents the final amount approved in the 2013 Cost of Service Rate Application as detailed in the final Chapter 2 Appendices 2012 Continuity MIFRS.

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

Actual capital expenditures exceeded plan from 5% to 10% per year over the 2013 to 2015 period. Actuals are within the plus/minus 10% target WHESC has determined for Capital Expenditures.

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

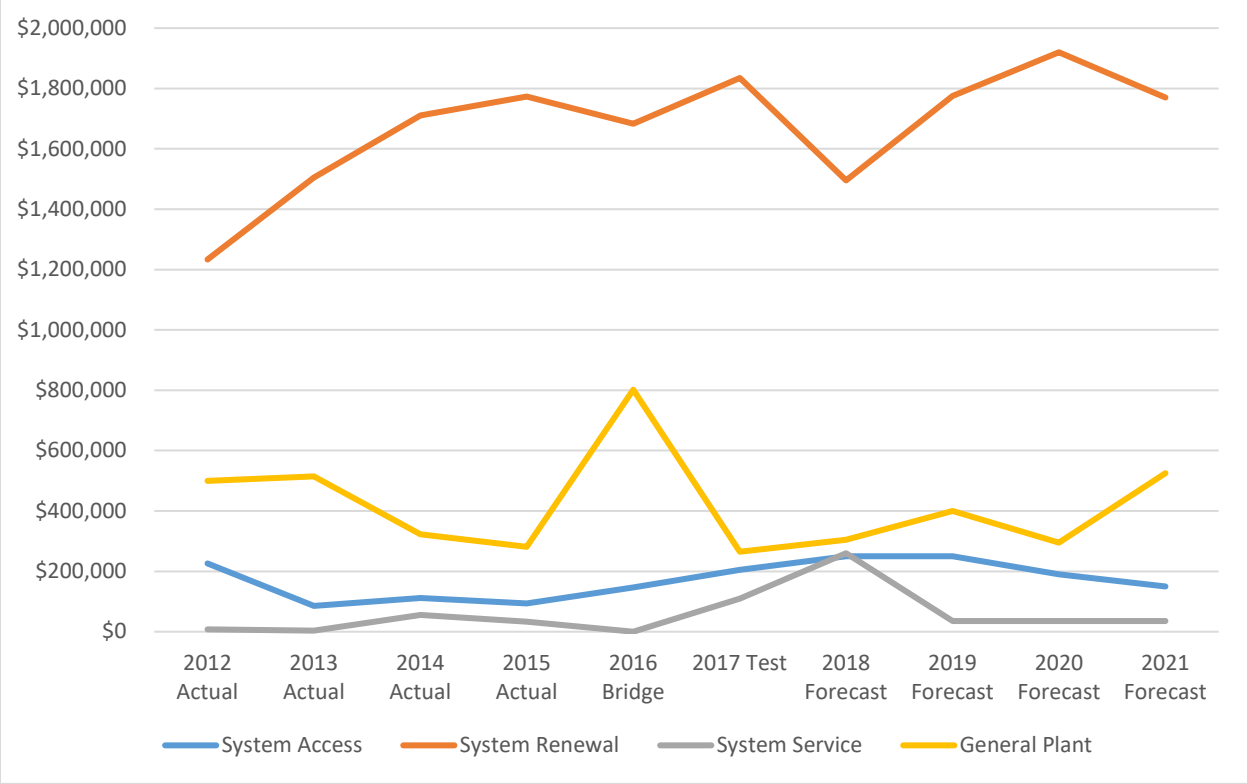
General Plant increased significantly in the 2016 Bridge Year as a result of the purchase of two new trucks at a cost of approximatley $650K.

WHESC does not have a previously filed or approved DSP, and as a result, variance explanations of actual capital expenditures compared to planned expenditures are not detailed.

5.4.4.1 Trends in Year-over-year Category Spending

Figure 5-36 summarizes trends in capital spending for each investment category over the historical and forecast periods. Year-over-year trends are discussed below.

Figure 5-36: Investments over the historical and forecast periods by category



2012 to 2013 Trends

Table 5-28: 2012 (actual) vs. 2013 (actual) capital expenditures

Description	2012 Actual	2013 Actual	Variance from 2012 Actual
System Access	225,766	85,482	-140,284
System Renewal	1,233,301	1,504,700	271,399
System Service	8,300	4,047	-4,253
General Plant	417,631	517,076	99,445
Total Capital Expenditures	**1,884,998**	**2,111,305**	**226,307**

System Access: Expenditures in 2012 included a road widening project of $287,848 offset by a Capital Contribution from the Region of Niagara of ($124,159). There were no major road widening projects in 2013. As a result, System Access spending is reduced in 2013 Actual compared to 2012 Actual.

System Renewal: There isn't one particular aspect that drives the variance, but instead a difference in the types of projects resulting in the small variance of $271,399. Reductions in Substation Renewal compared to 2012 are offset by additional overhead/underground line renewal projects in 2013.

System Service: This variance is below the materiality threshold variance.

General Plant: The variance was primarily driven by a large truck replacement in 2013 of $325,615. This was offset by a reduction in capital spending on Buildings and grounds compared to 2012 of ($290,340). Major renovations to the front office and conference room occurred in 2012.

2013 to 2014 Trends`

Table 5-29: 2013 (actual) vs. 2014 (actual) capital expenditures

Description	2013 Actual	2014 Actual	Variance from 2013 Actual
System Access	85,482	111,353	25,871
System Renewal	1,504,700	1,710,305	205,605
System Service	4,047	55,500	51,453
General Plant	517,076	322,389	-194,687
Total Capital Expenditures	**2,111,305**	**2,199,547**	**88,242**

System Access: The variance is below the materiality threshold.

System Renewal: There isn't one particular aspect that drives the variance, but instead a difference in the types of projects resulting in the small variance of $205,605. Overhead/Underground line renewal and conversion projects continue to be the main emphasis of capital spending.

System Service: This variance is the result of the purchase of SCADA ICCP software. This project remained in Work in Process for rate making purposes until 2015 when the software installation and modifications were completed and is currently fully operational. This software provides a direct link to the Crowland TS and provides more operating functionality than the existing Remote Terminal Unit (RTU) which is no longer used. WHESC can now perform functions related to distribution activities that previously had to be done via phone with Hydro One.

General Plant: The reduction is for the most part related to the purchase of the large truck replacement in 2013.

2014 to 2015 Trends

Table 5-30: 2014 (actual) vs. 2015 (actual) capital expenditures

Description	2014 Actual	2015 Actual	Variance from 2014 Actual
System Access	111,353	94,079	-17,274
System Renewal	1,710,305	1,773,585	63,280
System Service	55,500	33,237	-22,263
General Plant	322,389	281,463	-40,926
Total Capital Expenditures	**2,199,547**	**2,182,364**	**-17,183**

System Access: The variance is below the materiality threshold.

System Renewal: There isn't one particular aspect that drives the variance, but instead a difference in the types of projects resulting in the small variance of $63,280. Overhead/Underground line renewal and conversion projects continue to be the main emphasis of capital spending. The substation renewal program accounted for the majority of the variance as a result of an increase over 2014 of $137,899. Substation renewal will continue from the 2016 Bridge Year going forward.

System Service: The variance is below the materiality threshold.

General Plant: The variance is below the materiality threshold but is for the most related to reductions in Computer Hardware/Software compared to 2014.

2015 to 2016 Trends

Table 5-31: 2015 (actual) vs. 2016 (forecast) capital expenditures

Description	2015 Actual	2016 Bridge Year	Variance from 2015 Actual
System Access	94,079	147,000	52,921
System Renewal	1,773,585	1,683,000	-90,585
System Service	33,237	0	-33,237
General Plant	281,463	801,800	520,337
Total Capital Expenditures	**2,182,364**	**2,631,800**	**449,436**

System Access: The variance is below the materiality threshold.

System Renewal: There isn't one particular aspect that drives the variance, but instead a difference in the types of projects resulting in the small variance of ($90,585). Overhead/Underground line renewal and conversion projects continue to be the main emphasis of capital spending.

System Service: The variance is below the materiality threshold.

General Plant: The increase in General Plant capital spending is the replacement of two large trucks. The first is a 2016 International Bucket Truck for $364,100 of which $117,800 was included in 2015 WIP for rate base purposes. This vehicle replaces an 18 year old truck (1998) currently in service. The second truck is a Digger/Derrick used in plant construction at a total cost of $315,000. This vehicle replaces a 28 year old truck (1988) for which parts are difficult to locate. Loss of this vehicle would significantly impact plant construction activity and result in the increased use of contractors.

2016 to 2017 Trends

Table 5-32: 2016 (forecast) vs. 2017 (forecast) capital expenditures

Description	2016 Bridge Year	2017 Test Year	Variance from 2016 Bridge
System Access	147,000	204,501	57,501
System Renewal	1,683,000	1,834,485	151,485
System Service	0	110,000	110,000
General Plant	801,800	265,000	-536,800
Total Capital Expenditures	**2,631,800**	**2,413,986**	**-217,814**

System Access: The increase in System Access capital spending is related to smart meter replacements as a result of the start of testing. The initial seal period for smart meters installed in 2009 will expire in 2019. Measurement Canada expects utilities to pre-sample their meter population prior to applying for a final extension period. The new sampling procedure will require additional smart meter stock and possible additional operating costs.

System Renewal: There isn't one particular aspect that drives the variance, but instead a difference in the types of projects resulting in the small variance of $151,485. Overhead/Underground line renewal and conversion projects continue to be the main emphasis of capital spending along with substation renewal.

System Service: The variance is attributable to installation of a SCADA Radio System totaling $60,000. The second is for the purchase of new SCADA SmartVu software at a cost of $50,000. The current software will no longer be supported after 2017.

General Plant: Capital spending compared to 2016 Bridge Year is down significantly as 2016 had two major vehicle purchases. The 2017 Test Year marks the start of a program to improve Building Facilities & Grounds with repaving the service center parking lot. This project will be phased in over two years. There are no significant investments planned for CIS/Financial computer software in either of the 2016 Bridge or 2017 Test Years.

2018 to 2021 Trends

Table 5-33: Forecast capital expenditures – 2018 to 2021

Description	2018 Forecast	2019 Forecast	2020 Forecast	2021 Forecast
System Access	250,000	250,000	190,000	150,000
System Renewal	1,495,000	1,775,000	1,920,000	1,770,000
System Service	260,000	35,000	35,000	35,000
General Plant	305,000	400,000	295,000	525,000
Total Capital Expenditures	**2,310,000**	**2,460,000**	**2,440,000**	**2,480,000**

System Access: Forecast expenditures in the System Access category are for the most part comprised of New Overhead Services, Contributed Capital, and Meters. New Overhead Services of $40,000 and Contributed Capital of $50,000 are based on historical expenditures. Meters include both smart meters ($60,000 to $100,000 per year) and MIST Meters at $60,000 in both 2018 and 2019. The smart meters spending includes both growth, testing program requirement, and early retirements. The MIST meter replacements have been mandated by the OEB.

System Renewal: Expenditures in the System Renewal category are comprised for the most part of substation renewals and overhead/underground renewals. WHESC levels these expenditures out with a balance between reliability and affordability while leaving some flexibility for unexpected growth in projects or emergency rebuilds.

System Service: The increase in System Service capital expenditures in 2018 is related to RTU Relay replacements at two substations. WHESC has been experiencing operational issues with the relays at these substations which are from the same manufacturer and same vintage. Although WHESC has made repairs to extend their useful lives, further delay in replacement could cause significant reliability issues.

General Plant: Expenditures show spikes in capital spending in 2019 and 2021. A new service center roof is currently being planned for replacement in 2019. After updating its vehicle fleet in 2016, WHESC has only minor vehicle replacements in 2018 and 2019. There are currently two larger trucks which will require replacement over the next five years. A vintage year 2000 bucket truck will be purchased beginning with a deposit in 2020 and completion in 2021 at a cost of $370,000. A smaller digger/derrick vintage 1990 will be replaced in 2022 which will require a deposit estimated at $120,000 in 2021.

5.4.5 Justifying Capital Expenditures

As indicated in Chapter 1, the onus is on a distributor to provide the data, information and analyses necessary to support the capital-related costs upon which the distributor's rate proposal is based. Filings must enable the Board to assess whether and how a distributor's DS Plan delivers value to customers, including by controlling costs in

relation to its proposed investments through appropriate optimization, prioritization and pacing of capital-related expenditures.

5.4.5.1 Overall Plan

The Board's assessment of DS Plans includes the costs of material projects/activities included in the DS Plan, as well as the costs represented by the respective shares of the overall DS Plan budget allocated to each of the four investment categories.

Information to be provided in this section pertains to the latter; the former is addressed in section 5.4.5.2.

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)***

WHESC's DSP delivers value to customers by controlling costs in relation to its proposed investments through appropriate optimization, prioritization and pacing of capital-related expenditures. WHESC's customers' value system reliability and low cost. WHESC's capital plan, both historical and forecast, allow for a significant portion of investments to affect the replacement of end of life assets to maintain system reliability. A significant portion of the asset replacement projects include the voltage conversion process to realize short and long term efficiencies due to reduced system losses and long term efficiencies and reduced operating and capital costs as a result of the elimination of Municipal Substations.

5.4.5.1.1 Comparative Expenditures by Category over the Historical Period

Comparative capital expenditures by investment category are presented in Table 5-27.

5.4.5.1.2 Forecast Impact of System Investment on System O&M Costs

Replacement of end-of-life plant with new plant will still require the allocation of resources for ongoing OM&A purposes. Repair would be the most significant OM&A activity impacted by new plant. Certain assets, such as poles, offer few opportunities for repair related activities and generally require replacement when deemed at end of normal life or critically damaged. If assets approaching end of life are replaced at a rate that maintains equipment class average condition, then one would expect little or no change to OM&A

costs under no growth scenarios but would still see upward OM&A cost pressure on positive growth scenarios (more cumulative assets to maintain each year).

While it is difficult to quantify specific system investments that directly impact system O&M costs, there are a number of activities within the capital program that tend to have a positive impact on O&M related expenditures. See Section 5.2.1b for a complete list of these activities.

WHESC has replaced approximately 100 Pole-Tran transformers and direct buried underground cable with pad-mounted transformers and new primary cable in duct. This program will continue and it is expected that all Pole-Tran transformers will be replaced over the next 10 years. Renewal of these assets is anticipated to reduce future O&M costs.

A list of additional examples is provided below to help demonstrate commitment and consideration taken on the reduction of O&M related costs during the asset management and capital expenditure planning process.

- Installation of SCADAmate switches and Remote Terminal Units to provide system information and remote switching capability reducing operational costs during planned and unplanned events.
- System support expenditures (e.g. GIS, Asset Condition Inspections) are expected to provide a better overall understanding of WHESC's assets that will lead to more efficient and optimized design, maintenance and investment activities going forward. Asset Condition Inspections have been conducted and data gaps have been identified. Efficiencies will allow existing resources to partially compensate for growth related increases in OM&A activities.
- Continued development of the GIS and related field information gathering tools have reduced the amount of time to record and input the data into the GIS system and has assisted in meeting the requirements of Regulation 22/04.
- Change in Municipal Substation Designs have resulted in identical equipment components that are interchangeable between substations if necessary during planned or un-planned events.
- Installation of animal guards on pole-mounted transformers reducing the cost of equipment replacement due to animal high voltage contacts.
- Voltage Conversion projects which will reduce system losses and eventually eliminate the Municipal Substations.

5.4.5.1.3 Drivers of Investments by Category

Table 5-34 provides a more comprehensive picture of WHESC's investment drivers by category over the historical and forecast periods.

Table 5-34: Drivers of investment by category

		2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Bridge Year	2017 Test Year	2018 Forecast	2019 Forecast	2020 Forecast	2021 Forecast
Driver	Program Activity										
System Access											
System Relocations	Municipal Relocations	$163,689			$32,821	-$3,000	$14,501				
Customer Service Requests	Customer Connections	$39,404	$9,908	$40,922	$42,577	$40,000	$40,000	$40,000	$40,000	$40,000	$40,000
	Expansions (Subdivisions)	$76,534	$69,401	$30,316	$24,410	$50,000	$50,000	$50,000	$50,000	$50,000	$50,000
Commerical Customer	Transformer Sale	-$74,519	-$59,359	-$29,240	-$56,586						
Mandated Service	Retail Meters	$20,658	$65,532	$69,355	$50,857	$60,000	$100,000	$160,000	$160,000	$100,000	$60,000
Sub-Total		$225,766	$85,482	$111,353	$94,079	$147,000	$204,501	$250,000	$250,000	$190,000	$150,000
System Renewal											
End of Life service Assets	Substation Renewal	$201,785	$3,532		$137,899	$200,000	$170,000	$225,000	$150,000	$50,000	$100,000
	Overhead Line Renewal	$791,205	$1,013,546	$1,008,927	$794,499	$963,000	$749,485	$400,000	$740,000	$935,000	$1,110,000
	Underground Line Renewal	$145,674	$333,637	$536,326	$574,446	$310,000	$705,000	$710,000	$725,000	$775,000	$400,000
	Miscellaneous	$94,637	$153,985	$165,052	$266,741	$210,000	$210,000	$160,000	$160,000	$160,000	$160,000
Sub-Total		$1,233,301	$1,504,700	$1,710,305	$1,773,585	$1,683,000	$1,834,485	$1,495,000	$1,775,000	$1,920,000	$1,770,000
System Service											
SCADA and Automation	Scada Switches/Remote Fault Indciators/Radio Systems	$8,300	$4,047		$5,326		$60,000	$35,000	$35,000	$35,000	$35,000
	RTU/Relay Replacements							$175,000			
	Sever/Softerware Upgrades			$55,500	$27,911		$50,000	$50,000			
Sub-Total		$8,300	$4,047	$55,500	$33,237	$0	$110,000	$260,000	$35,000	$35,000	$35,000
General Plant											
Repairs/End of Life	Land & Buildings	$311,607	$22,167	$33,433	$18,710	$70,000	$125,000	$125,000	$275,000	$25,000	$25,000
Replacement	Furniture/Equipment	$11,025	$1,403								
Replacement/Upgrades	Computer Hardware	$13,289	$14,809	$112,624	$67,324	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000
Enhancements/Regulatory	Computer Software	$78,714	$85,022	$78,086	$46,130	$65,000	$40,000	$50,000	$50,000	$50,000	$50,000
Replacement/Regulatory	Communication/Measurement/Tools	$2,996	$68,060	$9,475		$5,500	$5,000	$5,000	$5,000	$5,000	$5,000
Replacement/Safety	Fleet		$325,615	$88,771	$149,299	$636,300	$70,000	$100,000	$45,000	$190,000	$420,000
Sub-Total		$417,631	$517,076	$322,389	$281,463	$801,800	$265,000	$305,000	$400,000	$295,000	$525,000
Total Regulated Capital Expenditures		$1,884,998	$2,111,305	$2,199,547	$2,182,364	$2,631,800	$2,413,986	$2,310,000	$2,460,000	$2,440,000	$2,480,000

System Access

Municipal Relocations: These are projects required to accommodate road work by the City of Welland or the Niagara Region. Projects are driven by these authorities and are difficult to predict. A portion of the capital costs are recovered through capital contributions based on a cost sharing agreement/act.

Customer Connections: These are projects that are, based on regulatory requirements, essential in order to meet the demand of new and existing customers connected or requesting to connect to WHESC's distribution system.

Expansions (Subdivisions): These projects are capital contributions to developers, based on regulatory requirements, for the installation of new subdivision assets.

Retail Meters: These are projects that are, based on regulatory requirements, essential in order to meet the demand of new and existing customers connected or requesting to connect to WHESC's distribution system. These projects also, based on regulatory requirements, allow for the provision of MIST (Interval or Smart) meters to be installed at new and existing commercial customer services at, or projected to be, 50kW demand or greater.

System Renewal

System Renewal investments are driven by assets at the end of their service life and system reliability. Assets that are replaced due to a safety concern also fall under the System Renewal category. Depending on the asset category and impact of end-of-life, some assets, such as substation transformers, are replaced proactively before they fail. Other assets such as distribution transformers may be run to failure, depending on impact, or replaced proactively depending as part of a material project. System Renewal benefits include planned projects such as substation renewal, overhead rebuilds, and underground rebuilds, as well as miscellaneous replacements that cannot be included in a rebuild.

Substation Renewal: As depicted in Table 5-16 (Section 5.3.2c.1), the oldest transformers are 14T1 (53 years), 7T1 (52 years), 8T1 (50 years), and 9T1 (47 years). The HV and LV switchgear at 14T1 are also 53 years old and the entire substation will be rebuilt in 2017. The HV and LV switchgear and feeder cables at 8T1 are all the same age as the transformer and WHESC is planning to rebuild the entire substation in 2018. The HV and LV switchgear at 9T1 were installed in 1969 and it is estimated that the primary, secondary, and feeder cables were installed in the same year. The LV switchgear and feeder cables at 9T1 are budgeted to be replaced in 2019, meanwhile the transformer and HV side will be replaced outside of the forecast period of this DSP (planned for 2022). Finally, the major assets at 7T1 other than the power transformer do not require replacement over the forecast period, therefore only the transformer is scheduled for replacement in 2020.

Underground and Overhead System Renewal: Table 5-35 presents the number of asset replacements over the forecast period for the major classes of underground and overhead systems: poles, distribution transformers and underground cable.

Table 5-35: Asset replacements over the forecast period

Year	Poles	Distribution Transformers		Underground Cable	
	Installed	Installed	Replaced	Installed (m)	Replaced (m)
2017	107	37	47	2,740	3,235
2018	70	30	38	3,150	3,850
2019	90	40	40	2,205	2,620
2020	114	33	42	1,600	2,900
2021	105	36	34	1,335	1,025

System Service

System Service investments over the forecast period focus on SCADA and Automation. This includes replacements and new installations of SCADA switches, Remote Fault Indicators, radio systems, RTUs, relay, servers, and software. These projects are required to ensure continued system performance through the replacement of SCADA devices. Assets, such as protection relays demonstrating performance issues or concerns, are replaced prior to failure due to risk of further asset damage to associated substation

equipment. Other assets, such as remote terminal units, are replaced once individual component failures have rendered the equipment to be of little value to the system. If a significant component failure introduces significant reliability risk, the remote terminal unit is replaced as like for like or with another technology that offers enhanced operability and/or lower installation cost. Other key assets, such as SCADA communication equipment, hardware and software are included in this asset replacement/enhancement program.

General Plant

Investments in this category are driven by inspections and expert opinion determining the requirement for replacement of assets or by policy requiring assets, such as IT hardware, to be replaced on a determined schedule. WHESC continues to invest in this category to maintain building assets that were originally installed in the late 1960's with the approach that asset maintenance is far more cost effective than complete replacement of land and buildings. Significant assets, such as the roof, tend to last for a long period of time, however replacement costs make it difficult to smooth costs overtime. With that in mind, other capital projects are scheduled to align with significant building asset replacements to smooth overall annual capital spending.

Fleet investments are planned to reduce the amount of risk to an acceptable level, balancing operational efficiency and continuity to providing equipment to support all applicable company processes. Vehicles that are used for the higher risk work, namely bucket trucks, are given additional safety assessment rankings based on the type of high risk work they are used for and tend to be replaced sooner than the other large digger trucks. However, all vehicles remain in service as long as possible to reduce overall capital replacement costs. Table 5-36 lists the vehicle replacements planned in the Bridge Year (2016) and over the forecast period.

Table 5-36: Fleet replacement schedule

Unit #	Vehicles Make and Model	2016	2017	2018	2019	2020	2021
31	1988 GMC TOPKICK DIGGER	$315,000					
18	1990 INTERNTIONAL DIGGER						$120,000
3	1995 FORD F-250	$40,000					
24	1997 F-250 4X4			$50,000			
9	1998 F-800 BUCKET	$246,300					
11	2000 INTERNATIONAL BUCKET					$120,000	$250,000
1	2000 F 150	$35,000					
36	2000 FORD RANGER SHORT BOX		$35,000				
37	2000 FORD RANGER LONG BOX		$35,000				
43	2002 HYSTER FORK LIFT			$50,000			
41	2005 MONTANA VAN					$30,000	
42	2005 CHEV 2500				$45,000		
44	2007 UPLANDER VAN					$40,000	
51	2010 GMC						$50,000

5.4.5.1.4 Information Related to the Distributor's System Capability Assessment

WHESC's distribution system is capable of meeting future demands with respect to load and generation connection needs. WHESC has not included any investments for any provisions required to connect REG type projects in the DSP. WHESC's distribution system capacity does not require any increases within the forecast period of 2017 to 2021.

5.4.5.2 Material investments

The focus of this section is on projects/activities that meet the materiality threshold set out in Chapter 2 of the Filing Requirements for Electricity Transmission and Distribution Applications. However, distributors are encouraged in all instances to consider the applicability of these requirements to ensure that all investments proposed for recovery in rates, including those deemed by the applicant to be distinct for any other reason (e.g. unique characteristics; marked divergence from previous trend) are supported by evidence that enables the Board's assessment according to the evaluation criteria set out below. The level of detail characterizing the evidence filed by a distributor to support a given investment project/activity should be proportional to the materiality of the investment.

A. General Information on the Project/Activity

The following information is to be provided for any material project in order to facilitate and understanding of the quantum of the expenditure, timing, and contingencies associated with the project:

- *total capital and where applicable, (non-capitalized) O&M costs proposed for recovery in rates*
- *related customer attachments and load, as applicable*
- *start date, in-service date and expenditure timing over the planning horizon*
- *the risks to the completion of the project or activity as planned and the manner in which such risks will be mitigated*
- *if not evident from Table 2, comparative information on expenditures for equivalent projects/activities over the historical period, where available*
- *information on total capital and OM&A costs associated with REG investment, if any, included in a project/activity; and a description of how the REG investment is expected to improve the system's ability to accommodate the connection of REG facilities*
- *where a proposed project requires Leave to Construct approval under Section 92 of the OEB Act, with construction commencing in the test year, the applicant must provide a summary of the evidence for that project consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular)*

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

The Board's evaluation of material investments aligns with the outcome s set out in section 5.0.4. Efficiency, customer value, reliability and safety are the primary criteria for evaluating any material investment; other criteria pertaining specifically to grid modernization will be applied where applicable.

The Board's investment evaluation criteria and the qualitative or quantitative evidence that a distributor can use to demonstrate that an investment is consistent with these criteria are set out below.

1. Efficiency, Customer Value, Reliability

a) identify the main 'driver' ('trigger') of the project/activity, and where applicable any secondary 'drivers'; related objectives and/or performance targets; and by reference to the distributor's asset management process (section 5.3.1), the source and nature of the information used to justify the investment

b) indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing and pacing projects in each investment category described in response to section 5.4.2(c)

c) using, where applicable, quantitative and/or qualitative analyses of the project and project alternatives involving design, scheduling, funding and/or ownership options (e.g. whole or part ownership solely by or jointly with 3rd parties)

–explain the effect of the investment on system operation efficiency and cost- effectiveness

–the net benefits accruing to customers as a result of the investment

–the impact of the investment on reliability performance including on the frequency and duration of outages

Where alternatives have been considered and the ranking of a proposed project relative to alternatives has been affected by the imputed value of benefits and costs, these benefits and costs should be described and explained in relation to the proposed project and alternatives.

Where a distributor's choices as to technical design, component characteristics, how the work is carried out, etc. have been affected by a decision to configure a project to meet both a 'trigger' driver and one or more other drivers in a manner that affects cost as well as benefits, these effects should be highlighted.

2. Safety

Provide information on the effect of the investment on health and safety protections and performance

3. Cyber-security, Privacy

Where applicable, provide information showing that the investment conforms to all applicable laws, standards and best utility practices pertaining to customer privacy, cyber-security and grid protection

4. Co-ordination, Interoperability

a) where applicable, explain how the investment applies recognized standards, referencing co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry.

b) describe how the investment potentially enables future technological functionality and/or addresses future operational requirements

5. Economic Development

Where applicable, describe the effect of the investment on Ontario economic growth and job creation

6. Environmental Benefits:

Where applicable, describe the effect of the investment on the use of clean technology, conservation and more efficient use of existing technologies

C. Category-specific requirements for each project/activity

As set out below, category-specific information and analyses should also be used to support a project/activity (or elements thereof as applicable).

a) System access– projects/activities in this category are driven by statutory, regulatory or other obligations on the part of the distributor to provide customers with access to their distribution system. Most frequently, investments relate to requests by customers for connections or connection modifications, but also include requests from municipal authorities for a distributor to relocate system assets in order to accommodate infrastructure

development or modifications. Consequently, investment budgets for this category can vary from one DS Plan to the next depending on business conditions.

In the event that the project involves replacing a distributor's system assets, there may also be asset life-cycle related considerations to the extent that infrastructure is taken out of service prior to the end of its service life and new infrastructure is commissioned.

Information bearing on these issues should therefore be included in a distributor's justification of a project/activity in this category, including (where applicable) but not restricted to:

- *factors affecting the timing/priority of implementing the project*
- *factors relating to customer preferences or input from customers and other third parties*
- *factors affecting the final cost of the project • how controllable costs have been minimized*
- *whether other planning objectives are met by the project or have intentionally been combined into the project and if so, which objectives and why*
- *whether technically feasible project design and/or implementation options exist, whether these options were considered and if not, why not*
- *where such options were considered and project decision support tools and methods described in response to section 5.4.2 (c) were used to help identify the proposed option, provide a summary of the results of the analysis, including where applicable:*
    - *the least cost option: a comparison of the life cycle cost of all options considered (including the proposed project) – over the service life of the proposed project*
    - *the cost efficient option: a comparison of net project benefits and costs over the service life of the proposed project including:*
        - *i. a project configured solely to meet the obligation; and*
        - *ii. the proposed project and where considered, technically feasible options to the proposed project that meet the same objectives.*
- *where applicable, the results of the 'final economic evaluation' carried out as per section 3.2 of the DSC*
- *where applicable (e.g. REG investment), information on the nature and magnitude of the system impacts of the project, the costs of any system modifications required to accommodate these impacts and the means by which these costs are to be recovered*

b) System renewal– projects/activities in this category are driven by the relationship between the ability of an asset or asset system to continue to perform at an acceptable standard on a predictable basis on one hand and on the other, the consequences for customers served by the asset(s) of a deterioration of this ability (i.e. "failure"). Generally, the lower the former and/or higher the latter, the more important it becomes to replace or refurbish the asset(s) sooner rather than later.

Hence, a distributor's discretion over the timing and priority of projects in this category may lessen over time, such as where assets with high consequence of failure are consistently operating outside applicable operating limits.

On the other hand, a distributor may have considerable discretion over timing and priority where deteriorating asset condition has little or no impact on performance and the consequences in terms of the number of customers and criticality of service potentially affected by an asset failure are relatively low.

Information bearing on these issues should therefore be included in a distributor's justification of each sustainment project/activity, including (where applicable) but not restricted to:

- *a description of the relationship between the characteristics of the assets targeted by a project and the consequences of asset performance deterioration or failure, referring to*
  - *the distributor's asset performance-related operational targets and asset lifecycle optimization policies and practices (i.e. filings in relation to sections 5.2.3 and 5.3.3)*
  - *information on the condition of the assets relative to their typical life-cycle; and performance record of the assets targeted by the project*
  - *the number of customers in each customer class potentially affected by a failure of the assets included in the project*
  - *quantitative customer impacts (e.g. frequency or duration of interruptions or number of customers affected) with associated risk level(s)*
  - *qualitative customer impacts (e.g. customer satisfaction; customer migration) with associated risk level(s)*
  - *the value of customer impact (e.g. high, medium, low) in terms of the characteristics of customers potentially affected by failure that have a bearing on the criticality and/or cost of failure (e.g. customer classes; customer access to backup service)*
- *other factors that may affect the timing of the proposed project, including the rate at which assets are replaced over the forecast period (i.e. investment intensity), where applicable; priority relative to other projects (this and other categories)*
- *identify the consequences for system O&M costs, including the implications for system O&M of not implementing the project*
- *identification of reliability and or safety factors that may have played a role*
- *where applicable and reasonable variation and/or uncertainty in the above factors exists, provide – using the tools and methods described in response to section 5.4.2 (c) – an analysis of project benefits and costs comparing alternatives to the timing of the proposed project, highlighting the trade-offs between rate of expenditure and mitigation of the consequences of asset performance deterioration. Where the ranking of the proposed project relative to the alternatives has been adjusted to account for significant benefits and costs the value of which cannot readily be quantified, these should be described and explained in relation to the proposed project and all alternatives.*
- *where the proposed project meets the requirement for 'like for like' renewal and has been configured at extra cost to address other distributor planning objectives (e.g. development related objectives), provide – using the tools and methods described in response to section 5.4.2 (c) – an analysis of project benefits*

and costs comparing a) a project configured solely to meet the requirement; b) the proposed project; and c) technically feasible alternatives to the proposed project that meet the same objectives as the proposed project. Where the ranking of the proposed project relative to alternatives has been adjusted to account for significant benefits and costs the value of which cannot readily be quantified, these should be described and explained in relation to the proposed project and all alternatives.

c) System service– projects/activities in this category are driven by the distributor's expectations that evolving customer use of the system may occasion the creation of system capacity constraints or otherwise adversely impact operations in a manner that challenges the distributor's service delivery standards or objectives. Distributor discretion in relation to investments in this category can be relatively high in terms of both initiating a project and determining the priority and timing of project-related expenditures.

Information used by a distributor to justify projects/activities in this category should include, but need not be restricted to:

- *where measurable, an assessment of the benefits of the project for customers in relation to the achievement of the objectives of the investment; express the result (including where value is in the form of an avoided cost) in terms of cost impact to customers where practicable*
- *where applicable, information on regional electricity infrastructure requirements identified in a regional planning process that affected the initiation or final configuration of the project; and on the corresponding distribution of the benefits and responsibility for project costs*
- *description of how advanced technology has been incorporated into the project (if applicable) and including how standards relating to interoperability and cybersecurity have been met.*
- *identification of any reliability, efficiency, safety and coordination benefits or affects the project will have on the distributor's system*
- *identifying and explaining the factors affecting implementation timing/priority*
- *providing, where applicable and using the tools and methods described in response to section 5.4.2 (c), an analysis of project benefits and costs comparing the proposed project to a) doing nothing; and b) technically feasible alternatives to the proposed project considered that meet the same objectives as the proposed project.*

  Where the ranking of the proposed project relative to alternatives has been adjusted to account for significant benefits and costs the value of which cannot readily be quantified, information should be provided that describes these 'qualitative' factors in relation to the proposed project and all alternatives, and that explains whether and how these factors affected the selection of the proposed project.

d) General plant– projects/activities in this category are driven by the distributor's evolving requirements for capital to support day to day business and operations activities. Distributor discretion in relation to investments in this category can be relatively high in terms of both initiating a project and determining the priority and timing of project-related expenditures.

Information used by a distributor to justify material projects/activities in this category should include but need not be restricted to:

- ***the results of quantitative and qualitative analyses (using the tools and methods described in response to section 5.4.2 (c) where applicable) of the proposed project/activity, including assessments of financially feasible options to the proposed project (including the 'do nothing option' where applicable), identifying the (net) benefits of the proposed investment in monetary terms where practicable;***
- ***For projects the capital cost of which substantially exceed the materiality threshold, (e.g. CIS, GIS, new office building) the distributor shall file a thorough business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).***

The following documents detail information to projects that meet WHESC''s materiality threshold of $53,000 for the year 2017. A list of these projects is listed in Table 5-37 below. Details of each project are found in Appendix 5-D.

Table 5-37: Material projects in the Test Year (2017) by investment category

Investment Category	Project/Activity	Capital Cost
System Access	Smart Meters	$100,000
System Renewal	MS 8 Transformer	$50,000
System Renewal	MS 14 Transformer/Switchgear/Primary Cabling Replacement	$120,000
System Renewal	Church Street/Niagara Street Rebuild/Conversion 4.16kV to 27.6kV	$300,000
System Renewal	Wellington Street-East Main to Eastdale Rebuild/Conversion 4.16kV to 27.6kV	$250,000
System Renewal	Ross Street/Kennedy Street Rebuild/Conversion 4.16kV to 27.6kV	$150,000
System Renewal	Maureen Ave 2.4kV Rebuild	$125,000
System Renewal	Riverview Drive Rebuild/Conversion 4.16kV to 27.6kV	$150,000
System Renewal	Robert Street Rebuild/Conversion 2.4kV to 16kV	$150,000
System Renewal	Silvan/Newleaf Phase 2 Rebuild/Conversion 2.4kV TO 16Kv	$280,000
System Renewal	Miscellaneous Pole Replacements	$100,000
System Renewal	Miscellaneous Transformer Replacements	$50,000
System Service	SCADA Switches/Remote Fault Indicators/Radio Systems	$60,000
System Service	SCADA SmartVU/Server Upgrade	$50,000
General Plant	Service Centre Parking Lot Paving	$100,000

DISTRIBUTION SYSTEM PLAN

APPENDIX 5-A

HYDRO ONE NEEDS ASSESSMENT REPORT

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

NEEDS ASSESSMENT REPORT

Region: Niagara

Date: April 30th 2016

Prepared by: Niagara Region Study Team

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

DISCLAIMER

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Niagara 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	Niagara (the "Region")		
Lead	Hydro One Networks Inc. ("Hydro One")		
Start Date	October 15, 2015	End Date	April 30th 2016

1. INTRODUCTION

The purpose of this Needs Assessment (NA) report is to undertake an assessment of the Niagara 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 and other parties as required.

For needs that require further regional planning and coordination, 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 NA for the Niagara 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 NA for Group 1 and 2 regions is complete and has been initiated for Group 3 Regions. The Niagara Region belongs to Group 3. The NA for this Region was triggered on October 15, 2015 and was completed on April 30th 2016

3. SCOPE OF NEEDS ASSESSMENT

The scope of the NA study was limited to 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 2025. Needs emerging over the next 10 years and requiring coordinated regional planning may be further assessed as part of the IESO-led SA, which will determine the appropriate regional planning approach: IRRP, RIP, and/or local planning. This NA included a study of transmission system connection facilities capability, which covers station 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 Independent Electricity System Operator (IESO), and Hydro One transmission provided information for the Niagara 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.

5. NEEDS ASSESSMENT METHODOLOGY

The assessment's primary objective was to identify the electrical infrastructure needs and system performance issues in the Region over the study period (2015 to 2024). The assessment reviewed available information, load forecasts and included single contingency analysis to confirm needs, if and when required. See Section 5 for further details.

6. RESULTS

Transmission Needs

A. Transmission Lines & Ratings

The 230kV and 115kV lines are adequate over the study period with a section of 115kV circuit Q4N being the exception.

B. 230 kV and 115 kV Connection Facilities

The 230kV and 115kV connection facilities in this region are adequate over the study period.

System Reliability, Operation and Restoration Review

There are no known issues with system reliability, operation and restoration in the Niagara region.

Aging Infrastructure / Replacement Plan

Within the regional planning time horizon, the following sustainment work is currently planned by Hydro One in the region:

- DeCew Falls SS: Circuit Breaker Replacement (2017)
- Sir Adam Beck SS #1: 115kV Refurbishment Project (2018)
- 115kV Q11/Q12S Line Refurbishment from Glendale TS to Beck SS #1 (2019)
- Carlton TS: Switchgear Replacement (2020)
- Sir Adam Beck SS #2: 230kV Circuit Breakers Replacement (2020)
- Glendale TS: Station Refurbishment and Reconfiguration (2021)
- Stanley TS: Station Refurbishment (2021)
- Thorold TS: Transformer Replacement (2021)
- Crowland TS: Transformer Replacement (2021)

Based on the findings of the Needs Assessment, the study team recommends that thethermal overloading of 115kV circuit Q4N shouldbe further assessed as part of a Local Plan. No further regional coordination or planning is required.

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1 Introduction

This Needs Assessment (NA) report provides a summary of needs that are emerging in the Niagara Region ("Region") over the next ten years. The development of the NA 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 NA is to undertake an assessment of the Niagara 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, as transmitter, with Local Distribution Companies (LDC) 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 local type of needs if straight forward wires solutions can address a need. Ultimately, assessment and findings of the local plans are incorporated in the RIP for the region.

This report was prepared by the Niagara Region NA study team (Table 1) and led by the transmitter, Hydro One Networks Inc. The report captures the results of the assessment based on information provided by LDCs, and the Independent Electricity System Operator (IESO).

Table 1: Study Team Participants for Niagara Region

No.	Company
1	Hydro One Networks Inc. (Lead Transmitter)
2	Independent Electricity System Operator
3	Canadian Niagara Power Inc.
4	Grimsby Power Inc.
5	Haldimand County Hydro Inc
6	Horizon Utilities Corp.
7	Hydro One Networks Inc. (Distribution)
8	Niagara Peninsula Energy Inc.
9	Niagara on the Lake Hydro Inc.
10	Welland Hydro Electric System Corp.

2 Regional Issue / Trigger

The NA for the Niagara Region was triggered in response to the OEB's 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 NA for Group 1 Regions is complete and has been initiated for Group 2 Regions. The Niagara Region belongs to Group 3.

3 Scope of Needs Assessment

This NA covers the Niagara Region over an assessment period of 2015 to 2024. The scope of the NA 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 NA.

3.1 Niagara Region Description and Connection Configuration

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

regional infrastructure planning needs assessment for Niagara region. A map of the region is shown below in Figure 1.

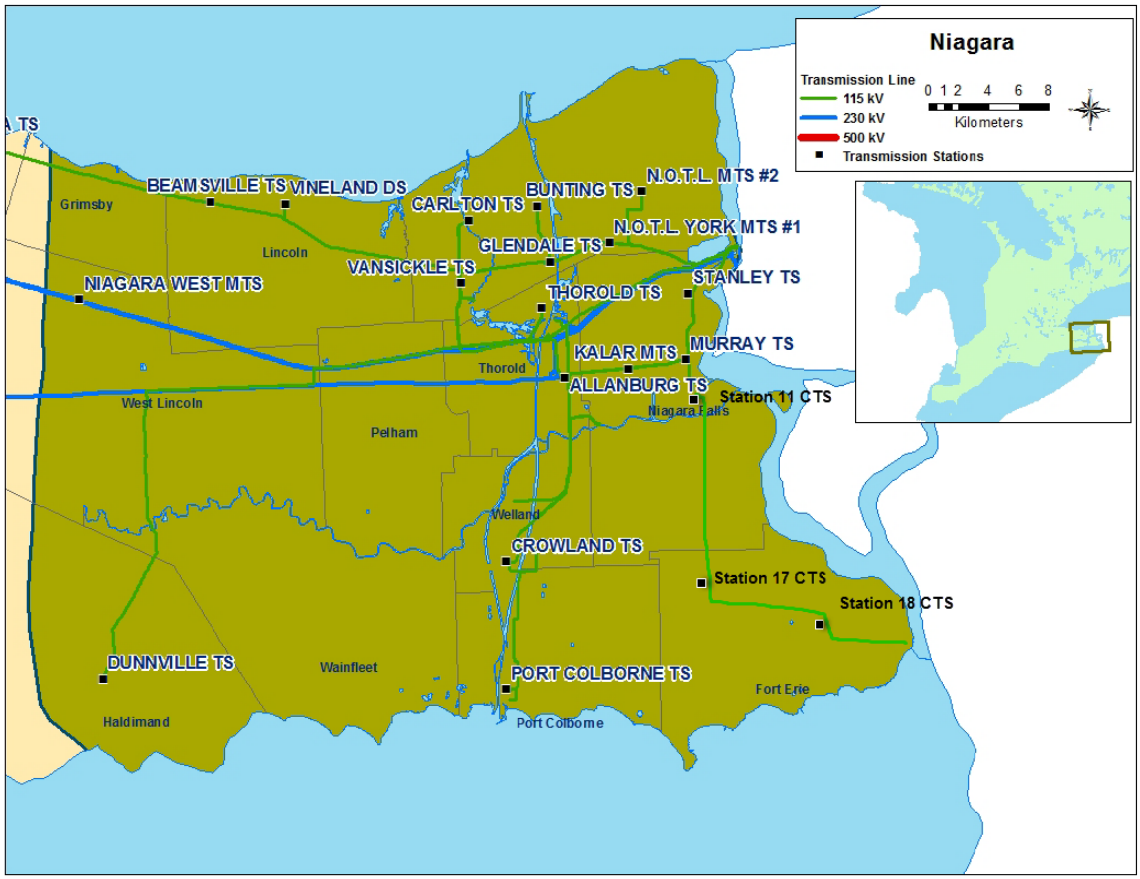

Figure 1: Niagara Region Map

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

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

The Niagara Region has the following local distribution companies (LDC):

- Canadian Niagara Power Inc.
- Grimsby Power Inc.
- Haldimand County Hydro Inc.
- Horizon Utilities
- Hydro One Distribution Inc.
- Niagara Peninsula Energy Inc.
- Niagara on the Lake Hydro Inc.
- Welland Hydro Electric System Corporation

Large transmission connected customers in the area will not actively participate in the regional planning process, however their load forecasts will used in determining regional supply needs.

Table 2: Transmission Lines and Stations in Niagara Region

115kV circuits	230kV circuits	Hydro One Transformer Stations	Customer Transformer Stations
Q3N, Q4N, Q11S, Q12S, Q2AH, A36N, A37N, D9HS, D10S, D1A, D3A, A6C, A7C,C1P, C2P	Q23BM, Q24HM, Q25BM, Q26M, Q28A, Q29HM, Q30M, Q35M, Q21P, Q22P	Allanburg TS*, Stanley TS, Niagara Murray TS, Thorold TS, Vansickle TS, Carlton TS, Glendale TS, Bunting TS, Dunville TS, Vineland TS, Beamsville TS, Sir Adam Beck SS #1, Sir Adam Beck SS #2, Crowland TS, Port Colborne TS	Niagara on the Lake #1 and #2 MTS, CNPI Station 11 , CNPI Station 17, CNPI Station 18, Kalar MTS, Niagara West MTS

Stations with Autotransformers installed

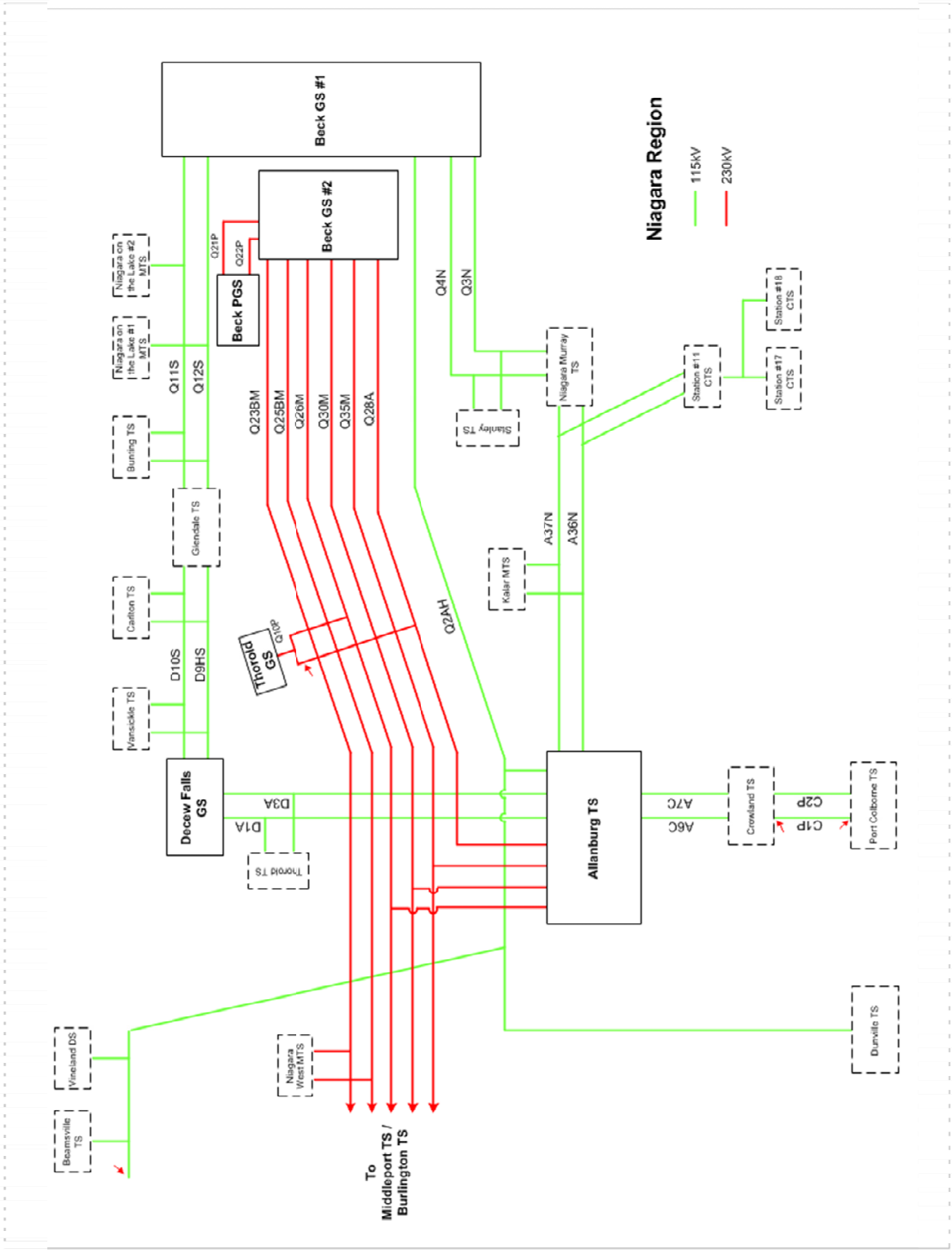

Figure 2: Simplified Niagara Regional Planning Electrical Diagram

4 Inputs and Data

In order to conduct this Needs Assessment, study team participants provided the following information and data to Hydro One:

- Actual 2013 regional coincident peak load and station non-coincident peak load provided by IESO;
- Historical (2012-2014) net load and gross load forecast (2015-2024 provided by LDCs and other Transmission connected customers;
- Conservation and Demand Management (CDM) and Distributed Generation (DG) data provided by IESO;
- Any known reliability and/or operating issues conditions identified by LDCs or the IESO;
- 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 gross load in region is expected to grow at an average rate of approximately 0.61% annually from 2015-2024.

The net load forecast takes the gross load forecast and applies the planned CDM targets and DG contributions. With these factors in place, the total regional load is expected to decrease at an average rate of approximately 0.26% annually from 2015-2024.

5 Needs Assessment Methodology

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

1. The Region is summer peaking so this assessment is based on summer peak loads.
2. Forecast loads are provided by the Region's LDCs.
3. Load data for the industrial customers in the region were assumed to be consistent with historical loads.
4. Accounting for (2), (3), above, the gross load forecast and a net load forecast were developed. The gross load 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 are analyzed to determine if the needs can be deferred. A gross and net non-coincident peak load forecast was used to perform the analysis for this report.

5. Review impact of any on-going and/or planned development projects in the Region during the study period.
6. Review and assess impact of any critical/major elements planned/identified to be replaced at the end of their useful life such as autotransformers, cables, and stations.
7. 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 10-Day Limited Time Rating (LTR). Summer LTR ratings were reviewed to assess the worst possible loading scenario from a ratings perspective.
8. Extreme weather scenario factor at 1.037 was also assessed for capacity planning over the study term.
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 is primarily based on, but is not limited to, the following criteria:
    - 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 summer long-term emergency (LTE) ratings. Thermal limits for transformers are acceptable using summer loading with summer 10-day LTR.
    - All voltages must be within pre and post contingency ranges as per Ontario Resource and Transmission Assessment Criteria (ORTAC) criteria.
    - With one element out of service, no more than 150 MW of load is lost by configuration. With two elements out of service, no more than 600 MW 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 criteria.

6 Results

6.1 Transmission Capacity Needs

230/115 kV Autotransformers

The 230/115kV transformers supplying the region are adequate for loss of single unit.

Transmission Lines & Ratings

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

The 115 kV circuits supplying the Region are adequate over the study period with Q4N as an exception between Sir Adam Beck SS #1 x Portal Junction.

230 kV and 115 kV Connection Facilities

A station capacity assessment was performed over the study period for the 230 kV and 115 kV transformer stations in the Region using the station summer peak load forecast provided by the study team. All stations in the area have adequate supply capacity for the study period even in the event of extreme weather scenario.

6.2 System Reliability, Operation and Restoration

6.2.1 Load Restoration

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

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

6.2.2 Thermal Overloading on Q4N Section

Under high generation scenarios at Sir Adam Beck GS #1, the loading on the *Beck SS #1 x Portal Junction* section (egress out from the GS) of 115kV circuit Q4N can exceed circuit ratings. Hydro One already has plans to address this issue as part of the Beck SS #1 Refurbishment Project.

6.2.3 Power Factor at Thorold TS

A few instances (<54 hours / year) of power factor below 0.9 (between 0.89 - 0.9) were observed at the HV side of Thorold TS. Hydro One Distribution will investigate these instances and work with Distribution customers to address.

7 Aging Infrastructure and Replacement Plan of Major Equipment

Hydro One reviewed the sustainment initiatives that are currently planned for the replacement of any autotransformers and power transformers during the study period. At this time, the following sustainment work is planned at the following stations:

- DeCew Falls SS Circuit Breaker Replacement (2017)
- Sir Adam Beck SS #1 115kV Refurbishment Project (2018)
- 115kV Q11/Q12S Line Refurbishment from Glendale TS to Beck SS #1 (2019)
- Carlton TS; Switchgear Replacement (2020)
- Sir Adam Beck SS #2 230kV Circuit Breakers Replacement (2020)
- Glendale TS; Station Refurbishment and Reconfiguration (2021)
- Stanley TS; Station Refurbishment (2021)
- Thorold TS; Transformer Replacement (2021)
- Crowland TS; Transformer Replacement (2021)

8 Recommendations

Based on the findings and discussion in Section 6 and 7 of this report, the study team recommends that no further regional coordination or further planning is required. The region will be reassessed within five years as part of the next planning cycle.

9 Next Steps

No further Regional Planning is required at this time. The Niagara Region Regional Planning will be reassessed during the next planning cycle or at any time should unforeseen conditions or needs warrant to initiate the regional planning for the region.

10 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

Appendix A: Non-Coincident Winter Peak Load Forecast

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Allanburg TS	Net Load Forecast	33.4	35.4	29.6										
Hydro One	Gross Peak Load				31.1	31.3	31.4	31.6	32.0	32.4	32.6	32.7	32.9	33.1
NPEI - Embedded	Gross Peak Load - DG - CDM				30.8	30.7	30.6	30.4	30.4	30.5	30.5	30.5	30.5	30.5
Beamsville TS	Net Load Forecast	53.6	55.9	49.0										
Hydro One	Gross Peak Load				54.9	55.6	56.8	58.0	59.2	59.4	59.6	59.8	60.0	60.2
Grimsby Power, NPEI - Embedded	Gross Peak Load - DG - CDM				54.1	54.2	55.0	55.5	56.1	55.8	55.6	55.5	55.4	55.3
Bunting TS	Net Load Forecast	58.3	55.9	49.6										
Horizion Utilities	Gross Peak Load				53.1	53.3	53.4	53.5	53.7	53.8	53.9	54.1	54.2	54.3
	Gross Peak Load - DG - CDM				52.5	52.1	51.8	51.4	51.0	50.7	50.5	50.3	50.2	50.1
Carlton TS	Net Load Forecast	100.1	98.3	76.7										
Horizion Utilities	Gross Peak Load				78.4	79.5	79.7	79.9	80.1	80.3	80.5	80.7	80.9	81.1
	Gross Peak Load - DG - CDM				77.6	77.8	77.5	76.8	76.1	75.7	75.4	71.6	71.4	71.2
Crowland TS	Net Load Forecast	89.1	93.6	74.6										
Welland Hydro	Gross Peak Load				75.2	77.5	78.5	80.0	81.0	82.0	83.0	84.0	85.0	86.0
Hydro One, CNPI - Embedded	Gross Peak Load - DG - CDM				70.4	71.9	72.3	72.9	73.0	73.3	73.8	74.2	74.8	75.3
Dunnville TS	Net Load Forecast	25.3	27.0	24.1										
Haldimand County Hydro	Gross Peak Load				24.1	24.3	24.4	24.5	24.7	24.9	25.0	25.1	25.2	25.4
Hydro One - Embedded	Gross Peak Load - DG - CDM				19.8	19.7	19.6	19.4	19.4	19.3	19.3	19.3	19.3	19.3
Glendale TS	Net Load Forecast	61.5	59.1	60.1										
Horizion Utilities	Gross Peak Load				66.5	62.5	62.6	62.8	62.9	63.1	63.2	63.4	63.5	63.7
	Gross Peak Load - DG - CDM				65.7	61.0	60.7	60.2	59.7	59.3	59.1	58.9	58.8	58.6
Kalar MTS	Net Load Forecast	39.5	38.6	33.9										
NPEI	Gross Peak Load				39.8	40.0	40.2	40.4	40.6	40.8	41.0	41.2	41.4	41.6
	Gross Peak Load - DG - CDM				39.4	39.2	39.1	38.8	38.6	38.5	38.4	38.4	38.4	38.4

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Niagara Murray TS	Net Load Forecast	97.0	101.7	90.2										
Hydro One	Gross Peak Load				89.7	90.0	90.4	90.7	91.0	91.4	91.7	92.0	92.4	92.7
NPEI - Embedded	Gross Peak Load - DG - CDM				88.9	88.3	88.0	87.4	86.9	86.5	86.3	86.2	86.1	86.0
Niagara On the Lake #1 MTS	Net Load Forecast	23.8	22.3	22.3										
Niagara On the Lake	Gross Peak Load				24.9	25.3	25.7	26.1	26.5	26.9	27.3	27.7	28.1	28.5
	Gross Peak Load - DG - CDM				24.7	24.8	25.0	25.1	25.2	25.3	25.6	25.8	26.1	26.3
Niagara On the Lake #2 MTS	Net Load Forecast	20.7	22.6	18.3										
Niagara On the Lake	Gross Peak Load				18.9	19.2	19.5	19.8	20.1	20.4	20.7	21.0	21.3	21.7
	Gross Peak Load - DG - CDM				18.8	18.8	19.0	19.0	19.1	19.2	19.4	19.6	19.8	20.0
Niagara West MTS	Net Load Forecast	47.5	43.5	35.7										
Grimsby Power	Gross Peak Load				35.8	35.9	36.1	36.5	36.7	37.0	37.2	37.6	37.8	38.1
NPEI Embedded	Gross Peak Load - DG - CDM				34.4	34.2	34.0	34.0	33.8	31.2	31.2	31.4	31.4	31.5
Stanley TS	Net Load Forecast	59.8	58.9	52.4										
NPEI	Gross Peak Load				52.7	52.9	53.1	53.3	53.5	53.7	53.9	54.1	54.3	54.5
	Gross Peak Load - DG - CDM				52.1	51.7	51.5	51.1	50.8	50.5	50.4	50.3	50.3	50.2
Station 17 TS	Net Load Forecast		16.1	16.6										
CNP	Gross Peak Load				16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6
	Gross Peak Load - DG - CDM				16.4	16.2	16.1	15.9	15.8	15.6	15.5	15.5	15.4	15.3
Station 18 TS	Net Load Forecast		32.3	35.2										
CNP	Gross Peak Load				35.2	37.7	40.2	40.2	40.2	40.2	40.2	40.2	40.2	40.2
	Gross Peak Load - DG - CDM				34.8	36.9	39.1	38.6	38.2	37.9	37.7	37.4	37.3	37.1
Port Colborne TS	Net Load Forecast		40.2	35.7										
CNP	Gross Peak Load				30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
	Gross Peak Load - DG - CDM				30.3	30.0	29.8	29.4	29.1	28.9	28.7	28.5	28.4	28.2

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Thorold TS	Net Load Forecast	20.1	21.3	18.4										
Hydro One	Gross Peak Load				21.3	21.5	21.6	21.7	22.0	22.2	22.4	22.5	22.6	22.7
	Gross Peak Load - DG - CDM				21.1	21.1	20.9	20.8	20.9	20.9	20.9	20.9	20.9	20.9
Vansickle TS	Net Load Forecast	46.3	53.3	43.7										
Horizion Utilities	Gross Peak Load				44.1	44.5	44.6	44.8	44.9	45.0	45.1	45.2	45.3	45.4
	Gross Peak Load - DG - CDM				43.7	43.6	43.4	43.0	42.7	42.4	42.2	42.1	42.0	41.9
Vineland TS	Net Load Forecast	17.4	17.0	17.0										
Hydro One	Gross Peak Load				21.9	22.3	22.4	22.7	23.1	23.5	23.8	24.0	24.3	24.5
NPEI - Embedded	Gross Peak Load - DG - CDM				21.7	21.8	21.8	21.8	22.0	22.2	22.3	22.4	22.5	22.6

Appendix B: 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
HVDS	High Voltage Distribution Station
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
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
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

DISTRIBUTION SYSTEM PLAN

APPENDIX 5-B

LETTER TO IESO

www.aesi-inc.com
aesi@aesi-inc.com

August 4, 2016

Independent Electricity System Operator
1600 – 120 Adelaide Street West
Toronto, ON
M5H 1T1

Dear Madam or Sir,

Re: Welland HydroElectric System Corporation IESO Letter of Comment for OEB Regulatory Case Submission

I am writing on behalf of Welland Hydro Electric System Corporation.(WHESC), a licensed distributor in the Province of Ontario. As WHESC will be filing a Cost of Service application with the Ontario Energy Board (OEB) in 2016 it is required, by the Chapter 5 Filing Requirements to prepare a Consolidated Distribution System Plan (DSP). As part of this plan, WHESC is mandated to request and include a Letter of Comment from the IESO regarding its investments related to renewable energy generation. We have attached an excerpt from the DSP including the details of WHESC's investments related to renewable energy generation. We are requesting that the IESO provide a letter of comment for Welland Hydro to include in its DSP prior to filing with the OEB.

Should you have any question or concerns, please contact me at varunk@aesi-inc.com or 905-875-2075, ext. 271.

Sincerely,

Varun Khanna, PEng.
Manager, Distribution Utility Services

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(5.4.3) System capability assessment for Renewable Energy Generation

WHESC's distribution system is efficiently utilized. The TS that remains in service has sufficient transformation capacity to accommodate any load or generation expected over the period of the DSP. The 27.6kV distribution feeders within WHESC territory are constructed and loaded such that they are not constrained in accepting new load or generation over the period of the DSP as noted in WHESC's most recent load forecast. Some system reconfiguration may be required to balance out feeder loading to accommodate new loads and generation. New feeder construction will be required to access new transformer station capacity that will become available in the future. Upstream capability (i.e. HONI TS, transmission, etc.) to accommodate new load and generation are determined through the Regional Planning process. Currently, as determined by Hydro One there are generation connection limitations at Crowland TS, WHESC is not aware of any other connection limitations that exist. See Final deliverables of the Regional Planning process (5.2.2 b) and Impact on DSP within that section.

5.4.3a - Applications from Renewable Generators

By the end of June 2016 WHESC had connected 78 microFIT's (MFIT) and 7 FIT's of renewable energy generators ranging in size up to 10000 kW, with the majority of MFIT installations being approximately 10 kW. The projects can be summarized in Figure 8 below.

Year	MFIT Connected	MFIT kW	FIT Connected	FIT KW
2010	2	20	0	0
2011	8	72	0	0
2012	12	100	2	350
2013	16	160	2	500
2014	10	90	3	11000
2015	17	170	0	0
2016 (June)	13	130	0	0

Figure 8: Existing FIT and microFIT Projects

In addition to this, there are currently 0 microFIT applications to process. WHESC is already seeing a decline in the number of applications and expects this trend to continue through the forecast period.

5.4.3b - Renewable Generation Forecast

WHESC anticipates connecting thirteen microFIT projects in 2016 with a total size of 130 kW. WHESC has been consistently connecting 12-15 microFIT projects per year over the historical period. WHESC expects this trend to continue and then to subsequently decline.

5.4.3c - Capacity to Connect REG

WHESC feeders and distribution system s has capacity well in excess of the upstream HONI capacity allocations. Each 27.6 kV feeder is rated at 600A and has a planned average maximum loading level of 400A which is equivalent to approximately 19 MW.

	WHESC Feeders - Crowland TS							
	M14	M15	M16	M17	M18	M19	M20	M22
Loading								
Voltage (kV)	27.6	27.6	27.6	27.6	27.6	27.6	27.6	27.6
Average Loading (A)	223	202	187	152	331	36	218	47
Average Loading (%)	37	34	31	25	55	6	36	8
Peak Loading (A)	364	293	277	156	546	36	331	36
Peak Loading (%)	61	49	46	26	91	6	55	6
Generation (kW)								
Max Capacity (kW)	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000
Generation Connected (kW)	211.8	79.37	126.93	11155	434.14	0	585	0
Remain Generation Capacity (kW)	18788	18920	18873	7845	18565	19,000	18415	19,000

Table 1: Generation Connection Capacity per Feeder

5.4.3d - Renewable Generation Connection Constraints

WHESC is supplied from one HONI transformer station:
Crowland TS

The HONI list of station capacity on the HONI website shows an approximate amount of generation that can be added at each bus or station owned by Hydro One. The list shows approximate values only and the actual capacity can only be determined by completing a Connection Impact Assessment. Information from the list related to Crowland TS is in the table below:

Station	Short Circuit Capacity (MVA)	Thermal Capacity (MW)
Crowland TS	124.9	67.6

Table 2: Hydro One TS Capacity

Subject to specific Connection Impact Assessments, it appears that capacity to connect renewable generation is available at the HONI source station.

WHESC has no identified REG enabling investments in this DSP.

DISTRIBUTION SYSTEM PLAN

APPENDIX 5-C

IESO LETTER OF COMMENT

IESO Letter of Comment

Welland Hydro Electric System Corporation

Renewable Energy Generation Investments Plan

August 25, 2016

ieso
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 [Independent Electricity System Operator][1] ("[IESO]") 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 [IESO], or participated in planning meetings with the [IESO];
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the Renewable Energy Generation ("REG") investments; and
- whether the REG investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

Welland Hydro Electric System Corporation – Distribution System ("DS") Plan

On August 4, 2016, the IESO received REG Investments Information ("Plan") from Welland Hydro Electric System Corporation ("WHESC") as part of their DS Plan. The IESO has reviewed the Plan and provides the following comments.

IESO FIT/microFIT Applications Received

As at the end of 2015, the Plan indicates that WHESC has connected 76 microFIT projects totalling 742 kW, and 7 FIT projects totalling 11,850 kW of capacity to its distribution system. For 2016, WHESC has forecast connecting an additional 160 kW from a potential 13 microFIT projects, and expects this trend to continue through the 5-year forecast of the Plan. No REG investments are included as part of WHESC's DS Plan.

According to the IESO's information as of June 30, 2016, the IESO has offered contracts to 76 microFIT projects totalling 702 kW, and 7 FIT projects totalling 12 MW of capacity. These projects have all reached commercial operation. The REG connections information in WHESC's Plan is therefore 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

Welland Hydro Electric System Corporation is one of the eight local distribution companies in the Niagara Region identified through the OEB regional planning process. As member of the Study Team, WHESC was involved in the development of the Niagara Region Needs Assessment Report which was published by Hydro One Networks Inc. in April 2016.[2]

The Needs Assessment Report indicated that there is no further regional coordination or planning required at this time. Therefore, the regional planning process for the Niagara region is now complete and will be undertaken again when the next 5-year planning cycle commences, unless there is sufficient load growth, or an event that triggers the requirement to initiate the regional planning process earlier.

The IESO appreciates the opportunity to comment on the REG Investments Plan provided by Welland Hydro Electric System Corporation, as part of its DS Plan at this time.

[2] http://www.hydroone.com/RegionalPlanning/Niagara/Documents/Needs%20Assessment%20Report%20-%20%20Niagara.pdf

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DISTRIBUTION SYSTEM PLAN

APPENDIX 5-D

PROJECT JUSTIFICATION FORMS

A. General Information						
Project/Activity	Smart Meters					
Project Number						
Investment Category	System Access					
	2012	**2013**	**2014**	**2015**	**2016**	**2017**
Capital Cost (5.4.5.2 A.1)	$17,202	$65,532	$63,482	$50,857	$60,000	$100,000
Capital Contribution	$0	$0	$0	$0	$0	$0
Net Cost	$17,202	$65,532	$63,482	$50,857	$60,000	$100,000
O&M Cost (5.4.5.2 A.1)	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
	N/A	N/A	N/A	N/A	N/A	N/A

Customer Attachments and Load (5.4.5.2 A.2)

WHESC will typically install and replace approximately 500 meters per year. In 2017 WHESC will start a meter pre-sampling program to meet regulatory requirements associated with Measurement Canada's meter seal extension policy.

Start Date (5.4.5.2 A.3)	**8-Aug-16**		**In-Service Date (5.4.5.2 A.3)**			**8-Aug-16**
Expenditure Timing For the Test Year	**2017 Q1**	**2017 Q2**	**2017 Q3**	**2017 Q4**		
	$25,000	$25,000	$25,000	$25,000		

Project Summary

WHESC is required to maintain its inventory to ensure compliance with Measurement Canada and to have meters available for new customer connections and replacement of meters at existing customer locations. The provincial government has mandated the provision of smart meters by all LDCs.

Risk Identification & Mitigation (5.4.5.2 A.4)

Projects in this program are driven by customers and regulatory agencies, therefore the main risk is with respect to the annual budget. WHESC mitigates this risk by budgeting annual expenditures based on historical average meter installation and replacement rates, as well as the expected rate of pre-sampling. Scheduling is generally not a risk for smart meter projects, since individual projects in this program tend to be small and meet their scheduling objectives. Furthermore, the time to install new meters is regulated under the Distribution System Code, and WHESC has historically met its target in this metric.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

Project activities do not have a direct comparator other than the previous years expenditures as indicated in the summary table above.

REG Investment Details including Capital and OM&A Cost (5.4.5.2 A.6)

Not applicable.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

Not applicable.

Attach Other project reference material i.e. Images, Drawings and or reference material

Not applicable.

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

Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1a)

The main driver for this project is our mandated obligation to service new customers and our regulated mandate to meet the obligations of our Measurement Canada issued Licence.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1.a)

Secondary drivers include technology upgrades that provide support to other internal tools and programs for customers.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1.a)

The objective is to have adequate stock to meet all of our obligations.

Efficiency, Customer Value & Reliability - Source and nature of information used to justify the investment (5.4.5.2 B.1.a)

Meter installations are governed by Measurement Canada and a requirement for service connection.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority Relative to Other Investments

This program is ranked third out of fifteen material projects/programs planned for the Test Year (2017) based on the scoring below.

Criteria	Safety	Regulatory	Growth	Reliability	Cost	Total Score
Weight	10	9	8	6	5	
Score	0	10	0	0	0	90

Justification: This program is driven by a regulatory requirement to meter customers.

Analysis of Project & Alternatives - Effect to the investment on system efficiency and cost-effectiveness (5.4.5.2 B.1.c)

Installation of smart meters reduces the need for manual meter reading, improving system operation and efficiency.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

The project will ensure the timeliness and accuracy of customers electrical bills.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

This project ensures the WHESC maintains a meter inventory that provides the critical information about the consumption of electricity on its distribution system. The data can also be used for internal tools to assist with system design and outage management.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

"Do nothing" is not a feasible alternative, since customers must be metered per the requirements of the Distribution System Code. All new meters are "smart meters" per the direction of the OEB. Meters under this program are owned by WHESC.

Safety (5.4.5.2 B.2)

The project has no adverse impact on Health and Safety.

Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)

Smart meters meet the latest standards in cyber-security and privacy.

Coordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, Coordination with Utilities,Regional Planning and/or 3rd party providers(where applicable)

Meter installations do not impact inter-utility coordination or regional planning. Coordination is typically dealt with at the customer level.

Coordination, Interoperability (5.4.5.2 B.4ii) Future Technological functionality and/or future operational requirements (where applicable)

Interoperability is supported through common communication protocols over the Advanced Metering Infrastructure network.

Economic Development (5.4.5.2 B.5) (where applicable)

Metering projects allow customers to connect to the electricity grid, supporting economic development of businesses and residents who rely on electricity.

Environmental Benefits (5.4.5.2 B.6) (where applicable)

Smart meters allow customers to view their TOU energy consumption habits and may adjust their consumption accordingly.

C. Category-Specific Requirements - System Access
Factors Affecting Timing/Priority (5.4.5.2 SA - C1)
Priority of an individual project within this program is based on customer expectation on when service will be delivered and as mandated by the Distribution System Code. Scheduling is based on WHESC's resource availability, and meets customer expectations the majority of the time.
Factors Related to Customer/Third-Party Preferences (5.4.5.2 SA - C2)
Not applicable.
Factors Affecting the Final Cost (5.4.5.2 SA - C3)
Final cost of the project is determined by the scope of work performed, which depends on the number of customer requests and the number of meter failures.
Methods Utilized to Minimize Controllable Cost (5.4.5.2 SA - C4)
Meters and metering equipment comply with Measurement Canada standards. Meter installations comply with USF standards if applicable and WHESC policy established to effect efficiency of installation.
Other Planning Objectives (5.4.5.2 SA - C5) (where applicable)
This project will maintain or improve reliability through the use of available technologies. The project will maintain safety performance, operational efficiency and cost-effectiveness based on the installation of the equipment to the latest standards.
Technically feasible project design and/or implementation options exist (5.4.5.2 SA - C6)
WHESC makes all connections in accordance with our Conditions of Service. Where options exist, WHESC works with customers to select the appropriate and most cost efficient solution.
Summary of results analysis - "Least Cost", "Cost efficient" options (5.4.5.2 SA - C7)
WHESC does not have a summary of results analysis. WHESC, per its Condition of Service, works with the customer to select the appropriate and most cost efficient solution.
Results of final a Economic Evaluation (5.4.5.2 SA - C8) (where applicable)
Not Applicable.
System impacts costs & cost recovery method (5.4.5.2 SA - C9) (where applicable)
Metering installations have low impact on the system. Cost recovery mechanisms are limited and typically only affected by very large Industrial customers requiring large services with greater requirements than the standard offering in WHESC's Condition of Service.

A. General Information						
Project/Activity	MS8 Transformer					
Project Number						
Investment Category	System Renewal					
	2012	**2013**	**2014**	**2015**	**2016**	**2017**
Capital Cost (5.4.5.2 A.1)						$50,000
Capital Contribution						$0
Net Cost						$50,000
O&M Cost (5.4.5.2 A.1)	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
						Undetermined

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments within project area: 1031
Customer load within project area: approximately 2,219 kW (2015 peak)

Start Date (5.4.5.2 A.3)	n/a		**In-Service Date (5.4.5.2 A.3)**		n/a
Expenditure Timing For the Test Year	**2017 Q1**	**2017 Q2**	**2017 Q3**	**2017 Q4**	
				$50,000	

Project Summary

This project includes the purchase of a 3 MVA transformer in 2017 for the staged replacement of substation assets at MS8 in 2018 and 2019. Existing station transformer was originally installed in 1966.

Risk Identification & Mitigation (5.4.5.2 A.4)

Scheduling Risks:

There are no other capital projects associated, allowing this project scheduling flexibility.

System Constraints Risks:

There are no system constraints associated with this project as no main circuits need to be isolated or power re-routed to complete the work.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

Cost estimates have been derived by using historical equipment costs. A 3 MVA transformer was previously purchased for MS 14 in 2015 and the cost estimate has been adjusted for expected present cost.

REG Investment Details including Capital and OM&A Cost (5.4.5.2 A.6)

The are no REG investment requirements associated with this work.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

Leave to Construct approval is not required as this distribution line is under 2 km in length and below 50 kV.

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

Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1.a)

The Main Investment Driver is Reliability. Replacement of end of life assets will maintain system reliability.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1.a)

The Secondary Investment Drive is Operational Efficiency. Through the voltage conversion program, 4.16 kV system load is decreased allowing the purchase of smaller more efficient transformers.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1.a)

The primary related investment objective is reliability, namely SAIDI and SAIFI. This project addresses defective equipment outages and the new station design is expected to reduce outages caused by adverse weather and animal contacts. The secondary related investment objective operational efficiency, namely the results of the Efficiency Assessment and total cost per customer and per kilometer of line. This project manages costs and will affect these metrics.

Efficiency, Customer Value & Reliability - Source and nature of information used to justify the investment (5.4.5.2 B.1.a)

Information used to justify the investment in the project includes the condition of the asset determined through inspection and testing programs combined with the knowledge of the age of the asset and the expected end of useful life through historical performance of other similar assets.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority Relative to Other Investments

This project is ranked ninth out of fifteen material projects/programs planned for the Test Year (2017) based on the scoring below.

Criteria	Safety	Regulatory	Growth	Reliability	Cost	Total Score
Weight	10	9	8	6	5	
Score	0	0	0	6	6	66

Justification: This project maintains system reliability by replacing an end-of-life substation transformer and manages cost, since refurbishment and/or enhanced maintenance of the transformer is avoided.

Analysis of Project & Alternatives - Effect to the investment on system efficiency and cost-effectiveness (5.4.5.2 B.1.c)

The project will not only replace end-of-life assets but will also promote efficiency through use of smaller more efficient equipment. Replacing the end-of-life transformer avoids costly refurbishments and/or enhanced maintenance.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Customers will benefit from the reduced risk of outages as a result of the project. Efficiencies gained will support WHESC's focus on cost containment.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

Municipal substations are constructed using more compact designs using similar equipment. Investment costs are lower and equipment interchangeability positively affects outage duration.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

Project Design Alternatives:

Eliminating the substation is an alternative and the eventual goal; however, it is not a short term option, since the substation presently serves 1031 customers on the 4.16 kV distribution feeders and the feeders must be converted before the substation is eliminated. The 3 MVA transformer size is the smallest able to serve the load - load growth is minimal in WHESC's service territory and new customer's are connected to the 27.6 kV system whenever feasible.

Scheduling Alternatives:

This project has scheduling flexibility; however, there is no benefit to receiving the equipment sooner and the project has been scheduled to smooth rate impacts. Deferring the project by a year would cause a rate shock in 2018 and continued deferral of this investment (i.e. a "do nothing" option) would negatively impact WHESC's reliability and O&M costs.

Safety (5.4.5.2 B.2)
This project will improve work safety by replacing existing live-front equipment with dead-front devices.
Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)
There are no Cyber-Security or privacy issues relevant to this project.
Coordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, Coordination with Utilities,Regional Planning and/or 3rd party providers(where applicable)
The station will meet USF, CSA, and ESA Standards. Utility coordination and Regional Planning are not applicable to this project.
Coordination, Interoperability (5.4.5.2 B.4ii) Future Technological functionality and/or future operational requirements (where applicable)
The new construction standards will provide more flexible operational options.
Economic Development (5.4.5.2 B.5) (where applicable)
Reliability is one of the key drivers of this project (replacing end-of-life equipment) and a reliable electricity supply is conducive to economic development.
Environmental Benefits (5.4.5.2 B.6) (where applicable)
These asset replacements will reduce environmental risk associated with asset failure, such as transformer leaks. New transformers meet the latest standards for energy efficiency.

C. Category-Specific Requirements - System Renewal
Asset performance-related operational targets and asset lifecycle optimization policies and practices (refer to 5.2.3 and 5.3.3) (5.4.5.2 SR - C1.1)
The project fulfills asset performance-related operational targets by continuing to lower or maintain SAIDI and SAIFI index results. The project also positively affects safety targets by creating a safer work space for the powerline maintainers. Operational efficiency metrics such as the Efficiency Assessment and total cost are positively affected by the investment. Customer bill impacts are mitigated by the pacing of the MS8 replacement over several years.
Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR - C1.2)
The majority of the equipment at this Municipal Substation was installed in 1966 and has reached its expected end of life. As indicated in the reference above, this includes the transformer, HV and LV switchgear, and feeder cables.
The number of customers in each class potentially affected by failure of the assets (5.4.5.2 SR - C1.3)
This station provides power at the 4.16 kV level. There are 1031 customers supplied by the station including eight small commercial customers.
Quantitative customer impacts (5.4.5.2 SR - C1.4)
There have been no significant asset failures resulting in prolonged outages to the customers supplied by this station over the past five years.
Qualitative customer impacts (5.4.5.2 SR - C1.5)
The completion of this project will maintain reliability performance associated with the assets of the substation itself. The new design will reduce impacts of adverse weather and animals due to the new station design.
Value of cust. impact in terms of characteristics of cust. potentially affected by failure that have a bearing on the criticality and/or cost of failure(5.4.5.2 SR -
There is low impact to customers in this area in terms of criticality and cost of asset failure. However, being mainly residential load, the majority of customers are unlikely to have any source of back up.
Timing & Priority of Project (5.4.5.2 SR - C2)
This project is part of an overall capital replacement plan for 2017. This project does not rely on any other 2017 project in any of the other Access, Service or General plant categories.
Consequences for system O&M costs (5.4.5.2 SR - C3)
O&M costs are expected to be remain stable as typical inspection and maintenance programs will continue on the new equipment. The investment avoids increased O&M costs due to enhanced preventative and reactive maintenance on the equipment.
Impact on Reliability performance and/or Safety (5.4.5.2 SR - C4)
System Reliability in this area will be maintained or improve due to the reduced number of asset failures and the new design that reduces the chance of interruptions caused by external sources such as animals and adverse weather.
Analysis of Project Benefits and Timing (5.4.5.2 SR - C5)
This project has been scheduled to be completed in the fourth quarter of 2017, since there is no benefit to receiving the transformer earlier in the 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 SR - C6)
Like for Like construction was not considered as the new design is more cost effective.

A. General Information						
Project/Activity	MS14 Transformer/Switchgear/Primary Cabling Replacement					
Project Number						
Investment Category	System Renewal					
	2012	**2013**	**2014**	**2015**	**2016**	**2017**
Capital Cost (5.4.5.2 A.1)				$48,350		$120,000
Capital Contribution				$0		$0
Net Cost				$48,350		$120,000
O&M Cost (5.4.5.2 A.1)	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
						Undetermined

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments within project area: 265
Customer load within project area: approximately 640 kW (2015 peak)

Start Date (5.4.5.2 A.3)	**1-Jul-17**	**In-Service Date (5.4.5.2 A.3)**		**31-Aug-17**
Expenditure Timing For the Test Year	**2017 Q1**	**2017 Q2**	**2017 Q3**	**2017 Q4**
		$60,000	$60,000	

Project Summary

This project includes the installation of a new 3 MVA transformer, 2 padmounted sectionalizers, and associated underground primary cables.

Risk Identification & Mitigation (5.4.5.2 A.4)

Scheduling Risks:

There are no other capital projects associated, allowing this project scheduling flexibility.

System Constraints Risks:

There are no system constraints associated with this project as no main circuits need to be isolated or power re-routed to complete the work.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

Cost estimates have been derived using historical equipment costs for a similar project prior to 2012. Cost estimates have been adjusted for their expected value in 2017.

REG Investment Details including Capital and OM&A Cost (5.4.5.2 A.6)

The are no REG investment requirements associated with this work.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

Leave to Construct approval is not required as this distribution line is under 2 km in length and below 50 kV.

Attach Other project reference material i.e. Images, Drawings and or reference material

Station images attached.

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

Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1.a)

The Main Investment Driver is reliability. Replacement of end-of-life assets will maintain reliability.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1.a)

The secondary investment driver is operational efficiency. Through the voltage conversion program, 4.16 kV system load has decreased allowing the purchase of smaller more efficient substation transformers. The replacement of end-of-life plant avoids increased costs due to enhanced maintenance and/or asset refurbishment, and avoids the cost of reactive replacement, which is more expensive than a planned replacement.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1.a)

The primary related investment objective is reliability, namely SAIDI and SAIFI. This project addresses defective equipment outages and the new station design is expected to reduce outages caused by adverse weather and animal contacts. The secondary related investment objective operational efficiency.

Efficiency, Customer Value & Reliability - Source and nature of information used to justify the investment (5.4.5.2 B.1a)

Information used to justify the investment in the project includes the condition of the asset determined through inspection and testing programs combined with the knowledge of the age of the asset and the expected end of useful life through historical performance of other similar assets.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1b) Priority Relative to Other Investments

This project is ranked fifth out of fifteen material projects/programs planned for the Test Year (2017) based on the scoring below.

Criteria	Safety	Regulatory	Growth	Reliability	Cost	Total Score
Weight	10	9	8	6	5	
Score	0	0	0	6	8	**76**

Justification: This project maintains system reliability by replacing end-of-life substation equipment and manages cost, since refurbishment and/or enhanced maintenance of the equipment is avoided.

Analysis of Project & Alternatives - Effect to the investment on system efficiency and cost-effectiveness (5.4.5.2 B.1.c)

The project will not only replace end-of-life assets but will also promote efficiency through use of smaller more efficient equipment. Cost effectiveness is improved by replacing end-of-life equipment that would otherwise require enhanced maintenance and/or refurbishment.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Customers will benefit from the reduced risk of outages as a result of the project. Efficiencies gained will support WHESC's focus on cost containment.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

Municipal substations are constructed using more compact designs and identical equipment. Investment costs are lower and equipment interchangeability positively affects outage duration.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

Project Design Alternatives:

Eliminating the substation is an alternative and the eventual goal; however, it is not a short term option, since the feeders carry 265 customers served at 4.16 kV. The feeders must be converted before the substation is eliminated. Substation design has been selected based on similar completed projects to save costs. The 3 MVA transformer allows operational flexibility to tie together stations and flexibility to swap out transformers when decommissioning (over the long term).

Scheduling Alternatives:

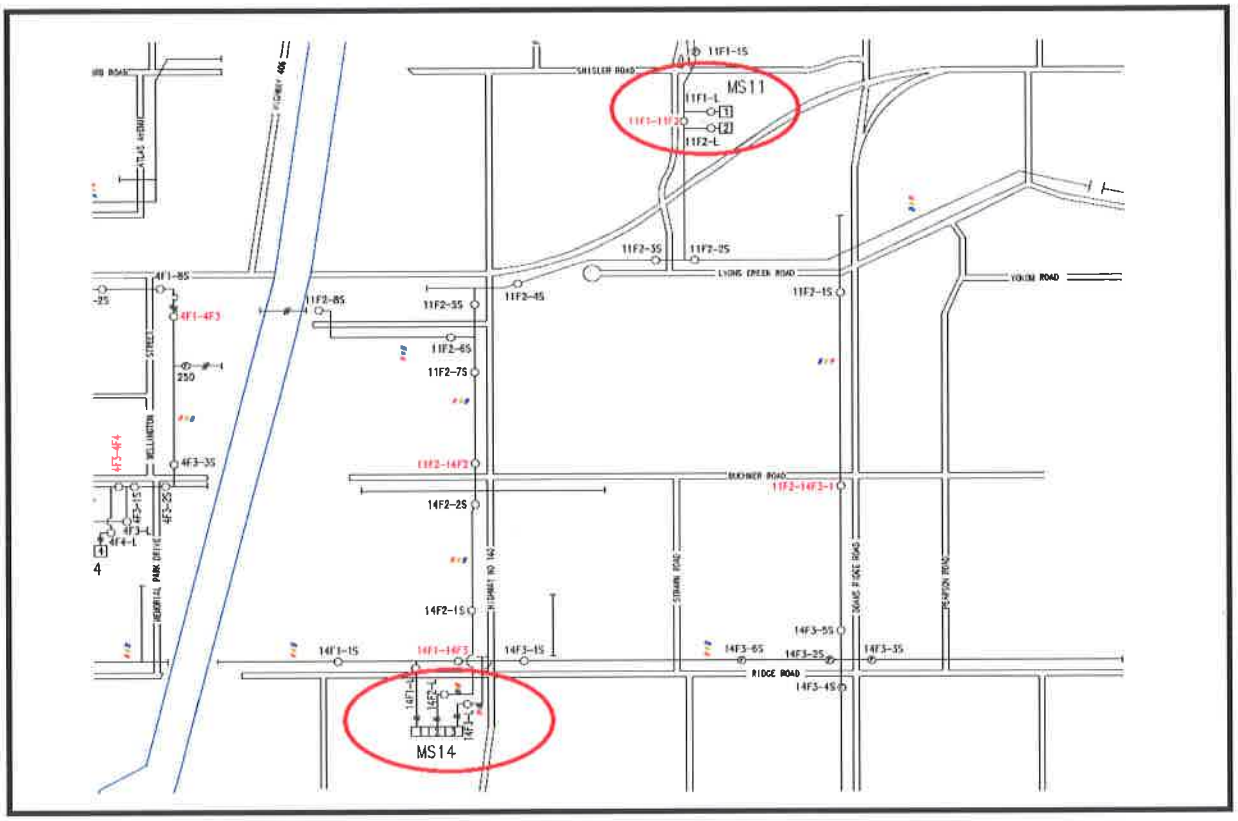
This project has scheduling flexibility throughout the year. The project has been planned for 2017 based on its priority per WHESC's project prioritization process. In the case of the "do nothing" project alternative, the projects benefits would not be achieved and WHESC's reliability and operational efficiency metrics would be negatively impacted.

Safety (5.4.5.2 B.2)
This project will improve work safety by replacing existing live-front equipment with dead-front devices.
Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)
There are no Cyber-Security or privacy issues relevant to this project.
Coordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, Coordination with Utlilities,Regional Planning and/or 3rd party providers(where applicable)
The new construction will meet, USF, CSA, and ESA standards. There are no other coordination or Regional planning requirements.
Coordination, Interoperability (5.4.5.2 B.4ii) Future Technological functionality and/or future operational requirements (where applicable)
The new construction standards will provide more flexible operational options. The use of standard-sized 3 MVA transformers at Multiple Substations improves operational flexibility.
Economic Development (5.4.5.2 B.5) (where applicable)
Reliability is one of the key drivers of this project (replacing end-of-life equipment) and a reliable electricity supply is conducive to economic development.
Environmental Benefits (5.4.5.2 B.6) (where applicable)
These asset replacements will reduce environmental risk associated with asset failure, such as transformer leaks. New transformers meet the latest standards for energy efficiency.

C. Category-Specific Requirements - System Renewal
Asset performance-related operational targets and asset lifecycle optimization policies and practices (refer to 5.2.3 and 5.3.3) (5.4.5.2 SR - C1.1)
The project fulfills asset performance-related operational targets by continuing to lower or maintain SAIDI and SAIFI index results. The project also positively affects safety targets by creating a safer work space for the powerline maintainers.
Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR - C1.2)
The majority of the equipment at this Municipal Substation was manufactured in 1963 and has surpassed its expected end of life.
The number of customers in each class potentially affected by failure of the assets (5.4.5.2 SR - C1.3)
This station provides power at the 4.16 kV level. There are 265 customers supplied by this station, mostly being residential and including five small commercial customers. This station is located in the rural area of town and it provides a backup source of power to one other Municipal Substation in the rural area.
Quantitative customer impacts (5.4.5.2 SR - C1.4)
Customers supplied by this substation experienced 260 customer hours of interruption in 2014 due to animal interference at the substation (the most recent outage). Temporary provisions were made to mitigate animal contacts at the time.
Qualitative customer impacts (5.4.5.2 SR - C1.5)
The completion of this project will maintain reliability performance associated with the assets of the substation itself. The new design will reduce impacts of adverse weather and animals due to the new station design.
Value of cust. impact in terms of characteristics of cust. potentially affected by failure that have a bearing on the criticality and/or cost of failure(5.4.5.2 SR -
There is low impact to customers in this area in terms of criticality and cost of asset failure. However, being mainly residential load, the majority of customers are unlikely to have any source of back up.
Timing & Priority of Project (5.4.5.2 SR - C2)
This project is part of an overall capital replacement plan for 2017. This project does not rely on any other 2017 project in any of the other Access, Service or General plant categories.
Consequences for system O&M costs (5.4.5.2 SR - C3)
O&M costs are expected to be remain stable as typical inspection and maintenance programs will continue on the new equipment. Without the investment as planned, O&M costs are expected to increase due to requirements for enhanced maintenance and/or trouble call responses.
Impact on Reliability performance and/or Safety (5.4.5.2 SR - C4)
System reliability in this area will be maintained or improve due to the reduced number of asset failures and the new design that reduces the chance of interruptions caused by external sources such as animals and adverse weather.
Analysis of Project Benefits and Timing (5.4.5.2 SR - C5)
This project has been scheduled to be completed in the second and third quarters of 2017 based on its ranking per WHESC's prioritization process.
Like for Like Renewal Analysis, Alternatives Comparison (like-for-like vs not like-for-like, timing, rate of replacement, etc.) (5.4.5.2 SR - C6)
Like for Like construction was not considered as the new design is more cost effective.

Other project reference material i.e. Images, Drawings and or reference material

Schematic Area



Existing Substation

Other project reference material i.e. Images, Drawings and or reference material
Example of Completed Substation

New Padmount Transformer

New Sectionalizer Reclosers

A. General Information						
Project/Activity	Church Street/Niagara Street Rebuild/Conversion 4.16kV to 27.6kV					
Project Number						
Investment Category	System Renewal					
	2012	**2013**	**2014**	**2015**	**2016**	**2017**
Capital Cost (5.4.5.2 A.1)					$450,000	$300,000
Capital Contribution					$0	$0
Net Cost					$450,000	$300,000
O&M Cost (5.4.5.2 A.1)	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
					Undetermined	Undetermined

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments within project area: 127
Customer load within project area: 250 kW

Start Date (5.4.5.2 A.3)	**3-Jan-17**		**In-Service Date (5.4.5.2 A.3)**			**31-Mar-17**
Expenditure Timing For the Test Year	**2017 Q1**	**2017 Q2**	**2017 Q3**	**2017 Q4**		
	$300,000					

Project Summary

This project includes the replacement of 25 poles, the majority were installed in the 1950's. Some of the older more deteriorated individual 35' poles have been replaced individually over time. The new main line poles will be upgraded to 55' and the side street poles will be upgraded to 40' to allow more space for construction of the higher voltage circuit and to allow proper space to meet the current construction standards.

Risk Identification & Mitigation (5.4.5.2 A.4)

Scheduling Risks:

The main scheduling risk associated with this project is the completion of the first phase of this project in 2016. It is preferable to complete this project in the first quarter to allow sufficient time to complete underground renewal projects during the second and third quarter when conditions are most ideal for underground work and restoration. To mitigate the risk, contractor crews are made available to supplement WHESC crews as needed.

System Constraints Risks:

There are no system constraints associated with this project as no main circuits need to be isolated or power re-routed to complete the work.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

Cost estimates have been derived by using historical project costs of overhead pole lines containing similar asset conditions and re-construction requirements. Similar projects on Major Street, Division Street, and Clare Avenue were completed in 2014 and final costs were referenced for cost estimating.

REG Investment Details including Capital and OM&A Cost (5.4.5.2 A.6)

The are no REG investment requirements associated with this work.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

Leave to Construct approval is not required as this distribution line is under 2km in length and below 50kV.

Attach Other project reference material i.e. Images, Drawings and or reference material

Project map and Images are included with this form.

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

Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1.a)

The Main Investment Driver is Reliability. Replacement of end-of-life assets combined with connecting existing loads to the higher voltage system will maintain and possibly improve Reliability. Connecting distribution transformers directly to the 27.6 kV feeder bypasses the Municipal Substation portion of the circuit and typically reduces the amount of circuit kilometers required to reach the point of connection for each transformer. The final phase of this project will also provide a loop, or backup, feed to commercial customers on Niagara Street.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1.a)

The Secondary Investment Drive is Operational Efficiency. The conversion of transformer connections from the 4.16 kV system to the 27.6 kV system results in Operational Efficiencies due to the reduction is Distribution System line losses. The eventual elimination of Municipal Substations will result in both Capital and Operational Cost Savings.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1.a)

The primary related investment objective is reliability, namely SAIDI and SAIFI. The secondary related investment objective is operational efficiency; the investment is expected to contribute to maintaining WHESC's Efficiency Assessment and total cost within its targets. The voltage conversion will also help WHESC achieve its target in distribution losses.

Efficiency, Customer Value & Reliability - Source and nature of information used to justify the investment (5.4.5.2 B.1.a)

Information used to justify the investment in the project includes the condition of the asset determined through inspection and testing programs combined with the knowledge of the age of the asset and the expected end of useful life through historical performance of other similar assets. WHESC's Geospatial Information System is used to collect/display data and create reports to assist in selecting/ranking projects.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority Relative to Other Investments

This project is ranked seventh out of fifteen material projects/programs planned for the Test Year (2017) based on the scoring below.

Criteria	Safety	Regulatory	Growth	Reliability	Cost	Total Score
Weight	10	9	8	6	5	
Score	0	0	0	6	8	76

Justification: This project is the second phase of a project initiated in 2016. The completion of this project has been given priority as it will establish an additional primary source to a commercial sector on Niagara Street. In addition, it will also create system efficiencies through the conversion and transfer of 250 kW of load from the 4.16 kV system to the 27.6 kV system.

Analysis of Project & Alternatives - Effect to the investment on system efficiency and cost-effectiveness (5.4.5.2 B.1.c)

The project will not only replace end-of-life assets but will also realize efficiencies through the voltage conversion process.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Customers will benefit from the reduced risk of outages as a result of the project. Efficiencies gained will support WHESC's focus on cost containment.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1cii)

Pole lines, constructed to new standards, are more robust and allow for greater spacing of equipment and clearances to ground, all having a positive effect on Reliability.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

Project Design Alternatives:

Underground Distribution design was not considered in this area for two reasons:
(1) All homes serviced from this pole line are overhead services and costs would be extensive to convert the area to underground.
(2) Customer preference has not listed aesthetics as priority and consider current reliability to be acceptable.
Customers prefer that the cost of service does not increase considerably. Wood poles will continue to be used in the area to reduce material costs. The option to convert the area instead of rebuilding it at 4.16 kV was selected to reduce distribution losses and for long term cost management of eventually eliminating Municipal Substations.

Scheduling Alternatives:

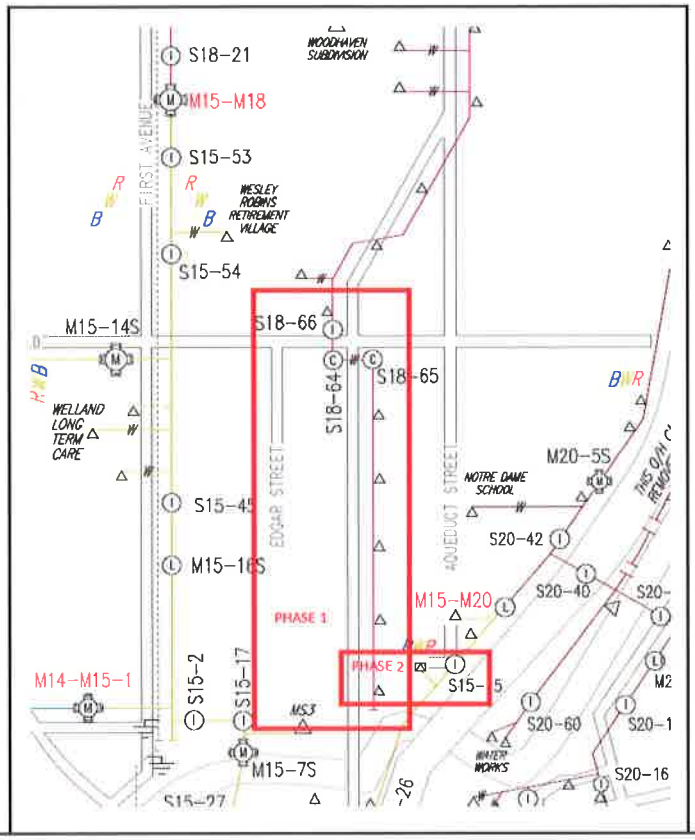
The project has been scheduled for 2017 per WHESC's project prioritization process. In the case of the "do nothing" option, the project benefits would not be achieved, which would likely result in lengthy outages and higher costs for customers. The project could be delayed to a later part of the budget year; however, it is preferable to perform the majority of line construction in the first and fourth quarter of the year to allow adequate time for underground system renewals during the spring and summer season. The project is preferred to be started in the first quarter to take advantage of the loop feed sooner rather than later.

Safety (5.4.5.2 B.2)
This project will improve worker safety by replacing existing poles with taller poles, resulting in more space for workers to install equipment while maintaining clearance from other energized circuits/equipment.
Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)
There are no Cyber-Security or privacy issues relevant to this project.
Coordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, Coordination with Utilities, Regional Planning and/or 3rd party providers (where appli
WHESC is a member of the Utilities Standards Forum (USF) and uses USF standards for the construction of new lines. The standards ensure that the design of the project will adhere to a standard that is Engineered and widely used by a large group of utilities across the Province. Coordination with other utilities is not relevant to this project. Third parties will be consulted with to request participation in transferring to the new poles. Third party attachers will benefit from the new construction standards as well, as increased clearances are realized.
Coordination, Interoperability (5.4.5.2 B.4ii) Future Technological functionality and/or future operational requirements (where applicable)
The new construction standards will provide increased spacing to meet the needs of future equipment installations.
Economic Development (5.4.5.2 B.5) (where applicable)
Reliability is one of the key drivers of this project (replacing end-of-life equipment) and a reliable electricity supply is conducive to economic development.
Environmental Benefits (5.4.5.2 B.6) (where applicable)
These asset replacements will reduce environmental risk associated with asset failure, such as transformer leaks. Engineering design tools will also provide for proper transfer sizing reducing additional operating losses normally associated with oversizing transformers as a result of limited design data in the past. New transformers meet the latest standards for energy efficiency.

C. Category-Specific Requirements - System Renewal
Asset performance-related operational targets and asset lifecycle optimization policies and practices (refer to 5.2.3 and 5.3.3) (5.4.5.2 SR - C1.1)
The project fulfills asset performance-related operational targets by continuing to lower or maintain SAIDI and SAIFI index results. The project also positively affects safety targets by creating a safer work space for the powerline maintainers. This investment is expected to contribute to the successful achievement of operational efficiency objectives, namely the Efficiency Assessment and total cost. A final benefit if improvements to distribution losses due to the voltage conversion.
Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR - C1.2)
The poles in this area were installed in the 1950's and have surpassed there typical end of useful life. In addition the primary and secondary conductors have surpassed their typical end of life.
The number of customers in each class potentially affected by failure of the assets (5.4.5.2 SR - C1.3)
There are 127 customers that could be affected by asset failure.
Quantitative customer impacts (5.4.5.2 SR - C1.4)
The customers in this area have not sustained any significant unplanned power interruptions due to asset failure in the project area. Some customers have experienced planned outages to deal with leaking or overloaded transformers.
Qualitative customer impacts (5.4.5.2 SR - C1.5)
The completion of this project will improve reliability performance, in part, due both replacement of assets and system redesign which will remove a portion of high voltage circuits currently located in streets with extensive vegetation.
Value of cust. impact in terms of characteristics of cust. potentially affected by failure that have a bearing on the criticality and/or cost of failure(5.4.5.2 SR -
There is low impact to customers in this area in terms of criticality and cost of asset failure. However, being mainly residential load, the majority of customers are unlikely to have any source of back up power.
Timing & Priority of Project (5.4.5.2 SR - C2)
This project is part of an overall capital replacement plan for 2017. This project does not rely on any other 2017 project in any of the other Access, Service or General plant categories.
Consequences for system O&M costs (5.4.5.2 SR - C3)
O&M costs are expected to be reduced within the area of this project. Replaced poles will not require inspection immediately and will only require the standard visual and sounding tests over the first 15 years following the asset installation date. The risk of asset failure resulting in regular or overtime costs will be reduced significantly.
Impact on Reliability performance and/or Safety (5.4.5.2 SR - C4)
System Reliability in this area will improve due to the reduced number of asset failures. Construction standards, providing additional equipment spacing, will reduce the chance of interruptions caused by external sources such as animals, trees and vehicles. Elimination of high voltage conductor within high vegetation areas will also improve reliability.
Analysis of Project Benefits and Timing (5.4.5.2 SR - C5)
This project has been scheduled to be completed within the first quarter of 2017 to take due to the benefits of establishing a new 27.6 kV backup to the commercial sector on Niagara Street.
Like for Like Renewal Analysis, Alternatives Comparison (like-for-like vs not like-for-like, timing, rate of replacement, etc.) (5.4.5.2 SR - C6)
Like for Like construction was not considered in this area due to the overall poor condition of the majority of assets. Individual asset replacement would be more costly and less effective as most assets equally require replacement. In addition, the main line poles were not tall enough to accommodate the installation of the 27.6kV circuit.

Other project reference material i.e. Images, Drawings and or reference material

Schematic Area



Existing Poles

Other project reference material i.e. Images, Drawings and or reference material
Example of Completed Project

A. General Information						
Project/Activity	Wellington Street - East Main to Eastdale Rebuild/Conversion 4.16kV to 27.6kV					
Project Number						
Investment Category	System Renewal					
	2012	**2013**	**2014**	**2015**	**2016**	**2017**
Capital Cost (5.4.5.2 A.1)					$88,000	$250,000
Capital Contribution					$0	$0
Net Cost					$88,000	$250,000
O&M Cost (5.4.5.2 A.1)	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
					Undetermined	Undetermined

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments within project area: 54
Customer load within project area: 625 kW

Start Date (5.4.5.2 A.3)	**1-Feb-17**		**In-Service Date (5.4.5.2 A.3)**	**31/04/2017**
Expenditure Timing For the Test Year	**2017 Q1**	**2017 Q2**	**2017 Q3**	**2017 Q4**
	$125,000	$125,000		

Project Summary

This project includes the replacement of 20 poles, the majority were installed in the 1960's. The new main line poles will be upgraded to 55' to allow for the construction of a higher voltage, providing capacity for the future voltage conversion of 81 existing loads and will also provide a point of supply for a high school being demolished and replaced on Tanguay Avenue.

Risk Identification & Mitigation (5.4.5.2 A.4)

Scheduling Risks:

The main scheduling risk associated with this project is the completion of the first phase of this project in 2016 and other Capital projects, such as Church Street, which is scheduled to be completed in the first quarter of 2017. Project deadlines will be established once more detailed schedules are received from the school site on Tanguay. To mitigate the risk, contractor crews are made available to supplement WHESC crews as needed.

System Constraints Risks:

There are no system constraints associated with this project as no main circuits need to be isolated or power re-routed to complete the work.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

Cost estimates have been derived by using historical project costs of overhead pole lines containing similar asset conditions and re-construction requirements. Similar projects on Major Street, Division Street, and Clare Avenue were completed in 2014 and final costs were referenced for cost estimating.

REG Investment Details including Capital and OM&A Cost (5.4.5.2 A.6)

The are no REG investment requirements associated with this work.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

Leave to Construct approval is not required as this distribution line is under 2km in length and below 50kV.

Attach Other project reference material i.e. Images, Drawings and or reference material

Project maps and Images are included with this form.

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

Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1.a)

The main investment driver is reliability. Replacement of end-of-life assets combined with connecting existing loads to the higher voltage system will maintain and possibly improve Reliability. Connecting distribution transformers directly to the 27.6 kV feeder bypasses the Municipal Substation portion of the circuit and typically reduces the amount of circuit kilometers required to reach the point of connection for each transformer.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1.a)

The secondary investment driver is operational efficiency. The conversion of transformer connections from the 4.16 kV system to the 27.6 kV system results in operational efficiencies due to the reduction is distribution system line losses. The eventual elimination of Municipal Substations will result in both capital and operational cost savings. Cost savings will also be realized by the availability to connect the new school to the 27.6 kV when the new service is ready, rather than having to invest additional labour to change out the transformer at a latter date. The portion of the project on Tanguay Avenue will provide 27.6 kV connection points for the future conversion of many more existing 4.16kV loads.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1.a)

The primary related investment objective is reliability, namely maintaining SAIDI ad SAIFI. The secondary related investment objective operational efficiency, namely maintaining the results of WHESC's Efficiency Assessment and total cost performance. Distribution losses targets are expected to be achieved as a result of this investment.

Efficiency, Customer Value & Reliability - Source and nature of information used to justify the investment (5.4.5.2 B.1.a)

Information used to justify the investment in the project includes the condition of the assets. Asset condition is determined through inspection and testing programs combined with the knowledge of the age of the asset and the expected end of useful life through historical performance of other similar assets. WHESC's Geo-spatial Information System is used to collect/display data and create reports to assist in selecting/ranking projects.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority Relative to Other Investments

This project is ranked seventh out of fifteen material projects/programs planned for the Test Year (2017) based on the scoring below.

Criteria	Safety	Regulatory	Growth	Reliability	Cost	Total Score
Weight	10	9	8	6	5	
Score	0	0	0	6	8	76

Justification: This project is the second phase of a project initiated in 2016. The completion of this project has been given priority based on another customers construction schedule and can be adjusted to suite if system requirements, or the required in service connection timelines change.

Analysis of Project & Alternatives - Effect to the investment on system efficiency and cost-effectiveness (5.4.5.2 B.1.c)

The project will not only replace end of life assets but will also realize efficiencies through the voltage conversion process.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Customers will benefit from the reduced risk of outages as a result of the project. Efficiencies gained will support WHESC's focus on cost containment.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

Pole lines constructed to new standards are more robust and allow for greater spacing of equipment and clearances to ground, all having a positive effect on Reliability.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

Project Design Alternatives:

Underground Distribution design was not considered in this area for two reasons,.
(1) All homes serviced from this pole line are overhead services and costs would be extensive to convert the area to underground.
(2) Customer preference has not listed aesthetics as priority and consider current reliability to be acceptable and prefer that cost of service does increase considerably.
Wood poles will continue to be used in the area to reduce material costs. WHESC considered the option of rebuilding the line at 4.16 kV rather than converting it to 27.6 kV, but this option was not selected since the long term cost benefits of decommissioning the Municipal Substation exceed the short term cost benefits of 4.16 kV construction.

Scheduling Alternatives:

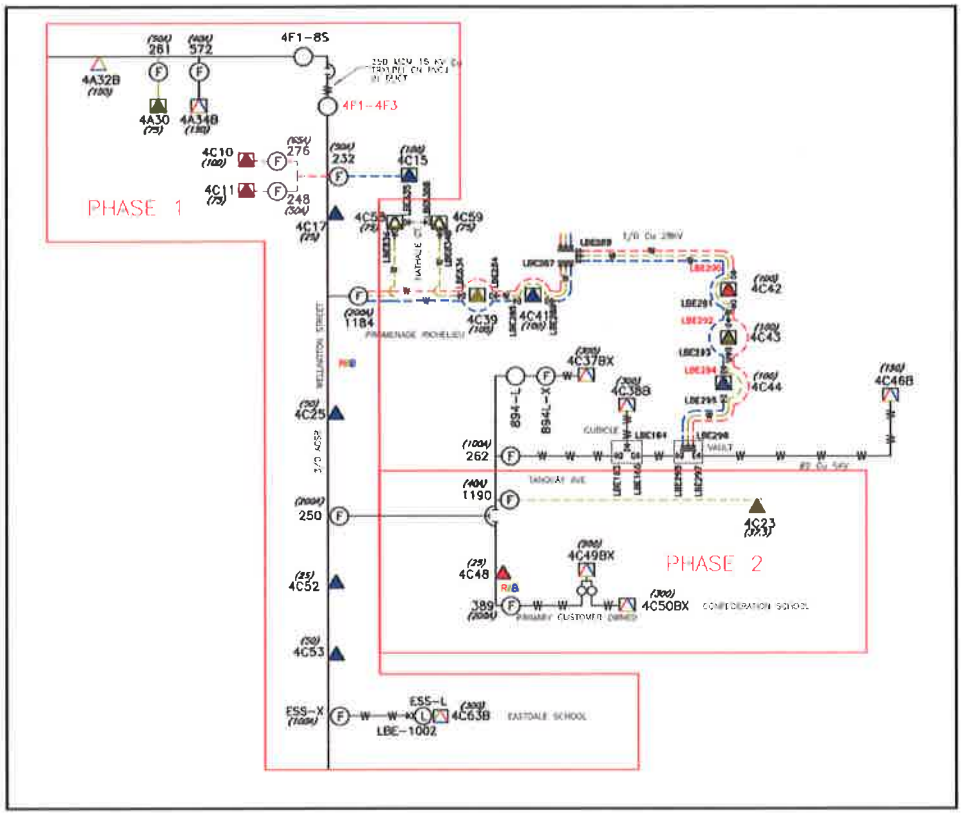
The project has been scheduled for 2017 per WHESC's project prioritization process. In the case of the "do nothing" option, the project benefits would not be achieved, which would likely results in more outages and higher costs for customers. The project can be delayed to a later part of the budget year if the high school construction schedule changes; however, it is preferable to complete the work prior to spring where conditions are ideal for underground renewal projects.

Safety (5.4.5.2 B.2)
This project will improve work safety by replacing existing poles with taller poles, resulting in more space for workers to install equipment while maintaining clearance from other energized circuits/equipment.
Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)
There are no Cyber-Security or privacy issues relevant to this project.
Coordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, Coordination with Utlilities,Regional Planning and/or 3rd party providers(where applicable)
WHESC is a member of the Utilities Standards Forum (USF) and uses USF standards for the construction of new lines. The standards ensure that the design of the project will adhere to a standard that is Engineered and widely used by a large group of utilities across the Province. Coordination with other utilities is not relevant to this project. Third parties will be consulted with to request participation in transferring to the new poles. Third party attachers will benefit from the new construction standards as well, as increased clearances are realized.
Coordination, Interoperability (5.4.5.2 B.4ii) Future Technological functionality and/or future operational requirements (where applicable)
The new construction standards will provide increased spacing to meet the needs of future equipment installations.
Economic Development (5.4.5.2 B.5) (where applicable)
This project will allow for the connection of a new high school. Following the new connection, the old high school will be disconnected as it will no longer be required. Reliability is one of the key drivers of this project (replacing end-of-life equipment) and a reliable electricity supply is conducive to economic development.
Environmental Benefits (5.4.5.2 B.6) (where applicable)
These asset replacements will reduce Environmental risk associated with asset failure, such as transformer leaks. Engineering design tools will also provide for proper transformer sizing reducing additional operating losses normally associated with oversizing transformers as a result of limited design data in the past. New transformers meet the latest standards for energy efficiency.

C. Category-Specific Requirements - System Renewal
Asset performance-related operational targets and asset lifecycle optimization policies and practices (refer to 5.2.3 and 5.3.3) (5.4.5.2 SR - C1.1)
The project fulfills asset performance-related operational targets by continuing to lower or maintain SAIDI and SAIFI index results. The project also positively affects safety targets by creating a safer work space for the powerline maintainers.
Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR - C1.2)
The majority of poles in this area were installed in the 1960's . From an age perspective, the poles have surpassed the typical end of useful life.
The number of customers in each class potentially affected by failure of the assets (5.4.5.2 SR - C1.3)
The are several distinct types of customers connected to the 4.16kV distribution in this area. There are 53 residential customers and 1 commercial customer (high school) that will be converted in the first stage of the project. The latter consist of 1 school, 1 day care, 1 nursing home, 2 mental health centers, 1 community center and 75 residential customers . Future conversions will include all of these latter mentioned customers and will also provide a 27.6kV backup to one high rise apartment building.
Quantitative customer impacts (5.4.5.2 SR - C1.4)
This area has not experienced any sustained unplanned outages due to asset failure. However, existing underground assets on Tanguay Avenue servicing non residential customers will benefit by the new high voltage feed, allowing for individual asset replacement prior to failure.
Qualitative customer impacts (5.4.5.2 SR - C1.5)
The completion of this project is expected to maintain or improve current reliability performance. Changes to the primary voltage connection of the equipment will improve operational efficiency and performance.
Value of cust. impact in terms of characteristics of cust. potentially affected by failure that have a bearing on the criticality and/or cost of failure(5.4.5.2 SR -
There is low impact to the Residential customers in this area, however, these customers typically do not have emergency backup systems. The existing commercial customers in this area have limited or no emergency backup systems. Future voltage conversions with connections resulting from the completion of this project will reduce risk of asset failure associated with these customers.
Timing & Priority of Project (5.4.5.2 SR - C2)
This project is part of an overall capital replacement plan for 2017. This project does not rely on any other 2017 project in any of the other Access, Service or General plant categories.
Consequences for system O&M costs (5.4.5.2 SR - C3)
O & M costs are expected to be reduced within the area of this project. Replaced poles will not require inspection immediately and will only require the standard visual and sounding tests over the first 15 years following the asset installation date. The risk of asset failure resulting in regular or overtime costs will be reduced significantly.
Impact on Reliability performance and/or Safety (5.4.5.2 SR - C4)
System Reliability in this area will be maintained. Construction standards, providing additional equipment spacing, will reduce the chance of interruptions caused by external sources such as animals, trees and vehicles.
Analysis of Project Benefits and Timing (5.4.5.2 SR - C5)
This project has been planned for 2017 per WHESC's project prioritization process. The timing has been determined to align with the connection of another asset to avoid additional spending to accomplish the same 27.6 kV connection benefits at a latter date.
Like for Like Renewal Analysis, Alternatives Comparison (like-for-like vs not like-for-like, timing, rate of replacement, etc.) (5.4.5.2 SR - C6)
Like for Like Renewal was not considered for this project as the existing poles are not tall enough to accommodate the installation of the new 27.6 kV circuit required to connect new loads and to complete the voltage conversion process for existing loads.

Other project reference material i.e. Images, Drawings and or reference material

Schematic Area



Existing Poles

Other project reference material i.e. Images, Drawings and or reference material
Example of Completed Project

A. General Information						
Project/Activity	Ross Street/Kennedy Street Rebuild/Conversion 4.16kV to 27.6kV					
Project Number						
Investment Category	System Renewal					
	2012	**2013**	**2014**	**2015**	**2016**	**2017**
Capital Cost (5.4.5.2 A.1)						$150,000
Capital Contribution						$0
Net Cost						$150,000
O&M Cost (5.4.5.2 A.1)	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
						Undetermined

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments within project area: 114
Customer load within project area: 275 kW

Start Date (5.4.5.2 A.3)	3-Oct-17	**In-Service Date (5.4.5.2 A.3)**		**30-Dec-17**
Expenditure Timing For the Test Year	**2017 Q1**	**2017 Q2**	**2017 Q3**	**2017 Q4**
				$150,000

Project Summary

This project includes the replacement of 10 poles, the majority were installed in the 1950's. Some of the older more deteriorated poles have been replaced, individually, over time. The new poles will be upgraded to a taller height to allow more space for construction of the higher voltage circuit, and to allow proper space to meet the current construction standards.

Risk Identification & Mitigation (5.4.5.2 A.4)

Scheduling Risks:

There are no other capital projects associated, allowing this project scheduling flexibility. For this reason it is scheduled for 4th quarter construction, but the schedule can be modified as necessary. Overhead rebuilds and conversion are reasonable well understood and generally meet budget and timing objectives.

System Constraints Risks:

There are no system constraints associated with this project as no main circuits need to be isolated or power re-routed to complete the work.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

Cost estimates have been derived by using historical project costs of overhead pole lines containing similar asset conditions and re-construction requirements. Similar projects on Orchard Street, Wright Street, and Deere Street were completed in 2015 and final costs were referenced for cost estimating.

REG Investment Details including Capital and OM&A Cost (5.4.5.2 A.6)

The are no REG investment requirements associated with this work.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

Leave to Construct approval is not required as this distribution line is under 2 km in length and below 50 kV.

Attach Other project reference material i.e. Images, Drawings and or reference material

Project map and Images are included with this form.

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

Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1.a)

The main investment driver is reliability. Replacement of end-of-life assets combined with connecting existing loads to the higher voltage system will maintain and possibly improve reliability. Connecting distribution transformers directly to the 27.6 kV feeder bypasses the Municipal Substation portion of the circuit and typically reduces the amount of circuit kilometers required to reach the point of connection for each transformer.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1.a)

The secondary investment driver is operational efficiency. The conversion of transformer connections from the 4.16 kV system to the 27.6 kV system results in operational efficiencies due to the reduction is distribution system line losses. The eventual elimination of Municipal Substations will result in both capital and operational cost savings.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1.a)

The primary related investment objective is reliability, namely maintaining SAIFI and SAIDI. The secondary related investment objective operational efficiency, namely maintaining the results of WHESC's Efficiency Assessment and total cost metrics. This investment also contributes to achieving WHESC's target in distribution losses.

Efficiency, Customer Value & Reliability - Source and nature of information used to justify the investment (5.4.5.2 B.1.a)

Information used to justify the investment in the project includes the condition of the asset determined through inspection and testing programs combined with the knowledge of the age of the asset and the expected end of useful life through historical performance of other similar assets. WHESC's Geospatial Information System is used to collect/display data and create reports to assist in selecting/ranking projects.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority Relative to Other Investments

This project is ranked thirteenth out of fifteen material projects/programs planned for the Test Year (2017) based on the scoring below.

Criteria	Safety	Regulatory	Growth	Reliability	Cost	Total Score
Weight	10	9	8	6	5	
Score	0	0	0	4	6	54

Justification: The completion of this project has been giving priority to be completed during the 2017 capital program, due to asset condition and the ability to gain efficiencies through the voltage conversion program.

Analysis of Project & Alternatives - Effect to the investment on system efficiency and cost-effectiveness (5.4.5.2 B.1.c)

The project will not only replace end-of-life assets but will also realize efficiencies through the voltage conversion process.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Customers will benefit from the reduced risk of outages as a result of the project. Efficiencies gained will support WHESC's focus on cost containment.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

Pole lines constructed to new standards are more robust and allow for greater spacing of equipment and clearances to ground, all having a positive effect on Reliability.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

Project Design Alternatives:

Underground Distribution design was not considered in this area for two reasons:
(1) All homes serviced from this pole line are overhead services and costs would be extensive to convert the area to underground.
(2) Customer preference has not listed aesthetics as a priority; customers consider current reliability to be acceptable and prefer that the cost of service does not increase considerably.
Wood poles will continue to be used in the area to reduce material costs. WHESC considered rebuilding the area at 4.16 kV instead of converting the lines to 27.6 kV, but this option was not selected since the long term benefit of cost reduction through eliminating Municipal Substations exceeds the short term cost benefits of 4.16 kV construction.

Scheduling Alternatives:

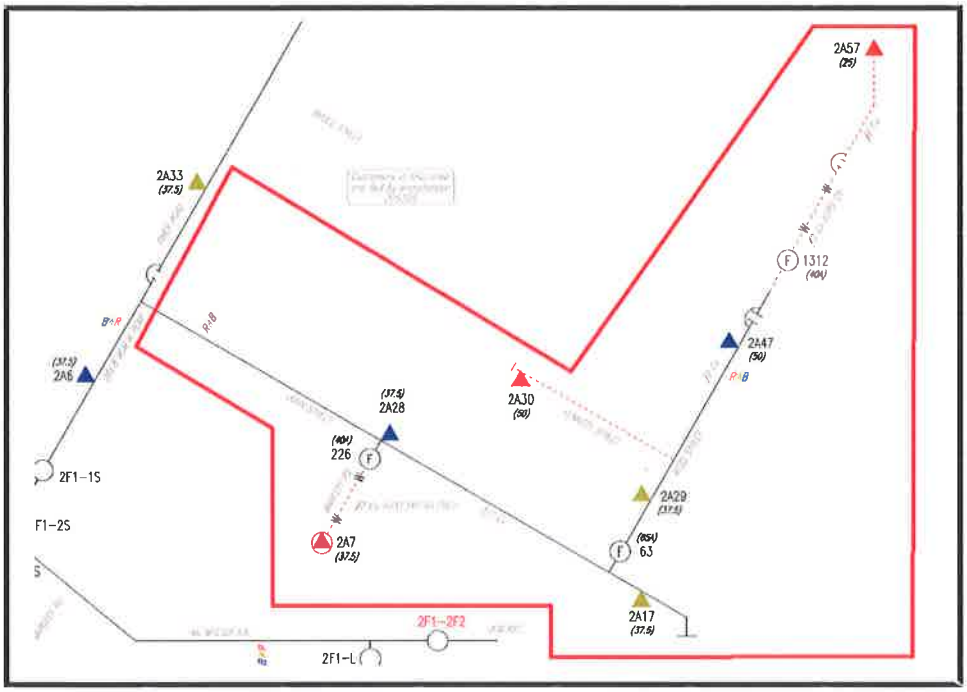
This project was scheduled in 2017 based on its priority per WHESC's project prioritization process. In the case of the "do nothing" option, the project benefits would not be achieved and customers would likely experience more outages while paying higher costs. This project has scheduling flexibility; it can be started earlier or delayed if necessary.

Safety (5.4.5.2 B.2)
This project will improve worker safety by replacing existing poles with taller poles, resulting in more space for workers to install equipment while maintaining clearance from other energized circuits/equipment.
Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)
There are no Cyber-Security or privacy issues relevant to this project.
Coordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, Coordination with Utilities,Regional Planning and/or 3rd party providers(where applicable)
WHESC is a member of the Utilities Standards Forum (USF) and uses USF standards for the construction of new lines. The standards ensure that the design of the project will adhere to a standard that is Engineered and widely used by a large group of utilities across the Province. Coordination with other utilities is not relevant to this project. Third parties will be consulted with to request participation in transferring to the new poles. Third party attachers will benefit from the new construction standards as well, as increased clearances are realized.
Coordination, Interoperability (5.4.5.2 B.4ii) Future Technological functionality and/or future operational requirements (where applicable)
The new construction standards will provide increased spacing to meet the needs of future equipment installations.
Economic Development (5.4.5.2 B.5) (where applicable)
Reliability is one of the key drivers of this project (replacing end-of-life equipment) and a reliable electricity supply is conducive to economic development.
Environmental Benefits (5.4.5.2 B.6) (where applicable)
These asset replacements will reduce environmental risk associated with asset failure, such as transformer leaks. Engineering design tools will also provide for proper transformers sizing reducing additional operating losses normally associated with oversizing transformers as a result of limited design data in the past. New transformers meet the latest standards for energy efficiency.

C. Category-Specific Requirements - System Renewal
Asset performance-related operational targets and asset lifecycle optimization policies and practices (refer to 5.2.3 and 5.3.3) (5.4.5.2 SR - C1.1)
The project fulfills asset performance-related operational targets by continuing to lower or maintain SAIDI and SAIFI index results. The project also positively affects safety targets by creating a safer work space for the powerline maintainers. Operational efficiency metrics such as Efficiency Assessment and total cost are maintained. Finally, distribution loss targets are expected to be achieved through the voltage conversion.
Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR - C1.2)
The poles in this area were installed in the 1950's and have surpassed there typical end of useful life. In addition, the primary and secondary conductors on some of the streets in the project area have surpassed their typical end of life.
The number of customers in each class potentially affected by failure of the assets (5.4.5.2 SR - C1.3)
There are 114 residential customers affected by asset failure.
Quantitative customer impacts (5.4.5.2 SR - C1.4)
The customers in this area have not experienced any sustained unplanned interruptions as a result of asset failure.
Qualitative customer impacts (5.4.5.2 SR - C1.5)
The completion of this project will improve reliability performance, in part, due to both replacement of assets and system redesign which will remove a portion of high voltage circuits currently located on side streets with extensive vegetation.
Value of cust. impact in terms of characteristics of cust. potentially affected by failure that have a bearing on the criticality and/or cost of failure(5.4.5.2 SR -
There is low impact to customers in this area in terms of criticality and cost of asset failure. However, being mainly residential load, the majority of customers are unlikely to have any source of back up power.
Timing & Priority of Project (5.4.5.2 SR - C2)
This project is part of an overall capital replacement plan for 2017. This project does not rely on any other 2017 project in any of the other System Access, System Service, or General Plant categories.
Consequences for system O&M costs (5.4.5.2 SR - C3)
O&M costs are expected to be reduced within the area of this project. Replaced poles will not require inspection immediately and will only require the standard visual and sounding tests over the first 15 years following the asset installation date. The risk of asset failure resulting in regular or overtime costs will be reduced significantly.
Impact on Reliability performance and/or Safety (5.4.5.2 SR - C4)
System reliability in this area will be maintained due to the reduced risk of asset failure. Construction standards, providing additional equipment spacing, will reduce the chance of interruptions caused by external sources such as animals, trees and vehicles.
Analysis of Project Benefits and Timing (5.4.5.2 SR - C5)
This project has been scheduled to be completed in the fourth quarter of 2017. Other 2017 projects have further benefits due to timing and have been prioritized as such per WHESC's prioritization process.
Like for Like Renewal Analysis, Alternatives Comparison (like-for-like vs not like-for-like, timing, rate of replacement, etc.) (5.4.5.2 SR - C6)
Like for Like construction was not considered in this area due to the overall poor condition of the majority of assets. Individual asset replacement would be more costly and less effective as most assets equally require replacement.

Other project reference material i.e. Images, Drawings and or reference material

Schematic Area



Existing Poles

Other project reference material i.e. Images, Drawings and or reference material
Example of Completed Project

A. General Information						
Project/Activity	Maureen Avenue 2.4kV Rebuild					
Project Number						
Investment Category	System Renewal					
	2012	**2013**	**2014**	**2015**	**2016**	**2017**
Capital Cost (5.4.5.2 A.1)						$125,000
Capital Contribution						$0
Net Cost						$125,000
O&M Cost (5.4.5.2 A.1)	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
						Undetermined

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments within project area: 88
Customer load within project area: 250 kW

Start Date (5.4.5.2 A.3)	**1-Apr-17**		**In-Service Date (5.4.5.2 A.3)**		**30-Jun-17**
Expenditure Timing For the Test Year	**2017 Q1**	**2017 Q2**	**2017 Q3**	**2017 Q4**	
		$125,000			

Project Summary

This project includes the replacement of 2 Pole-tran transformers and underground primary cable that was installed in 1974. The new design will also allow for the removal of two pole mounted transformers that are currently installed in the rear lot of customer properties. One of the existing underground primary cables providing a loop feed to this subdivision failed in 2016. The replacement was postponed as this project was re-scheduled for the 2017 capital program.

Risk Identification & Mitigation (5.4.5.2 A.4)

Scheduling Risks:

This program has been scheduled for the 2nd quarter due to the failure of the loop feed. Construction is also scheduled in the second quarter due to ideal weather/ground conditions for work of this nature. The biggest budgetary and schedule risk for underground rebuilds is based on labour time and costs, which is mitigated through good planning and project execution.

System Constraints Risks:

There are no system constraints associated with this project, as no main circuits need to be isolated or power re-routed to complete the work.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

Cost estimates have been derived by using historical project costs containing similar asset conditions and re-construction requirements. Similar projects on Preston Street, Wiltshire Street, and McColl Street were completed in 2013 and final costs were referenced for cost estimating.

REG Investment Details including Capital and OM&A Cost (5.4.5.2 A.6)

The are no REG investment requirements associated with this work.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

Leave to Construct approval is not required as this distribution line is under 2 km in length and below 50 kV.

Attach Other project reference material i.e. Images, Drawings and or reference material

Project map and images are included with this form.

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

Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1.a)

The main investment driver is reliability. Replacement of end-of-life assets combined with re-establishing the primary loop feed will maintain and possibly improve reliability.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1.a)

The secondary investment driver is operational efficiency. The re-establishment of the primary loop feed will reduce restoration times should a primary cable in any one section of the loop fail.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1.a)

The primary related investment objective is reliability, namely SAIDI and SAIFI performance. The secondary related investment objective operational efficiency, since the project replaces end-of-life plant and will reduce outage restoration times.

Efficiency, Customer Value & Reliability - Source and nature of information used to justify the investment (5.4.5.2 B.1.a)

Information used to justify the investment in the project includes the condition of the asset determined through inspection and testing programs combined with the knowledge of the age of the asset and the expected end of useful life through historical performance of other similar assets. In addition, cable fault reports collect the data necessary to analyze the performance and health of the underground primary and secondary cables. WHESC's Geospatial Information System is used to collect/display data and create reports to assist in selecting/ranking projects.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority Relative to Other Investments

This project is ranked fourteenth out of fifteen material projects/programs planned for the Test Year (2017) based on the scoring below.

Criteria	Safety	Regulatory	Growth	Reliability	Cost	Total Score
Weight	10	9	8	6	5	
Score	0	0	0	8	0	48

Justification: The completion of this project has been giving priority to be completed during the 2017 capital program, due to asset condition and asset performance.

Analysis of Project & Alternatives - Effect to the investment on system efficiency and cost-effectiveness (5.4.5.2 B.1.c)

The project will replace end-of-life assets. Voltage conversion was not available for this area of town.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Customers will benefit from the reduced risk of outages as a result of the project.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

The impact of the investment will reduce the risk of both frequency and duration of outages due to the fact that new assets will re-establish a loop feed.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

Project Design Alternatives:

The existing design of Pole-tran transformers is dated and does not provide the safety conditions of current padmount transformers. A voltage conversion was not considered as a viable option due to the extensive cost of providing a new 27.6 kV circuit to the area.

Scheduling Alternatives:

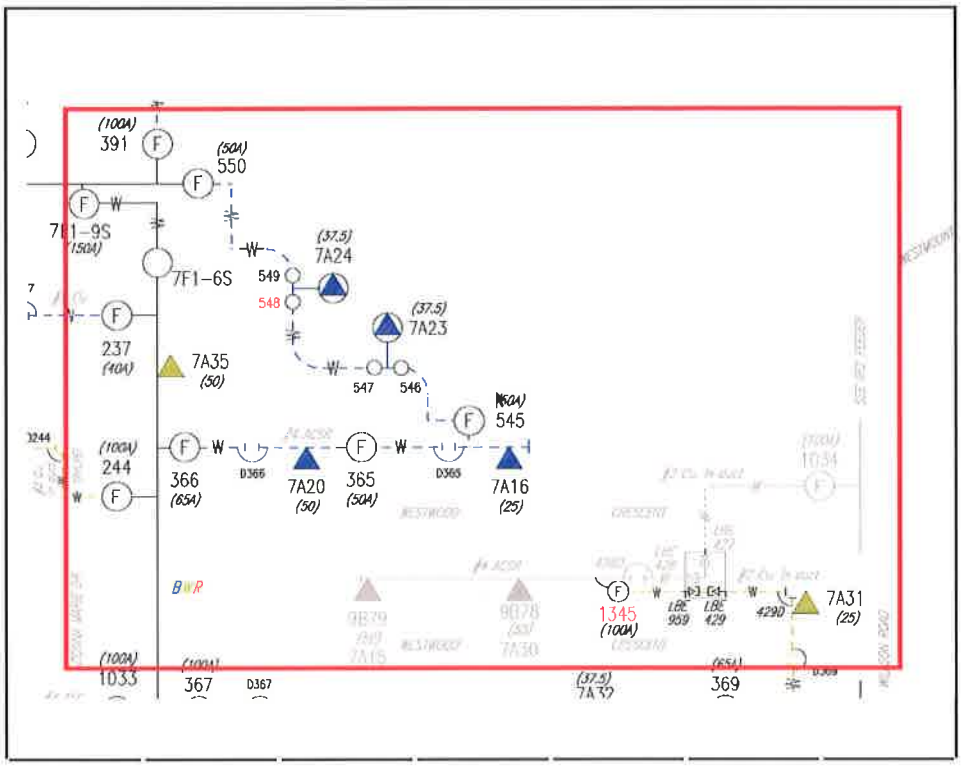
This project was planned for 2017 based on its priority per WHESC's prioritization process. In the case of the "do nothing" option (project deferral), the project benefits would not be achieved and customers would likely experience more outages of longer duration. The project could be moved into the 3rd quarter if necessary.

Safety (5.4.5.2 B.2)
This project will improve worker safety in two distinct areas. New padmount transformers will provide a safer working environment due to the current dead-front design standard. Secondly, two rear lot pole mounted transformers will be removed reducing the risk associated with climbing poles and rigging transformers for replacement.
Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)
There are no Cyber-Security or privacy issues relevant to this project.
Coordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, Coordination with Utlilities,Regional Planning and/or 3rd party providers(where applicable)
WHESC is a member of the Utilities Standards Forum (USF) and uses USF standards for the construction of new underground systems. The standards ensure that the design of the project will adhere to a standard that is Engineered and widely used by a large group of utilities across the Province. Coordination with other utilities is not relevant to this project.
Coordination, Interoperability (5.4.5.2 B.4ii) Future Technological functionality and/or future operational requirements (where applicable)
The new construction standards will provide a safer working environment. System configuration and switching will be simplified due to the new engineered design.
Economic Development (5.4.5.2 B.5) (where applicable)
Reliability is one of the key drivers of this project (replacing end-of-life equipment) and a reliable electricity supply is conducive to economic development.
Environmental Benefits (5.4.5.2 B.6) (where applicable)
These asset replacements will reduce environmental risk associated with asset failure, such as transformer leaks. Engineering design tools will also provide for proper transfer sizing reducing additional operating losses normally associated with oversizing transformers as a result of limited design data in the past. New transformers meet the latest standards for energy efficiency.

C. Category-Specific Requirements - System Renewal
Asset performance-related operational targets and asset lifecycle optimization policies and practices (refer to 5.2.3 and 5.3.3) (5.4.5.2 SR - C1.1)
The project fulfills asset performance-related operational targets by mitigating the continued risk of increased SAIDI and SAIFI index as a result of not having a back-up loop feed to this area.
Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR - C1.2)
The underground assets in this area are 42 years old and have far exceeded their useful end of life. A critical section of the underground loop feed has failed. Temporary mitigation plans are in place prior to asset replacement.
The number of customers in each class potentially affected by failure of the assets (5.4.5.2 SR - C1.3)
There are 88 residential customers affected by asset failure.
Quantitative customer impacts (5.4.5.2 SR - C1.4)
The customers in this area have experienced an unplanned power interruption due to one primary cable failure.
Qualitative customer impacts (5.4.5.2 SR - C1.5)
The completion of this project will improve reliability performance and reduce the risk of further significant reliability issues.
Value of cust. impact in terms of characteristics of cust. potentially affected by failure that have a bearing on the criticality and/or cost of failure(5.4.5.2 SR -
There is low impact to customers in this area in terms of criticality and cost of asset failure. However, being mainly residential load, the majority of customers are unlikely to have any source of back up power.
Timing & Priority of Project (5.4.5.2 SR - C2)
This project is part of an overall capital replacement plan for 2017. This project does not rely on any other 2017 project in any of the other System Access, System Service, or General Plant categories.
Consequences for system O&M costs (5.4.5.2 SR - C3)
O&M costs are expected to be reduced within the area of this project. The risk of asset failure resulting in regular or overtime costs will be reduced significant
Impact on Reliability performance and/or Safety (5.4.5.2 SR - C4)
System reliability in this area will improve due to the reduced number of asset failures. Elimination of rear lot pole mounted transformers will reduce the risk of sustained outage duration due to poor asset access through customer properties.
Analysis of Project Benefits and Timing (5.4.5.2 SR - C5)
This project has been scheduled to be completed in the second quarter of 2017 to mitigate risk of a long term outage.
Like for Like Renewal Analysis, Alternatives Comparison (like-for-like vs not like-for-like, timing, rate of replacement, etc.) (5.4.5.2 SR - C6)
Like for Like construction was not an option for this project.

Other project reference material i.e. Images, Drawings and or reference material

Schematic Area



Existing Pole Tran Transformer & Rear lot Pole with Transformer

Other project reference material i.e. Images, Drawings and or reference material
Example of Completed Project

New Padmount Transformer

New Streetlight Pole & Secondary Pedestal

A. General Information						
Project/Activity	Riverview Drive Rebuild/Conversion 4.16kV to 27.6kV					
Project Number						
Investment Category	System Renewal					
	2012	**2013**	**2014**	**2015**	**2016**	**2017**
Capital Cost (5.4.5.2 A.1)						$150,000
Capital Contribution						$0
Net Cost						$150,000
O&M Cost (5.4.5.2 A.1)	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
						Undetermined

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments within project area: 127
Customer load within project area: 250 kW

Start Date (5.4.5.2 A.3)	**3-Oct-17**		**In-Service Date (5.4.5.2 A.3)**		**31-Dec-17**
Expenditure Timing For the Test Year	**2017 Q1**	**2017 Q2**	**2017 Q3**	**2017 Q4**	
				$150,000	

Project Summary

This project includes the replacement of 10 poles, the majority of which were installed in the 1950's. The new poles will be upgraded to a taller height to allow more space for construction of the higher voltage circuit and to allow proper space to meet the current construction standards.

Risk Identification & Mitigation (5.4.5.2 A.4)

Scheduling Risks:

There are no other capital projects associated, allowing this project scheduling flexibility. For this reason it is scheduled for 4th quarter construction, but the schedule can be modified as necessary. Overhead rebuild/conversion projects are reasonably well understood and generally meet budget and timing objectives.

System Constraints Risks:

There are no system constraints associated with this project as no main circuits need to be isolated or power re-routed to complete the work.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

Cost estimates have been derived by using historical project costs of overhead pole lines containing similar asset conditions and re-construction requirements. Similar projects on Orchard Street, Wright Street, and Deere Street were completed in 2015 and final costs were referenced for cost estimating.

REG Investment Details including Capital and OM&A Cost (5.4.5.2 A.6)

The are no REG investment requirements associated with this work.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

Leave to Construct approval is not required as this distribution line is under 2km in length and below 50kV.

Attach Other project reference material i.e. Images, Drawings and or reference material

Project map and images are included with this form.

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

Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1.a)

The main investment driver is reliability. Replacement of end-of-life assets combined with connecting existing loads to the higher voltage system will maintain and possibly improve reliability. A section of primary conductor with poor equipment access will be removed to improve reliability and worker Safety. Connecting distribution transformers directly to the 27.6 kV feeder bypasses the Municipal Substation portion of the circuit and typically reduces the amount of circuit kilometers required to reach the point of connection for each transformer.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1a)

The secondary investment driver is operational efficiency. The conversion of transformer connections from the 4.16 kV system to the 27.6 kV system results in operational efficiencies due to the reduction is distribution system line losses. The eventual elimination of Municipal Substations will result in both capital and operational cost savings.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1.a)

The primary related investment objective is reliability, namely maintaining WHESC's SAIDI and SAIFI performance. The secondary related investment objective operational efficiency, namely maintaining WHESC's performance with respect to the Efficiency Assessment and total cost metrics.

Efficiency, Customer Value & Reliability - Source and nature of information used to justify the investment (5.4.5.2 B.1.a)

Information used to justify the investment in the project includes the condition of the asset determined through inspection and testing programs, combined with the knowledge of the age of the asset and the expected end of useful life through historical performance of other similar assets. WHESC's Geospatial Information System is used to collect/display data and create reports to assist in selecting/ranking projects.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority Relative to Other Investments

This project is ranked tenth out of fifteen material projects/programs planned for the Test Year (2017) based on the scoring below.

Criteria	Safety	Regulatory	Growth	Reliability	Cost	Total Score
Weight	10	9	8	6	5	
Score	0	0	0	5	7	65

Justification: The completion of this project has been giving priority to be completed during the 2017 capital program, due to asset condition and the ability to gain efficiencies through the voltage conversion program.

Analysis of Project & Alternatives - Effect to the investment on system efficiency and cost-effectiveness (5.4.5.2 B.1.c)

The project will not only replace end-of-life assets, but will also realize efficiencies through the voltage conversion process.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Customers will benefit from the reduced risk of outages as a result of the project. Efficiencies gained will support WHESC's focus on cost containment.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

Pole lines constructed to the new standards are more robust and allow for greater spacing of equipment and clearances to the ground, all having a positive effect on Reliability.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

Project Design Alternatives:

A rebuild at the same primary voltage was considered with no efficiencies gained. Total conversion to an underground system would be unnecessarily costly and not seen as beneficial or valued by our customers.

Scheduling Alternatives:

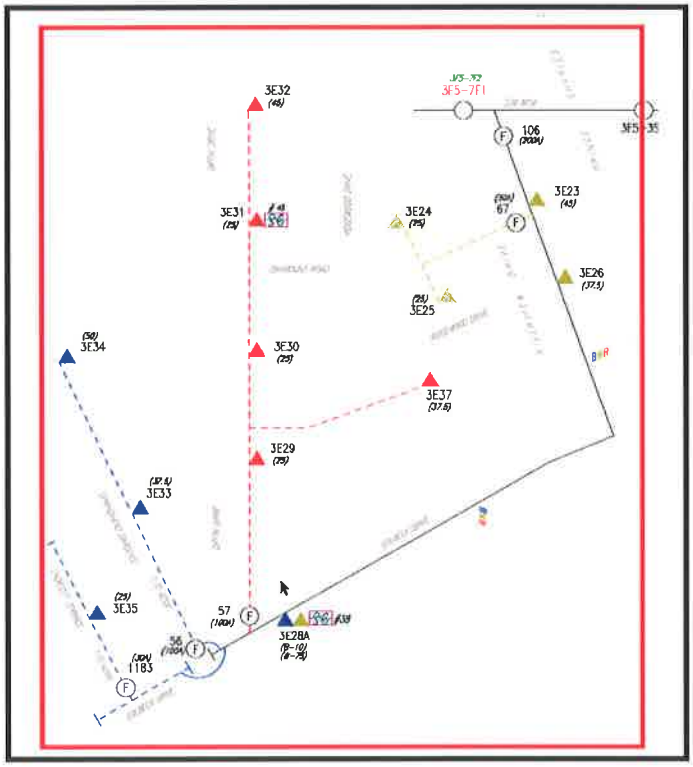
This project was planned for 2017 based on its priority per WHESC's project prioritization process. In the case of the "do nothing" option (project deferral), the project benefits would not be achieved and customers would likely experience more outages and higher electricity delivery costs. This project has scheduling flexibility throughout the year.

Safety (5.4.5.2 B.2)
This project will improve worker safety by replacing existing poles with taller poles, resulting in more space for workers to install equipment while maintaining clearance from other energized circuits/equipment.
Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)
There are no Cyber-Security or privacy issues relevant to this project.
Coordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, Coordination with Utlilities,Regional Planning and/or 3rd party providers(where applicable)
WHESC is a member of the Utilities Standards Forum (USF) and uses USF standards for the construction of new lines. The standards ensure that the design of the project will adhere to a standard that is Engineered and widely used by a large group of utilities across the Province. Coordination with other utilities is not relevant to this project. Third parties will be consulted with to request participation in transferring to the new poles. Third party attachers will benefit from the new construction standards as well, as increased clearances are realized.
Coordination, Interoperability (5.4.5.2 B.4.ii) Future Technological functionality and/or future operational requirements (where applicable)
The new construction standards will provide increased spacing to meet the needs of future equipment installations.
Economic Development (5.4.5.2 B.5) (where applicable)
Reliability is one of the key drivers of this project (replacing end-of-life equipment) and a reliable electricity supply is conducive to economic development.
Environmental Benefits (5.4.5.2 B.6) (where applicable)
These asset replacements will reduce environmental risk associated with asset failure, such as transformer leaks. Engineering design tools will also provide for proper transformer sizing, reducing additional operating losses normally associated with oversizing transformers as a result of limited design data in the past. New transformers meet the latest standards for energy efficiency.

C. Category-Specific Requirements - System Renewal
Asset performance-related operational targets and asset lifecycle optimization policies and practices (refer to 5.2.3 and 5.3.3) (5.4.5.2 SR - C1.1)
The project fulfills asset performance-related operational targets by continuing to lower or maintain SAIDI and SAIFI index results. The project also positively affects safety targets by creating a safer work space for the powerline maintainers. This project's effect on operational efficiency and cost effectiveness is expected to maintain WHESC's Efficiency Assessment and total cost metrics. Finally, the voltage conversion will contribute to WHESC's achieving its objectives in distribution losses.
Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR - C1.2)
The majority of poles in this area were installed in the 1950's and have surpassed there typical end of useful life. In addition the primary and secondary conductors have surpassed their typical end of life.
The number of customers in each class potentially affected by failure of the assets (5.4.5.2 SR - C1.3)
There are 127 residential customers that could be affected by asset failure.
Quantitative customer impacts (5.4.5.2 SR - C1.4)
There were no asset failures in the project area that resulted in any prolonged customer outages over the past five years.
Qualitative customer impacts (5.4.5.2 SR - C1.5)
The completion of this project will maintain the current reliability performance in this area.
Value of cust. impact in terms of characteristics of cust. potentially affected by failure that have a bearing on the criticality and/or cost of failure(5.4.5.2 SR -
There is low impact to customers in this area in terms of criticality and cost of asset failure. However, being mainly residential load, the majority of customers are unlikely to have any source of back up power.
Timing & Priority of Project (5.4.5.2 SR - C2)
This project is part of an overall capital replacement plan for 2017. This project does not rely on any other 2017 project in any of the other System Access, System Service, or General plant categories.
Consequences for system O&M costs (5.4.5.2 SR - C3)
O&M costs are expected to be reduced within the area of this project. Replaced poles will not require inspection immediately and will only require the standard visual and sounding tests over the first 15 years following the asset installation date. The risk of asset failure resulting in regular or overtime costs will be reduced significantly.
Impact on Reliability performance and/or Safety (5.4.5.2 SR - C4)
System reliability in this area will improve due to the reduced probability of asset failures. Construction standards, providing additional equipment spacing, will reduce the chance of interruptions caused by external sources such as animals, trees and vehicles. Elimination of high voltage conductor within high vegetation areas will also improve reliability.
Analysis of Project Benefits and Timing (5.4.5.2 SR - C5)
This project has been scheduled to be completed in the fourth quarter of 2017, since other projects planned for 2017 have timing benefits to be completed earlier in the 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 SR - C6)
Like for Like construction was not considered in this area due to the overall poor condition of the majority of assets. Individual asset replacement would be more costly and less effective as most assets equally require replacement.

Other project reference material i.e. Images, Drawings and or reference material

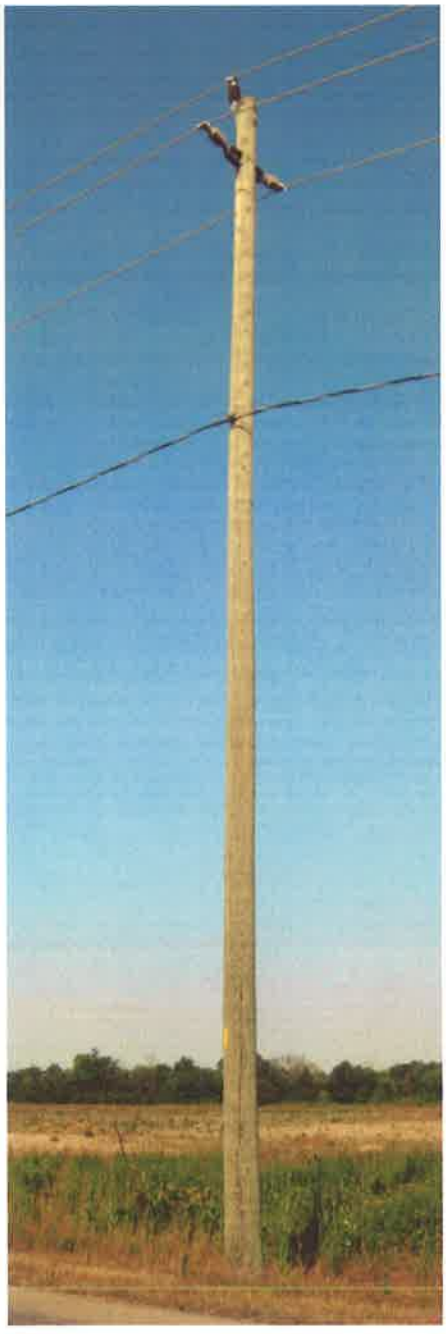
Schematic Area



Existing Poles & Transformers

Other project reference material I.e. Images, Drawings and or reference material
Example of Completed Project

New Pole Installation



New Padmount Transformer

A. General Information						
Project/Activity	Robert Street Rebuild/Conversion 2.4kV to 16kV					
Project Number						
Investment Category	System Renewal					
	2012	**2013**	**2014**	**2015**	**2016**	**2017**
Capital Cost (5.4.5.2 A.1)						$150,000
Capital Contribution						$0
Net Cost						$150,000
O&M Cost (5.4.5.2 A.1)	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
						Undetermined

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments within project area: 59
Customer load within project area: 225kW

Start Date (5.4.5.2 A.3)	**3-Jan-17**		**In-Service Date (5.4.5.2 A.3)**		**31-Mar-17**
Expenditure Timing For the Test Year	**2017 Q1**	**2017 Q2**	**2017 Q3**	**2017 Q4**	
			$150,000		

Project Summary

This project includes the replacement of 3 Pole-tran transformers and underground primary cable that was installed in 1975. The new design will also include voltage conversion of this area to 16 kV.

Risk Identification & Mitigation (5.4.5.2 A.4)

Scheduling Risks:

There are no other capital projects associated, allowing this project scheduling flexibility. For this reason it is scheduled for 3rd quarter construction, but the schedule can be modified as necessary. Scheduling will utilize the advantages of construction during good weather and ground conditions. Underground rebuild/conversion projects are reasonably well understood and generally meet budget and timing objectives. The biggest budgetary/scheduling risk is labour cost/hours, which is mitigated through good planning and project execution.

System Constraints Risks:

There are no system constraints associated with this project as no main circuits need to be isolated or power re-routed to complete the work.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

Cost estimates have been derived by using historical project costs containing similar asset conditions and re-construction requirements. A similar project on Graystone Avenue was completed in 2014/2015 and final costs were referenced for cost estimating.

REG Investment Details including Capital and OM&A Cost (5.4.5.2 A.6)

The are no REG investment requirements associated with this work.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

Leave to Construct approval is not required as this distribution line is under 2km in length and below 50kV.

Attach Other project reference material i.e. Images, Drawings and or reference material

Project map and images are included with this form.

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

Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1.a)

The main investment driver is reliability. Replacement of end-of-life assets and conversion to the higher voltage system will improve reliability.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1.a)

The secondary investment driver is operational efficiency. The replacement of Pole-tran transformers will simplify system switching. The conversion to the higher voltage system will result in lower system losses driving efficiency. The eventual elimination of Municipal Substations will result in both capital and operational Cost Savings.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1.a)

The primary related investment objective is reliability, namely maintaining WHESC's SAIDI and SAIFI performance. The secondary related investment objective operational efficiency, namely maintaining WHESC's performance with respect to the Efficiency Assessment and total cost metrics. In addition, this project contributes to WHESC achieving its performance objective for distribution losses.

Efficiency, Customer Value & Reliability - Source and nature of information used to justify the investment (5.4.5.2 B.1.a)

Information used to justify the investment in the project includes the condition of the asset determined through inspection and testing programs combined with the knowledge of the age of the asset and the expected end of useful life through historical performance of other similar assets. In addition, cable fault reports collect the data necessary to analyze the performance and health of underground primary and secondary cables. WHESC's Geospatial Information System is used to collect/display data and create reports to assist in selecting/ranking projects.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority Relative to Other Investments

This project is ranked sixth out of fifteen material projects/programs planned for the Test Year (2017) based on the scoring below.

Criteria	Safety	Regulatory	Growth	Reliability	Cost	Total Score
Weight	10	9	8	6	5	
Score	0	0	0	7	7	77

Justification: The completion of this project has been giving priority to be completed during the 2017 capital program, due to asset condition and asset performance.

Analysis of Project & Alternatives - Effect to the investment on system efficiency and cost-effectiveness (5.4.5.2 B.1.c)

The project will not only replace end-of-life assets, but will also improve efficiency through the voltage conversion.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Customers will benefit from the reduced risk of outages. Cost containment will be realized by efficiencies gained through voltage conversions.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

The impact of the investment will reduce the risk of both frequency and duration of outages due to the fact that new assets will be installed and there will be less circuit kilometers from the power source to the point of connection.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

Project Design Alternatives:

The existing design of Pole-tran transformers is dated and does not provide the safety conditions realized with current padmount transformers. The transformers could have remained on the 2.4 kV system, but the result would be no efficiencies gained.

Scheduling Alternatives:

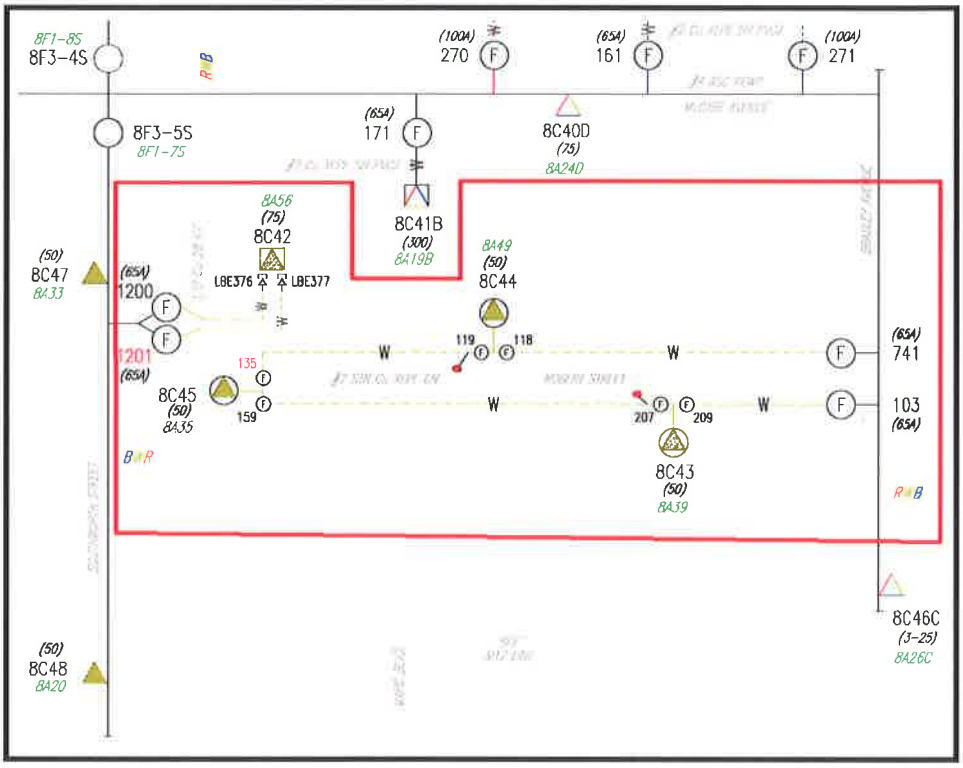
The project was planned for 2017 based on its priority per WHESC's project prioritization process. In the case of the "do nothing" option (project deferral), the investment benefits would not be realized and customers would likely experience more outages and higher costs. The project can be moved to the 2nd quarter if necessary.

Safety (5.4.5.2 B.2)
This project will improve worker safety with the installation of new padmount transformers which incorporate a dead-front design standard.
Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)
There are no Cyber-Security or privacy issues relevant to this project.
Coordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, Coordination with Utlilities,Regional Planning and/or 3rd party providers(where applicable)
WHESC is a member of the Utilities Standards Forum (USF) and uses USF standards for the construction of new underground distribution. The standards ensure that the design of the project will adhere to a standard that is Engineered and widely used by a large group of utilities across the Province. Coordination with other utilities is not relevant to this project.
Coordination, Interoperability (5.4.5.2 B.4ii) Future Technological functionality and/or future operational requirements (where applicable)
The new construction standards will provide a safer working environment. System configuration and switching will be simplified due to the new engineered design.
Economic Development (5.4.5.2 B.5) (where applicable)
Reliability is one of the key drivers of this project (replacing end-of-life equipment) and a reliable electricity supply is conducive to economic development.
Environmental Benefits (5.4.5.2 B.6) (where applicable)
These asset replacements will reduce environmental risk associated with asset failure, such as transformer leaks. Engineering design tools will also provide for proper transformer sizing reducing additional operating losses normally associated with oversizing transformers as a result of limited design data in the past. New transformers meet the latest standards in energy efficiency.

C. Category-Specific Requirements - System Renewal
Asset performance-related operational targets and asset lifecycle optimization policies and practices (refer to 5.2.3 and 5.3.3) (5.4.5.2 SR - C1.1)
The project fulfills asset performance-related operational targets by mitigating the continued risk of increased SAIDI and SAIFI index as a result of replacing aging assets that have experienced some operational issues. By addressing operational efficiency and cost effectiveness, the project contributes to maintaining WHESC's performance with respect to its Efficiency Assessment and total cost metrics. Finally, performance targets in distribution losses are expected to be achieved through the voltage conversion.
Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR - C1.2)
The underground assets in this area are 41 years old and have far exceeded their useful life.
The number of customers in each class potentially affected by failure of the assets (5.4.5.2 SR - C1.3)
There are 59 residential customers that would be affected by asset failure.
Quantitative customer impacts (5.4.5.2 SR - C1.4)
The customers within this project area have sustained unplanned outages due to two primary cable failures and planned outages due to equipment leaks.
Qualitative customer impacts (5.4.5.2 SR - C1.5)
The completion of this project will improve reliability in this area.
Value of cust. impact in terms of characteristics of cust. potentially affected by failure that have a bearing on the criticality and/or cost of failure(5.4.5.2 SR -
There is low impact to customers in this area in terms of criticality and cost of asset failure. However, being mainly residential load, the majority of customers are unlikely to have any source of back-up power.
Timing & Priority of Project (5.4.5.2 SR - C2)
This project is part of an overall capital replacement plan for 2017. This project does not rely on any other 2017 project in any of the other System Access, System Service, or General Plant categories.
Consequences for system O&M costs (5.4.5.2 SR - C3)
O&M costs are expected to be reduced within the area of this project as assets are replaced and ongoing costs associated with equipment leaks and underground primary cable failures are eliminated.
Impact on Reliability performance and/or Safety (5.4.5.2 SR - C4)
System reliability in this area will improve due to the reduced number of asset failures.
Analysis of Project Benefits and Timing (5.4.5.2 SR - C5)
This project has been scheduled to be completed in the third quarter of 2017 to realize the advantages of construction during good weather and ground conditions.
Like for Like Renewal Analysis, Alternatives Comparison (like-for-like vs not like-for-like, timing, rate of replacement, etc.) (5.4.5.2 SR - C6)
Like for Like construction was not an option for this project.

Other project reference material i.e. Images, Drawings and or reference material

Schematic Area



Existing Pole Tran Transformer & Primary Dip

Other project reference material i.e. Images, Drawings and or reference material
Example of Completed Project

New Padmount Transformer

New Streetlight Pole & Secondary Pedestal

A. General Information						
Project/Activity	Silvan/Newleaf Phase 2 Rebuild/Conversion 2.4kV to 16kV					
Project Number						
Investment Category	System Renewal					
	2012	**2013**	**2014**	**2015**	**2016**	**2017**
Capital Cost (5.4.5.2 A.1)						$280,000
Capital Contribution						$0
Net Cost						$280,000
O&M Cost (5.4.5.2 A.1)	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
						Undetermined

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments within project area: 106
Customer load within project area: 500 kW

Start Date (5.4.5.2 A.3)	**1-Mar-17**		**In-Service Date (5.4.5.2 A.3)**			**31-Aug-17**
Expenditure Timing For the Test Year	**2017 Q1**	**2017 Q2**	**2017 Q3**	**2017 Q4**		
		$140,000	$140,000			

Project Summary

This project includes the replacement of 14 Pole-tran transformers and underground primary cable that was installed in 1976. The new design will also include a voltage conversion of this area to 16 kV.

Risk Identification & Mitigation (5.4.5.2 A.4)

Scheduling Risks:

There are no other capital projects associated, allowing this project scheduling flexibility. For this reason it is scheduled for 2nd and 3rd quarter construction, but the schedule can be modified as necessary. Scheduling will utilize the advantages of construction during good weather and ground conditions. Underground rebuild/conversion projects are reasonably well understood and generally meet budget and timing objectives. The biggest budgetary/scheduling risk is labour cost/hours, which is mitigated through good planning and project execution.

System Constraints Risks:

There are no system constraints associated with this project, as no main circuits need to be isolated or power re-routed to complete the work.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

Cost estimates have been derived by using historical project costs of similar asset conditions and re-construction requirements. A project on Graystone Avenue was completed in 2014/2015 and final costs were referenced for cost estimating.

REG Investment Details including Capital and OM&A Cost (5.4.5.2 A.6)

The are no REG investment requirements associated with this work.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

Leave to Construct approval is not required as this distribution line is under 2km in length and below 50kV.

Attach Other project reference material i.e. Images, Drawings and or reference material

Project map and images are included with this form.

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

Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1.a)

The main investment driver is reliability. Replacement of end-of-life assets and conversion to the higher voltage system will improve reliability.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1.a)

The secondary investment driver is operational efficiency. The replacement of the pole tran transformers will simplify system switching. The conversion to the higher voltage system will result in lower system losses driving efficiency. The eventual elimination of Municipal Substations will result in both capital and operational cost savings.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1.a)

The primary related investment objective is reliability, namely WHESC's SAIDI and SAIFI performance. The secondary related investment objective operational efficiency, namely WHESC's performance with respect to its Efficiency Assessment and total cost metrics.

Efficiency, Customer Value & Reliability - Source and nature of information used to justify the investment (5.4.5.2 B.1.a)

Information used to justify the investment in the project includes the condition of the asset determined through inspection and testing programs combined with the knowledge of the age of the asset and the expected end of useful life through historical performance of other similar assets. In addition, cable fault reports collect the data necessary to analyze the performance and health of the underground primary and secondary cables. WHESC's Geospatial Information System is used to collect/display data and create reports to assist in selecting/ranking projects.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority Relative to Other Investments

This project is ranked fourth out of fifteen material projects/programs planned for the Test Year (2017) based on the scoring below.

Criteria	Safety	Regulatory	Growth	Reliability	Cost	Total Score
Weight	10	9	8	6	5	
Score	0	0	0	8	8	88

Justification: The completion of this project has been giving priority to be completed during the 2017 capital program, due to asset condition and asset performance.

Analysis of Project & Alternatives - Effect to the investment on system efficiency and cost-effectiveness (5.4.5.2 B.1.c)

The project will not only replace end-of-life assets, but will also improve efficiency through voltage conversion.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Customers will benefit from the reduced risk of outages. Cost containment will be realized by efficiencies gained through voltage conversions.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

The impact of the investment will reduce the risk of both frequency and duration of outages due to the fact that new assets will be installed and there will be less circuit kilometers from the power source to the point of connection.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

Project Design Alternatives:

The existing design of Pole-tran transformers is dated and does not provide the safety conditions of current padmount transformers. The transformers could have remained on the 2.4 kV system but the result would be no efficiencies gained.

Scheduling Alternatives:

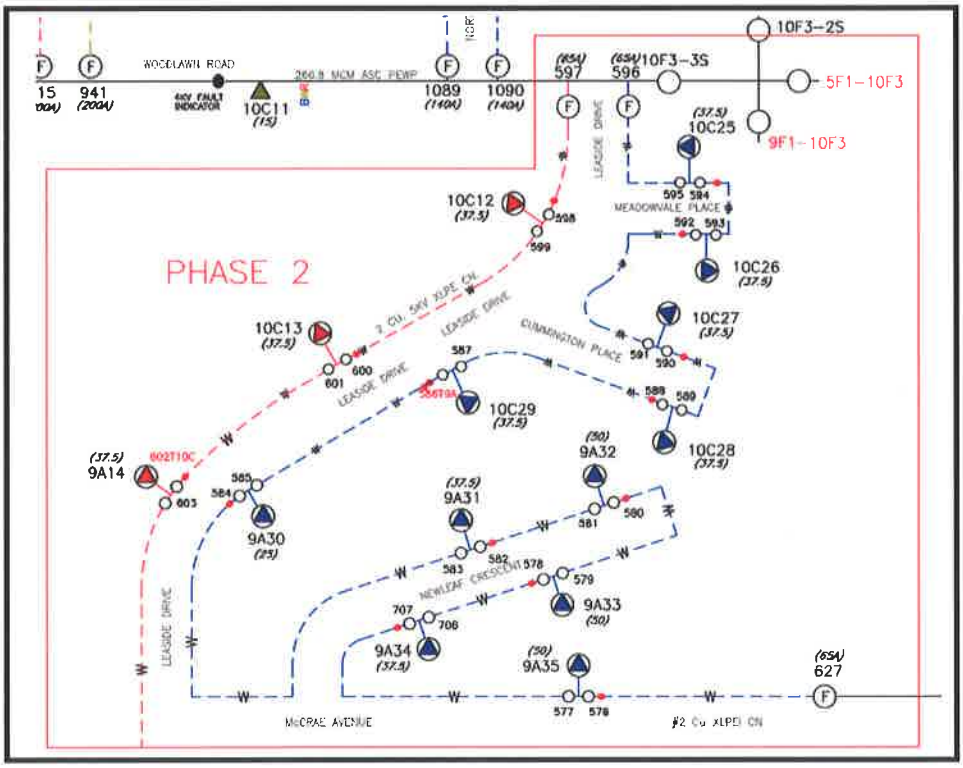
The project has been planned for 2017 based its priority per WHESC's project prioritization process. In the case of the "do nothing" option (project deferral), the investment benefits would not be realized and customers would likely experience more outages and pay a higher cost of electricity in the long term. The project can be completed in either of the two planned quarters if necessary.

Safety (5.4.5.2 B.2)
This project will improve worker safety with the installation of new padmount transformers which incorporate a dead-front design standard.
Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)
There are no Cyber-Security or privacy issues relevant to this project.
Coordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, Coordination with Utilities,Regional Planning and/or 3rd party providers(where applicable)
WHESC is a member of the Utilities Standards Forum (USF) and uses USF standards for the construction of new lines. The standards ensure that the design of the project will adhere to a standard that is Engineered and widely used by a large group of utilities across the Province. Coordination with other utilities is not relevant to this project.
Coordination, Interoperability (5.4.5.2 B.4ii) Future Technological functionality and/or future operational requirements (where applicable)
The new construction standards will provide a safer working environment. System configuration and switching will be simplified due to the new engineered design.
Economic Development (5.4.5.2 B.5) (where applicable)
Reliability is one of the key drivers of this project (replacing end-of-life equipment) and a reliable electricity supply is conducive to economic development.
Environmental Benefits (5.4.5.2 B.6) (where applicable)
These asset replacements will reduce environmental risk associated with asset failure, such as transformer leaks. Engineering design tools will also provide for proper transformer sizing reducing additional operating losses normally associated with oversizing transformers as a result of limited design data in the past. New transformers meet the latest standards for energy efficiency.

C. Category-Specific Requirements - System Renewal
Asset performance-related operational targets and asset lifecycle optimization policies and practices (refer to 5.2.3 and 5.3.3) (5.4.5.2 SR - C1.1)
The project fulfills asset performance-related operational targets by mitigating the continued risk of increased SAIDI and SAIFI index as a result replacing aging assets that have experienced some operational issues. The project contributes to maintain operational efficiency and cost effectiveness performance, specifically operational targets for the Efficiency Assessment and total cost metrics. Voltage conversion contributes to WHESC achieving its asset performance-related operational targets in distribution losses.
Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR - C1.2)
The underground assets in this area are 40 years old and have far exceeded their useful life.
The number of customers in each class potentially affected by failure of the assets (5.4.5.2 SR - C1.3)
There are 106 residential customers that would be affected by asset failure.
Quantitative customer impacts (5.4.5.2 SR - C1.4)
The customers in this area have experienced unplanned power interruptions due to underground primary cable failures.
Qualitative customer impacts (5.4.5.2 SR - C1.5)
The completion of this project will improve reliability in this area.
Value of cust. impact in terms of characteristics of cust. potentially affected by failure that have a bearing on the criticality and/or cost of failure(5.4.5.2 SR -
There is low impact to customers in this area in terms of criticality and cost of asset failure. However, being mainly residential load, the majority of customers are unlikely to have any source of back up power.
Timing & Priority of Project (5.4.5.2 SR - C2)
This project is part of an overall capital replacement plan for 2017. This project does not rely on any other 2017 project in any of the other System Access, System Service, or General Plant categories.
Consequences for system O&M costs (5.4.5.2 SR - C3)
O&M costs are expected to be reduced within the area of this project as assets are replaced resulting in less cable failure costs. Without the project as planned, it is expected that O&M costs would increase due to trouble call responses.
Impact on Reliability performance and/or Safety (5.4.5.2 SR - C4)
System reliability in this area will improve due to the reduced number of asset failures.
Analysis of Project Benefits and Timing (5.4.5.2 SR - C5)
This project has been scheduled to be completed in the second and third quarter of 2017 to realize the advantages of construction during good weather and ground conditions.
Like for Like Renewal Analysis, Alternatives Comparison (like-for-like vs not like-for-like, timing, rate of replacement, etc.) (5.4.5.2 SR - C6)
Like for Like construction was not an option for this project.

Other project reference material i.e. Images, Drawings and or reference material

Schematic Area



Existing Pole Tran Transformer & Primary Dip

Other project reference material i.e. Images, Drawings and or reference material
Example of Completed Project

New Padmount Transformer

New Streetlight Pole & Secondary Pedestal

A. General Information						
Project/Activity	Miscellaneous Pole Replacements					
Project Number						
Investment Category	System Renewal					
	2012	**2013**	**2014**	**2015**	**2016**	**2017**
Capital Cost (5.4.5.2 A.1)	$78,259	$89,289	$107,968	$101,094	$100,000	$100,000
Capital Contribution	$0	$0	$0	$0	$0	$0
Net Cost	$78,259	$89,289	$107,968	$101,094	$100,000	$100,000
O&M Cost (5.4.5.2 A.1)	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
						Undetermined

Customer Attachments and Load (5.4.5.2 A.2)

The number of customers affected by the pole replacement vary depending on the location and configuration of attachments.

Start Date (5.4.5.2 A.3)	**Not Applicable**		**In-Service Date (5.4.5.2 A.3)**		**Not applicable**
Expenditure Timing For the Test Year	**2017 Q1**	**2017 Q2**	**2017 Q3**	**2017 Q4**	
	$25,000	$25,000	$25,000	$25,000	

Project Summary

This project funds individual pole replacements that are required to be replaced during the course of the year and are not included in a project that exceeds materiality. Poles are replaced due to asset condition or associated assets that are deemed to require replacement as a result of in field condition assessments, asset failure, or other external factors.

Risk Identification & Mitigation (5.4.5.2 A.4)

Scheduling Risks:

Scheduling risks are minimal as the amount of assets replaced under this category is not significant in relation to the larger projects in the System Renewal category. Most of these smaller projects require minimal time for planning and execution. The primary budgetary risk is the number of poles identified for replacement in a given year. WHESC manages this risk by budgeting based on historical pole replacement rates and managing pole replacements through other projects such as overhead rebuilds.

System Constraints Risks:

There are typically no overall electrical system constraints associated with single pole replacements. However, each situation is assessed and the extent of the associated assets replaced is addressed with each pole replacement. If significant work is required, the replacement may be included as part of a larger project and/or the replacement may be deferred if possible.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

Historical information is used to estimate the quantity of individual poles requiring replacement in a given year.

REG Investment Details including Capital and OM&A Cost (5.4.5.2 A.6)

There are no REG investments associated with this work.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

Leave to Construct approval is not required.

Attach Other project reference material i.e. Images, Drawings and or reference material

There is no project reference material.

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

Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1.a)

The main driver for this project is reliability. Poles are inspected and flagged for replacement due to their condition. Poles that are in very poor condition will be replaced on an as-needed basis in order to minimize unplanned outages.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1.a)

The secondary driver is customer value. Identifying and changing poles prior to failure is more cost effective. Further efficiencies can be gained if individual replacements can be delayed to be included as part of a larger project.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1.a)

The objective of this program is to ensure reliable service and meet customers connection needs. The primary investment objective is reliability, namely maintaining WHESC's SAIDI and SAIFI metrics. The secondary investment objective is customer value, namely replacing end-of-life poles before failure to avoid reactive replacement costs that would negatively impact WHESC's Efficiency Assessment and total cost metrics.

Efficiency, Customer Value & Reliability - Source and nature of information used to justify the investment (5.4.5.2 B.1.a)

This project was planned by incorporating the elements of WHESC's asset condition assessments, historical spending levels and the unit replacement costs.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority Relative to Other Investments

This project is ranked first out of fifteen material projects/programs planned for the Test Year (2017) based on the scoring below.

Criteria	Safety	Regulatory	Growth	Reliability	Cost	Total Score
Weight	10	9	8	6	5	
Score	10	0	0	10	5	**185**

Justification: This project is of high priority as the integrity of the pole can affect all other assets attached to it, directly affecting the ability of WHESC to supply electricity to its customers. Poles in very poor condition pose a safety and reliability risk and replacing them before failure delivers customer value.

Analysis of Project & Alternatives - Effect to the investment on system efficiency and cost-effectiveness (5.4.5.2 B.1.c)

Through the use of WHESC's Geospatial Information System, inspection and asset data can be collected and analyzed to determine the most cost efficient options for pole replacements.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Customers will benefit from the reduced risk of outages as a result of the project. Efficiencies gained will support WHESC's focus on cost containment.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

The project reduces both frequency and duration of outages by identifying poles in poor condition. Construction activities can be coordinated to minimize service disruption to customers.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1ciii)

Project Design Alternatives:

Concrete poles have been considered but are only used in areas where they become more cost effective than wood, such as extremely high pole requirements, or where there is a special need for improved aesthetics. Poles are included in overhead rebuilds when geographically feasible and this program requires one-off pole replacements.

Scheduling Alternatives:

This program has been planned for 2017 based on its priority per WHESC's prioritization process. In the case of the "do nothing" option (program deferral), the identified poles would continue to deteriorate and pose a risk to safety and system reliability. The projects within this program have scheduling flexibility throughout the budget year and are scheduled based on the urgency of the pole replacement.

Safety (5.4.5.2 B.2)
The project helps to mitigate the risks to workers that may have to climb poles or work on assets attached to poles.
Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)
There are no Cyber-Security or privacy issues associated with this project.
Coordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, Coordination with Utilities,Regional Planning and/or 3rd party providers(where applicable)
Individual pole replacements at this level do not impact inter-utility coordination or regional planning activities.
Coordination, Interoperability (5.4.5.2 B.4ii) Future Technological functionality and/or future operational requirements (where applicable)
Poles of appropriate/adequate height are installed to the latest standards and sized for operational needs to meet future expected requirements.
Economic Development (5.4.5.2 B.5) (where applicable)
Reliability is one of the drivers of this project and a reliable electricity supply is conducive to economic development.
Environmental Benefits (5.4.5.2 B.6) (where applicable)
Proactively inspecting, assessing, and replacing poles will mitigate and/or reduce risk to the environment due to the pole itself and the assets attached to it.

C. Category-Specific Requirements - System Renewal
Asset performance-related operational targets and asset lifecycle optimization policies and practices (refer to 5.2.3 and 5.3.3) (5.4.5.2 SR - C1.1)
The project fulfills asset performance-related operational targets by continuing to lower or maintain SAIDI and SAIFI index results. The project also positively affects safety targets by creating a safer work space for the powerline maintenance personnel.
Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR - C1.2)
Assets within this program are flagged for replacement based on the asset condition assessment. Poles that are planned for replacement have typically exceeded their useful end of life by many years. There are very few poles that are replaced due to failure that have not reached their end of useful life.
The number of customers in each class potentially affected by failure of the assets (5.4.5.2 SR - C1.3)
A single pole failure can affect a severe number of customers depending on its location within the distribution system. Poles closer to the source of power or poles on a higher voltage circuit typically affect more customers.
Quantitative customer impacts (5.4.5.2 SR - C1.4)
There is no quantitative data available as customer impacts are varied based on the pole location and assets attached to it.
Qualitative customer impacts (5.4.5.2 SR - C1.5)
This project will ensure that WHESC's reliability is not negatively impacted by an excessive number of poles that are in need of replacement.
Value of cust. impact in terms of characteristics of cust. potentially affected by failure that have a bearing on the criticality and/or cost of failure(5.4.5.2 SR -
The characteristics of customers potentially affected by poles in poor condition varies widely from a high number of residential customers with a low cost of failure to a large commercial customer with a potentially high cost of failure, to a pole that affects both classes/quantity of customers. Replacement prioritization considers the impact of the poles condition for each individual project.
Timing & Priority of Project (5.4.5.2 SR - C2)
The program is comprised of multiple individual projects, all of which may have varied timing requirements.
Consequences for system O&M costs (5.4.5.2 SR - C3)
O&M costs are expected to be contained by making both proactive and planned pole replacements. Without the project as planned, it is expected that system O&M costs would increase due to re-testing of poles and trouble call responses.
Impact on Reliability performance and/or Safety (5.4.5.2 SR - C4)
Reliability will be maintained by replacing poles prior to failure. Safety to workers will be maintained by ensuring poles have adequate strength and integrity.
Analysis of Project Benefits and Timing (5.4.5.2 SR - C5)
The analysis of assets results in an estimated number of poles that will require replacement either through this program or through line reconstruction work. The system will benefit by mitigating unplanned interruptions due to sudden asset failure. Pole replacements are paced to balance the risk of failure against replacement costs and maintenance of pole stock levels.
Like for Like Renewal Analysis, Alternatives Comparison (like-for-like vs not like-for-like, timing, rate of replacement, etc.) (5.4.5.2 SR - C6)
Like for like is typically not used for pole replacements; however, assets attached the pole are sometimes transferred to the new pole as a cost savings or cost containment measure.

A. General Information						
Project/Activity	Miscellaneous Transformer Replacements					
Project Number						
Investment Category	System Renewal					
	2012	**2013**	**2014**	**2015**	**2016**	**2017**
Capital Cost (5.4.5.2 A.1)	$27,771	$81,026	$39,399	$73,031	$50,000	$50,000
Capital Contribution	$0	$0	$0	$0	$0	$0
Net Cost	$27,771	$81,026	$39,399	$73,031	$50,000	$50,000
O&M Cost (5.4.5.2 A.1)	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
	N/A	N/A	N/A	N/A	N/A	N/A

Customer Attachments and Load (5.4.5.2 A.2)

The number of customers affected by the transformer replacement is typically 1 to 25.

Start Date (5.4.5.2 A.3)	**Not Applicable**		**In-Service Date (5.4.5.2 A.3)**		**Not applicable**
Expenditure Timing For the Test Year	**2017 Q1**	**2017 Q2**	**2017 Q3**	**2017 Q4**	
	$12,000	$12,000	$14,000	$12,000	

Project Summary

This project funds individual transformers that are required to be replaced during the course of the year that are not included in a project that exceeds materiality. Transformers are replaced due to asset condition or associated assets that are deemed to require replacement as a result of in field condition assessments, asset failure, or other external factors.

Risk Identification & Mitigation (5.4.5.2 A.4)

Scheduling Risks:

Scheduling Risks are minimal as the amount of assets replaced under this category is not significant in relation to the larger projects in the System Renewal category. Most of these smaller projects require minimal time for planning and execution. The primary budgetary risk is the number of transformers identified for replacement in a given year. WHESC manages this risk by budgeting based on historical transformer replacement rates and managing transformer replacements through other projects such as overhead rebuilds.

System Constraints Risks:

There are typically no overall electrical system constraints associated with single transformer replacements. However, each situation is assessed and the extent of the associated assets replaced is addressed with each transformer replacement. If significant work is required, the replacement may be included as part of a larger project and replacement may be deferred if possible.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

Historical information is used to estimate the quantity of individual transformers requiring replacement in a given year.

REG Investment Details including Capital and OM&A Cost (5.4.5.2 A.6)

There are no REG investments associated with this work.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

Leave to Construct approval is not required.

Attach Other project reference material i.e. Images, Drawings and or reference material

There is no project reference material.

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

Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1.a)

The main driver for this project is reliability. Transformers are inspected and flagged for replacement due to 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 due to concerns over transformer leaking. Additionally, overloaded transformers are identified using smart meter data that is inputted into an engineering tool to identify peak transformer loading during a known system high load period. Replacing these transformers reduces the risk of unplanned outages, transformer failures and potentially transformer fires.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1.a)

The secondary driver is customer value. Replacement of transformers and proper sizing, through the use of engineering tools, promotes efficiency and cost savings by sizing the transformers properly. The result is lower equipment losses while maintaining connection availability to customers (i.e. through service upgrades).

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1.a)

The objective of this program is to ensure reliable service and meet customers connection needs. The primary investment objective is reliability, namely maintaining WHESC's SAIDI and SAIFI performance. The secondary investment objective is customer value, namely maintaining WHESC's performance with respect to its Efficiency Assessment and total cost metrics.

Efficiency, Customer Value & Reliability - Source and nature of information used to justify the investment (5.4.5.2 B.1.a)

This project was planned by incorporating the elements of WHESC's asset condition assessments, transformer load analysis, historical spending levels, and unit replacement costs.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority Relative to Other Investments

This project is ranked first out of fifteen material projects/programs planned for the Test Year (2017) based on the scoring below.

Criteria	Safety	Regulatory	Growth	Reliability	Cost	Total Score
Weight	10	9	8	6	5	
Score	10	0	0	4	5	149

Justification: This project is of high priority as it directly affects the ability of WHESC to supply electricity to its customers. A portion of this project funds transformer failures which require immediate replacement to restore power to customers. Transformers in very poor condition would pose a safety risk if not addressed through this program.

Analysis of Project & Alternatives - Effect to the investment on system efficiency and cost-effectiveness (5.4.5.2 B.1.c)

Through the use of available data and engineering tools, transformers are sized for optimal performance and operating efficiency, while providing the appropriate additional capacity to address expected future requirements.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Although this is not a System Access program, it does provide benefits to customers by providing capacity to address customer service upgrades.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

The project reduces both frequency and duration of outages by identifying transformers in poor condition and/or in an overloaded state. Construction activities can be coordinated to minimize service disruption to customers.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

Project Design Alternatives:

Where options are available with respect to design, scheduling, funding and ownership, the most cost effective solution will be selected. This is normally only considered when the size of transformer required, exceeds WHESC's standard offer through our Conditions of Service. Transformers are included in overhead rebuilds where geographically feasible, and transformers under this program are replaced through spot replacements.

Scheduling Alternatives:

This program has been planned for 2017 based on its priority per WHESC's prioritization process. In the case of the "do nothing" option (program deferral), the identified transformers would continue to deteriorate and pose a risk to safety and system reliability. The projects within this program have scheduling flexibility throughout the budget year and are scheduled based on the urgency of the transformer replacement.

Safety (5.4.5.2 B.2)
The project helps to mitigate the risks to workers and the general public associated with transformer failure. Transformers replaced as part of a project will be installed to the latest USF standards, allocating more equipment space, thereby promoting safety to workers.
Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)
There are no Cyber-Security or privacy issues associated with this project.
Coordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, Coordination with Utilities,Regional Planning and/or 3rd party providers(where applicable)
Transformer replacements at this level do not impact inter-utility coordination or regional planning activities.
Coordination, Interoperability (5.4.5.2 B.4ii) Future Technological functionality and/or future operational requirements (where applicable)
Transformers are installed to the latest standards and sized for operational needs and to meet future expected customer requirements.
Economic Development (5.4.5.2 B.5) (where applicable)
Reliability is one of the drivers of this project and a reliable electricity supply is conducive to economic development.
Environmental Benefits (5.4.5.2 B.6) (where applicable)
Proactively inspecting, assessing and replacing transformers will mitigate and/or reduce risk to the environment. New transformers meet the latest standards for energy efficiency.

C. Category-Specific Requirements - System Renewal
Asset performance-related operational targets and asset lifecycle optimization policies and practices (refer to 5.2.3 and 5.3.3) (5.4.5.2 SR - C1.1)
The project fulfills asset performance-related operational targets by continuing to lower or maintain SAIDI and SAIFI index results. The project also positively affects safety targets by creating a safer work space for the powerline maintenance personnel.
Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR - C1.2)
Assets within this program are flagged for replacement based on asset condition assessment. Transformers that are planned for replacement have typically exceeded their useful end of life by many years. There are very few transformers that are replaced due to failure that have not reached their end of useful life. Transformers, prominently pole mounted, perform well beyond useful end of life. WHESC conducts padmount transformer painting programs to ensure that this style of transformer, at a minimum, reaches the end of useful life.
The number of customers in each class potentially affected by failure of the assets (5.4.5.2 SR - C1.3)
A single transformer failure can affect one customer in a single family dwelling or hundreds of customers in an apartment building. Typically, most transformers supply approximately 12 customers in an urban residential neighborhood.
Quantitative customer impacts (5.4.5.2 SR - C1.4)
There is no quantitative data available as customer impacts are varied based on size of transformer, operating conditions and environment.
Qualitative customer impacts (5.4.5.2 SR - C1.5)
This project will ensure that WHESC's reliability is not negatively impacted by excessive transformer failures. Proper transformer analysis, for appropriate replacement sizing, will ensure reliability and drive customer satisfaction and customer value through efficiencies.
Value of cust. impact in terms of characteristics of cust. potentially affected by failure that have a bearing on the criticality and/or cost of failure(5.4.5.2 SR - C
The characteristics of customers potentially affected by transformers failures varies widely from a high number of residential customers with a low cost of failure to a large commercial customer with a potentially high cost of failure. Replacement prioritization considers the impact and cost of the transformer failure for each individual project.
Timing & Priority of Project (5.4.5.2 SR - C2)
The project is comprised of multiple individual projects, all of which may have varied timing requirements.
Consequences for system O&M costs (5.4.5.2 SR - C3)
O&M costs are expected to be reduced due to asset replacement. Proper transformer sizing and more efficient transformer designs will result in lower operating costs.
Impact on Reliability performance and/or Safety (5.4.5.2 SR - C4)
Reliability will be maintained by replacing transformers prior to failure. Safety to workers will be improved due to new transformer designs. New padmount transformers with dead-front high voltage connections, internal fuses and load break switches provide a safer working environment for utility staff.
Analysis of Project Benefits and Timing (5.4.5.2 SR - C5)
The analysis of assets results in an estimated number of transformers that will require replacement, either through this program or through line reconstruction work. The system will benefit by mitigating unplanned interruptions due to sudden asset failure. Transformer replacements are paced to balance the risk of failure against replacement costs and maintenance of transformer stock levels.
Like for Like Renewal Analysis, Alternatives Comparison (like-for-like vs not like-for-like, timing, rate of replacement, etc.) (5.4.5.2 SR - C6)
Like for like will be used where practical and typically only where the transformer asset is replaced. If additional major component replacement, such as the pole, is required then current USF standards will be used during the work process.

A. General Information						
Project/Activity	Scada Switches/Remote Fault Indicators/Radio Systems					
Project Number						
Investment Category	System Service					
	2012	**2013**	**2014**	**2015**	**2016**	**2017**
Capital Cost (5.4.5.2 A.1)						$60,000
Capital Contribution						$0
Net Cost						$60,000
O&M Cost (5.4.5.2 A.1)	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
	N/A	N/A	N/A	N/A	N/A	N/A

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments within project area: No attachments associated with the project.
Customer load within project area: Not applicable
Customer attachments downstream of project area: Not applicable
Customer load downstream of project: Not Applicable

Start Date (5.4.5.2 A.3)	**No specific start date**		**In-Service Date (5.4.5.2 A.3)**		**Equipment installed in stages**
Expenditure Timing For the Test Year	**2017 Q1**	**2017 Q2**	**2017 Q3**	**2017 Q4**	
	$15,000	$15,000	$15,000	$15,000	

Project Summary

The SCADA system currently uses Bell copper leased lines for the majority of communications between the Master Station and in field RTUs, which costs WHESC monthly rental fees. Wireless Radio systems and Digi Cell modems will be installed in key locations to eliminate the leased lines over time.

Risk Identification & Mitigation (5.4.5.2 A.4)

Scheduling Risks:

The project scheduling will be influenced by both internal staff and contracted staff availability throughout the year. There are no other external influences that are expected to affect the timing of the project or introduce any risk to current communication services being used at this time.

System Constraints Risks:

There are no electrical system constraints relevant to the project. Space availability on existing assets will be evaluated during the project to determine ideal locations for equipment installation.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

There is no relevant information for expenditures on equipment upgrades. Historic network operating costs are available for determination of potential savings and ROI.

REG Investment Details including Capital and OM&A Cost (5.4.5.2 A.6)

There are no REG investments associated with this work.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

Leave to Construct approval is not required.

Attach Other project reference material i.e. Image, Drawings and or reference material

SCADA Network connectivity will be upgraded as new equipment/communication paths are created.

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

Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1a)

The main driver of this project is Operational Efficiency. The new network will create cellular hubs combined with radio hot spots. Several devices currently requiring individual dedicated circuits will be combined, reducing monthly communication network fees/costs.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1a)

The secondary driver of this project is maintaining the communication system for WHESC's SCADA system. Replacing these assets will allow for future elimination of other aging hardware assets in WHESC's SCADA communication network.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1a)

This project will provide cost containment for future O&M SCADA network communication costs.

Efficiency, Customer Value & Reliability - Source and nature of information used to justify the investment (5.4.5.2 B.1a)

Initial test sites using Digi cellular equipment have resulted in monthly cost savings.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1b) Priority Relative to Other Investments

This project is ranked fifteenth out of fifteen material projects/programs planned for the Test Year (2017) based on the scoring below.

Criteria	Safety	Regulatory	Growth	Reliability	Cost	Total Score
Weight	10	9	8	6	5	
Score	0	0	0	0	8	40

Justification: The investment is driven by cost savings: equipment owned by WHESC will not need to be leased, thus saving recurring costs.

Analysis of Project & Alternatives - Effect to the investment on system operation efficiency and cost-effectiveness (5.4.5.2 B.1c)

Inexpensive equipment availability with necessary performance levels has been the key driver to the selection of this wireless system. WHESC does not own any communication networks, such as fiber optics.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1ci)

The project will result in containment of operational costs for the SCADA network.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1cii)

Current reliability performance of the existing SCADA system will be maintained, contributing to the reduction of outage durations.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1ciii)

Project Design Alternatives:

This design was selected due to simplicity, equipment availability and equipment cost that will be owned and maintained by WHESC. The current and alternative networks have typically been owned by others (i.e. Bell or Fiber companies). These alternatives were considered but were evaluated to be the more expensive alternative due to on-going costs and cost increases beyond WHESC's control.

Scheduling Alternatives:

This program has been planned for 2017 based on its priority per WHESC's prioritization process. In the case of the "do nothing" option (program deferral), WHESC would continue to pay leasing fees for copper lines. The projects has scheduling flexibility within the budget year.

Safety (5.4.5.2 B.2)

The communication network provides a two-way communication path for the SCADA system, providing insight for System Operators. Switching operations can be performed from the control room to avoid unwanted situations or to provide switching necessary for the protection of workers during emergency or planned work situations.

Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)

SCADA infrastructure utilizes a private network with firewall security and standard communication protocols utilized by most Ontario utilities, complying with the latest cyber-security standards.

Coordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, Coordination with Utilities,Regional Planning and/or 3rd party providers(where applicable)

Co-ordination with telecommunications utilities is conducted to terminate leases of land lines.

Coordination, Interoperability (5.4.5.2 B.4ii) Future Technological functionality and/or further operational requirements (where applicable)

At this time there is no expectation that this communication system upgrade will have any affects on the future replacement of other SCADA system equipment. Interoperability is supported through standard communication protocols.

Economic Development (5.4.5.2 B.5) (where applicable)

This investment is not expected to impact economic development.

Environmental Benefits (5.4.5.2 B.6) (where applicable)

There are no expected environmental benefits.

C. Category-Specific Requirements - System Service
Benefits to Customer vs Cost Impact (5.4.5.2 SS - C1)
This project will result in cost containment. Customers will continue to realize system reliability benefits due to the ability to conduct SCADA remote operations through the communications network.
Regional electricity infrastructure requirements (5.4.5.2 SS - C2)
Regional electricity infrastructure requirements do not apply.
Advanced technology (5.4.5.2 SS - C3)
The installation of the new wireless equipment will lead to the elimination of rack mounted modems installed in the late 1980's. The new technology will be much simpler to maintain and replace due to failure.
Reliability, efficiency, safety and coordination benefits (5.4.5.2 SS - C4)
The new equipment will maintain current reliability, efficiency, safety, and coordination benefits currently realized by the SCADA system.
Timing & Priority of Project (54.5.2 SS - C5)
Timing of the project will be spaced throughout the year as external resources are made available and internal resources are not impacted negatively.
Analysis of project benefits and costs i.e. "Do Nothing" & " Technically feasible alternatives" (5.4.5.2 SS - C6)
The "Do Nothing" alternative will result in lost or delayed realization of cost benefits and cost containment. The long term effect of not acting may result in equipment failure with no hardware support for repair or replacement.

A. General Information						
Project/Activity	Scada SmartVU/Server Upgrade					
Project Number						
Investment Category	System Service					
	2012	**2013**	**2014**	**2015**	**2016**	**2017**
Capital Cost (5.4.5.2 A.1)						$50,000
Capital Contribution						$0
Net Cost						$50,000
O&M Cost (5.4.5.2 A.1)	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
	N/A	N/A	N/A	N/A	N/A	N/A

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments within project area: No attachments associated with the project.
Customer load within project area: Not applicable
Customer attachments downstream of project area: Not applicable
Customer load downstream of project: Not Applicable

Start Date (5.4.5.2 A.3)			**In-Service Date (5.4.5.2 A.3)**		
Expenditure Timing For the Test Year	**2017 Q1**	**2017 Q2**	**2017 Q3**	**2017 Q4**	
			$50,000		

Project Summary

The current SCADA system vendor is Survalent Technology which is a common system to Ontario LDCs. In 2007, WHESC upgraded the server from a VMS operating platform to the current Windows Base Worldview system. Survalent Technology will end its support of Worldview in 2017 and is recommending that customers upgrade to the new platform SmartVU.

Risk Identification & Mitigation (5.4.5.2 A.4)

Scheduling Risks:

The new platform must be installed and operational by the end of 2017 to mitigate the risk of no system support. Without system support, WHESC would have to procure additional IT support, either through hiring additional resources or through a third party. The software would no longer be supported with patches to improve cyber-security and there is an operational risk of the software no longer working.

System Constraints Risks:

There are no electrical system constraints relevant to the project.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

There is no relevant information for expenditures on equipment. In 2007 the operating system was upgraded in conjunction with hardware replacements. All costs were inclusive in the total.

REG Investment Details including Capital and OM&A Cost (5.4.5.2 A.6)

There are no REG investments associated with this work.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

Leave to Construct approval is not required.

Attach Other project reference material i.e. Image, Drawings and or reference material

There is no project reference material.

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

Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1a)

The main drive of the SCADA software upgrade is to maintain operational efficiency. The SCADA system allows Operators to apply system protection and operate in field devices, eliminating the need for a truck roll to equipment locations in the field.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1a)

The secondary driver of this project is maintaining system reliability. The SCADA software upgrade will ensure continued software support until the next major software release. The SCADA system is one of the key tools to assist staff in maintaining system reliability, it provides system operators information to manage the distribution network as well as providing remote system switching during emergency and planned work activities.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1a)

This project will ensure continued software support. The SCADA system will remain key to WHESC's success in maintaining the electrical distribution system reliability performance targets, namely SAIDI.

Efficiency, Customer Value & Reliability - Source and nature of information used to justify the investment (5.4.5.2 B.1a)

Survalent Technologies has advised that software support for Worldview will expire in 2017. Without this project there is a cost and reliability risk if WHESC's SCADA system goes down.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1b) Priority Relative to Other Investments

This project is ranked eleventh out of fifteen material projects/programs planned for the Test Year (2017) based on the scoring below.

Criteria	Safety	Regulatory	Growth	Reliability	Cost	Total Score
Weight	10	9	8	6	5	
Score	0	0	0	6	5	61

Justification: The investment is driven by the reliability benefits of the SCADA system and the cost savings of maintaining vendor support. This project does not affect any other projects in 2017, but must be completed and operational by the end of 2017. The project has been planned for Q3 completion to allow additional time for integration should there be any unforeseen software issues.

Analysis of Project & Alternatives - Effect to the investment on system operation efficiency and cost-effectiveness (5.4.5.2 B.1c)

The operating system must be current and have support services to maintain operational efficiency. Upgrading the software with the current vendor, rather than changing vendors, is more cost effective and will have greater success as staff are familiar with the Survalent System.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1ci)

The SCADA system must be current and have support services to maintain operational efficiency. Continued use of the SCADA system will allow WHESC to maintain system reliability for its customers.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1cii)

The project will provide WHESC with the current tools used to promote and maintain system reliability.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1ciii)

Project Design Alternatives:

Survalent Technologies is widely used across Ontario with a large network of Ontario LDC users. Survalent provides services, support and user conferences to promote customer valued services, training and support. For this reason, no other vendor was considered.

Scheduling Alternatives:

Without system support, WHESC would have to procure additional IT support, either through hiring additional resources or through a third party. The software would no longer be supported with patches to improve cyber-security and there is an operational risk of the software no longer working. Therefore, the investment has been scheduled for 2017.

Ownership Alternatives:

WHESC will own the software license and associated hardware.

Safety (5.4.5.2 B.2)

The SCADA system allows operators to perform remote system switching. The operation of Substation breakers and SCADAMate pole mounted load break switches remotely, allows in field staff to maintain a safe distance from the equipment while operations are being performed.

Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)

SCADA infrastructure utilizes a private network with firewall security and standard communication protocols utilized by most Ontario utilities. Without the investment as planned, cyber-security would be compromised as the software would no longer receive patch updates from the vendor.

Coordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, Coordination with Utlilities,Regional Planning and/or 3rd party providers(where applicable)

These asset replacements do not impact inter-utility coordination or regional planning activities. Planning for this project has been conducted through vendor consultation, including alternative vendors, in arriving at a decision to upgrade to Survalent's system.

Coordination, Interoperability (5.4.5.2 B.4ii) Future Technological functionality and/or further operational requirements (where applicable)

Keeping the operating system current will allow WHESC the option of adding on more functionality, such as automated switching, to the SCADA system. Interoperability is enhanced by using Survalent's system, which is already in place for WHESC's OMS.

Economic Development (5.4.5.2 B.5) (where applicable)

Reliability is one of the project drivers, and a reliable supply of electricity is conducive of economic development.

Environmental Benefits (5.4.5.2 B.6) (where applicable)

There are no expected environmental benefits.

C. Category-Specific Requirements - System Service
Benefits to Customer vs Cost Impact (5.4.5.2 SS - C1)
Customers will continue to realize system reliability with the support of the SCADA system. Cost impact is minimal and is a normal occurrence over time as operating systems are made obsolete by vendors and replaced with new ones.
Regional electricity infrastructure requirements (5.4.5.2 SS - C2)
Regional electricity infrastructure requirements do not apply.
Advanced technology (5.4.5.2 SS - C3)
Keeping the operating system current will allow WHESC the option of adding on more functionality, such as automated switching, to the SCADA system.
Reliability, efficiency, safety and coordination benefits (5.4.5.2 SS - C4)
The new equipment will maintain current reliability, efficiency, safety, and coordination benefits currently realized by the SCADA system.
Timing & Priority of Project (54.5.2 SS - C5)
This project does not tie into any other projects. Timing has been established to allow for proper installation and integration of the new Operating System.
Analysis of project benefits and costs i.e. "Do Nothing" & " Technically feasible alternatives" (5.4.5.2 SS - C6)
The "Do Nothing" alternative will result in loss of operating system support. Without system support, WHESC would have to procure additional IT support, either through hiring additional resources or through a third party. The software would no longer be supported with patches to improve cyber-security and there is an operational risk of the software no longer working.

A. General Information						
Project/Activity	Service Centre Parking Lot Paving					
Project Number						
Investment Category	General Plant					
	2012	**2013**	**2014**	**2015**	**2016**	**2017**
Capital Cost (5.4.5.2 A.1)						$100,000
Capital Contribution						$0
Net Cost						$100,000
O&M Cost (5.4.5.2 A.1)	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
	N/A	N/A	N/A	N/A	N/A	N/A

Customer Attachments and Load (5.4.5.2 A.2)

Not Applicable

Start Date (5.4.5.2 A.3)	**1-May-16**		**In-Service Date (5.4.5.2 A.3)**		**30-Jun-16**
Expenditure Timing For the Test Year	**2017 Q1**	**2017 Q2**	**2017 Q3**	**2017 Q4**	
		$100,000			

Project Summary

This project will replace 50% of the paved areas - the most deteriorated sections - at the Service Centre and correct drainage issues, which cause water to pool.

Risk Identification & Mitigation (5.4.5.2 A.4)

The project schedule will be influenced by the availability of a consultant to engineer and spec. the work, tender and acquire a service provider and materials. This risk will be managed through careful oversight by WHESC to ensure the project meets its budget and timing objectives.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

There is no relevant information available for equivalent projects.

REG Investment Details including Capital and OM&A Cost (5.4.5.2 A.6)

There are no REG investment requirements associated with this work.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

Leave to Construct approval is not required.

Attach Other project reference material i.e. Images, Drawings and or reference material

Service Centre Drawing and Pictures attached.

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

Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1a)

The main investment driver is customer value. The investment avoids numerous and costly temporary fixes to the paved area/

Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1a)

The secondary investment driver is safety. The investment will provide safe access for vehicles to the service center property.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1a)

This investment contributes to maintaining WHESC's operational efficiency and cost effectiveness targets, namely its Efficiency Assessment and total cost metrics. Without the investment, customer satisfaction metrics would likely be negatively affected, since customers use the parking lot.

Efficiency, Customer Value & Reliability - Source and nature of information used to justify the investment (5.4.5.2 B.1a)

Customer value is intangible.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1b) Priority Relative to Other Investments

This project is ranked twelfth out of fifteen material projects/programs planned for the Test Year (2017) based on the scoring below.

Criteria	Safety	Regulatory	Growth	Reliability	Cost	Total Score	Justification: The deteriorating parking lot poses risk to safety and on-going repair costs.
Weight	10	9	8	6	5		
Score	2	0	0	0	8	60	

Analysis of Project & Alternatives - Effect to the investment on system efficiency and cost-effectiveness (5.4.5.2 B.1c)

Cost effectiveness is achieved by correcting the issue with a single capital project, rather than through costly and numerous "small fixes".

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1ci)

The net benefits to customers is safe vehicle access to the service center property.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1cii)

The project does not affect system reliability.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1ciii)

The use of concrete, rather than asphalt, is cost prohibitive. The project has been planned for 2017 based on its priority per WHESC's project prioritization project.

Safety (5.4.5.2 B.2)

The project will provide a proper surface for staff and customers to access the service center property.

Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)

There are no Cyber-Security or privacy issues relevant to this project.

Coordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, Coordination with Utilities,Regional Planning and/or 3rd party providers(where applicable)

Not applicable.

Coordination, Interoperability (5.4.5.2 B.4ii) Future Technological functionality and/or future operational requirements (where applicable)

Not applicable.

Economic Development (5.4.5.2 B.5) (where applicable)

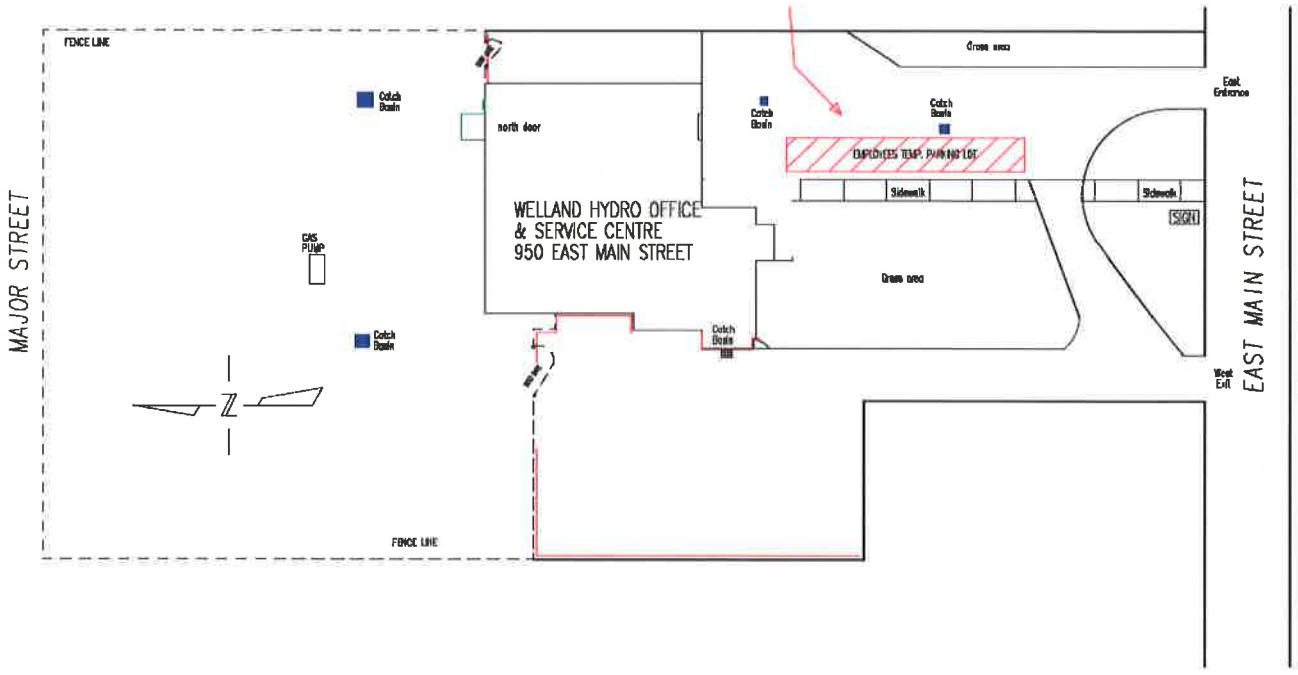
Not applicable.

Environmental Benefits (5.4.5.2 B.6) (where applicable)

The new surface will reduce wear and tear on vehicles.

C. Category-Specific Requirements - General Plant
Results of quantitative and qualitative analysis, business case documenting the justifications for the expenditure (5.4.5.2 GP - C1)
There is no formal analysis. WHESC has been conducting minor repairs to pot holes and deteriorating asphalt over the last ten years. The quantity of area now requiring repairs dictates the necessity for complete replacement.
Business Case Documenting the Justifications for Expenditure, Alternative Considered, Benefits for Customers (short/long term), and Impact on Distributor Costs (short/long term)
WHESC has been conducting minor repairs to pot holes and deteriorating asphalt over the for the last ten years. The quantity of area now requiring repairs dictates the necessity for complete replacement. Thus the current alternative is no longer viable and the use of concrete, rather than asphalt, is cost prohibitive. Over the short and long term the project will provide a proper surface for staff and customers to access the service center property, as well as, reduce wear and tear on vehicles. Long term reduction in O&M cost is expected as the new asphalt should not require any maintenance for the foreseeable future.

Other project reference material i.e. Images, Drawings and or reference material
Service Centre



Other project reference material i.e. Images, Drawings and or reference material
Pictures