Exhibit 2:

RATE BASE

OVERVIEW

This Exhibit provides the details and analysis of the Rate Base forecast for ETPL. It provides explanation of variances between 2012 Board Approved amounts, Historic Actuals for 2012 through 2016, the 2017 Bridge Year and the 2018 Test Year. ETPL has prepared its Rate Base for the purpose of calculating its revenue requirement in this Application following Chapter 2 of the "*Filing Requirements for Electricity Distribution Rate Applications – 2017 Edition for 2018 Rates Applications*" issued on July 20, 2017. In accordance with the Filing Requirements, ETPL has calculated its Rate Base on the average of the 2018 Test Year opening and 2018 Test Year closing balances of gross fixed assets and accumulated depreciation, plus a Working Capital Allowance ("**WCA**"), calculated as a percentage of the sum of the cost of power and controllable expenses.

ETPL has opted not to prepare a Lead/Lag study in order to save further costs to be borne by the ratepayer and instead has proposed to accept a WCA Factor of 7.5%. For more information regarding the WCA factor see Section 2.4 in this exhibit.

Capital assets include property, plant and equipment and intangible assets that enable the delivery of electricity for distribution purposes. The 2018 Rate Base calculation excludes any non-distribution assets. Controllable expenses include operations and maintenance, billing and collections and administration expenses.

Table 2-1 below summarizes ETPL's Rate Base calculation for the 2012 Board Approved amounts, Historical Actuals for 2012 through 2016, the 2017 Bridge Year and the 2018 Test Year. Both the 2017 Bridge Year and 2018 Test Year amounts are based on forecasted costs. The budgeted Rate Base for the 2018 Test Year is $40,296,054 which is 28% higher than the 2012 Board Approved rate base. For more information regarding the calculation of the Board Approved, please see Section 2.1.4 below. For more information on the gross asset additions please see Section 2.2 below.

TABLE 2-1: RATE BASE CONTINUITY SCHEDULE

Description	2012 BAP	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge	2018 Test
Accounting Standard	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Gross Fixed Assets	$ 41,263,081	$ 40,110,141	$ 43,689,878	$ 47,304,405	$ 50,890,499	$ 52,627,568	$ 56,177,481	$ 59,420,431
Accumulated Depreciation	-$ 14,833,530	-$ 16,053,187	-$ 17,249,204	-$ 18,566,358	-$ 19,745,488	-$ 19,940,333	-$ 21,734,751	-$ 23,577,531
Net Book Value	$ 26,429,551	$ 24,056,954	$ 26,440,674	$ 28,738,047	$ 31,145,011	$ 32,687,234	$ 34,442,729	$ 35,842,900
Average Net Book Value	$ 26,429,551	$ 23,752,669	$ 25,248,814	$ 27,589,361	$ 29,941,529	$ 31,916,123	$ 33,564,982	$ 35,142,814
Total Working Capital	$ 38,753,300	$ 49,803,212	$ 54,043,184	$ 55,502,890	$ 59,856,474	$ 66,093,183	$ 69,585,594	$ 68,709,864
Working Capital Allow. Factor	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	7.5%
Working Capital Allowance	$ 5,037,929	$ 6,474,418	$ 7,025,614	$ 7,215,376	$ 7,781,342	$ 8,592,114	$ 9,046,127	$ 5,153,240
Rate Base	$ 31,467,480	$ 30,227,087	$ 32,274,428	$ 34,804,736	$ 37,722,871	$ 40,508,237	$ 42,611,109	$ 40,296,054

Table 2-2 below summarizes ETPL's working capital allowance calculation. The forecasted working capital allowance for the 2018 Test Year is $5,153,240, which is 2.29% higher than the 2012 Board Approved. There are three main drivers to the change in working capital. First, an increase in working capital from the increase in the Cost of Power of over 75% which results in an increase in WCA of $2,186,000 between 2012 and 2018 if the allowance factor does not change. Second, a slight increase in controllable expenses from $5,660,000 2012 Board Approved to $6,469,000 in proposed 2018 Test Year. Third, a reduction from the 13% to 7.5% use of the Board default amount. For more details on the working capital allowance calculation please see Section 2.4 below.

TABLE 2-2: Working Capital Allowance Calculation

Description	2012 Board Approved	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge	2018 Test
Accounting Standard	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Operations	$ 186,301	$ 160,299	$ 100,096	$ 110,018	$ 128,569	$ 91,574	$ 93,131	$ 116,389
Miantenance	$ 685,298	$ 595,216	$ 645,161	$ 578,159	$ 320,160	$ 286,802	$ 291,677	$ 298,526
Billing & Collecting	$ 991,287	$ 860,983	$ 1,172,874	$ 1,259,465	$ 1,111,468	$ 981,647	$ 998,335	$ 1,040,307
Community Relations	$ -	$ 18,711	$ 22,086	$ 22,871	$ 21,168	$ 24,584	$ 24,953	$ 25,327
Admin & General	$ 3,728,786	$ 3,219,930	$ 3,660,512	$ 3,632,435	$ 4,210,858	$ 4,607,894	$ 4,718,455	$ 4,918,914
Property Taxes	$ 57,416	$ 49,869	$ 49,018	$ 48,531	$ 64,612	$ 54,540	$ 55,358	$ 56,188
LEAP	$ 11,506	$ 11,506	$ 11,825	$ 11,825	$ 11,825	$ 11,825	$ 11,825	$ 12,942
Total Controllable	$ 5,660,594	$ 4,916,514	$ 5,661,572	$ 5,663,305	$ 5,868,660	$ 6,058,865	$ 6,193,734	$ 6,468,593
Cost of Power	$ 33,092,706	$ 44,886,698	$ 48,381,613	$ 49,839,585	$ 53,987,814	$ 60,034,318	$ 63,391,860	$ 62,241,271
Total Working Capital	$ 38,753,300	$ 49,803,212	$ 54,043,184	$ 55,502,890	$ 59,856,474	$ 66,093,183	$ 69,585,594	$ 68,709,864
Allowance Factor	13%	13%	13%	13%	13%	13%	13%	7.5%
Working Capital Allowance	**$ 5,037,929**	**$ 6,474,418**	**$ 7,025,614**	**$ 7,215,376**	**$ 7,781,342**	**$ 8,592,114**	**$ 9,046,127**	**$ 5,153,240**

FIXED ASSET CONTINUITY STATEMENTS

ETPL has completed the Fixed Asset Continuity Schedules (Board Appendix 2-BA) Actuals for 2012 through 2016, the 2017 Bridge Year and the 2018 Test Year. These schedules are provided in Attachment 2-A of this Exhibit and have also been filed in Live Excel format.

The continuity schedules reconcile to the annual recorded depreciation expense. Please see Table 2-3 below for the reconciliation between annual change in accumulated depreciation and depreciation expense. As shown below, the depreciation expense has been reduced for fully allocated transportation depreciation.

Annual Amortization Expense for Rate-Setting Purposes

Paragraph 2.5.1.2 of the Filing Requirements requires that the depreciation expense in the fixed asset continuity statements reconcile to the calculated depreciation expenses under Exhibit 4 – Operating Costs and presented by account. In accordance with this requirement there are no reconciling items between the fixed asset continuity statements in this Exhibit and the calculated depreciation expense in Exhibit 4. Table 2-3 below details the reconciliation of depreciation.

TABLE 2-3: DEPRECIATION EXPENSE RECONCILIATION

Table 2-3: Depreciation Expense Reconciliation

Line No.	Description	2012 BAP	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge	2018 Test
1	Accounting Standard	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
2	Change in Accumulated Depreciation	$ 2,030,082	$ 1,727,485	$ 1,435,333	$ 1,473,128	$ 1,504,591	$ 1,738,527	$ 1,794,418	$ 1,842,780
3	Less:								
4	Fully Allocated Transportation Depreciation		$ -	-$ 404,857	$ 5,650	-$ 20,828	$ 25,904	$ 47,543	$ -
5					$ -				
6	**Depreciation Expense**	**$ 2,030,082**	**$ 1,727,485**	**$ 1,840,191**	**$ 1,467,478**	**$ 1,525,419**	**$ 1,712,622**	**$ 1,746,875**	**$ 1,842,780**

RATE BASE VARIANCE ANALYSIS

ETPL has prepared the following table to illustrate the rate base variances for each required comparator.

TABLE 2-4: RATE BASE VARIANCE SUMMARY

Description	2012 BAP	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge	2018 Test
Accounting Standard	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS
Gross Fixed Assets	$ 41,263,081	$ 40,110,141	$ 43,689,878	$ 47,304,405	$ 50,890,499	$ 52,627,568	$ 56,177,481	$ 59,420,431
Accumulated Depreciation	-$ 14,833,530	-$ 16,053,187	-$ 17,249,204	-$ 18,566,358	-$ 19,745,488	-$ 19,940,333	-$ 21,734,751	-$ 23,577,531
Net Book Value	$ 26,429,551	$ 24,056,954	$ 26,440,674	$ 28,738,047	$ 31,145,011	$ 32,687,234	$ 34,442,729	$ 35,842,900
Average Net Book Value	$ 26,429,551	$ 23,752,669	$ 25,248,814	$ 27,589,361	$ 29,941,529	$ 31,916,123	$ 33,564,982	$ 35,142,814
Total Working Capital	$ 38,753,300	$ 49,803,212	$ 54,043,184	$ 55,502,890	$ 59,856,474	$ 66,093,183	$ 69,585,594	$ 68,709,864
Working Capital Allow. Factor	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	7.5%
Working Capital Allowance	$ 5,037,929	$ 6,474,418	$ 7,025,614	$ 7,215,376	$ 7,781,342	$ 8,592,114	$ 9,046,127	$ 5,153,240
Rate Base	$ 31,467,480	$ 30,227,087	$ 32,274,428	$ 34,804,736	$ 37,722,871	$ 40,508,237	$ 42,611,109	$ 40,296,054
		2012 BAP vs. 2012 Actual	**2012 Actual vs. 2013 Actual**	**2013 Actual vs. 2014 Actual**	**2014 Actual vs. 2015 Actual**	**2015 Actual vs. 2016 Actual**	**2016 Actual vs. 2017 Bridge**	**2017 Bridge vs. 2018 Test**
Gross Fixed Assets		-$ 1,152,940	$ 3,579,737	$ 3,614,527	$ 3,586,094	$ 1,737,069	$ 3,549,913	$ 3,242,950
Accumulated Depreciation		-$ 1,219,657	-$ 1,196,017	-$ 1,317,154	-$ 1,179,130	-$ 194,845	-$ 1,794,418	-$ 1,842,780
Net Book Value		-$ 2,372,597	$ 2,383,720	$ 2,297,373	$ 2,406,964	$ 1,542,223	$ 1,755,495	$ 1,400,170
Average Net Book Value		-$ 2,676,882	$ 1,496,145	$ 2,340,547	$ 2,352,169	$ 1,974,594	$ 1,648,859	$ 1,577,833
Total Working Capital		$ 11,049,912	$ 4,239,972	$ 1,459,705	$ 4,353,585	$ 6,236,709	$ 3,492,411	-$ 875,730
Working Capital Allow. Factor		$ -	$ -	$ -	$ -	$ -	$ -	-$ 0
Working Capital Allowance		$ 1,436,489	$ 551,196	$ 189,762	$ 565,966	$ 810,772	$ 454,013	-$ 3,892,887
Rate Base		-$ 1,240,394	$ 2,047,341	$ 2,530,308	$ 2,918,135	$ 2,785,366	$ 2,102,873	-$ 2,315,055

The overall changes in rate base can be attributed to either changes in Gross Assets or changes in Working Capital Allowance which are primarily driven by increases in cost of power. For detailed variance explanations of these, please see Section 2.2.2 and Section 2.4.4, respectively.

2012 Board Approved vs 2012 Actual

As provided in the following Table 2-5, the 2012 actual rate base of $30,227,087 is $1,240,394 less than the 2012 Board Approved rate base of $31,467,480

Table 2-5: Rate Base Variance 2012 BA vs 2012 Actual

Description	**2012 BAP**	**2012 Actual**	**Variance**
Accounting Standard	CGAAP	CGAAP	
Gross Fixed Assets	$ 41,263,081	$ 40,110,141	-$ 1,152,940
Accumulated Depreciation	-$ 14,833,530	-$ 16,053,187	-$ 1,219,657
Net Book Value	$ 26,429,551	$ 24,056,954	-$ 2,372,597
Average Net Book Value	$ 26,429,551	$ 23,752,669	-$ 2,676,882
Total Working Capital	$ 38,753,300	$ 49,803,212	$ 11,049,912
Working Capital Allow. Factor	13.0%	13.0%	0.0%
Working Capital Allowance	$ 5,037,929	$ 6,474,418	$ 1,436,489
Rate Base	$ 31,467,480	$ 30,227,087	-$ 1,240,394

The average net book value of assets was $2,676,882 lower and the working capital allowance was $1,436,489 higher than the 2011 Board Approved.

The rate base reduction is mainly attributed to the fact that since the 2012 COS application was not approved until January of 2013 the $2,000,000 of Smart Meter assets that were approved as part of ETPL's 2012 COS application were not included as capital until after year ended 2012. Actual working capital allowance in 2012 increased over 2012 Board Approved due to an increase in commodity costs for 2012 over estimated costs improved in rate by approximately $10,000,000 or $1,400,000 in WCA.

<u>2012 Actual vs 2013 Actual</u>

The 2013 rate base of $32,274,428 is $2,047,341 greater than the 2012 rate base of $30,227,087. Table 2-6 shows the details of the year over year change.

Table 2-6: Rate Base Variance 2012 Actual vs 2013 Actual

Description	2012 Actual	2013 Actual	Variance
Accounting Standard	CGAAP	CGAAP	
Gross Fixed Assets	$ 40,110,141	$ 43,689,878	$ 3,579,737
Accumulated Depreciation	-$ 16,053,187	-$ 17,249,204	-$ 1,196,017
Net Book Value	$ 24,056,954	$ 26,440,674	$ 2,383,720
Average Net Book Value	$ 23,752,669	$ 25,248,814	$ 1,496,145
Total Working Capital	$ 49,803,212	$ 54,043,184	$ 4,239,972
Working Capital Allow. Factor	13.0%	13.0%	$ -
Working Capital Allowance	$ 6,474,418	$ 7,025,614	$ 551,196
Rate Base	$ 30,227,087	$ 32,274,428	$ 2,047,341

The increase in the rate base from 2012 to 2013 can be attributed to (i) the increased net book value of $2,383,720 related to normal capital spending; (ii) the capitalization of $2,887,517 of smart meter costs less write off of stranded meters $1,169,000; and (iii) normal capital costs primarily related to system enhancement and voltage conversions. Working Capital allowance also increased in 2013 adding to the increased rate base. This increase was primarily due to a further increase in commodity costs of $3,484,915.

2013 Actual vs 2014 Actual

The 2014 rate base of $34,804,736 is $2,530,308 greater than the 2013 rate base of $32,274,428. The following table shows the details of the year over year change.

Table 2-7: Rate Base Variance 2013 Actual vs 2014 Actual

Description	2013 Actual	2014 Actual	Variance
Accounting Standard	CGAAP	CGAAP	
Gross Fixed Assets	$ 43,689,878	$ 47,304,405	$ 3,614,527
Accumulated Depreciation	-$ 17,249,204	-$ 18,566,358	-$ 1,317,154
Net Book Value	$ 26,440,674	$ 28,738,047	$ 2,297,373
Average Net Book Value	$ 25,248,814	$ 27,589,361	$ 2,340,547
Total Working Capital	$ 54,043,184	$ 55,502,890	$ 1,459,705
Working Capital Allow. Factor	13.0%	13.0%	$ -
Working Capital Allowance	$ 7,025,614	$ 7,215,376	$ 189,762
Rate Base	$ 32,274,428	$ 34,804,736	$ 2,530,308

The Rate Base increase of $2,530,308 is primarily related to the capital expenditure increases incurred in 2014 which increased net book value by $2,297,373. While the $189,762 increase in WCA is solely attributable to an increase in commodity costs of $1,457,000.

2014 Actual vs 2015 Actual

The 2015 rate base of $37,722,871 is $2,918,135 greater than the 2014 rate base of $34,804,736. The following table shows the details of the year over year change.

Table 2-7: Rate Base Variance 2014 Actual vs 2015 Actual

Description	2014 Actual	2015 Actual	Variance
Accounting Standard	CGAAP	CGAAP	
Gross Fixed Assets	$ 47,304,405	$ 50,890,499	$ 3,586,094
Accumulated Depreciation	-$ 18,566,358	-$ 19,745,488	-$ 1,179,130
Net Book Value	$ 28,738,047	$ 31,145,011	$ 2,406,964
Average Net Book Value	$ 27,589,361	$ 29,941,529	$ 2,352,169
Total Working Capital	$ 55,502,890	$ 59,856,474	$ 4,353,585
Working Capital Allow. Factor	13.0%	13.0%	$ -
Working Capital Allowance	$ 7,215,376	$ 7,781,342	$ 565,966
Rate Base	$ 34,804,736	$ 37,722,871	$ 2,918,135

The increase in rate base is driven by the $2,406,964 investment in ETPL's infrastructure, focusing on distribution system renewal, primarily voltage conversion and (ii) the increase in WCA is attributed to normal growth in operating costs coupled with a $4,000,000 increase in commodity costs resulting in the $565,966 increase in WCA.

2015 Actual vs 2016 Actual

The 2016 rate base of $40,508,237 is $2,785,366 greater than the 2015 rate base of $37,722,871. The following table shows the details of the year over year change.

Table 2-8: Rate Base Variance 2015 Actual vs 2016 Actual

Description	2015 Actual	2016 Actual	Variance
Accounting Standard	CGAAP	MIFRS	
Gross Fixed Assets	$ 50,890,499	$ 52,627,568	$ 1,737,069
Accumulated Depreciation	-$ 19,745,488	-$ 19,940,333	-$ 194,845
Net Book Value	$ 31,145,011	$ 32,687,234	$ 1,542,223
Average Net Book Value	$ 29,941,529	$ 31,916,123	$ 1,974,594
Total Working Capital	$ 59,856,474	$ 66,093,183	$ 6,236,709
Working Capital Allow. Factor	13.0%	13.0%	$ -
Working Capital Allowance	$ 7,781,342	$ 8,592,114	$ 810,772
Rate Base	$ 37,722,871	$ 40,508,237	$ 2,785,366

The 2016 average net book value of capital has increased by $1,974,594 from 2015 due to the completion of planned capital spending on distribution assets. The conversion to IFRS in 2015 has impacted the gross change in net book value due to adopting the new capitalization policies as well as removing fully amortized assets cost and associated amortization from the calculation of net book value. The increase in WCA allowance once again is directly attributed to an increase in commodity costs of $6,000,000 representing a $786,000 increase to WCA while the remaining $25,000 increase is due to normal inflationary increases in operating costs of approximately 3% year over year.

2016 Actual vs 2017 Bridge Year

The 2017 Bridge Year rate base of $42,611,109 is $2,102,873 greater than the 2016 rate base of $40,508,237. The following table shows the details of the year over year change.

Table 2-9: Rate Base Variance 2016 Actual vs 2017 Bridge Year

Description	2016 Actual	2017 Bridge	Variance
Accounting Standard	MIFRS	MIFRS	
Gross Fixed Assets	$ 52,627,568	$ 56,177,481	$ 3,549,913
Accumulated Depreciation	-$ 19,940,333	-$ 21,734,751	-$ 1,794,418
Net Book Value	$ 32,687,234	$ 34,442,729	$ 1,755,495
Average Net Book Value	$ 31,916,123	$ 33,564,982	$ 1,648,859
Total Working Capital	$ 66,093,183	$ 69,585,594	$ 3,492,411
Working Capital Allow. Factor	13.0%	13.0%	$ -
Working Capital Allowance	$ 8,592,114	$ 9,046,127	$ 454,013
Rate Base	$ 40,508,237	$ 42,611,109	$ 2,102,873

The 2017 proposed average net book value of capital has increased by $1,648,859 from 2016 due to the completion of planned capital spending on distribution assets. The increase in WCA once again is directly attributed to an increase in commodity costs of $3,000,000 representing a $436,000 increase to WCA while the remaining $17,000 increase is due to normal inflationary increases in operating costs of approximately 2% year over year.

2017 Bridge Year vs. 2018 Test Year

The 2018 proposed Test Year rate base of $40,296,054 is $2,315,055 less than the 2017 Bridge Year rate base of $42,611,109. The following table shows the details of the year over year change.

Table 2-10: Rate Base Variance 2017 Bridge Year vs 2018 Test Year

Description	2017 Bridge	2018 Test	Variance
Accounting Standard	MIFRS	MIFRS	
Gross Fixed Assets	$ 56,177,481	$ 59,420,431	$ 3,242,950
Accumulated Depreciation	-$ 21,734,751	-$ 23,577,531	-$ 1,842,780
Net Book Value	$ 34,442,729	$ 35,842,900	$ 1,400,170
Average Net Book Value	$ 33,564,982	$ 35,142,814	$ 1,577,833
Total Working Capital	$ 69,585,594	$ 68,709,864	-$ 875,730
Working Capital Allow. Factor	13.0%	7.5%	-$ 0
Working Capital Allowance	$ 9,046,127	$ 5,153,240	-$ 3,892,887
Rate Base	$ 42,611,109	$ 40,296,054	-$ 2,315,055

The 2018 average net book value of capital has increased by $1,577,833 from 2017 projected due to the completion of planned capital spending on distribution assets as proposed in ETPL's DSP included in this application in Exhibit 2-C.

The large decrease in WCA allowance relates to a $1,150,000 decrease in forecasted commodity costs from the reduction in load forecast due to CDM projected and weather normalization, the impact of this change is a $149,000 reduction in WCA (when using the same WCA factor). Details on the load forecast utilized in the calculation of proposed commodity costs can be found in Exhibit 3. Increases in OM&A due to forecasted changes in operating cost spending of approximately 4% (inclusive of $140,000 in costs related to cyber security and risk) attribute to an increase in WCA of approximately $35,000 (when using the last approved WCA factor). Therefore since the changes to total working capital represent a decrease in WCA under the currently approved allowance of 13% of $113,885 the remaining $3,779,043 decrease is directly attributed to the utilization of an allowance factor of 7.5% which is the factor that ETPL is proposing to utilize in this application.

GROSS ASSETS (PP&E)

ETPL's capital spending is categorized in accordance with the Board's APH. ETPL's assets include distribution assets and general plant. In accordance with the USoA, ETPL has included asset accounts 1611and 1612 in the category of Intangible assets, 1805 to 1860 in the category of distribution plant, accounts 1915 to 1990 in the category of general plant.

OVERVIEW

This overview provides background information on the ETPL distribution system and a general overview of the types of capital programs and project works that are undertaken. ETPL is a local distribution company located in Southwestern Ontario representing the amalgamation of eight Public Utilities Commissions and currently services 18,265 customers in the municipalities of Port Stanley, Aylmer, Belmont, Ingersoll, Thamesford, Otterville, Norwich, Burgessville, Beachville, Embro, Tavistock, Mitchell, Dublin and Clinton. ETPL's service territory spans north to south a distance of approximately 125 km and all municipalities are embedded within Hydro One service territory. ETPL has three operations centers located in Aylmer, Mitchell and Ingersoll with the later retaining all executive, administration, finance, customer service, metering and engineering departments.

The communities serviced by ETPL have varying degrees of customer density and the majority are classified as rural based on the guidelines set out in Appendix C of the Distribution System Code. ETPL however considers and operates all communities as urban centers with respect to inspection and maintenance requirements.

Each of ETPL's communities are embedded and supplied from various Hydro One distribution circuit(s) with the Town of Aylmer having the only transmission connected supply point. ETPL is supplied by seven (7) Transmission Stations, one (1) high voltage Distribution Station, and three (3) Distribution Stations owned and operated by Hydro One as detailed below in Table 2-11.

Due to the nature of ETPL's service territory we have 20 wholesale metering installations used at each boundary between our distribution system and HONI's. This equates to approximately one (1) wholesale point for each 922 customers. This obviously creates additional costs as compared to LDC's with large contiguous service territories.

Table 2-11: ETPL Supply Stations

MUNICIPALITY	HYDRO ONE SUPPLY STATION	ETPL CONNECTED FEEDER ID	SUPPLY VOLTAGE (KV)	CONNECTION TYPE
Aylmer	Aylmer TS Aylmer TS Edgeware TS	M1 Future - 2017 M4	27.6Y/16 27.6Y/16 27.6Y/16	Dedicated Dedicated Embedded
Beachville	Ingersoll TS	M44	27.6Y/16	Embedded
Belmont	Buchanan TS	M21	27.6Y/16	Embedded
Burgessville	North Norwich DS (supplied by Tillsonburg TS)	F2 (Tillsonburg M3)	8.32Y/4.8	Embedded
Clinton	Constance DS Constance DS	F2 F4	27.6Y/16 27.6Y/16	Embedded Embedded
Dublin	Dublin DS (supplied by Seaforth TS)	F1 (Seaforth M2)	8.32Y/4.8	Embedded
Embro	Ingersoll TS	M46	27.6Y/16	Embedded
Ingersoll	Ingersoll TS Ingersoll TS Ingersoll TS Ingersoll TS	M49 M50 M51 M52	27.6Y/16 27.6Y/16 27.6Y/16 27.6Y/16	Embedded Embedded Embedded (dedicated to GM-CAMI) Embedded (dedicated to GM-CAMI)
Mitchell	Seaforth TS	M2	27.6Y/16	Embedded
Norwich	Tillsonburg TS	M3	27.6Y/16	Embedded
Otterville	Tillsonburg TS Otterville DS (supplied by Tillsonburg TS)	M1 F1 (Tillsonburg M1)	27.6Y/16 8.32Y/4.8	Embedded Embedded
Port Stanley	Edgeware TS	M3	27.6Y/16	Embedded

Tavistock	Stratford TS	M7	27.6Y/16	Embedded
Thamesford	Ingersoll TS	M43	27.6Y/16	Embedded
	Ingersoll TS	M45	27.6Y/16	Embedded

ETPL currently owns and operates nine (9) municipal 4kV substations as listed below. Each station is supplied via a different 27.6Y/16 kV feeder from Hydro One's system; typically embedded in ETPL's service territory downstream of a wholesale primary metering unit.

Table 2-12: Municipal Stations

MUNICIPALITY	***STATION ID***	***# OF FEEDERS***
Aylmer	MS1	2
	MS2	4
Beachville	MS1	2
Clinton	MS1	3
Ingersoll	MS1	3
	MS3	3
Mitchell	MS1	1
Port Stanley	MS1	3
Tavistock	MS1	3

Table 2-13 below details the current mix of overhead and underground lines in each of the 14 municipalities serviced by ETPL.

Table 2-13: O/H vs. U/G Overview

MUNICIPALITY	**OH CONDUCTOR (KM)**		**UG CABLE (KM)**		**TOTAL (KM)**
Aylmer	34.425	(65%)	18.443	(35%)	52.868
Beachville	9.128	(94%)	0.603	(6%)	9.731
Belmont	12.440	(59%)	8.509	(41%)	20.949
Burgessville	3.765	(78%)	1.092	(22%)	4.857
Clinton	22.088	(77%)	6.721	(23%)	28.809

Dublin	2.599	(96%)	0.102	(4%)	2.701
Embro	10.058	(95%)	0.559	(5%)	10.617
Ingersoll	70.553	(71%)	4.288	(29%)	14.924
Mitchell	23.281	(72%)	9.155	(28%)	32.436
Norwich	10.636	(71%)	4.288	(29%)	14.924
Otterville	9.643	(91%)	0.981	(9%)	10.624
Port Stanley	20.280	(77%)	6.003	(23%)	26.283
Tavistock	12.803	(63%)	7.598	(37%)	20.401
Thamesford	9.808	(84%)	1.805	(16%)	11.613
TOTAL	251.507	(73%)	94.282	(27%)	345.789

Table 2-14 below details the breakdown of lines by voltage level

Table 2-14: Voltage Overview

	VOLTAGE (KV)	HYDRO LINES (KM)	%	
"28kV System"	27.6	115.678	32.4%	57.8%
	16.0	90.850	25.4%	
"8kV System"	8.32	10.319	2.9%	7.3%
	4.8	15.772	4.4%	
"4kV System"	4.16	64.676	18.1%	34.9%
	2.4	59.840	16.8%	

There are currently no capacity constraints on the nine (9) municipal substations owned and operated by ETPL. This will continue to be the case for the indefinite future as voltage conversion removes load from each of the substations.

Table 2-15: Station Characteristics

	STATION CHARACTERISTICS			
DISTRIBUTION STATION	STATION RATING	# OF FEEDERS	# OF CUSTOMERS	LOADING % [1]
Clinton MS1	5MVA	4	1494	66%
Port Stanley MS1	5MVA	3	917	21%
Beachville MS1	3MVA	2	402	40%
Aylmer MS2 - TX1	3MVA	4	992	15%
Mitchell MS2	3MVA	2	236	9%
Ingersoll MS1	5MVA	3	767	23%
Ingersoll MS3	5MVA	3	436	21%
Aylmer MS1	5MVA	2	613	46%
Aylmer MS2 - TX2	3MVA	4	992	30%
Tavistock MS1	5MVA	3	693	38%

Currently there is no known capacity constraints at any embedded distribution supply point connected to HONI system.

The following tables and figures provide information on the quantity and age profile of major assets which are accurate as of February 2015. The age profile for each asset is known with varying degrees of certainty and further detail is provided within the 2015 Asset Management Plan & Asset Condition assessment included in Appendix I of the DSP which is included in this exhibit as Attachment 2C.

Overhead Line Poles

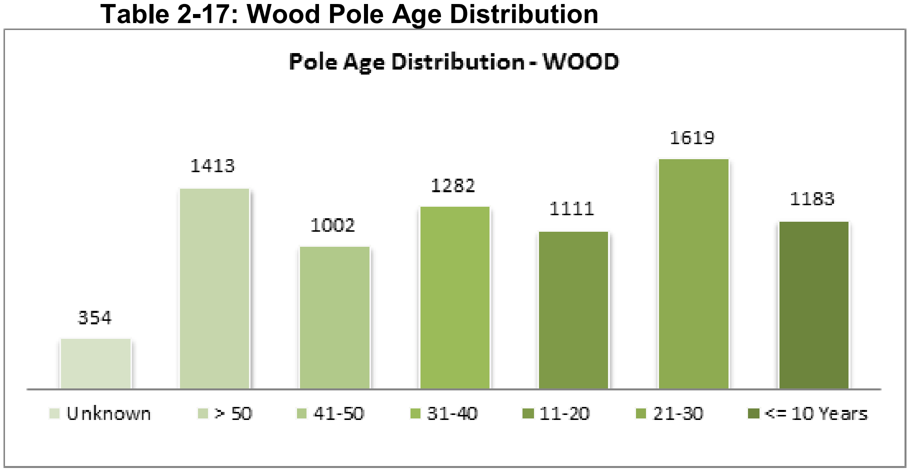
Table 2-16: Poles - Age Summary

OVERHEAD LINE POLES	8,511	Wood	7964
		Concrete	340

[1] Loading percentage was calculated as an average of the peak phase currents from April 2014 to April 2015 compared to the transformer rating.

		Steel	207
MAXIMUM AGE		76 years	
AVERAGE AGE		31 years	

Table 2-17: Wood Pole Age Distribution



Distribution Transformers

Table 2-18: Transformer Age Summary

DISTRIBUTION TRANSFORMERS	3,310	Polemount	2446
		Padmount 1PH	744
		Padmount 3PH	120

Medium Voltage Underground Cable

Table 2-19: MV Cable Age Summary

MEDIUM VOLTAGE UNDERGROUND CABLE	129 km	1PH	85.32 km
		3PH	14.43 km (x3)

2.2.1 Capital Planning Process

ETPL's capital expenditure plan balances the following objectives:

- Meet mandated service obligations with respect to new customer connections, meter replacements and facility relocations.
- Maintain or improve the safety and reliability of the distribution system to meet customer expectations.
- Effective renewal of end of life assets as prescribed by the ACA & AMP, creating a balance between capital investments in new infrastructure and O&M costs ensuring that the total cost over the life of the asset is minimized.
- Establishment of long term planning horizons to maintain stable financial impacts to customers.
- Provide adequate system capacity for load growth, and connection of Renewable Electricity Generation.
- Ensure that general plant expenditures are sufficient to enable objectives to be achieved in an efficient manner.

The criteria used to select, pace and prioritize projects in a manner that achieve the proper balance of the objectives listed above are detailed in the AMP included in the DSP-Appendix I and have been summarized below:

- Financial
- Service Quality
- Company Image
- Legal
- Regulatory
- Safety (Public and Employee)
- Environmental

All of these criteria represent various inputs into the decision framework used by ETPL and encompass variables such as customer preference, consultation with municipal government, maintenance requirements, load growth requirements and specific asset condition assessments etc.

There are a number of assumptions that are made during the capital expenditure process primarily focused of third party driven system access type investments which include:

- The capital expenditure level for developer driven projects is established on historical trends and adjusted based on information from municipal contacts and developers. This however assumes that historical trends will hold true and adjustments made for known developments come to fruition in a given year.
- The capital expenditure level for municipal facility relocation projects is established through historical trends and adjusted based on consultation with municipalities. This assumes that projects tabbed for a given year move forward and the effect on ETPL infrastructure is consistent with initial plans.
- The use of historical growth, CDM and DG rates to establish a forecast for the demand of the distribution system.

Each of these priorities is addressed in the Distribution System Plan filed as Attachment 2-C.

2.2.2 Regional Planning and Consultations

ETPL communities are included in two Regional Planning Areas; the London and Greater Bruce/Huron regions which are both in the Local Wires Planning stages. ETPL will continue to actively participate in all regional planning activities and currently does not expect any extraordinary investments as a result.

Outside of the regional planning framework ETPL frequently coordinates operations and planning activities with HONI and will continue to do so moving forward.

2.2.3 Asset Management Process

ETPL's Asset Management practices were formalized in 2011 when it engaged METSCO Energy Solutions to develop an Asset Condition Assessment (ACA) and Asset Management Plan (AMP - included in DSP Appendix H) which was included in the 2012 Cost of Service Rate Application (EB-2012-0121). This formed the basis for more effective Asset Management moving forward and has since been updated with the 2015 AMP (included in DSP Appendix I). It was created to provide an overview of the assets managed by ETPL and outlines the purpose, strategy, objectives and expenditures required to provide safe, reliable and cost effective hydro to our customers.

Prior to formalizing the Asset Management Process in 2011, ETPL had been following good utility practices by replacing assets that had or would be reaching end of life, or otherwise identified as potential failure risks during inspection or testing. The engagement of a third party to formalize the process revealed that ETPL had been potentially under-investing in asset replacement although this had not resulted in sub-standard performance (reliability) of the distribution system.

As noted in the 2012 Cost of Service Rate Application (EB-2012-0121), ETPL considered the potential rate impact to customers and opted to gradually increase the investment in asset replacement over a number of years. This decision was supported by the OEB and intervenors through the proceeding and no change was required with the proposed level of spending on capital for 2013 (OEB Decision and Order November 29, 2012).

PLANNING

In accordance with the Filing Requirements, ETPL is filing its Distribution System Plan ("DSPlan") as a stand-alone document as Attachment 2-C of this Exhibit. ETPL's Distribution System Plan is organized using the headings indicated in Chapter Five of the Board's Filing Requirements for Electricity Distribution and Transmission Applications, entitled Consolidated Distribution System Plan Filing Requirements (the "DS Plan Filing Requirements"). ETPL understands it has met the Chapter 5 requirements in all relevant aspects.

2.2.4 Required Information

ETPL has filed its Capital Expenditure Summary 2013 – 2022 from Chapter 5 Consolidated DS Plan Filing requirements on the following page. Explanatory notes on variances are included in the consolidated DS Plan. ETPL capital additions for the 2018TY are expected to be $3,088,205. Capital additions for the 2019 to 2022 planning period remain fairly stable at approximately the $3,200,000 level.
Board Appendices 2-AA and 2-AB are provided on the following pages. The following Table 2AA provides the details for the capital projects for the 2013 to 2016 actuals, 2017BY and 2018TY

and 2019 to 2022 forecast.

Appendix 2-AA
Capital Projects Table

Projects	2013	2014	2015	2016	2017 Bridge Year	2018 Test Year
Reporting Basis	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
System Access						
Comm & Ind Connections	110,248	199,892	251,974	192,895	204,000	204,000
Residential Connections	41,910	377,856	395,111	371,236	231,000	231,000
Munc Road Reconstruction	70,551	123,310	452,380	229,747		
Subdivisions	104,546	402,882	140,002	110,037		
Joint Use Make Ready Work	933	0	0	14,044		
Meter Stock Purchases	57,723	151,357	73,325	142,345	248,628	234,500
MIT-EXPN-3878 WELLINGTON ST.	12,719	0	0	0		
AYL-FACRL-84 SOUTH ST. W.	2,473	0	0	0		
ING-FACRL-HOLCROFT ST.	312,060	1,664	0	0		
ING-FACRL-CHARLES ST.W.	3,915	24,339	0	0		
TAVI-FACRL-79 MARIA ST.	40,238	0	0	0		
BEL-FACRL-Belmont PME	829	0	0	0		
ING-FACRL-Holcroft St Rail Xing		87,643	0	0		
PTS-FACRL-Mitchell St		1,960	0	0		
THA-FACRL-CHRISTIAN RETREAT		32,484	0	0		
CLI-SRVCI-270 Victoria St	0	17,068	0	0		
TAV-FACRL-117 Hope St		0	3,225	0		
Facility Relocates		0	0	0	50,000	150,000
		0	0	0		
	0	0	0	0		
	0	0	0	0		
Miscellaneous	165	0	950	0		
Sub-Total	**758,310**	**1,420,455**	**1,316,968**	**1,060,304**	**733,628**	**819,500**
System Renewal						
TAV-EXPN-WILLIAM ST.	14,360	0	0	0		
TAV-UGUPG-JACOB ST.	8,925	0	0	0		
BEL-REPL FAC-HAZELWOOD UG UPG	60,787	0	0	0		
ING-REPL FAC-MELITA & WONHAM	97,003	0	0	0		
CLI-TXCVN-MAPLEHILL APTS	12,769	0	0	0		
AYL-Fath Ave Rear Yard	58,173	10,815	0	0		
ING-GOLDEN GARDENS	126,981	22,912	0	0		
TAV-CONUIT-HOPE & CENTENNIAL	1,437	0	0	0		
PTS-GEORGE ST/RIVER/VALLEY/LAK	12,373	428,520	38,991	-8,021		
OTT-27OHRECON-DOVER ST.		20,247	0	0		
MIT-OHUPG-NAPIER & CLAYTON		94,998	0	0		
TAV-UGUPG-ARENA & SCHOOL		36,093	0	0		
BEL-FACRL-Belmont PME		65,619	0	0		
NOR-OHUPG-STOVER ST N		285,371	728	0		
CLI-27OHCVN-VICTORIA ST.			13,283	0		
ING-UGRECON-UNDERWOOD AVE-PLLN			56,524	73,875		
PTS-OHUPGD-473 LOWER SPRING ST			6,590	0		
TAV-REPLCON-WILLIAM ST.SEWPUMP			5,093	0		
AYL-OHUPG-207 Talbot St E			1,078	-992		
BEL-FACRL-140 Borden Ave			0	1,991		
PTS-FACRL-Edith Cavell Blvd. E.			0	140,086		
ING-FACRL-205 INGERSOLL ST. S				14,789		
NOR-OHUPF-Municipal Supply Upgr				3,949		
THA-REPLACE FAULTED RABBIT-				7,896		
CLI-EXPN-Mary St				3,183		
ING-REPL SYNERTEC-325 INGERSOLL			0	711		
AYL-LDISP-89 Progress Dr (IGPC)				14,257		
ING-OGCONV-Bruce & Metcalfe						295,000
AYL-OHCONV-BMO & Comm Living						135,240
AYL-ONCONV-Myrtle to John w/ pool						258,840
AYL-OHCONV-Caverly RD, Anne to Fath						82,200
AYL-UGCONV-Davenport School						105,450
PTS-OHUPGD-George St Completion						60,000
AYL-OHCONV-Talbot, Myrtle to Wellington						200,120
CLI-OHCONV-Princess, Percival to Schools						161,400
MIT-UGCONV-St Andrew & Maple Crt						188,472
MIT-OHCONV-Step Down TX, Arthur St.						46,000
CLI-OHCONV-Princess, Percival to William St						241,728

Appendix 2-AA
Capital Projects Table

Projects	2013	2014	2015	2016	2017 Bridge Year	2018 Test Year
Reporting Basis	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
System Renewal						
BEA-OHCON-Station Egress and Crossing					120,000	
TAV-STNUPG-Station Upgrades (PH2)					100,000	
OTT-OHUPG-Grove & Maple					110,292	
AYL-UGCONV-Talbot St. E.-King to Queen					185,000	
AYL-STATION-New Feeder Egress & PME					304,200	
AYL-OHCONV-South Street, Caverly to Rutherford					132,000	
CLI-OHCONV-Bayfield Road					274,500	
Service Upgrades	0	0	0	63,119	50,000	
Conversions	218,830	735,463	1,288,617	701,866		
SubStation Upgrades	12,222	4,681	85,829	56,971	15,000	8,000
Replacement - Poles	71,613	62,883	133,130	176,409	123,000	200,000
Replacement - Transformers	15,295	11,336	52,935	50,465		
Replacement - Insulators	8,103	262,169	0	0		
Replacement - Switches	0	0	0	48,155	50,000	
Replacement - Primary	7,530	0	4,939	0		
Replacement - Secondary	690	0	0	0		
	0	0	0	0		
Emergencies - Storm	8,721	8,754	13,841	13,593		
Emergencies - Misc	13,455	52,104	24,845	29,060		
Unplanned Capital Investments					150,000	100,000
	0	0	0	0		
Maps & Records	40,129	196,286	104,063	124,402	120,000	120,000
		0		0		
Miscellaneous		0		-132		
Sub-Total	**789,397**	**2,298,252**	**1,830,486**	**1,515,632**	**1,733,992**	**2,202,450**
System Service						
Smart Grid, SCADA & Automation	42,216	3,856	64,232	188,030	50,000	90,000
AYL-NEW HYDRO ONE TS					383,343	
Sub-Total	**42,216**	**3,856**	**64,232**	**188,030**	**433,343**	**90,000**
General Plant						
Leasehold Improvements	57,279	49,451	132,939	41,813	49,000	35,000
Rolling Stock	386,632	137,334	371,568	347,832	135,000	20,000
Computer Hardware	57,214	34,018	11,372	22,003	79,950	56,000
Computer Software	54,671	87,557	218,361	27,000		
Tools	16,442	23,803	28,871	15,489	35,000	20,000
Communications Equipment				31,915		
New Shop built in Mitchell					350,000	
Miscellaneous						
Sub-Total	**572,237**	**332,164**	**763,110**	**486,054**	**648,950**	**131,000**
Miscellaneous						
Total	**2,162,160**	**4,054,727**	**3,974,796**	**3,250,020**	**3,549,913**	**3,242,950**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets *(input as negative)*						
Total	**2,162,160**	**4,054,727**	**3,974,796**	**3,250,020**	**3,549,913**	**3,242,950**

2.2.5 Breakdown by Function

The table below categorizes ETPL's assets into four categories; distribution plant, general plant, contributions and grants and intangible assets. In accordance with the USoA, ETPL has included gross assets as follows:

- Intangible Plant Assets – includes USoA accounts 1606 to 1611, these accounts capture assets such as software.
- Distribution Plant Assets – includes USoA accounts 1805 to 1860, these accounts capture assets such as substation equipment, poles, wires, transformers and meters.
- General Plant Assets – includes USoA accounts 1905 to 1990, these accounts capture assets such as administration buildings, computer hardware, transportation equipment and tools.
- Contribution and Grants – includes USoA account 1995, this account captures all contribution in aid of capital that ETPL has received or forecasted to be received as per the Distribution System Code. ETPL does utilize Account 2440.

Detailed breakdown by major plant accounts is included in the variance analysis on gross assets in Section 2.2.3 below.

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

First year of Forecast Period: *2018*

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2013			2014			2015			2016			2017			2018	2019	2020	2021	2022
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access	560,000	758,310	35.4%	405,000	1,420,455	250.7%	680,220	1,316,968	93.6%	806,021	1,060,304	31.5%	793,628	$ 1,092,827	37.7%	879,500	920,100	812,700	816,300	759,900
System Renewal	1,986,000	789,397	-60.3%	2,198,000	2,298,252	4.6%	1,995,440	1,830,486	-8.3%	1,978,591	1,515,632	-23.4%	1,673,992	1,327,158	-20.7%	2,142,450	2,002,230	1,907,040	2,168,882	1,939,454
System Service	275,775	42,215	-84.7%	225,000	3,856	-98.3%	530,000	64,232	-87.9%	253,430	188,030	-25.8%	448,318	17,991	-96.0%	73,000	74,875	76,750	55,900	55,000
General Plant	470,000	572,239	21.8%	425,000	332,164	-21.8%	468,250	763,110	63.0%	558,900	486,054	-13.0%	633,975	166,690	-73.7%	148,000	234,875	451,750	223,400	526,450
TOTAL EXPENDITURE	3,291,775	2,162,161	-34.3%	3,253,000	4,054,727	24.6%	3,673,910	3,974,796	8.2%	3,596,942	3,250,020	-9.6%	3,549,913	2,604,666	-26.6%	3,242,950	3,232,080	3,248,240	3,264,482	3,280,804
System O&M			--			--			--			--		$ -	--	$ 116,389	$ 117,553	$ 118,728	$ 119,915	$ 121,115

2.2.6 Variance Analysis on Gross Asset Additions

The following variance analysis has been prepared based on ETPL's materiality threshold; per the materiality calculation being noted in Exhibit 1, Section 1.8 of this Application. ETPL has chosen to use $50,000 as its basis for the variance analysis of Gross Asset Additions. In ETPL's daily operations, it forecasts, reports and analyzes its gross asset additions on a project categorization basis. ETPL has prepared its variance analysis herein on the same basis.

Accordingly, annual gross asset additions are first broken into project categories, and then the material project categories are then further described with specific significant projects where applicable.

2012 Board Approved vs. 2012 Actual CGAAP

Table 2-20: 2012 Board Approved vs. 2012 Actual by Account

Line No.	USofA	Description	2012 Board Approved	2012 Actual	Variance
1		**Intangible Plant**			
2	1611	Computer Software	$ 691,691	$ 1,085,463	**$ 393,772**
3	1612	Land Rights		$ 42,932	**$ 42,932**
4		**Subtotal**	**$ 691,691**	**$ 1,128,395**	**$ 436,704**
5		**Distribution Plant**			
6	1805	Land	$ 158,944	$ 103,344	**-$ 55,600**
7	1808	Buildings	$ 174,882	$ 195,951	**$ 21,069**
	1810	Leasehold Improvements	$ 7,040		**-$ 7,040**
8	1815	Transformer Station Equipment >50kV			**$ -**
9	1820	Distribution Station Equipment <50 kV	$ 499,229	$ 604,689	**$ 105,460**
10	1830	Pole, Towers & Fixtures	$ 6,151,373	$ 6,051,734	**-$ 99,639**
11	1835	Overhead Conductors & Devices	$ 10,995,470	$ 11,314,399	**$ 318,929**
12	1840	Underground Conduit	$ 2,614,048	$ 2,687,172	**$ 73,124**
13	1845	Underground Conductors & Devices	$ 5,347,890	$ 5,677,683	**$ 329,793**
14	1850	Line Transformers	$ 7,628,590	$ 7,280,070	**-$ 348,520**
15	1855	Services (Overhead & Underground)	$ 3,678,910	$ 3,903,443	**$ 224,533**
16	1860	Meters	$ 2,973,557	$ 2,945,678	**-$ 27,879**
17		**Subtotal**	**$ 40,229,933**	**$ 40,764,163**	**$ 534,230**
18		**General Plant**			
19	1905	Land			**$ -**
20	1910	Leasehold Improvements	$ 214,461	$ 187,457	**-$ 27,004**
21	1915	Office Furniture & Equipment (10 Years)	$ 69,792	$ 86,364	**$ 16,572**
22	1920	Computer Equip.-Hardware(post Mar 19/07)	$ 124,599	$ 147,759	**$ 23,160**
23	1930	Transportation Equipment	$ 3,072,447	$ 2,671,828	**-$ 400,619**
24	1935	Stores Equipment	$ 1,254	$ -	**-$ 1,254**
25	1940	Tools, Shop & Garage Equipment	$ 188,865	$ 175,798	**-$ 13,067**
26	1945	Measurement & Testing Equipment	$ 14,462	$ 14,462	**$ 0**
27	1950	Power Operated Equipment	$ 64,091	$ 64,091	**-$ 0**
28	1955	Communications Equipment			**$ -**
29	1980	System Supervisor Equipment	$ 200,000	$ 213,965	**$ 13,965**
30	1990	Other Tangible Property			**$ -**
31		**Subtotal**	**$ 3,949,971**	**$ 3,561,722**	**-$ 388,249**
32		**Contribution & Grants**			
33	1995	Contribution & Grants	-$ 4,226,235	-$ 5,344,138	**-$ 1,117,903**
34		**Subtotal**	**-$ 4,226,235**	**-$ 5,344,138**	**-$ 1,117,903**
35		**Grand Total**	**$ 40,645,360**	**$ 40,110,141**	**-$ 535,219**

The ending 2012 gross asset balance of $40,110,141 was $535,219 less than the 2012 Board Approved ending balance of $40,645,360. The decrease was due to a large vehicle that was budgeted for was not purchased. As well as higher than expected capital contributions being received.

2012 Actual CGAAP vs. 2013 Actual CGAAP

Table 2-21: 2012 Actuals vs. 2013 Actual Gross Assets by Account

Line No.	USofA	Description	2012 Actuals	2013 Actuals	Variance
1		**Intangible Plant**			
2	1611	Computer Software	$ 1,085,463	$ 1,140,133	**$ 54,671**
3	1612	Land Rights	$ 42,932	$ 43,879	**$ 947**
4		**Subtotal**	**$ 1,128,395**	**$ 1,184,013**	**$ 55,618**
5		**Distribution Plant**			
6	1805	Land	$ 103,344	$ 104,039	**$ 695**
7	1808	Buildings	$ 195,951	$ 220,868	**$ 24,917**
8	1815	Transformer Station Equipment >50kV	$ -		**$ -**
9	1820	Distribution Station Equipment <50 kV	$ 604,689	$ 617,564	**$ 12,875**
10	1830	Pole, Towers & Fixtures	$ 6,051,734	$ 6,523,423	**$ 471,688**
11	1835	Overhead Conductors & Devices	$ 11,314,399	$ 12,015,007	**$ 700,608**
12	1840	Underground Conduit	$ 2,687,172	$ 2,717,442	**$ 30,270**
13	1845	Underground Conductors & Devices	$ 5,677,683	$ 6,022,156	**$ 344,473**
14	1850	Line Transformers	$ 7,280,070	$ 7,774,879	**$ 494,810**
15	1855	Services (Overhead & Underground)	$ 3,903,443	$ 4,211,523	**$ 308,080**
16	1860	Meters	$ 2,945,678	$ 4,757,127	**$ 1,811,449**
17		**Subtotal**	**$ 40,764,163**	**$ 44,964,028**	**$ 4,199,865**
18		**General Plant**			
19	1905	Land	$ -		**$ -**
20	1908	Buildings & Fixtures	$ -	$ -	**$ -**
	1910	Leasehold Improvements	$ 187,457	$ 240,730	**$ 53,273**
21	1915	Office Furniture & Equipment (10 Years)	$ 86,364	$ 89,423	**$ 3,059**
22	1920	Computer Equip.-Hardware(post Mar 19/07)	$ 147,759	$ 204,972	**$ 57,213**
23	1930	Transportation Equipment	$ 2,671,828	$ 3,011,860	**$ 340,032**
24	1935	Stores Equipment	$ -		**$ -**
25	1940	Tools, Shop & Garage Equipment	$ 175,798	$ 192,239	**$ 16,442**
26	1945	Measurement & Testing Equipment	$ 14,462	$ 14,462	**$ -**
27	1950	Power Operated Equipment	$ 64,091	$ 64,091	**$ -**
27	1955	Communications Equipment	$ -		**$ -**
28	1980	System Supervisor Equipment	$ 213,965	$ 256,181	**$ 42,216**
29	1990	Other Tangible Property	$ -		**$ -**
30		**Subtotal**	**$ 3,561,722**	**$ 4,073,957**	**$ 512,235**
31		**Contribution & Grants**			
32	1995	Contribution & Grants	-$ 5,344,138	-$ 6,790,435	**-$ 1,446,296**
33		**Subtotal**	**-$ 5,344,138**	**-$ 6,790,435**	**-$ 1,446,296**
34		**Grand Total**	**$ 40,110,141**	**$ 43,431,563**	**$ 3,321,421**

2013 Actual gross fixed assets are $3,321,421 greater than 2012 actual this variance can be attributed to the following categories of investments:

- Conversions,
- General pole replacements,

- Engineering, Operations and Control Room support,
- Capital expansion requests,
- Commercial and industrial investments,
- Transformer replacements, and
- Emergencies.

Conversion projects relate to costs to convert the distribution system from 2.4/4.16 kV to 16/27.6kV. These projects tend to span multiple years. Modernizing the system assists with power quality issues and minimizing outages. The ending 2013 gross assets balance of $43,689,878 is $3,321,421 greater than the 2012 ending balance of $40,110,141. This variance can be attributed to the following investment categories:

- Stranded meter adjustment
- Net distribution capital expenditures of $2,753,569 was net of contributed capital of $1,446,296 and other capital expenditures were $567,852 with the largest expenditure being related to the purchase of a bucket truck for $340,032.
- 2012 capital expenditures did not include administration costs

ETPL also had and opening balance adjustment in 2013 of $1,574,294 which was due to Stranded Meter Adjustment as well as Smart Meter transfer to Fixed Assets.

2013 Actual – CGAAP vs. 2014 Actual - MIFRS

The ending 2014 gross asset balance of $47,304,405 was $3,872,842 greater than the 2013 ending balance of $43,431,563. The number of service connections was higher than forecasted and resulted in increased expenditures on C&I services, Residential Services and meters. In addition, ETPL spent approximately $235,000 more than budgeted on municipal facility relocations and other capital expenditures of $293,578 including: a new vehicle purchase of $94,891, leasehold improvements of $47,056 and computer hardware and software investment of $121,575

2014 Actual - MIFRS vs. 2015 Actual - MIFRS

Table 2-23: 2014 Actual Gross Assets vs. 2015 Actual Gross Assets

Line No.	USofA	Description	2014 Actuals	2015 Actuals	Variance
1		**Intangible Plant**			
2	1611	Computer Software	$ 1,227,691	$ 1,446,052	**$ 218,361**
3	1612	Land Rights	$ 43,879	$ 43,879	**$ -**
4		**Subtotal**	**$ 1,271,570**	**$ 1,489,931**	**$ 218,361**
5		**Distribution Plant**			
6	1805	Land	$ 104,039	$ 104,039	**$ -**
7	1808	Buildings	$ 224,882	$ 253,270	**$ 28,387**
8	1815	Transformer Station Equipment >50kV	$ -		**$ -**
9	1820	Distribution Station Equipment <50 kV	$ 617,564	$ 566,197	**-$ 51,366**
10	1830	Pole, Towers & Fixtures	$ 7,711,126	$ 8,389,746	**$ 678,619**
11	1835	Overhead Conductions & Devices	$ 13,352,040	$ 14,325,844	**$ 973,804**
12	1840	Underground Conduit	$ 2,763,114	$ 2,877,038	**$ 113,924**
13	1845	Underground Conductors & Devices	$ 6,719,334	$ 7,017,532	**$ 298,197**
14	1850	Line Transformers	$ 8,258,464	$ 8,898,199	**$ 639,735**
15	1855	Services (Overhead & Underground)	$ 4,735,335	$ 5,340,994	**$ 605,660**
16	1860	Meters	$ 4,868,340	$ 5,133,176	**$ 264,836**
17		**Subtotal**	**$ 49,354,238**	**$ 52,906,036**	**$ 3,551,797**
18		**General Plant**			
19	1905	Land	$ -		**$ -**
20	1908	Buildings & Fixtures	$ -		**$ -**
	1910	Leasehold Improvements	$ 287,786	$ 414,833	**$ 127,047**
21	1915	Office Furniture & Equipment (10 Years)	$ 91,818	$ 97,709	**$ 5,892**
22	1920	Computer Equip.-Hardware(post Mar 19/07)	$ 238,990	$ 250,362	**$ 11,372**
23	1930	Transportation Equipment	$ 3,106,751	$ 3,193,997	**$ 87,246**
24	1935	Stores Equipment	$ -		**$ -**
25	1940	Tools, Shop & Garage Equipment	$ 216,043	$ 228,294	**$ 12,251**
26	1945	Measurement & Testing Equipment	$ 14,462	$ 31,082	**$ 16,620**
27	1950	Power Operated Equipment	$ 64,091	$ 223,086	**$ 158,995**
27	1955	Communications Equipment	$ -		**$ -**
28	1980	System Supervisor Equipment	$ 260,037	$ 324,269	**$ 64,232**
29	1990	Other Tangible Property	$ -		**$ -**
30		**Subtotal**	**$ 4,279,977**	**$ 4,763,632**	**$ 483,655**
31		**Contribution & Grants**			
32	1995	Contribution & Grants	-$ 7,601,380	-$ 8,269,099	**-$ 667,719**
33		**Subtotal**	**-$ 7,601,380**	**-$ 8,269,099**	**-$ 667,719**
34		**Grand Total**	**$ 47,304,405**	**$ 50,890,499**	**$ 3,586,094**

The ending 2015 gross assets balance of $50,890,499 is $3,586,094 greater than the 2014 ending balance of $47,304,405. Net distribution capital expenditures of a large municipality facility relocation that was greater than originally expected and new services (both Residential and C&I) which were greater than expected $2,884,945 and other capital expenditures were $702,016

This variance can be attributed to the following categories of investments:

- Conversions,
- General pole replacements,
- Engineering, Operations and Control Room support,
- Capital expansion requests,
- Commercial and industrial investments,
- Transformer replacements, and
- Emergencies.

Conversion projects relate to costs to convert the distribution system from 2.4/4.16 kV to 16/27.6kV. These projects tend to span multiple years. These remaining variances can be attributed to the following investment categories:

- Computer Hardware and Software investments of $229,733
- Leasehold improvements of $127,047
- Large Truck purchase of $246,241
- Station building improvements of $28,387

This variance represents costs related to purchases, replacements and enhancements to the Supervisory Control and Data Acquisition ("SCADA") $64,232.

2015 Actual - MIFRS vs. 2016 Actual – MIFRS

Table 2-24: 2015 Actual Gross Assets vs. 2016 Actual Gross Assets

Line No.	USofA	Description	2015 Actuals	2016 Actuals	Variance
1		**Intangible Plant**			
2	1611	Computer Software	$ 1,446,052	$ 1,473,052	**$ 27,000**
3	1612	Land Rights	$ 43,879	$ 45,679	
4		**Subtotal**	**$ 1,489,931**	**$ 1,518,731**	**$ 28,800**
5		**Distribution Plant**			
6	1805	Land	$ 104,039	$ 178,544	**$ 74,505**
7	1808	Buildings	$ 253,270	$ 256,463	**$ 3,194**
8	1815	Transformer Station Equipment >50kV	$ -		**$ -**
9	1820	Distribution Station Equipment <50 kV	$ 566,197	$ 566,197	**$ -**
10	1830	Pole, Towers & Fixtures	$ 8,389,746	$ 8,861,005	**$ 471,260**
11	1835	Overhead Conductiors & Devices	$ 14,325,844	$ 14,872,610	**$ 546,766**
12	1840	Underground Conduit	$ 2,877,038	$ 3,098,041	**$ 221,003**
13	1845	Underground Conductors & Devices	$ 7,017,532	$ 7,420,132	**$ 402,600**
14	1850	Line Transformers	$ 8,898,199	$ 9,246,202	**$ 348,003**
15	1855	Services (Overhead & Underground)	$ 5,340,994	$ 5,932,575	**$ 591,581**
16	1860	Meters	$ 5,133,176	$ 5,379,222	**$ 246,046**
17		**Subtotal**	**$ 52,906,036**	**$ 55,810,992**	**$ 2,904,957**
18		**General Plant**			
19	1905	Land	$ -		**$ -**
20	1908	Buildings & Fixtures	$ -		**$ -**
21	1910	Leasehold Improvements	$ 414,833	$ 456,646	**$ 41,813**
22	1915	Office Furniture & Equipment (10 Years)	$ 97,709	$ 97,709	**$ -**
23	1920	Computer Equip.-Hardware(post Mar 19/07)	$ 250,362	$ 272,365	**$ 22,003**
24	1930	Transportation Equipment	$ 3,193,997	$ 3,053,163	**-$ 140,834**
25	1935	Stores Equipment	$ -		**$ -**
26	1940	Tools, Shop & Garage Equipment	$ 228,294	$ 243,783	**$ 15,489**
27	1945	Measurement & Testing Equipment	$ 31,082	$ 31,082	**$ -**
28	1950	Power Operated Equipment	$ 223,086	$ 224,659	**$ 1,574**
29	1955	Communications Equipment	$ -	$ 31,915	**$ 31,915**
30	1980	System Supervisor Equipment	$ 324,269	$ 512,299	**$ 188,030**
31	1990	Other Tangible Property	$ -		**$ -**
32		**Subtotal**	**$ 4,763,632**	**$ 4,923,623**	**$ 159,991**
33		**Contribution & Grants**			
34	1995	Contribution & Grants	-$ 8,269,099	-$ 6,797,192	**$ 1,471,907**
35		**Subtotal**	**-$ 8,269,099**	**-$ 6,797,192**	**$ 1,471,907**
36		**Grand Total**	**$ 50,890,499**	**$ 55,456,155**	**$ 4,565,656**

The ending 2016 gross assets balance of $55,465,155 is $4,565,565 greater than the 2015 ending balance of $50,890,499, the net being distribution capital expenditures of $2,904,957 and other capital expenditures of $1,660,699. This variance can be attributed to the following categories of investments:

- Conversions, to convert the distribution system from 2.4/4.16 kV to 16/27.6kV
- General pole replacements,
- Engineering, Operations and Control Room support,
- Capital expansion requests,
- Commercial and industrial investments,
- Transformer replacements,
- Emergencies.

The remaining variance can be attributed to the following investment categories:

- Computer Hardware and Software investments of $49,004
- Leasehold improvements of $41,813
- Truck Disposals of ($140,834)
- SCADA and system automation of $188,030
- Capital contribution realignment due to IFRS $1,471,907

2016 Actual - MIFRS vs. 2017 Bridge Year - MIFRS

Table 2-25: 2016 Actual Gross Assets vs. 2017 Bridge

Line No.	USofA	Description	2016 Actuals	2017 Bridge	Variance
1		**Intangible Plant**			
2	1611	Computer Software	$ 1,473,052	$ 1,473,052	**$ -**
3	1612	Land Rights	$ 45,679	$ 45,679	**$ -**
4		**Subtotal**	**$ 1,518,731**	**$ 1,518,731**	**$ -**
5		**Distribution Plant**			
6	1805	Land	$ 178,544	$ 178,544	**$ -**
7	1808	Buildings	$ 256,463	$ 278,050	**$ 21,587**
8	1815	Transformer Station Equipment >50kV	$ -		**$ -**
9	1820	Distribution Station Equipment <50 kV	$ 566,197	$ 527,137	**-$ 39,061**
10	1830	Pole, Towers & Fixtures	$ 8,861,005	$ 9,377,050	**$ 516,044**
11	1835	Overhead Conductions & Devices	$ 14,872,610	$ 15,613,123	**$ 740,512**
12	1840	Underground Conduit	$ 3,098,041	$ 3,184,673	**$ 86,632**
13	1845	Underground Conductors & Devices	$ 7,420,132	$ 7,646,891	**$ 226,759**
14	1850	Line Transformers	$ 9,246,202	$ 9,732,678	**$ 486,476**
15	1855	Services (Overhead & Underground)	$ 5,932,575	$ 6,393,139	**$ 460,564**
16	1860	Meters	$ 5,379,222	$ 5,580,612	**$ 201,390**
17		**Subtotal**	**$ 55,810,992**	**$ 58,511,896**	**$ 2,700,903**
18		**General Plant**			
19	1905	Land	$ -		**$ -**
20	1908	Buildings & Fixtures	$ -		**$ -**
	1910	Leasehold Improvements	$ 456,646	$ 553,257	**$ 96,611**
21	1915	Office Furniture & Equipment (10 Years)	$ 97,709	$ 102,190	**$ 4,480**
22	1920	Computer Equip.-Hardware(post Mar 19/07)	$ 272,365	$ 281,013	**$ 8,648**
23	1930	Transportation Equipment	$ 3,053,163	$ 3,119,508	**$ 66,345**
24	1935	Stores Equipment	$ -		**$ -**
25	1940	Tools, Shop & Garage Equipment	$ 243,783	$ 253,099	**$ 9,316**
26	1945	Measurement & Testing Equipment	$ 31,082	$ 43,721	**$ 12,638**
27	1950	Power Operated Equipment	$ 224,659	$ 345,564	**$ 120,905**
27	1955	Communications Equipment	$ 31,915	$ 31,915	**$ -**
28	1980	System Supervisor Equipment	$ 512,299	$ 561,144	**$ 48,844**
29	1990	Other Tangible Property	$ -		**$ -**
30		**Subtotal**	**$ 4,923,623**	**$ 5,291,410**	**$ 367,787**
31		**Contribution & Grants**			
32	1995	Contribution & Grants	-$ 6,797,192	-$ 6,797,192	**$ -**
33		**Subtotal**	**-$ 6,797,192**	**-$ 6,797,192**	**$ -**
34		**Grand Total**	**$ 55,456,155**	**$ 58,524,845**	**$ 3,068,690**

The 2017 projected ending gross asset balance of $58,524,845 is $3,068,690 greater than the 2016 year-end amount of $55,456,155. The increase is related to planned distribution system capital expenditures of $2,700,903 and $367,787 in other capital expenditures, Leasehold improvements of $96,611, new service trucks and trailers of $187,250

2017 Bridge Year-MIFRS vs. 2018 Test Year-MIFRS

Table 2-26: 2017 Bridge Year vs. 2018 Test Year

Line No.	USofA	Description	2017 Bridge	2018 Test	Variance
1		**Intangible Plant**			
2	1611	Computer Software	$ 1,473,052	$ 1,525,552	**$ 52,500**
3	1612	Land Rights	$ 45,679	$ 45,679	**-$ 0**
4		**Subtotal**	**$ 1,518,731**	**$ 1,571,231**	**$ 52,500**
5		**Distribution Plant**			
6	1805	Land	$ 178,544	$ 178,544	**$ -**
7	1808	Buildings	$ 278,050	$ 1,008,806	**$ 730,756**
8	1815	Transformer Station Equipment >50kV	$ -		**$ -**
9	1820	Distribution Station Equipment <50 kV	$ 527,137	$ 566,197	**$ 39,061**
10	1830	Pole, Towers & Fixtures	$ 9,377,050	$ 9,460,163	**$ 83,113**
11	1835	Overhead Conductiors & Devices	$ 15,613,123	$ 15,878,256	**$ 265,133**
12	1840	Underground Conduit	$ 3,184,673	$ 3,307,522	**$ 122,850**
13	1845	Underground Conductors & Devices	$ 7,646,891	$ 7,921,861	**$ 274,970**
14	1850	Line Transformers	$ 9,732,678	$ 9,871,406	**$ 138,728**
15	1855	Services (Overhead & Underground)	$ 6,393,139	$ 7,563,825	**$ 1,170,686**
16	1860	Meters	$ 5,580,612	$ 5,745,100	**$ 164,488**
17		**Subtotal**	**$ 58,511,896**	**$ 61,501,680**	**$ 2,989,785**
18		**General Plant**			
19	1905	Land			**$ -**
20	1908	Buildings & Fixtures			**$ -**
	1910	Leasehold Improvements	$ 553,257	$ 523,146	
21	1915	Office Furniture & Equipment (10 Years)	$ 102,190	$ 97,709	**-$ 4,480**
22	1920	Computer Equip.-Hardware(post Mar 19/07)	$ 281,013	$ 327,815	**$ 46,802**
23	1930	Transportation Equipment	$ 3,119,508	$ 3,198,163	**$ 78,655**
24	1935	Stores Equipment	$ -		**$ -**
25	1940	Tools, Shop & Garage Equipment	$ 253,099	$ 288,783	**$ 35,684**
26	1945	Measurement & Testing Equipment	$ 43,721	$ 31,082	**-$ 12,638**
	1950	Power Operated Equipment	$ 345,564	$ 224,659	**-$ 120,905**
27	1955	Communications Equipment	$ 31,915	$ 31,915	**$ -**
28	1980	System Supervisor Equipment	$ 561,144	$ 607,299	**$ 46,156**
29	1990	Other Tangible Property			**$ -**
30		**Subtotal**	**$ 5,291,410**	**$ 5,330,573**	**$ 39,163**
31		**Contribution & Grants**			
32	1995	Contribution & Grants	-$ 6,797,192	-$ 6,790,435	**$ 6,758**
33		**Subtotal**	**-$ 6,797,192**	**-$ 6,790,435**	**$ 6,758**
34		**Grand Total**	**$ 58,524,845**	**$ 61,613,050**	**$ 3,088,205**

The total projected ending gross asset balance for the 2018TY of $61,613,050 is $3,088,205 greater than the 2017 projected ending amount $58,524,845. Net distribution assets are planned to increase by $2,996,543 and general capital expenditures are planned to increase by $91,663 which includes $99,302 of Hardware and Software investment, $78,655 of vehicle purchases, ($120,905) in disposal of Power Operated Equipment and $46,156 in SCADA and automation investment.

INCREMENTAL CAPITAL MODULE

ETPL has not made incremental capital expenditures during the IRM period 2012 to 2016.

ALLOWANCE FOR WORKING CAPITAL

ETPL is proposing a working capital allowance of $5,153,240 utilizing the Board's deemed allowance factor of 7.5% as shown in Table 2-27 below.

TABLE 2-27: SUMMARY OF WORKING CAPITAL ALLOWANCE

Description	2012 BAP	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge	2018 Test
Accounting Standard	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Operations	186300.6904	$ 160,299	$ 100,096	$ 110,018	$ 128,569	$ 91,574	$ 93,131	$ 116,389
Miantenance	685297.7208	$ 595,216	$ 645,161	$ 578,159	$ 320,160	$ 286,802	$ 291,677	$ 296,636
Billing & Collecting	$ 991,287	$ 860,983	$ 1,172,874	$ 1,259,465	$ 1,111,468	$ 981,647	$ 998,335	$ 1,040,307
Community Relations	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Admin & General	$ 3,728,786	$ 3,238,641	$ 3,682,598	$ 3,655,307	$ 4,232,026	$ 4,632,478	$ 4,798,766	$ 5,003,437
Property Taxes	$ 57,416	$ 49,869	$ 49,018	$ 48,531	$ 64,612	$ 54,540		
LEAP	$ 11,506	$ 11,506	$ 11,825	$ 11,825	$ 11,825	$ 11,825	$ 11,825	$ 11,825
Total Controllable	$ 5,660,594	$ 4,916,514	$ 5,661,572	$ 5,663,305	$ 5,868,660	$ 6,058,865	$ 6,193,734	$ 6,468,593
Cost of Power	$ 33,092,706	$ 44,886,698	$ 48,381,613	$ 49,839,585	$ 53,987,814	$ 60,034,318	$ 63,391,860	$ 62,241,271
Total Working Capital	$ 38,753,300	$ 49,803,212	$ 54,043,184	$ 55,502,890	$ 59,856,474	$ 66,093,183	$ 69,585,594	$ 68,709,864
Allowance Factor	13%	13%	13%	13%	13%	13%	13%	7.5%
Working Capital Allowance	**$ 5,037,929**	**$ 6,474,418**	**$ 7,025,614**	**$ 7,215,376**	**$ 7,781,342**	**$ 8,592,114**	**$ 9,046,127**	**$ 5,153,240**

2.4.1 Overview

ALLOWANCE FACTOR

In a letter dated June 3, 2015, the Board provided an update to electricity distributors and other interested parties on the options for the calculation of allowance for working capital. The letter provided the following direction:

> *"Effective immediately, the OEB is adopting a new default value of 7.5% of the sum of the cost of power and operating, maintenance and administration costs. As in the past, distributors who do not wish to use the default value can request approval for a distributor-specific working capital allowance supported by the appropriate evidence from a lead-lag study or equivalent analysis."*

2.4.2 Controllable Costs

The controllable OM&A costs used in the working capital allowance calculation for 2012 through the 2018 Test Year are shown in Table 2-2 below.

In the calculation of the 2018 working capital allowance, ETPL has utilized the expected expenses for Operations, Maintenance, Billing & Collecting, Community Relations, Administration & General expenses, property taxes and annual LEAP donations. For year over year variance analysis and more details of expected expenses, please see Exhibit 4, Sections 4.2 and 4.3. ETPL has included an estimate for 2018 LEAP payments based on an estimated service requirement of $10,785,163 multiplied by 0.12% or $12,942. For more details of the calculation and payments of the LEAP funding, please see Exhibit 4, Section 4.9.

Appendix 2-JA
Summary of Recoverable OM&A Expenses

	Last Rebasing Year (2012 Board-Approved)	Last Rebasing Year (2012 Actuals)	2013 Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Test Year
Reporting Basis								
Operations	$ 187,551	$ 160,299	$ 100,096	$ 110,018	$ 128,569	$ 91,574	$ 93,131	$ 116,389
Maintenance	$ 696,405	$ 595,216	$ 645,161	$ 578,159	$ 320,160	$ 286,802	$ 291,677	$ 296,636
SubTotal	**$ 883,956**	**$ 755,515**	**$ 745,257**	**$ 688,177**	**$ 448,729**	**$ 378,376**	**$ 384,808**	**$ 413,025**
%Change (year over year)					-40.6%	-15.7%	1.7%	7.3%
%Change (Test Year vs Last Rebasing Year - Actual)								-45.3%
Billing and Collecting	$ 987,418	$ 860,983	$ 1,172,874	$ 1,259,465	$ 1,111,468	$ 981,647	$ 998,335	$1,040,307
Community Relations								
Administrative and General	$ 3,789,220	$ 3,238,641	$ 3,682,598	$ 3,655,307	$ 4,232,026	$ 4,632,478	$ 4,798,766	$5,003,437
SubTotal	**$ 4,776,638**	**$ 4,099,624**	**$ 4,855,472**	**$ 4,914,772**	**$ 5,343,494**	**$ 5,614,125**	**$ 5,797,101**	**$ 6,043,744**
%Change (year over year)					30.3%	5.1%	3.3%	4.3%
%Change (Test Year vs Last Rebasing Year - Actual)								47.4%
Total	**$ 5,660,594**	**$ 4,855,139**	**$ 5,600,729**	**$ 5,602,949**	**$ 5,792,223**	**$ 5,992,501**	**$ 6,181,909**	**$ 6,456,768**
%Change (year over year)					19.3%	3.5%	3.2%	4.4%

	Last Rebasing Year (2012 Board-Approved)	Last Rebasing Year (2012 Actuals)	2013 Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Test Year
Operations	$ 187,551	$ 160,299	$ 100,096	$ 110,018	$ 128,569	$ 91,574	$ 93,131	$ 116,389
Maintenance	$ 696,405	$ 595,216	$ 645,161	$ 578,159	$ 320,160	$ 286,802	$ 291,677	$ 296,636
Billing and Collecting	$ 987,418	$ 860,983	$ 1,172,874	$ 1,259,465	$ 1,111,468	$ 981,647	$ 998,335	$ 1,040,307
Community Relations	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Administrative and General	$ 3,789,220	$ 3,238,641	$ 3,682,598	$ 3,655,307	$ 4,232,026	$ 4,632,478	$ 4,798,766	$ 5,003,437
Total	**$ 5,660,594**	**$ 4,855,139**	**$ 5,600,729**	**$ 5,602,949**	**$ 5,792,223**	**$ 5,992,501**	**$ 6,181,909**	**$ 6,456,768**
%Change (year over year)					19.3%	3.5%	3.2%	4.4%

	Last Rebasing Year (2012 Board-Approved)	Last Rebasing Year (2012 Actuals)	Variance 2012 Board-approved – 2012 Actuals	2013 Actuals	Variance 2013 Actuals vs. 2012 Actuals	2014 Actuals	Variance 2014 Actuals vs. 2013 Actuals	2015 Actuals	Variance 2015 Actuals vs. 2014 Actuals	2016 Actuals	Variance 2016 Actuals vs. 2015 Actuals	2017 Bridge Year	Variance 2017 Bridge vs. 2016 Actuals	2018 Test Year	Variance 2018 Test vs. 2017 Bridge
Operations	$ 187,551	$ 160,299	$ 27,251	$ 100,096	-$ 60,203	$ 110,018	$ 9,922	$ 128,569	-$ 31,730	$ 91,574	-$ 36,995	$ 93,131	$ 1,557	$ 116,389	$ 23,258
Maintenance	$ 696,405	$ 595,216	$ 101,189	$ 645,161	$ 49,945	$ 578,159	-$ 67,001	$ 320,160	-$ 275,056	$ 286,802	-$ 33,358	$ 291,677	$ 4,876	$ 296,636	$ 4,959
Billing and Collecting	$ 987,418	$ 860,983	$ 126,435	$ 1,172,874	$ 311,891	$ 1,259,465	$ 86,591	$ 1,111,468	$ 250,485	$ 981,647	-$ 129,820	$ 998,335	$ 16,688	$1,040,307	$ 41,972
Community Relations	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Administrative and General	$ 3,789,220	$ 3,238,641	$ 550,580	$ 3,682,598	$ 443,958	$ 3,655,307	-$ 27,292	$ 4,232,026	$ 993,385	$ 4,632,478	$ 400,452	$4,798,766	$166,288	$5,003,437	$204,671
Total OM&A Expenses	$ 5,660,594	$ 4,855,139	$ 805,455	$ 5,600,729	$ 745,590	$ 5,602,949	$ 2,219	$ 5,792,223	$ 937,084	$ 5,992,501	$ 200,278	$6,181,909	$189,408	$6,456,768	$274,859
Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB)															
Total Recoverable OM&A Expenses	$ 5,660,594	$ 4,855,139	$ 805,455	$ 5,600,729	$ 745,590	$ 5,602,949	$ 2,219	$ 5,792,223	$ 937,084	$ 5,992,501	$ 200,278	$6,181,909	$189,408	$6,456,768	$274,859
Variance from previous year				$ 745,590		$ 2,219		$ 189,274		$ 200,278		$ 189,408		$ 274,859	
Percent change (year over year)				15%		0%		3%		3%		3%		4%	
Percent Change: Test year vs. Most Current Actual										7.75%					
Simple average of % variance for all years										32.99%					4%
Compound Annual Growth Rate for all years															5.9%
Compound Growth Rate (2016 Actuals vs. 2012 Actuals)										7.27%					

Note:

1 If it has been more than three years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than three years ago, a minimum of three years of actual information is required.
2 Recoverable OM&A that is included on these tables should be identical to the recoverable OM&A that is shown for the corresponding periods on Appendix 2-JB.

2.4.3 Cost of Power

OVERVIEW

ETPL has calculated the cost of power for the 2017 Bridge Year and 2018 Test Year based upon the results of the load forecast provided in Exhibit 3. The commodity prices utilized in these calculations were published on October 19th, 2016 in the Board's Regulated Price Plan Report – November 1st, 2016 to October 31st, 2017. Should the Board publish a revised RPP Report prior to reaching a decision in this application ETPL will update the electricity prices in the forecast. However, ETPL does not intend to utilize the commodity prices as provided as part of the Ontario Fair Hydro Plan since these rates and measures are only temporary in nature and the costs calculated here will underpin ETPL's rates for the foreseeable future.

In the following table ETPL breaks down its calculations of commodity pricing and Cost of Power expense by charge type to arrive at total cost of power included in working capital allowance in the application.

Table 2-28: Calculation of Commodity

Calculation of Commodity

Customer Class	2016 Actual kWh's	Non-RPP	%	RPP	%
Residential	142,880,161	10,792,103	8%	132,088,058	92%
GS<50 kW	51,232,321	11,810,043	23%	39,422,278	77%
GS>50 to 999 kW	119,942,492	113,781,810	95%	6,160,682	5%
GS>1,000 to 4,999 kW	53,672,433	53,672,433	100%	-	0%
Large Use	108,673,765	108,673,765	100%	-	0%
Unmetered Load	536,433	54,364	10%	482,069	90%
Sentinel Lighting	187,932	0	0%	187,932	100%
Street Lighting	2,024,729	1,357,181	67%	667,548	33%
Embedded Distributor	16,919,807	16,919,807	100%	-	0%
Total	***496,070,073***	***317,061,506***		***179,008,567***	
%	100%	64%		36%	

HOEP ($/MWh)	$ 24.63		
Global Adjustment ($/MWh)	$ 87.76		
Total $/MWh	$ 112.39	$ 112.39	
$/kWh	$ 0.1124	$ 0.1124	
%	64%	36%	
Weighted Average Price	$ 0.07183	$ 0.04056	$ 0.1124

Utilizing the above pricing ETPL has calculated its commodity costs for the 2017 and 2018 rates applying the applicable load forecasts. ETPL has calculated RPP and Non-RPP bundled in one calculation for ease of display.

Table 2-29: Electricity Projections

Electricity Projections

	2017			2018		
Customer Class	**Volume**	**Rate ($/kWh)**	**Total Cost**	**Volume**	**Rate ($/kWh)**	**Total Cost**
Residential	133,927,949	$ 0.1118	$ 14,973,144.68	132,055,423	$ 0.1124	$ 14,841,709.01
GS<50 kW	48,915,619	$ 0.1118	$ 5,468,766.24	48,061,878	$ 0.1124	$ 5,401,674.48
GS>50 to 999 kW	114,652,868	$ 0.1118	$ 12,818,190.65	110,318,653	$ 0.1124	$ 12,398,713.37
GS>1,000 to 4,999 kW	62,080,889	$ 0.1118	$ 6,940,643.39	52,947,236	$ 0.1124	$ 5,950,739.87
Large Use	98,980,671	$ 0.1118	$ 11,066,039.05	96,934,399	$ 0.1124	$ 10,894,457.15
Unmetered Load	510,974	$ 0.1118	$ 57,126.94	517,597	$ 0.1124	$ 58,172.68
Sentinel Lighting	226,333	$ 0.1118	$ 25,303.99	221,514	$ 0.1124	$ 24,895.95
Street Lighting	1,962,132	$ 0.1118	$ 219,366.41	1,985,669	$ 0.1124	$ 223,169.37
Embedded Distributor	16,296,711	$ 0.1118	$ 1,821,972.34	16,296,711	$ 0.1124	$ 1,831,587.40
Total	477,554,147		$ 53,390,553.68	459,339,081		$ 51,625,119.28

Likewise ETPL calculated its Transmission Network and Connection charges utilizing the currently approved rates as supplied in the RTSR Model submitted as part of this application. The volumes utilized for both 2017 and 2018 are provided in Exhibit 3 as part of ETPL's load forecasting.

Table 2-30: Transmission Network

Transmission Network

	2017			2018		
Customer Class	Volume	Rate ($/kWh)	Total Cost	Volume	Rate ($/kWh)	Total Cost
Residential	133,927,949	$ 0.0063	$ 843,746.08	132,055,423	$ 0.0061	$ 809,919.94
GS<50 kW	48,915,619	$ 0.0059	$ 288,602.15	48,061,878	$ 0.0057	$ 276,056.54
GS>50 to 999 kW	324,430	$ 2.6482	$ 859,154.93	308,209	$ 2.5781	$ 794,586.84
GS>1,000 to 4,999 kW	137,505	$ 2.8748	$ 395,298.20	114,163	$ 2.7987	$ 319,504.99
Large Use	171,751	$ 3.1869	$ 547,354.03	166,236	$ 3.1025	$ 515,748.18
Unmetered Load	510,974	$ 0.0059	$ 3,014.75	517,597	$ 0.0057	$ 2,972.95
Sentinel Lighting	587	$ 2.0441	$ 1,198.98	574	$ 1.9900	$ 1,142.38
Street Lighting	5,384	$ 2.0441	$ 11,006.38	5,449	$ 1.9900	$ 10,843.47
Embedded Distributor	34,856	$ 3.8460	$ 134,057.71	34,856	$ 3.7442	$ 130,507.98
Total	184,029,056		$ 3,083,433.20	181,264,385		$ 2,861,283.28

Transmission Connection

	2017			2018		
Customer Class	Volume	Rate ($/kWh)	Total Cost	Volume	Rate ($/kWh)	Total Cost
Residential	133,927,949	$ 0.0056	$ 749,996.51	132,055,423	$ 0.0054	$ 719,044.90
GS<50 kW	48,915,619	$ 0.0052	$ 254,361.22	48,061,878	$ 0.0051	$ 243,005.34
GS>50 to 999 kW	324,430	$ 1.8703	$ 606,781.01	308,209	$ 1.8185	$ 560,490.55
GS>1,000 to 4,999 kW	137,505	$ 2.0036	$ 275,504.20	114,163	$ 1.9482	$ 222,406.50
Large Use	171,751	$ 2.2727	$ 390,339.05	166,236	$ 2.2098	$ 367,348.12
Unmetered Load	510,974	$ 0.0052	$ 2,657.07	517,597	$ 0.0051	$ 2,617.01
Sentinel Lighting	587	$ 1.4388	$ 843.94	574	$ 2.3122	$ 1,327.36
Street Lighting	5,384	$ 2.3780	$ 12,804.25	5,449	$ 2.3122	$ 12,599.25
Embedded Distributor	34,856	$ 2.6423	$ 92,101.06	34,856	$ 2.5692	$ 89,552.22
Total	184,029,056		$ 2,385,388.30	181,264,385		$ 2,218,391.24

On December 5th, 2016 the OEB released its Decision and Order for Wholesale Market Service Rates (WMS) effective January 1, 2017. In this decision the Board directed LDC's to bill its customer $0.0032 per kWh and for Class B customers an additional $0.0004 per kWh would be added for a total of $0.0036 per kWh. Therefore ETPL has calculated it WMS charges utilizing this pricing breakdown as follows.

Table 2-31: Wholesale Market Service

Wholesale Market Service

	2017			2018		
Customer Class	**Volume**	**Rate ($/kWh)**	**Total Cost**	**Volume**	**Rate ($/kWh)**	**Total Cost**
Residential	133,927,949	$ 0.0036	$ 482,140.62	132,055,423	$ 0.0036	$ 475,399.52
GS<50 kW	48,915,619	$ 0.0036	$ 176,096.23	48,061,878	$ 0.0036	$ 173,022.76
GS>50 to 999 kW	114,652,868	$ 0.0036	$ 412,750.32	110,318,653	$ 0.0036	$ 397,147.15
GS>1,000 to 4,999 kW	62,080,889	$ 0.0036	$ 223,491.20	52,947,236	$ 0.0036	$ 190,610.05
Large Use	98,980,671	$ 0.0036	$ 356,330.42	96,934,399	$ 0.0036	$ 348,963.84
Unmetered Load	510,974	$ 0.0036	$ 1,839.51	517,597	$ 0.0036	$ 1,863.35
Sentinel Lighting	226,333	$ 0.0036	$ 814.80	221,514	$ 0.0036	$ 797.45
Street Lighting	1,962,132	$ 0.0036	$ 7,063.68	1,985,669	$ 0.0036	$ 7,148.41
Embedded Distributor	16,296,711	$ 0.0036	$ 58,668.16	16,296,711	$ 0.0036	$ 58,668.16
Total	477,554,147		$ 1,719,194.93	459,339,081		$ 1,653,620.69

Similarly as part of the same order the OEB determined that LDC’s would charge their customers $0.0021 per kWh for Rural or Remote Electricity Rate Protection charges effective January 1, 2017.

Table 2-32: Rural and Remote Rate Protection

Rural and Remote Rate Protection						
	2017			2018		
Customer Class	Volume	Rate ($/kWh)	Total Cost	Volume	Rate ($/kWh)	Total Cost
Residential	133,927,949	$ 0.0021	$ 281,248.69	132,055,423	$ 0.0021	$ 277,316.39
GS<50 kW	48,915,619	$ 0.0021	$ 102,722.80	48,061,878	$ 0.0021	$ 100,929.94
GS>50 to 999 kW	114,652,868	$ 0.0021	$ 240,771.02	110,318,653	$ 0.0021	$ 231,669.17
GS>1,000 to 4,999 kW	62,080,889	$ 0.0021	$ 130,369.87	52,947,236	$ 0.0021	$ 111,189.20
Large Use	98,980,671	$ 0.0021	$ 207,859.41	96,934,399	$ 0.0021	$ 203,562.24
Unmetered Load	510,974	$ 0.0021	$ 1,073.05	517,597	$ 0.0021	$ 1,086.95
Sentinel Lighting	226,333	$ 0.0021	$ 475.30	221,514	$ 0.0021	$ 465.18
Street Lighting	1,962,132	$ 0.0021	$ 4,120.48	1,985,669	$ 0.0021	$ 4,169.91
Embedded Distributor	16,296,711	$ 0.0021	$ 34,223.09	16,296,711	$ 0.0021	$ 34,223.09
Total	477,554,147		$ 1,002,863.71	459,339,081		$ 964,612.07

The following 3 tables detail the costs related to Smart metering entity, Ontario Electricity Support Program costs and Low Voltage Charges. The Smart Metering costs are calculated utilizing forecasted customer numbers and the approved rate of $0.79 per customer per month while OESP in 2017 uses $0.0011 per kWh applied to forecast for 2017 and $0.00 per customer in 2018. Lastly Low Voltage charges were calculated using the applicable load forecasts and the calculated and proposed LV charges that are detailed in Exhibit 8 of this application.

Table 2-33: Smart Meter Entity Fixed Charge

Smart Meter Entity Fixed Charge

	2017			2018		
Customer Class	**Customer**	**Rate ($/kWh)**	**Total Cost**	**Volume**	**Rate ($/kWh)**	**Total Cost**
Residential	16,987	$ 0.7900	$ 161,033.43	17,119	$ 0.7900	$ 162,290.40
GS<50 kW	2,006	$ 0.7900	$ 1,584.55	2,018	$ 0.7900	$ 1,594.43
Total	18,992		$ 162,617.98	19,138		$ 163,884.83

Ontario Electricity Support

	2017			2018		
Customer Class	**Volume**	**Rate ($/kWh)**	**Total Cost**	**Volume**	**Rate ($/kWh)**	**Total Cost**
Residential	133,927,949	$ 0.0011	$ 61,383.64	132,055,423	$ -	$ -
GS<50 kW	48,915,619	$ 0.0011	$ 22,419.66	48,061,878	$ -	$ -
GS>50 to 999 kW	114,652,868	$ 0.0011	$ 52,549.23	110,318,653	$ -	$ -
GS>1,000 to 4,999 kW	62,080,889	$ 0.0011	$ 28,453.74	52,947,236	$ -	$ -
Large Use	98,980,671	$ 0.0011	$ 45,366.14	96,934,399	$ -	$ -
Unmetered Load	510,974	$ 0.0011	$ 234.20	517,597	$ -	$ -
Sentinel Lighting	226,333	$ 0.0011	$ 103.74	221,514	$ -	$ -
Street Lighting	1,962,132	$ 0.0011	$ 899.31	1,985,669	$ -	$ -
Embedded Distributor	16,296,711	$ 0.0011	$ 7,469.33	16,296,711	$ -	$ -
Total	477,554,147		$ 218,878.98	459,339,081		$ -

Low Voltage Charges

	2017			2018		
Customer Class	**Volume**	**Rate ($/kWh)**	**Total Cost**	**Volume**	**Rate ($/kWh)**	**Total Cost**
Residential	133,927,949	$ 0.0021	$ 276,556.34	132,055,423	$ 0.0029	$ 384,203.10
GS<50 kW	48,915,619	$ 0.0020	$ 95,397.37	48,061,878	$ 0.0026	$ 127,085.80
GS>50 to 999 kW	324,430	$ 0.7099	$ 230,309.00	308,209	$ 1.1886	$ 366,330.57
GS>1,000 to 4,999 kW	137,505	$ 0.7635	$ 104,979.66	114,163	$ 1.5192	$ 173,438.97
Large Use	171,751	$ 0.0733	$ 12,590.43	166,236	$ 1.4469	$ 240,530.45
Unmetered Load	510,974	$ 0.0020	$ 996.52	517,597	$ 0.0026	$ 1,367.35
Sentinel Lighting	587	$ 0.5482	$ 321.58	574	$ 0.6985	$ 400.98
Street Lighting	5,384	$ 0.5482	$ 2,952.02	5,449	$ 0.8725	$ 4,754.47
Embedded Distributor	34,856	$ -	$ -	34,856	$ 1.6581	$ 57,796.43
Total	184,029,056		$ 724,102.92	181,264,385		$ 1,355,908.12

Table 2-34 summarizes the above and breaks down into its individual elements the Cost of Power requested in the application and embedded in the working capital allowance that makes up part of ETPL's requested Rate Base.

Table 2-34: Cost of Power 2017 Bridge Year vs 2018 Test year

	2017 Bridge Year	2018 Test Year
Electricity Projections	$ 53,390,553.68	$ 51,625,119.28
Transmission Network	$ 3,083,433.20	$ 2,861,283.28
Transmission Connection	$ 2,385,388.30	$ 2,218,391.24
Wholesale Market Service	$ 1,719,194.93	$ 1,653,620.69
Rural and Remote Rate Protection	$ 1,002,863.71	$ 964,612.07
Smart Meter Entity Fixed Charge	$ 162,617.98	$ 163,884.83
Ontario Electricity Support	$ 218,878.98	$ -
Low Voltage Charges	$ 724,102.92	$ 1,355,908.12
Total	**$62,687,033.71**	**$60,842,819.50**

2.4.4 Variance Analysis on Working Capital Allowance

The following variance analysis has been provided based on ETPL's materiality threshold; per the materiality calculation being noted in Exhibit 1, Section 1.8 of this Application. ETPL has chosen to use $54,000 as its basis for variance analysis of Working Capital Allowance. Table 2-35 below presents the year over year variances discussed below.

Table 2-35: Working Capital Variance

Description	2012 BAP	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge	2018 Test
Accounting Standard	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Total Controllaable Expenses	$ 5,660,594	$ 4,916,514	$ 5,661,572	$ 5,663,305	$ 5,868,660	$ 6,058,865	$ 6,193,734	$ 6,468,593
Total Cost of Power	$ 33,092,706	$ 44,886,698	$ 48,381,613	$ 49,839,585	$ 53,987,814	$ 60,034,318	$ 63,391,860	$ 62,241,271
Total Working Capital	**$ 38,753,300**	**$ 49,803,212**	**$ 54,043,184**	**$ 55,502,890**	**$ 59,856,474**	**$ 66,093,183**	**$ 69,585,594**	**$68,709,864**
Allowance Factor	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%	7.50%
Working Capital Allowance	**$ 5,037,929**	**$ 6,474,418**	**$ 7,025,614**	**$ 7,215,376**	**$ 7,781,342**	**$ 8,592,114**	**$ 9,046,127**	**$ 5,153,240**
		2012 BAP vs. 2012 Actual	**2012 Actual vs. 2013 Actual**	**2013 Actual vs 2014 Actual**	**2014 Actual vs 2015 Actual**	**2015 Actual vs 2016 Actual**	**2016 Actual vs 2017 Bridge**	**2017 Bridge vs. 2018 Test**
Total Controllaable Expenses		-$ 744,079	$ 745,057	$ 1,733	$ 205,355	$ 190,205	$ 134,869	$ 274,859
Total Cost of Power		$ 11,793,992	$ 3,494,915	$ 1,457,972	$ 4,148,229	$ 6,046,504	$ 3,357,542	-$ 1,150,589
Total Working Capital		**$ 11,049,912**	**$ 4,239,972**	**$ 1,459,705**	**$ 4,353,585**	**$ 6,236,709**	**$ 3,492,411**	**-$ 875,730**
Allowance Factor		0%	0%	0%	0%	0%	0%	-5.5%
Working Capital Allowance		**$ 1,436,489**	**$ 551,196**	**$ 189,762**	**$ 565,966**	**$ 810,772**	**$ 454,013**	**-$ 3,892,887**

2012 BOARD APPROVED VERSUS 2012 ACTUAL, VARIANCE $1,436,489

In 2012 ETPL completed significantly more capital projects than in historical years. The result of this increased spend was an increase in capitalized labour which in turn caused a fairly large decrease in OM&A costs. The reduction in operating costs in 2012 was more than offset by an $11,000,000 increase in commodity costs for 2012 actual vs. the amount approved in ETPL's 2012 Cost of service application.

Table 2-36: Working Capital Variance 2012 BA vs 2012 Actual

Description	2012 BAP	2012 Actual	variance	WCA Variance
Accounting Standard	CGAAP	CGAAP		
Total Controllaable Expenses	$ 5,660,594	$ 4,916,514	-$ 744,079	-$ 96,730
Total Cost of Power	$ 33,092,706	$ 44,886,698	$ 11,793,992	$ 1,533,219
Total Working Capital	**$ 38,753,300**	**$ 49,803,212**	**$11,049,912**	**$ 1,436,489**
Allowance Factor	13.00%	13.00%	0%	
Working Capital Allowance	**$ 5,037,929**	**$ 6,474,418**	**$ 1,436,489**	

2012 ACTUAL VERSUS 2013 ACTUAL, VARIANCE $551,196

In 2013 capitalized labour returned to its normal levels with less capital spending being undertaken. This resulted in WCA for operating costs to be almost exactly the same amount as was approved in the 2012 application. The remaining increase was due to an increase in commodity costs which were a further $3,500,000 more than 2012 actual and $15,288,907 or 46% greater than the 2012 Board approved amount.

Table 2-37: Working Capital Variance 2012 Actual vs 2013 Actual

Description	2012 Actual	2013 Actual	variance	WCA Variance
Accounting Standard	CGAAP	CGAAP		
Total Controllaable Expenses	$ 4,916,514	$ 5,661,572	$ 745,057	$ 96,857
Total Cost of Power	$ 44,886,698	$ 48,381,613	$ 3,494,915	$ 454,339
Total Working Capital	**$ 49,803,212**	**$ 54,043,184**	**$ 4,239,972**	**$ 551,196**
Allowance Factor	13.00%	13.00%	13%	
Working Capital Allowance	**$ 6,474,418**	**$ 7,025,614**	**$ 551,196**	

2013 ACTUAL VERSUS 2014 ACTUAL, VARIANCE $189,763

2014 controllable costs wer relatively unchanged from the 2013 OM&A spending levels. Commodity costs continued to rise and the further $1,460,000 in spend resulted in the variance of $189,536.

Table 2-37: Working Capital Variance 2013 Actual vs 2014 Actual

Description	2013 Actual	2014 Actual	variance	WCA Variance
Accounting Standard	CGAAP	CGAAP		
Total Controllaable Expenses	$ 5,661,572	$ 5,663,305	$ 1,733	$ 225
Total Cost of Power	$ 48,381,613	$ 49,839,585	$1,457,972	$ 189,536
Total Working Capital	**$ 54,043,184**	**$ 55,502,890**	$1,459,705	**$ 189,762**
Allowance Factor	13.00%	13.00%	0%	
Working Capital Allowance	**$ 7,025,614**	**$ 7,215,376**	**$ 189,762**	

2014 ACTUAL VERSUS 2015 ACTUAL - CGAAP, VARIANCE $565,966

In 2015 ETPL increased its controllable expenses by $205,355 which resulted in a $26,696 in WCA while the remaining $539,270 increase can be directly attributed to the $4,148,229 increase in cost of power. While the increase in OM&A in 2015 amounts to a 4% increase it should be pointed out that in total ETPL's controllable expenses have only increased by $208,000 since it last decision or 1.2% per year since the decision, well below inflation. For details on the OM&A spending see Exhibit 4.

Table 2-38: Working Capital Variance 2014 Actual vs 2015 Actual

Description	2014 Actual	2015 Actual	variance	WCA Variance
Accounting Standard	CGAAP	MIFRS		
Total Controllaable Expenses	$ 5,663,305	$ 5,868,660	$ 205,355	$ 26,696
Total Cost of Power	$ 49,839,585	$ 53,987,814	$ 4,148,229	$ 539,270
Total Working Capital	**$ 55,502,890**	**$ 59,856,474**	**$ 4,353,585**	**$ 565,966**
Allowance Factor	13.00%	13.00%	0%	
Working Capital Allowance	**$ 7,215,376**	**$ 7,781,342**	**$ 565,966**	

2015 ACTUAL VERSUS 2016 ACTUAL, VARIANCE $810,772

2016 commodity costs rose once again by $6,050,000 resulting in an increase in WCA of $786,045 with the remaining increase of $24,727 resulting from increases to controllable expenses.

Table 2-39: Working Capital Variance 2015 Actual vs 2016 Actual

Description	2015 Actual	2016 Actual	variance	WCA Variance
Accounting Standard	MIFRS	MIFRS		
Total Controllaable Expenses	$ 5,868,660	$ 6,058,865	$ 190,205	$ 24,727
Total Cost of Power	$ 53,987,814	$ 60,034,318	$ 6,046,504	$ 786,045
Total Working Capital	**$ 59,856,474**	**$ 66,093,183**	**$ 6,236,709**	**$ 810,772**
Allowance Factor	13.00%	13.00%	0%	
Working Capital Allowance	**$ 7,781,342**	**$ 8,592,114**	**$ 810,772**	

2016 ACTUAL - VERSUS 2017 Bridge Year, VARIANCE $454,013

2017 OM&A activities are essentially as forecasted with resulting costs forecasted to be approximately $135,000 higher than 2016 actual due to normal inflation of approximately 2% year over year. The OM&A increase causes a $17,533 increase in WCA for 2017 Bridge as compared to 2016 Actuals while the increase of $436,480 in WCA is due to the increase in commodity costs of $3,400,000.

Table 2-40: Working Capital Variance 2016 Actual vs 2017 Actual

Description	2016 Actual	2017 Bridge	variance	WCA Variance
Accounting Standard	MIFRS	MIFRS		
Total Controllaable Expenses	$ 6,058,865	$ 6,193,734	$ 134,869	$ 17,533
Total Cost of Power	$ 60,034,318	$ 63,391,860	$ 3,357,542	$ 436,480
Total Working Capital	**$ 66,093,183**	**$ 69,585,594**	**$ 3,492,411**	**$ 454,013**
Allowance Factor	13.00%	13.00%	0%	
Working Capital Allowance	**$ 8,592,114**	**$ 9,046,127**	**$ 454,013**	

2017 Bridge Year versus 2018 Test Year, Variance ($3,892,887)

The reduction in WCA between the 2018 Test Year and 2017 Bridge Year can be attributed to different factors. First, the change from an allowance factor of 13% to 7.5% drives a decrease of $3,779,043 in WCA. The remaining reduction in WCA can be attributed to the decrease in Cost of Power projected for the 2018 Test Year attributable to the 18,200,000 kWh reduction in ETPL's forecast due to CDM activities. This is a reduction of $149,500 when the change in allowance factor is ignored. The last piece of the variance is $35,700 increase in WCA on $275,000 of controllable expenses when the change in allowance factor is ignored.

Table 2-41: Working Capital Variance 2017 Bridge Year vs 2018 Test Year

Description	2016 Actual	2017 Bridge	2018 Test	variance	WCA Variance
Accounting Standard	MIFRS	MIFRS	MIFRS		
Total Controllaable Expenses	$ 6,058,865	$ 6,193,734	$ 6,468,593	$ 274,859	$ 35,732
Total Cost of Power	$ 60,034,318	$ 63,391,860	$ 62,241,271	-$ 1,150,589	-$ 149,577
Total Working Capital	**$ 66,093,183**	**$ 69,585,594**	**$ 68,709,864**	**-$ 875,730**	**-$ 113,845**
Allowance Factor	13.00%	13.00%	7.50%	-5.5%	***-$ 3,779,043***
Working Capital Allowance	**$ 8,592,114**	**$ 9,046,127**	**$ 5,153,240**	**-$ 3,892,887**	

CAPITAL EXPENDITURES

2.5.1 Planning Overview

Please note that when the term "Capital Expenditures" is used, ETPL has presented all information on the basis of Capital Additions and has not included Work in Process in its numbers, unless otherwise indicated.

In accordance with the Filing Requirements, ETPL is filing its consolidated Distribution System Plan ("DSP") as a stand-alone document in Attachment 2-C to this Exhibit. ETPL has organized the information contained in the DSP using the headings indicated in Chapter 5 of the Board's "*Filing Requirements for Electricity Distribution and Transmission Applications, Consolidated Distribution System Plan Filing Requirements"* dated March 28, 2013. 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 EPI's capital expenditure plan. ETPL has provided historical spending by material capital project in the categories mentioned for the 2010 Actual, 2011 Actual, 2012 Actual, 2013 Actual, 2014 Actual, 2015 Bridge and 2016 Test years. ETPL has assigned all historical and future projects to the new categories as required by the Board. ETPL has leveled the plan to address pacing and affordability.

ETPL participates in two regional planning groups; Group 1 - London Area Region (Aylmer, Beachville, Belmont, Burgessville, Embro, Ingersoll, Norwich, Otterville, Port Stanley, Thamesford), and Group 2 – Greater Bruce / Huron Region (Clinton, Dublin, Mitchell, Tavistock). ETPL also routinely participates in coordinated infrastructure investment planning with third parties, namely HONI, Union Gas, Rogers and Bell Aliant. For more information related to ETPL's planning process, please see Section 5.1.4 and Section 5.2.2 of the DSP contained in Attachment 2-C.

2.5.2 Analysis of Capital Expenditures

Table 2-42 below provides a summary of historical capital expenditures for the past five historical years, 2012 through 2016. Table 2-43 provides projections for the 2017 Bridge Year and 2018 Test Year, as well as projections for the period 2019 through 2022. These tables are consistent with Board Appendix 2-AB which is also included as Attachment 2-E to this Exhibit. ETPL has made its best efforts to categorize historical projects into the DSP categories. The annual capital expenditures include all new spending in the fiscal period that is in service. Costs for projects that are considered Work in Process ("WIP") at the end of a fiscal year are not captured in the year spent; they are captured in the year capitalized.

TABLE 2-42: HISTORICAL CAPITAL EXPENDITURE SUMMARY, APPENDIX 2-AB

CATEGORY	Historical Period (previous plan[1] & actual)														
	2013			2014			2015			2016			2017		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access	560,000	758,310	35.4%	405,000	1,420,455	250.7%	680,220	1,316,968	93.6%	806,021	1,060,304	31.5%	793,628	$ 1,092,827	37.7%
System Renewal	1,986,000	789,397	-60.3%	2,198,000	2,298,252	4.6%	1,995,440	1,830,486	-8.3%	1,978,591	1,515,632	-23.4%	1,673,992	1,327,158	-20.7%
System Service	275,775	42,215	-84.7%	225,000	3,856	-98.3%	530,000	64,232	-87.9%	253,430	188,030	-25.8%	448,318	17,991	-96.0%
General Plant	470,000	572,239	21.8%	425,000	332,164	-21.8%	468,250	763,110	63.0%	558,900	486,054	-13.0%	633,975	166,690	-73.7%
TOTAL EXPENDITURE	3,291,775	2,162,161	-34.3%	3,253,000	4,054,727	24.6%	3,673,910	3,974,796	8.2%	3,596,942	3,250,020	-9.6%	3,549,913	2,604,666	-26.6%

TABLE 2-43: FORECASTED EXPENDITURE SUMMARY, APPENDIX 2-AB

CATEGORY	Forecast Period (planned)				
	2018	2019	2020	2021	2022
	$ '000				
System Access	879,500	920,100	812,700	816,300	759,900
System Renewal	2,142,450	2,002,230	1,907,040	2,168,882	1,939,454
System Service	73,000	74,875	76,750	55,900	55,000
General Plant	148,000	234,875	451,750	223,400	526,450
TOTAL EXPENDITURE	3,242,950	3,232,080	3,248,240	3,264,482	3,280,804
System O&M	$ 116,389	$ 117,553	$ 118,728	$ 119,915	$ 121,115

2.5.2.1 CAPITAL EXPENDITURE VARIANCE ANALYSIS – 2012-2016

The following tables summarize ETPL's capital additions by major project by year. A written explanation of variances, including that of actuals versus Board-approved amounts for ETPL's last Board-approved cost of service is included below.

2012 Budget vs. Actual

Table 2-44: 2012 Budget vs. Actuals

	HISTORICAL		
	2012		
CATEGORY	**BUDGET**	**ACTUAL**	**VARIANCE FROM BUDGET**
System Access	$345,000	$929,841	$584,841 (170%)
System Renewal	$2,300,000	$2,222,700	-$77,300 (-3%)
System Service	$200,000	$213,964	$13,964 (7%)
General Plant	$480,000	$249,537	-$230,463 (-48%)
TOTAL	**$3,325,000**	**$3,616,044**	**9%**

System Access spending was considerably higher than budget and is a result of increased expenditures on C&I services, Residential Services and meters as the number of services connected were higher than expected. ***System Renewal*** and ***System Service*** were slightly below budget and the variance was not material. General Plant was under budget by -48% as a result of not purchasing a large vehicle which was moved to the 2013 budget. Even with this deferral of the vehicle, the total 2012 spend was approximately 9% over budget.

2013 Budget vs. Actual

Table 2-45: 2013 Budget vs. Actuals

	HISTORICAL		
	2013		
CATEGORY	**BUDGET**	**ACTUAL**	**VARIANCE FROM BUDGET**
System Access	$560,000	$758,310	$198,310 (35%)
System Renewal	$1,986,000	$789,397	-$1,196,603 (-60%)
System Service	$275,775	$42,215	-$233,560 (-85%)
General Plant	$470,000	$572,237	$102,237 (22%)
TOTAL	**$3,291,775**	**$2,162,161**	**-34%**

System Access spending was higher than the budgeted amount; this is primarily the result of a large facility relocation request costing approximately $312,000. ***System Renewal*** spending was considerably lower than expected which offset the overspending in System Access and ***General Plant*** which was over budget. ***System Service*** spending was lower than budgeted as a result of less spending than expected in system automation initiatives. The total 2013 spend was 34% below budget as a result of less spending than expected in system automation initiatives.

2014 Budget vs. Actual

Table 2-46: 2014 Budget vs. Actuals

	HISTORICAL		
	2014		
CATEGORY	**BUDGET**	**ACTUAL**	**VARIANCE FROM BUDGET**
System Access	$405,000	$1,420,455	-$1,015,455 (251%)
System Renewal	$2,198,000	$2,298,252	-$100,252 (5%)
System Service	$225,000	$3,856	$221,144 (-98%)
General Plant	$425,000	$332,164	$92,836 (-22%)
TOTAL	**$3,253,000**	**$4,054,727**	**25%**

In 2014, ***System Access*** spending was considerably higher than budget and is a result of increased expenditures on C&I services, Residential Services and meters; all of which indicate that the number of services connected were higher than expected. In addition, ETPL spent approximately $235,000 more than budgeted on municipal facility relocations. ***System Renewal*** spending was within 5% of budget with minimal adjustments made to account for overages in System Access spending; this was more likely due to reduced spending in 2013. ***System Service*** was again less than budgeted as a result of minimal spending in system automation initiatives. ***General Plant*** spending was less than budget as a result of a large vehicle not being purchased. This resulted in the total 2014 spend to be within 25% of budget.

2015 Budget vs. Actual

Table 2-47: 2015 Budget vs. Actuals

	HISTORICAL		
	2015		
CATEGORY	BUDGET	ACTUAL	VARIANCE FROM BUDGET
System Access	$680,220	$1,316,968	$636,748 (94%)
System Renewal	$1,995,440	$1,830,486	-$164,954 (-8%)
System Service	$530,000	$64,232	-$465,768 (-88%)
General Plant	$468,250	$763,110	$294,860 (63%)
TOTAL	**$3,673,910**	**$3,974,796**	**8%**

System Access exceeded the budgeted amount due to two factors; a large municipality facility relocation that was greater than originally expected and new services (both Residential and C&I) which were greater than expected. ***System Renewal*** spending within an acceptable was reduced slightly to help balance System Access spending. ***System Service*** spending was considerably lower than budgeted as a result of minimal spending on system automation initiatives and changes to the payment schedule with Hydro One regarding the new breaker position at the Aylmer TS. ***General Plant*** spending was higher than budget due to an increase in the purchase price of a large vehicle along with some leasehold improvements aimed at creating efficiencies within our metering department.

2016 Budget vs. Actual

Table 1: 2016 Budget vs. Actuals

	Historical		
	2016		
CATEGORY	**Budget**	**Actual**	**Variance from Budget**
System Access	$806,021	$982,907	$176,886 (22%)
System Renewal	$1,978,591	$1,404,998	-$573,593 (-29%)
System Service	$253,430	$188,030	- $65,400 (26%)
General Plant	$558,900	$674,084	$115,184 (21%)
TOTAL	**$3,596,942**	**$3,250,020**	**-10%**

System Access spending was again over budget however much closer than previous years as a result of a more realistic budget. Still, both Residential and C&I services exceeded expectations and accounted for the majority of the variance. ***System Renewal*** spending was less than planned as a result of a mid-year reduction in the targeted CAPEX spending level. This coincided with a few developer/municipally driven projects that did not move forward, along with a pole line rebuild that is affected by Hydro One plans in the area and allowed ETPL to obtain a desired spending level of approximately $3.2mil. ***System Service*** spending was slightly below budget as a result of decreased spending on System Automation. ***General Plant*** spending was higher than budget due to small increases in each of fleet, tools, and leasehold improvement expenditures.

2017 Budget vs. Actual

Table 2: 2017 Budget vs. Actuals

	Historical (Bridge Year)		
	2017		
CATEGORY	**Budget**	**Actual**	**Variance from Budget**
System Access	$793,628	In progress	T.B.D
System Renewal	$1,673,992	In progress	T.B.D
System Service	$448,318	In progress	T.B.D
General Plant	$633,975	In progress	T.B.D
TOTAL	**$3,199,913**	**In progress**	**T.B.D**

Further details on capital additions on the 2012 to 2016 period are provided in Section 3.5.2 of the Distribution System Plan which is in Attachment 2C to this exhibit.

2.5.3 Variance Analysis by Spending Category

The following variance analysis has been prepared based on ETPL's materiality threshold; per the materiality calculation being noted in Exhibit 1, Section 1.9 of this Application. ETPL has chosen to use $50,000 as its basis for the variance analysis of Gross Asset Additions.

Table 2-52: Forecast Capital Expenditures

	Forecast Capital Expenditures						Average (2018-2022)
	2017	2018 (Test)	2019	2020	2021	2022	
CATEGORY	Plan	Plan	Plan	Plan	Plan	Plan	
System Access	$733,628	$819,500	$860,100	$752,700	$756,300	$759,900	$789,700
System Renewal	$1,733,992	$2,202,450	$2,062,230	$1,967,040	$2,228,882	$1,939,454	$2,080,011
System Service	$433,343	$90,000	$90,000	$55,000	$55,000	$55,000	$69,000
General Plant	$648,950	$131,000	$219,750	$473,500	$224,300	$526,450	$315,000
TOTAL	$3,549,913	$3,242,950	$3,232,080	$3,248,240	$3,264,482	$3,280,804	$3,253,711

2.5.4 CAPITALIZATION POLICY

ETPL's capitalization policies and principles are based on Canadian Generally Accepted Accounting Principles ("CGAAP"), and guidelines set out by the Ontario Energy Board, where applicable. Effective January 1st, 2013 ETPL developed a new capitalization policy that is consistent with IFRS as property, plant and equipment ("PP&E") expenditures include only directly attributable costs.

The cost of self-constructed assets are recorded and recognized at cost, and include direct labour and benefits, materials, fleet and contractor costs, which are incurred during the development, implementation, or construction phase of the asset.

Assets with a cost in excess of $1,000 expected to provide future economic benefit greater than one year are capitalized. Expenditures that create a physical betterment or improvement of an asset will also be capitalized. With respect to transportation equipment, all costs associated with placing a vehicle into service are capitalized. Computer software that is acquired or developed by ETPL will be capitalized and classified as an intangible asset.

Certain capital assets may be funded or paid by a customer or third party developer through capital contributions. Under IFRS, the capital contributions that are recognized as deferred revenue have been reclassified as a reduction to rate base under MIFRS. ETPL does not anticipate borrowing to fund capital expenditures and as such ETPL has not capitalized any interest in the 2018 test year. Historically, ETPL has not capitalized interest including the 2018 COS application. Under IFRS, an entity must present and record separately from PP&E those assets that are within the scope of International Accounting Standard 38 Intangible Assets ("IAS 38"). The Board Report (EB-2008-0408) states the following:

> *"IFRS requires certain assets to be recorded as intangible assets (e.g. computer software and land rights) that were previously included in PP&E. Utilities shall include such intangible assets in rate base and the amortization expense in depreciation expense for determining the revenue requirement. This reclassification is also necessary to preserve continuity of the rate base."*

Based on the above, for MIFRS, ETPL has included intangible assets as PP&E for rate setting purposes. The major differences between IFRS and CGAAP with respect to the accounting for PP&E and intangible assets are outlined below.

2.5.5 Guideline for Capitalization of Assets

Capital Assets

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. 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.

Repair

A repair is a cost incurred to maintain the service potential of a capital asset. Expenditures for repairs are expensed to the current operating period. Expenditures for repairs and/or maintenance designed to maintain an asset in its original state are charged to an operating account.

Cost

Cost is the amount of consideration to acquire, construct, develop or better a capital asset. The cost of an item of property, plant and equipment includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes the cost of materials and direct labour and any other costs directly attributable to bringing the asset to a working condition for its intended use.

2.5.6 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:

- Are significant in relation to the total cost of the item;
- 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.

Capital Spares

ETPL recognizes spare inventory as property, plant and equipment. Spare inventory is dedicated specifically as backup for the distribution system. It is expected that these items are not intended for resale, have a longer period of future benefit compare to inventory items intended for resale, are an integral component of the distribution system and are expected to be placed in service.

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. 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.

Depreciation of an asset ceases at the earlier of the date that the asset is classified as held for sale and the date that the asset is derecognized. Depreciation does not cease when the asset becomes idle or is retired from active use unless the asset is fully depreciated. Depreciation is calculated using the ½ year rule. Under this rule, capital asset additions are assumed to be put into service equally throughout the year, therefore, on average depreciation starts at the midpoint of the acquisition year. Due to the change in estimate of the remaining useful life of many of the assets beginning on January 1, 2013 are amortized over the remaining years of useful life of each component.

Opening Balances

The International Accounting Standards Board ("IASB") amended "IFRS 1 – First-time adoption of IFRS" in May, 2010 to allow rate-regulated entities to use the previous accounting net book value as the IFRS cost on the date of transition to IFRS. This is referred to as the deemed cost exemption.

ETPL elected to use the deemed cost election under IFRS 1 for opening balance sheet values for its capital assets upon transition to IFRS in 2015. Based on paragraph D8B of IFRS 1, entities with operations subject to rate regulations may hold items of PP&E or intangible assets where the carrying amount of such items might include amounts that were determined under previous GAAP but do not qualify for capitalization in accordance with IFRS.

In this case, a first-time adopter may elect to use the previous GAAP carrying amount of such an item at the date of transition to IFRS as deemed cost. For the purposes of paragraph D8B, operations are subject to rate regulation if they provide goods or services to customers at prices (i.e., rates) established by an authorized body empowered to establish rates that bind the customers, and that are designed to recover the specific costs the entity incurs in providing the regulated goods or services, and to earn a specified return. Based on the definition above, ETPL qualifies for this exemption.

Under this exemption the deemed cost at the date of transition becomes the new IFRS cost basis. Therefore, on January 1, 2015, the opening accumulated depreciation is $nil under IFRS and the opening cost equates to the closing CGAAP net book value ("NBV"). Capital contribution adjustment represents the adjustment to net book value of distribution system assets. Accumulated customer contribution balance has been set to zero as at January 1, 2015 for IFRS, as the cumulative balance has been offset against the costs of related capital assets for which the contribution was received. Starting in 2015, customer contributions will be recorded as deferred revenue for IFRS.

Change of Capitalization Policy

IFRS prescribes which costs can be included as part of the cost of an asset and indicates that only costs that are directly attributable to a specific asset can be capitalized. Indirect overhead costs, such as general and administration costs that are not directly attributable to an asset, that were being capitalized under CGAAP, are not allowed under IFRS. Based on the Board Report EB 2008-0408, the Board required utilities to adhere to IFRS capitalization accounting requirements for rate-making and regulatory reporting purposes. After the adoption of IFRS, the utility is required to file a copy of its capitalization policy, as part of its first cost of service rate filing after adopting IFRS.

In light of all the above, ETPL, in conjunction with its IFRS advisor and auditor, performed a thorough analysis of all costs that were being capitalized under CGAAP in order to determine if they were eligible for capitalization under IFRS. These costs included materials, labour, benefits, truck, subcontractor, overhead, customer contributions and borrowing costs. The analysis conducted by ETPL has been summarized in the following sections of this evidence.

Material Cost

These costs include stocked items taken from warehouse and issued out to each project as well as direct materials which are purchased and delivered to the job site directly. These costs represent the purchase price and initial delivery/handling costs of the materials. Under both CGAAP and IFRS, these costs are capitalized since they are directly attributable costs of bringing the asset to the location and to a condition necessary for it to operate in the manner intended by management, hence there will be no impact on the amount of material costs being capitalized for IFRS.

Material Burden

ETPL has not allocated material burden since 2013 when ETPL changed its Capitalization Policy.

Labour Costs

The labour costs that are capitalized to PP&E comprise of engineering, design, linemen, construction, and supervision time with working timesheets which record the nature of the actions and activities being undertaken and time spent on each task by each type of employee. Under both CGAAP and IFRS, these costs are capitalized since they are directly attributable costs of bringing the asset to the location and to a condition necessary for it to operate in the manner intended by management. Therefore, there will be no impact on the amount of labour costs being capitalized under IFRS relating to this cost category.

Benefit Costs

Employee benefit costs represent the costs associated with employee pensions, vacations, etc. For each hour of regular time recorded, via a timesheet, directly attributable to a capital project, ETPL adds a benefit rate per hour that allocates the estimated annual costs per employee type. Under both CGAAP and IFRS, these costs are capitalized since they are directly attributable costs of bringing the asset to the location and to a condition necessary for it to operate in the manner intended by management. ETPL has determined there will be no impact on the amount of employee benefit costs being capitalized under IFRS.

Labour Burden

Under CGAAP, a fixed percentage of overhead and administration costs, referred to as "labour burden", may be allocated to direct labour costs, and forms part of the cost of an asset. These costs include the labour costs, related benefits and other general administrative costs of the senior operations management and directors that cannot be attributed to a specific project. Therefore, these costs are determined to be general overhead and have been recognized as an expense.

Transportation and Fleet Costs

These costs include the costs associated with maintaining automobiles, trucks and equipment, trailers and other fleet equipment. Some of these costs include fuel costs, repairs, and parts, insurance and all other items of expense necessary to keep the rolling stock in service. These costs can also include the labour costs and the associated benefits of the staff directly involved in rolling stock maintenance.

A fleet rate is determined on an annual basis for each vehicle group by dividing the annual costs accumulated for each vehicle type by their annual usage. When a vehicle is used for a capital project, a fleet rate is charged based on the type of vehicle used multiplied by hourly usage of the vehicle. Under both CGAAP and IFRS, these costs are capitalized since they are directly attributable costs of bringing the asset to the location and to a condition necessary for it to operate in the manner intended by management. ETPL has determined there will be no impact on the amount of transportation costs being capitalized under IFRS.

Fleet Burden

ETPL has not allocated material burden since late 2013 when it implemented the new Capitalization Policy.

Third Party Costs

Sub-contractor costs are incurred when ETPL engages a third party to perform services. Under both CGAAP and IFRS, these costs are capitalized since they are directly attributable costs of bringing the asset to the location and to a condition necessary for it to operate in the manner intended by management. STEI has determined there will be no impact on the amount of third party costs being capitalized under IFRS.

Capitalization of Borrowing Costs

IAS 23 Borrowing Costs establishes the criteria for the recognition of interest on borrowings as a component of the carrying amount of an acquired or self-constructed item of capital assets. Borrowing costs that are directly attributable to the acquisition, construction, or production of a qualifying asset form part of the cost of that asset.

ETPL does not anticipate borrowing to fund capital expenditures and as such has not capitalized any interest in the 2017 test year. Historically, STEI has not capitalized any interest including the 2018 COS application.

Customer Contributions

Under CGAAP, ETPL recorded customer contributions as an offset to the cost of capital asset and amortized as part of the net capital asset. Under IFRS, ETPL cannot capitalize these customer contributions as part of its net capital assets, but instead will defer the contributions as a liability and amortize them as revenue. As outlined in Board Report (EB 2008-0408):

> *"For regulatory reporting and rate making purposes the amount of customer contributions will be treated as deferred revenue to be included as an offset to rate base and amortized to income over the life of the facility to which it relates".*

Consistent with the Board's guidance, ETPL will record customer contributions received after January 1, 2015 as deferred revenue and amortizing them as revenue over the life of the related asset. Customer contributions received prior to this date will be netted against the cost of the related asset as a result of deemed cost election chosen for IFRS 1. For the purpose of this Application, capital contributions are included as an offset to rate base and the related amortized revenue as an offset to depreciation expense.

2.5.7 Capitalization of Overhead

ETPL determined the following burdens are directly attributable to PP&E and should therefore be capitalized.

Board Appendix 2-DA Overhead Expense is provided below.

BENEFIT BURDEN

The benefit burden rate consists of direct benefits. The burden rate of 90% recovers the employment benefits that employees are entitled to receive such as CPP, EI, medical and dental benefits, OMERS, EHT and WSIB. This burden is applied to hourly labour cost by specific job via payroll input to activity specific job costs.

VEHICLE BURDEN

With respect to repairs and maintenance, IFRS states that the costs of day-to-day servicing of an item of PP&E cannot be recognized in the carrying amount. These costs are expensed as incurred. Therefore the vehicle charge to capital only includes fuel and consumables.

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	2014 Historical Year	2015 Historical Year	2016 Historical Year	2017 Bridge Year	2018 Test Year
Distribution	$ 688,177	$ 448,729	$ 378,376	$ 384,808	$ 413,025
Billing and Collecting	$ 1,259,465	$ 1,111,468	$ 981,647	$ 998,335	$ 1,040,307
Community Relations	$ 22,871	$ 21,168	$ 24,584	$ 24,953	$ 25,327
Administrative and General	$ 4,376,576	$ 4,934,199	$ 5,274,396	$ 5,456,568	$ 5,691,140
Total OM&A Before Capitalization (B)	$ 6,347,089	$ 6,515,564	$ 6,659,003	$ 6,864,664	$ 7,169,798

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	2014 Historical Year	2015 Historical Year	2016 Historical Year	2017 Bridge Year	2018 Test Year	Directly Attributable? (Yes/No)	Explanation for Change in Overhead Capitalized
Labour Burden	$ 744,139	$ 723,341	$ 666,502	$ 682,755	$ 713,030	Yes	Training expenses no longer Capitalized under MIFRS
Material Burden	$ -	$ -	$ -	$ -	$ -	Yes	No Changes necessary on transition to MIFRS
Vehicle Burden	$ -	$ -	$ -	$ -	$ -	Yes	No Changes necessary on transition to MIFRS
Insert description of additional item(s) and new rows if needed							
Total Capitalized OM&A (A)	$ 744,139	$ 723,341	$ 666,502	$ 682,755	$ 713,030		
% of Capitalized OM&A (=A/B)	12%	11%	10%	10%	10%		

2.5.8 Cost of Eligible Investments for Distributors

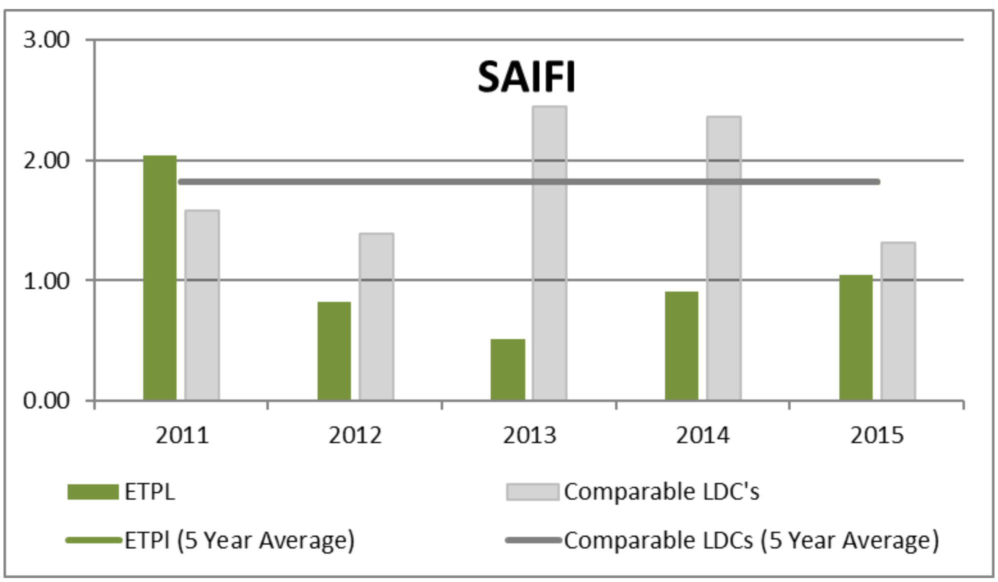
ETPL has not incurred any costs for the connection of qualifying generation facilities.

2.5.9 Service Quality and Reliability Performance

For each of the following reliability metrics ETPL has included the reliability measure for comparable LDCs[1]. The selections of comparable LDCs were based primarily on customer count ranging from 15,000 to 21,000. The varying characteristics of each utility make it difficult to make a direct comparison however still allow for a more valuable benchmarking assessment and any marked adverse deviations from the trend are highlighted. Also included is a comparison of ETPL's SAIDI and SAIFI metrics as compared to the industry as a whole.

SAIFI

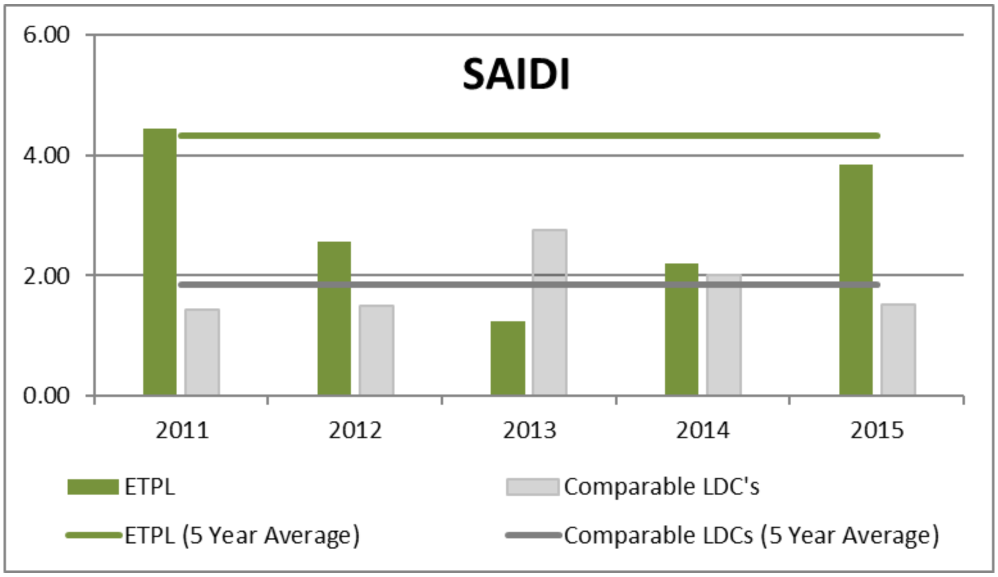
Table 2-53: SAIFI Comparisons



[1] Comparable LDC's were selected based on a customer base between 15,000 and 21,000. The specific LDCs were Collus Powerstream, Festival Hydro, Halton Hills, InnPower and St. Thomas Energy.

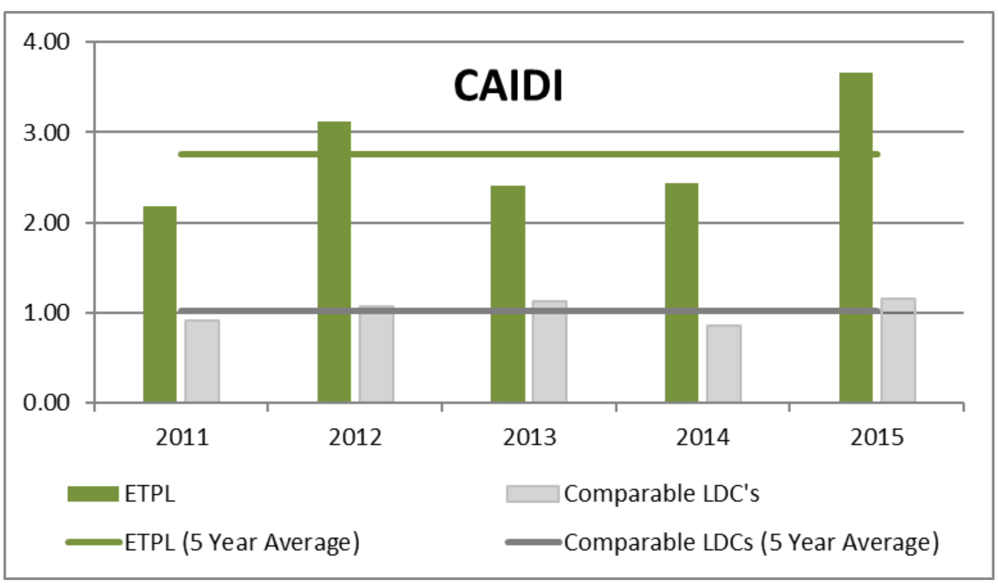
SAIDI

Table 2-54: SAIDI Comparisons



CAIDI

Table 2-55: CAIDI Comparisons



SAIFI - excluding Loss of Supply

Table 2-56: SAIFI (LOS adjusted) Comparisons

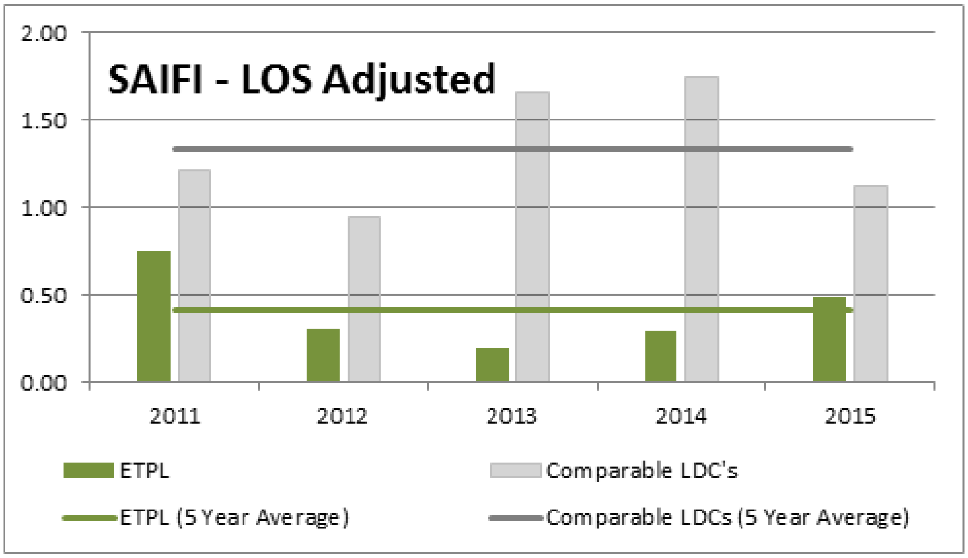
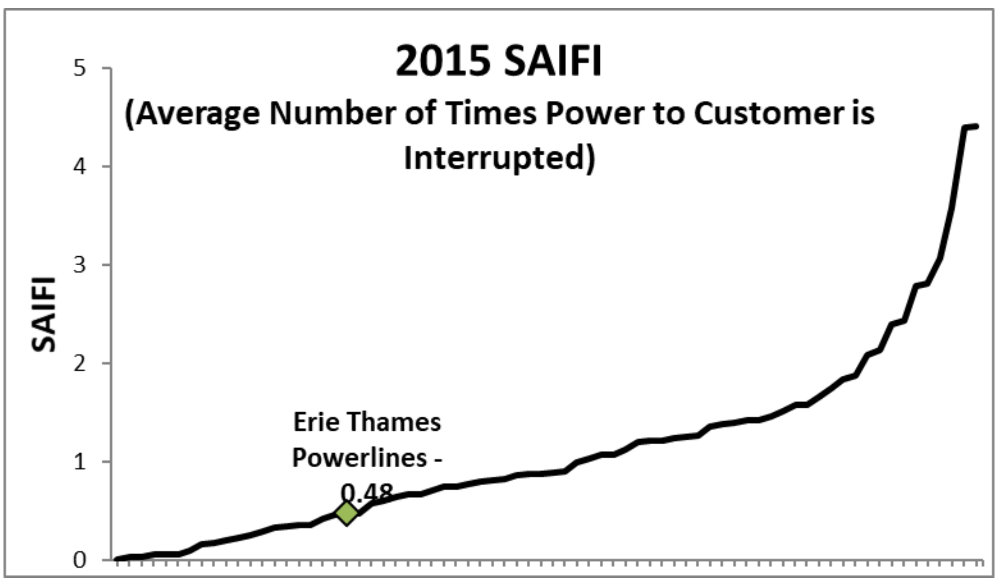
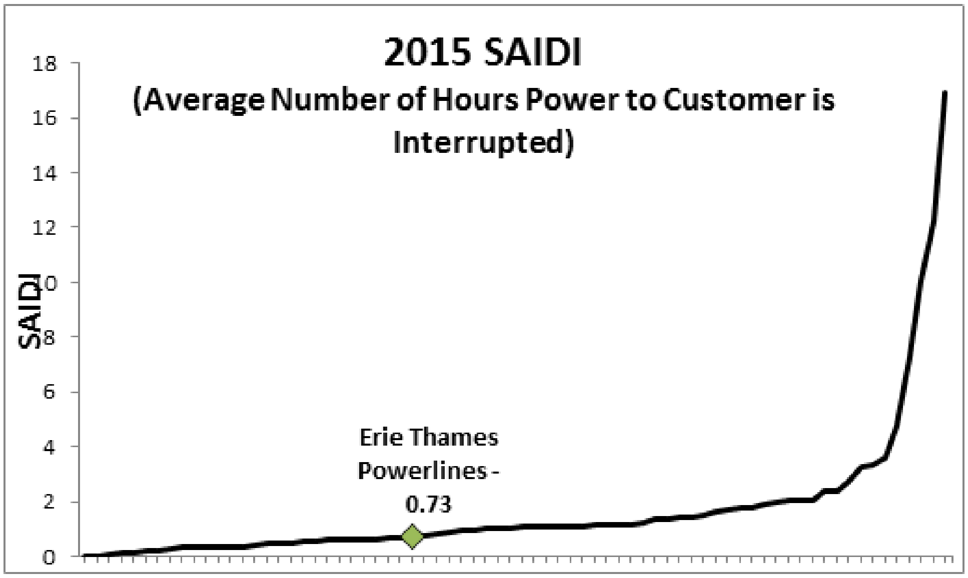


Table 2-57: SAIFI (LOS Adjusted) Industry Comparison



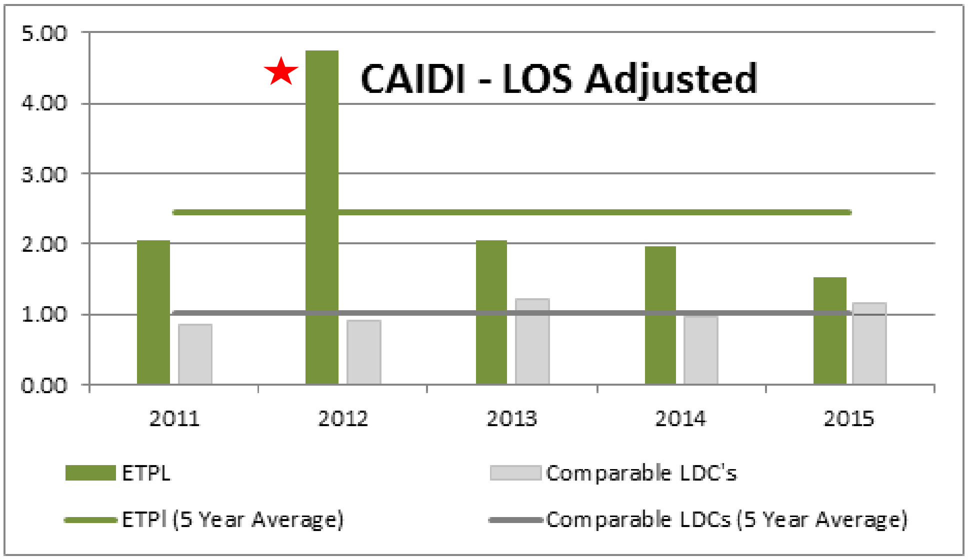
1 **Table 2-58: SAIDI (LOS Adjusted) Industry Comparison**

2 

3

CAIDI - excluding Loss of Supply

Table 2-59: CAIDI (LOS Adjusted) Comparison



In 2012 ETPL reported a drastic increase in LOS adjusted CAIDI. This was a result of a 4kV substation transformer failure caused by a direct lightning strike to a high voltage bushing. The transformer was subsequently replaced resulting in outages to 1200 customers totaling 103,390 hours of customer outage duration.

ETPL understands that CAIDI can be a flawed metric and is no longer included on the OEB scorecard, due to the fact that more frequent outages or higher SAIFI values will create artificially low CAIDI values. In ETPL's case, our LOS adjusted SAIFI values are typically low compared to industry averages and therefore the CAIDI metric provides some valuable information.

Historically Erie Thames Powerlines CAIDI reliability metrics have been higher than industry levels indicating that the average restoration time is longer than industry standards. This can primarily be explained by the geographic makeup of our service territory with significant driving distances between a number of our communities and service centers. It can be seen that restoration times tend to be greater in communities further from ETPL service centers.

Tillsonburg TS - M1 services Otterville which is a driving distance of approximately 30mins

Edgeware TS - M3 service Port Stanley which is a driving distance of approximately 35mins

North Norwich DS - F2 services Burgessville which is a driving distance of approximately 25 mins

Stratford TS - M7 service Tavistock which is a driving distance of approximately 40 mins.

An outlier from this reasoning is the Edgeware TS - M4 feeder which supplies the southern half of Aylmer. The vast majority of this area is older underground subdivisions and rear yard construction which typically require longer outages due to troubleshooting and access issues. Although CAIDI values are historically higher than industry levels, ETPL has been able to maintain SAIDI & SAIFI values below industry levels ensuring that customers are experiencing fewer outages. Various investments have been made to improve restoration efforts and are detailed in subsequent sections.

ETPL's performance is within the range of acceptable performance over the previous five years and no corrective action is required. The following Table 2-60 sets out the service reliability indicators for the last five years (2012-2016).

Table 2-60 Service Reliability and Quality Indicators (Appendix 2-G)

Appendix 2-G
Service Reliability and Quality Indicators
2012-2016

Service Reliability

Index	Including outages caused by loss of supply					Excluding outages caused by loss of supply					Excluding Major Event Days				
	2012	2013	2014	2015	2016	2012	2013	2014	2015	2016	2012	2013	2014	2015	2016
SAIDI	2.560	1.230	2.210	3.850	3.960	1.470	0.410	0.590	0.730	1.880	1.470	0.410	0.590	0.730	3.000
SAIFI	0.820	0.510	0.910	1.050	1.130	0.310	0.200	0.300	0.480	0.470	0.310	0.200	0.300	0.480	0.740

5 Year Historical Average

Index	Including outages caused by loss of supply	Excluding outages caused by loss of supply	Excluding Major Event Days
SAIDI	2.762	1.016	1.240
SAIFI	0.884	0.352	0.406

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

Service Quality

Indicator	OEB Minimum Standard	2012	2013	2014	2015	2016
Low Voltage Connections	90.0%	98.8%	98.8%	99.4%	98.4%	99.6%
High Voltage Connections	90.0%	n/a	n/a	n/a	n/a	n/a
Telephone Accessibility	65.0%	94.6%	95.8%	95.5%	98.4%	98.4%
Appointments Met	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Written Response to Enquires	80.0%	100.0%	98.8%	98.6%	100.0%	100.0%
Emergency Urban Response	80.0%	90.5%	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%	6.2%	4.2%	4.4%	1.6%	1.6%
Appointment Scheduling	90.0%	100.0%	100.0%	94.5%	95.8%	99.2%
Rescheduling a Missed Appointment	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Reconnection Performance Standard	85.0%	100.0%	100.0%	100.0%	100.0%	100.0%

**no missed appointments so none needed to be resc

Exhibit 2: Rate Base

Tab 6 (of 6): Exhibit 2 Appendices

Attachment 1 (of 8):

2-A Appendix 2-BA Fixed Asset Continuity Schedules

File Number:	2017-0038
Exhibit:	2
Tab:	1
Schedule:	1
Page:	
Date:	September 6, 2017

Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Accounting Standard CGAAP
Year **2012**

			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)	$ 1,045,367	$ 40,096		$ 1,085,463	-$ 561,591	-$ 68,496		-$ 630,087	$ 455,376
CEC	1612	Land Rights (Formally known as Account 1906)	$ 37,600	$ 5,332		$ 42,932				$ -	$ 42,932
N/A	1805	Land	$ 103,344			$ 103,344				$ -	$ 103,344
47	1808	Buildings	$ 173,327	$ 22,624		$ 195,951	-$ 63,941	-$ 7,386		-$ 71,327	$ 124,624
13	1810	Leasehold Improvements				$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV				$ -				$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 503,732	$ 155,957	-$ 55,000	$ 604,689	-$ 219,482	-$ 23,268	$ 55,000	-$ 187,750	$ 416,939
47	1825	Storage Battery Equipment				$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 5,481,315	$ 570,419		$ 6,051,734	-$ 2,197,726	-$ 228,717		-$ 2,426,443	$ 3,625,291
47	1835	Overhead Conductors & Devices	$ 10,519,285	$ 795,114		$ 11,314,399	-$ 6,904,827	-$ 435,629		-$ 7,340,456	$ 3,973,943
47	1840	Underground Conduit	$ 2,351,312	$ 335,860		$ 2,687,172	-$ 188,838	-$ 100,770		-$ 289,608	$ 2,397,565
47	1845	Underground Conductors & Devices	$ 5,236,041	$ 441,642		$ 5,677,683	-$ 587,364	-$ 218,274		-$ 805,638	$ 4,872,045
47	1850	Line Transformers	$ 6,601,894	$ 678,176		$ 7,280,070	-$ 948,498	-$ 277,639		-$ 1,226,137	$ 6,053,932
47	1855	Services (Overhead & Underground)	$ 3,323,674	$ 579,769		$ 3,903,443	-$ 1,274,113	-$ 144,542		-$ 1,418,656	$ 2,484,788
47	1860	Meters	$ 2,802,098	$143,580		$ 2,945,678	-$ 355,607	-$ 114,956		-$ 470,562	$ 2,475,116
47	1860	Meters (Smart Meters)				$ -				$ -	$ -
N/A	1905	Land				$ -				$ -	$ -
47	1908	Buildings & Fixtures				$ -				$ -	$ -
13	1910	Leasehold Improvements	$ 161,501	$ 25,956		$ 187,457	-$ 8,964	-$ 4,234		-$ 13,198	$ 174,259
8	1915	Office Furniture & Equipment (10 years)	$ 75,387	$ 10,976		$ 86,364	-$ 58,478	-$ 4,720		-$ 63,198	$ 23,165
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 97,941			$ 97,941	-$ 97,941			-$ 97,941	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 3,892			$ 3,892	-$ 3,892			-$ 3,892	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ 45,925		$ 45,925		-$ 4,593		-$ 4,593	$ 41,332
10	1930	Transportation Equipment	$ 2,733,121	$ 104,692	-$ 165,985	$ 2,671,828	-$ 1,633,870	-$ 277,988	$ 165,985	-$ 1,745,873	$ 925,955
8	1935	Stores Equipment				$ -				$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 159,238	$ 16,560		$ 175,798	-$ 80,871	-$ 14,987		-$ 95,858	$ 79,940
8	1945	Measurement & Testing Equipment	$ 14,462			$ 14,462	-$ 2,035	-$ 1,426		-$ 3,461	$ 11,001
8	1950	Power Operated Equipment	$ 64,091			$ 64,091	-$ 5,768	-$ 6,429		-$ 12,197	$ 51,894
8	1955	Communications Equipment				$ -				$ -	$ -
8	1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -
8	1960	Miscellaneous Equipment				$ -				$ -	$ -
47	1970	Load Management Controls Customer Premises				$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises				$ -				$ -	$ -
47	1980	System Supervisor Equipment		$ 213,965		$ 213,965		-$ 10,698		-$ 10,698	$ 203,267
47	1985	Miscellaneous Fixed Assets				$ -				$ -	$ -
47	1990	Other Tangible Property				$ -				$ -	$ -
47	1995	Contributions & Grants	-$ 4,773,539	-$ 570,599		-$ 5,344,138	$ 647,119	$ 217,267		$ 864,386	-$ 4,479,752
47	2440	Deferred Revenue[5]									
						$ -				$ -	$ -
		Sub-Total	**$ 36,715,081**	**$ 3,616,045**	**-$ 220,985**	**$ 40,110,141**	**-$ 14,546,687**	**-$ 1,727,485**	**$ 220,985**	**-$ 16,053,187**	**$ 24,056,954**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 36,715,081**	**$ 3,616,045**	**-$ 220,985**	**$ 40,110,141**	**-$ 14,546,687**	**-$ 1,727,485**	**$ 220,985**	**-$ 16,053,187**	**$ 24,056,954**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 1,727,485**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 1,727,485

Notes:

1. Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2. The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3. The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4. The additions in column (E) must not include construction work in progress (CWIP).

5. Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6. The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

File Number:	2017-0038
Exhibit:	2
Tab:	1
Schedule:	1
Page:	
Date:	September 6, 2017

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard CGAAP
Year **2013**

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 1,085,463	$ 54,671	$ -	$ 1,140,133	-$ 630,087	-$ 107,454	$ -	-$ 737,541	$ 402,593
CEC	1612	Land Rights (Formally known as Account 1906)	$ 42,932	$ 947	$ -	$ 43,879	$ -	$ -	$ -	$ -	$ 43,879
N/A	1805	Land	$ 103,344	$ 695	$ -	$ 104,039	$ -	$ -	$ -	$ -	$ 104,039
47	1808	Buildings	$ 195,951	$ 24,917	$ -	$ 220,868	-$ 71,327	-$ 3,747	$ -	-$ 75,074	$ 145,794
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 604,689	$ 16,591	$ -	$ 621,279	-$ 187,750	-$ 10,484	$ -	-$ 198,234	$ 423,045
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 6,051,734	$ 508,874	$ -	$ 6,560,608	-$ 2,426,443	-$ 118,542	$ -	-$ 2,544,985	$ 4,015,623
47	1835	Overhead Conductors & Devices	$ 11,314,399	$ 770,131	$ -	$ 12,084,530	-$ 6,840,664	-$ 194,412	$ -	-$ 7,035,076	$ 5,049,454
47	1840	Underground Conduit	$ 2,687,172	$ 46,781	$ -	$ 2,733,954	-$ 289,608	-$ 65,746	$ -	-$ 355,354	$ 2,378,600
47	1845	Underground Conductors & Devices	$ 5,677,683	$ 379,360	$ -	$ 6,057,043	-$ 805,638	-$ 148,260	$ -	-$ 953,898	$ 5,103,145
47	1850	Line Transformers	$ 7,280,070	$ 649,661	-$ 110,118	$ 7,819,613	-$ 1,226,137	-$ 151,651	$ 110,118	-$ 1,267,670	$ 6,551,943
47	1855	Services (Overhead & Underground)	$ 3,903,443	$ 332,065	$ -	$ 4,235,508	-$ 1,418,656	-$ 67,625	$ -	-$ 1,486,280	$ 2,749,228
47	1860	Meters	$ 1,632,236	$ 35,278	$ -	$ 1,667,514	-$ 887,756	-$ 310,677	$ -	-$ 1,198,433	$ 469,081
47	1860	Meters (Smart Meters)	$ 2,887,735	$ 229,651	$ -	$ 3,117,386	$ -	$ -	$ -	$ -	$ 3,117,386
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements	$ 187,457	$ 53,273	$ -	$ 240,730	-$ 13,198	-$ 3,893	$ -	-$ 17,091	$ 223,639
8	1915	Office Furniture & Equipment (10 years)	$ 86,364	$ 3,059	$ -	$ 89,423	-$ 63,198	-$ 5,093	$ -	-$ 68,291	$ 21,131
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ 97,941	$ -	$ -	$ 97,941	-$ 97,941	$ -	$ -	-$ 97,941	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 3,892	$ -	$ -	$ 3,892	-$ 3,892	$ -	$ -	-$ 3,892	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 45,925	$ 57,214	$ -	$ 103,139	-$ 4,593	-$ 14,850	$ -	-$ 19,443	$ 83,696
10	1930	Transportation Equipment	$ 2,671,828	$ 386,632	-$ 46,600	$ 3,011,860	-$ 1,745,872	-$ 260,859	$ 46,600	-$ 1,960,132	$ 1,051,728
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 175,798	$ 16,442	$ -	$ 192,239	-$ 95,858	-$ 21,830	$ -	-$ 117,688	$ 74,551
8	1945	Measurement & Testing Equipment	$ 14,462	$ -	$ -	$ 14,462	-$ 3,461	-$ 1,808	$ -	-$ 5,269	$ 9,193
8	1950	Power Operated Equipment	$ 64,091	$ -	$ -	$ 64,091	-$ 12,197	-$ 8,012	$ -	-$ 20,209	$ 43,882
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 213,965	$ 42,216	$ -	$ 256,181	-$ 10,698	-$ 47,015	$ -	-$ 57,713	$ 198,468
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 5,344,138	-$ 1,446,296	$ -	-$ 6,790,435	$ 864,386	$ 106,624	$ -	$ 971,011	-$ 5,819,424
47	2440	Deferred Revenue[5]					$ -	$ -	$ -	$ -	
						$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 41,684,434**	**$ 2,162,162**	**-$ 156,718**	**$ 43,689,878**	**-$ 15,970,589**	**-$ 1,435,333**	**$ 156,718**	**-$ 17,249,204**	**$ 26,440,674**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 41,684,434**	**$ 2,162,162**	**-$ 156,718**	**$ 43,689,878**	**-$ 15,970,589**	**-$ 1,435,333**	**$ 156,718**	**-$ 17,249,204**	**$ 26,440,674**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 1,435,333**			

$ 1,574,293.00

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	
Stores Equipment	
Net Depreciation	-$ 1,435,333

File Number:	2017-0038
Exhibit:	2
Tab:	1
Schedule:	1
Page:	
Date:	September 6, 2017

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)	$ 1,085,463	$ 54,671		$ 1,140,133	-$ 630,087	-$ 107,454		-$ 737,541	$ 402,593
CEC	1612	Land Rights (Formally known as Account 1906)	$ 42,932	$ 947		$ 43,879	$ -			$ -	$ 43,879
N/A	1805	Land	$ 103,344	$ 695		$ 104,039	$ -			$ -	$ 104,039
47	1808	Buildings	$ 195,951	$ 24,917		$ 220,868	-$ 71,327	-$ 3,747		-$ 75,074	$ 145,794
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 604,689	$ 12,875		$ 617,564	-$ 187,750	-$ 10,484		-$ 198,234	$ 419,329
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 6,051,734	$ 471,688		$ 6,523,423	-$ 2,426,443	-$ 118,542		-$ 2,544,985	$ 3,978,438
47	1835	Overhead Conductors & Devices	$ 11,314,399	$ 700,608		$ 12,015,007	-$ 6,840,664	-$ 194,412		-$ 7,035,076	$ 4,979,931
47	1840	Underground Conduit	$ 2,687,172	$ 30,270		$ 2,717,442	-$ 289,608	-$ 65,746		-$ 355,354	$ 2,362,088
47	1845	Underground Conductors & Devices	$ 5,677,683	$ 344,473		$ 6,022,156	-$ 805,638	-$ 148,260		-$ 953,898	$ 5,068,258
47	1850	Line Transformers	$ 7,280,070	$ 604,928	-$ 110,118	$ 7,774,879	-$ 1,226,137	-$ 151,651	$ 110,118	-$ 1,267,670	$ 6,507,209
47	1855	Services (Overhead & Underground)	$ 3,903,443	$ 308,080		$ 4,211,523	-$ 1,418,656	-$ 67,625		-$ 1,486,280	$ 2,725,243
47	1860	Meters	$ 1,632,236	$ 25,249		$ 1,657,485	-$ 887,756	-$ 310,677		-$ 1,198,433	$ 459,052
47	1860	Meters (Smart Meters)	$ 2,887,735	$ 211,907		$ 3,099,642	$ -			$ -	$ 3,099,642
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ 187,457	$ 53,273		$ 240,730	-$ 13,198	-$ 3,893		-$ 17,091	$ 223,639
8	1915	Office Furniture & Equipment (10 years)	$ 86,364	$ 3,059		$ 89,423	-$ 63,198	-$ 5,093		-$ 68,291	$ 21,131
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 97,941			$ 97,941	-$ 97,941			-$ 97,941	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 3,892			$ 3,892	-$ 3,892			-$ 3,892	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 45,925	$ 57,214		$ 103,139	-$ 4,593	-$ 14,850		-$ 19,443	$ 83,696
10	1930	Transportation Equipment	$ 2,671,828	$ 386,632	-$ 46,600	$ 3,011,860	-$ 1,745,872	-$ 260,859	$ 46,600	-$ 1,960,132	$ 1,051,728
8	1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 175,798	$ 16,442		$ 192,239	-$ 95,858	-$ 21,830		-$ 117,688	$ 74,551
8	1945	Measurement & Testing Equipment	$ 14,462			$ 14,462	-$ 3,461	-$ 1,808		-$ 5,269	$ 9,193
8	1950	Power Operated Equipment	$ 64,091			$ 64,091	-$ 12,197	-$ 8,012		-$ 20,209	$ 43,882
8	1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 213,965	$ 42,216		$ 256,181	-$ 10,698	-$ 47,015		-$ 57,713	$ 198,468
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 5,344,138	-$ 1,446,296		-$ 6,790,435	$ 864,386	$ 106,624		$ 971,011	-$ 5,819,424
47	2440	Deferred Revenue[5]	$ -				$ -				
			$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 41,684,434**	**$ 1,903,847**	**-$ 156,718**	**$ 43,431,563**	**-$ 15,970,589**	**-$ 1,435,333**	**$ 156,718**	**-$ 17,249,204**	**$ 26,182,359**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 41,684,434**	**$ 1,903,847**	**-$ 156,718**	**$ 43,431,563**	**-$ 15,970,589**	**-$ 1,435,333**	**$ 156,718**	**-$ 17,249,204**	**$ 26,182,359**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 1,435,333**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 1,435,333

File Number:	2017-0038
Exhibit:	2
Tab:	1
Schedule:	1
Page:	
Date:	September 6, 2017

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard CGAAP Revised
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)	$ 1,140,133	$ 87,557	$ -	$ 1,227,691	-$ 737,541	-$ 79,742		-$ 817,283	$ 410,408
CEC	1612	Land Rights (Formally known as Account 1906)	$ 43,879	$ -	$ -	$ 43,879	$ -			$ -	$ 43,879
N/A	1805	Land	$ 104,039	$ -	$ -	$ 104,039	$ -			$ -	$ 104,039
47	1808	Buildings	$ 220,868	$ 4,014	$ -	$ 224,882	-$ 75,074	-$ 8,915		-$ 83,989	$ 140,893
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 617,564	$ 3,665	$ -	$ 621,229	-$ 198,234	-$ 24,703		-$ 222,937	$ 398,292
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 6,523,423	$ 1,270,813	-$ 44,396	$ 7,749,839	-$ 2,544,985	-$ 285,579	$ 41,616	-$ 2,788,948	$ 4,960,891
47	1835	Overhead Conductors & Devices	$ 12,015,007	$ 1,410,235	-$ 1,899	$ 13,423,343	-$ 7,035,076	-$ 507,379	$ 1,899	-$ 7,540,555	$ 5,882,787
47	1840	Underground Conduit	$ 2,717,442	$ 61,799	$ -	$ 2,779,241	-$ 355,354	-$ 109,611		-$ 464,965	$ 2,314,276
47	1845	Underground Conductors & Devices	$ 6,022,156	$ 734,039	-$ 1,122	$ 6,755,073	-$ 953,898	-$ 254,852	$ 1,122	-$ 1,207,629	$ 5,547,444
47	1850	Line Transformers	$ 7,774,879	$ 598,730	-$ 69,006	$ 8,304,604	-$ 1,267,670	-$ 322,047	$ 69,006	-$ 1,520,711	$ 6,783,893
47	1855	Services (Overhead & Underground)	$ 4,211,523	$ 548,804	$ -	$ 4,760,328	-$ 1,486,280	-$ 178,937		-$ 1,665,218	$ 3,095,110
47	1860	Meters		$ -	$ -	$ -				$ -	$ -
47	1860	Meters (Smart Meters)	$ 4,757,127	$ 162,463	-$ 23,020	$ 4,896,571	-$ 1,198,433	-$ 318,105	$ 8,153	-$ 1,508,385	$ 3,388,186
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ 240,730	$ 47,056	$ -	$ 287,786	-$ 17,091	-$ 10,570		-$ 27,661	$ 260,125
8	1915	Office Furniture & Equipment (10 years)	$ 89,423	$ 2,395	$ -	$ 91,818	-$ 68,291	-$ 4,048		-$ 72,339	$ 19,478
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 97,941	$ -	$ -	$ 97,941	-$ 97,941			-$ 97,941	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 3,892	$ -	$ -	$ 3,892	-$ 3,892			-$ 3,892	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 103,139	$ 34,018	$ -	$ 137,157	-$ 19,443	-$ 24,029		-$ 43,473	$ 93,685
10	1930	Transportation Equipment	$ 3,011,860	$ 137,334	-$ 42,443	$ 3,106,751	-$ 1,960,132	-$ 236,642	$ 28,306	-$ 2,168,467	$ 938,284
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 192,239	$ 23,803	$ -	$ 216,043	-$ 117,688	-$ 19,475		-$ 137,164	$ 78,879
8	1945	Measurement & Testing Equipment	$ 14,462	$ -	$ -	$ 14,462	-$ 5,269	-$ 1,446		-$ 6,715	$ 7,747
8	1950	Power Operated Equipment	$ 64,091	$ -	$ -	$ 64,091	-$ 20,209	-$ 6,409		-$ 26,618	$ 37,473
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -			$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 256,181	$ 3,856	$ -	$ 260,037	-$ 57,713	-$ 25,618		-$ 83,331	$ 176,706
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 6,790,435	$ -	$ -	-$ 6,790,435	$ 971,011	$ 287,836		$ 1,258,847	-$ 5,531,588
47	2440	Deferred Revenue [5]	$ -	-$ 810,946		-$ 810,946	$ -				
						$ -				$ -	$ -
		Sub-Total	**$ 43,431,563**	**$ 4,319,638**	**-$ 181,886**	**$ 47,569,314**	**-$ 17,249,204**	**-$ 2,130,272**	**$ 150,102**	**-$ 19,229,374**	**$ 29,150,886**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 43,431,563**	**$ 4,319,638**	**-$ 181,886**	**$ 47,569,314**	**-$ 17,249,204**	**-$ 2,130,272**	**$ 150,102**	**-$ 19,229,374**	**$ 29,150,886**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable [6]									
		Total						**-$ 2,130,272**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 2,130,272

File Number:	2017-0038
Exhibit:	2
Tab:	1
Schedule:	1
Page:	
Date:	September 6, 2017

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS
Year 2014

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 1,140,133	$ 87,557		$ 1,227,691	-$ 737,541	-$ 159,241		-$ 896,781	$ 330,909
CEC	1612	Land Rights (Formally known as Account 1906)	$ 43,879			$ 43,879	$ -			$ -	$ 43,879
N/A	1805	Land	$ 104,039			$ 104,039	$ -			$ -	$ 104,039
47	1808	Buildings	$ 220,868	$ 4,014		$ 224,882	-$ 75,074	-$ 3,989		-$ 79,063	$ 145,820
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 617,564			$ 617,564	-$ 198,234	-$ 10,591		-$ 208,826	$ 408,738
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 6,523,423	$ 1,232,100	-$ 44,396	$ 7,711,126	-$ 2,544,985	-$ 142,789	$ 41,616	-$ 2,646,159	$ 5,064,968
47	1835	Overhead Conductors & Devices	$ 12,015,007	$ 1,338,932	-$ 1,899	$ 13,352,040	-$ 7,035,076	-$ 211,408	$ 1,899	-$ 7,244,584	$ 6,107,456
47	1840	Underground Conduit	$ 2,717,442	$ 45,672		$ 2,763,114	-$ 355,354	-$ 66,590		-$ 421,944	$ 2,341,171
47	1845	Underground Conductors & Devices	$ 6,022,156	$ 698,300	-$ 1,122	$ 6,719,334	-$ 953,898	-$ 159,846	$ 1,122	-$ 1,112,622	$ 5,606,712
47	1850	Line Transformers	$ 7,774,879	$ 552,591	-$ 69,006	$ 8,258,464	-$ 1,267,670	-$ 161,023	$ 69,006	-$ 1,359,688	$ 6,898,776
47	1855	Services (Overhead & Underground)	$ 4,211,523	$ 523,811		$ 4,735,335	-$ 1,486,280	-$ 74,557		-$ 1,560,838	$ 3,174,497
47	1860	Meters	$ 1,657,485			$ 1,657,485	-$ 1,198,433			-$ 1,198,433	$ 459,052
47	1860	Meters (Smart Meters)	$ 3,099,642	$ 134,232	-$ 23,020	$ 3,210,855	$ -	-$ 318,105	$ 8,153	-$ 309,952	$ 2,900,903
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ 240,730	$ 47,056		$ 287,786	-$ 17,091	-$ 4,805		-$ 21,895	$ 265,890
8	1915	Office Furniture & Equipment (10 years)	$ 89,423	$ 2,395		$ 91,818	-$ 68,291	-$ 2,424		-$ 70,716	$ 21,102
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 97,941			$ 97,941	-$ 97,941			-$ 97,941	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 3,892			$ 3,892	-$ 3,892			-$ 3,892	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 103,139	$ 34,018		$ 137,157	-$ 19,443	-$ 24,029		-$ 43,473	$ 93,685
10	1930	Transportation Equipment	$ 3,011,860	$ 137,334	-$ 42,443	$ 3,106,751	-$ 1,960,132	-$ 216,635	$ 28,306	-$ 2,148,461	$ 958,290
8	1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 192,239	$ 23,803		$ 216,043	-$ 117,688	-$ 21,336		-$ 139,024	$ 77,019
8	1945	Measurement & Testing Equipment	$ 14,462			$ 14,462	-$ 5,269	-$ 1,808		-$ 7,077	$ 7,385
8	1950	Power Operated Equipment	$ 64,091			$ 64,091	-$ 20,209	-$ 8,011		-$ 28,220	$ 35,870
8	1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 256,181	$ 3,856		$ 260,037	-$ 57,713			-$ 57,713	$ 202,324
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 6,790,435			-$ 6,790,435	$ 971,011			$ 971,011	-$ 5,819,424
47	2440	Deferred Revenue[5]		-$ 810,946		-$ 810,946		$ 119,932		$ 119,932	-$ 691,014
						$ -				$ -	$ -
		Sub-Total	**$ 43,431,563**	**$ 4,054,728**	**-$ 181,886**	**$ 47,304,405**	**-$ 17,249,204**	**-$ 1,467,256**	**$ 150,102**	**-$ 18,566,358**	**$ 28,738,047**
		Less Socialized Renewable Energy Generation Investments **(input as negative)**				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets ***(input as negative)***				$ -				$ -	$ -
		Total PP&E	**$ 43,431,563**	**$ 4,054,728**	**-$ 181,886**	**$ 47,304,405**	**-$ 17,249,204**	**-$ 1,467,256**	**$ 150,102**	**-$ 18,566,358**	**$ 28,738,047**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]						-$ 5,872			
		Total						**-$ 1,473,128**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	
Stores Equipment	
Net Depreciation	-$ 1,473,128

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

File Number:	2017-0038
Exhibit:	2
Tab:	1
Schedule:	1
Page:	
Date:	September 6, 2017

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS
Year 2015

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 1,227,691	$ 218,361		$ 1,446,052	-$ 896,781	-$ 123,587		-$ 1,020,368	$ 425,684
CEC	1612	Land Rights (Formally known as Account 1906)	$ 43,879	$ -		$ 43,879	$ -			$ -	$ 43,879
N/A	1805	Land	$ 104,039	$ -		$ 104,039	$ -			$ -	$ 104,039
47	1808	Buildings	$ 224,882	$ 28,387		$ 253,270	-$ 79,063	-$ 4,259		-$ 83,321	$ 169,948
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 617,564	$ 0	-$ 51,366	$ 566,197	-$ 208,826	-$ 9,728	$ 16,728	-$ 201,826	$ 364,372
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 7,711,126	$ 706,809	-$ 28,190	$ 8,389,746	-$ 2,646,159	-$ 160,727	$ 62,829	-$ 2,744,057	$ 5,645,689
47	1835	Overhead Conductors & Devices	$ 13,352,040	$ 983,489	-$ 9,685	$ 14,325,844	-$ 7,244,584	-$ 230,568	$ 9,685	-$ 7,465,468	$ 6,860,376
47	1840	Underground Conduit	$ 2,763,114	$ 113,924		$ 2,877,038	-$ 421,944	-$ 68,363		-$ 490,307	$ 2,386,731
47	1845	Underground Conductors & Devices	$ 6,719,334	$ 298,197		$ 7,017,532	-$ 1,112,622	-$ 170,886		-$ 1,283,508	$ 5,734,023
47	1850	Line Transformers	$ 8,258,464	$ 725,235	-$ 85,500	$ 8,898,199	-$ 1,359,688	- 213,390	$ 85,500	-$ 1,487,577	$ 7,410,622
47	1855	Services (Overhead & Underground)	$ 4,735,335	$ 605,660		$ 5,340,994	-$ 1,560,838	-$ 83,970		-$ 1,644,807	$ 3,696,187
47	1860	Meters				$ -				$ -	$ -
47	1860	Meters (Smart Meters)	$ 4,868,340	$ 353,471	-$ 88,635	$ 5,133,176	-$ 1,508,385	- 321,765	$ 46,223	-$ 1,783,927	$ 3,349,249
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ 287,786	$ 127,047		$ 414,833	-$ 21,895	-$ 6,387		-$ 28,283	$ 386,550
8	1915	Office Furniture & Equipment (10 years)	$ 91,818	$ 5,892		$ 97,709	-$ 70,716	-$ 4,139		-$ 74,855	$ 22,855
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 97,941			$ 97,941	-$ 97,941			-$ 97,941	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 3,892			$ 3,892	-$ 3,892			-$ 3,892	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 137,157	$ 11,372		$ 148,529	-$ 43,473	-$ 28,568		-$ 72,041	$ 76,488
10	1930	Transportation Equipment	$ 3,106,751	$ 212,573	-$ 125,327	$ 3,193,997	-$ 2,148,461	-$ 155,910	$ 125,327	-$ 2,179,045	$ 1,014,952
8	1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 216,043	$ 12,251		$ 228,294	-$ 139,024	-$ 16,109		-$ 155,133	$ 73,160
8	1945	Measurement & Testing Equipment	$ 14,462	$ 16,620		$ 31,082	-$ 7,077	-$ 2,847		-$ 9,923	$ 21,159
8	1950	Power Operated Equipment	$ 64,091	$ 158,995		$ 223,086	-$ 28,220	$ 1,959		-$ 26,261	$ 196,825
8	1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 260,037	$ 64,232		$ 324,269	-$ 57,713	-$ 58,431		-$ 116,143	$ 208,126
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 6,790,435			-$ 6,790,435	$ 971,011	$ 126,689		$ 1,097,700	-$ 5,692,735
47	2440	Deferred Revenue [5]	-$ 810,946	-$ 667,719		-$ 1,478,665	$ 119,932	$ 5,564		$ 125,496	-$ 1,353,169
			$ -			$ -				$ -	$ -
		Sub-Total	**$ 47,304,405**	**$ 3,974,797**	**-$ 388,703**	**$ 50,890,499**	**-$ 18,566,358**	**-$ 1,525,420**	**$ 346,290**	**-$ 19,745,488**	**$ 31,145,011**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 47,304,405**	**$ 3,974,797**	**-$ 388,703**	**$ 50,890,499**	**-$ 18,566,358**	**-$ 1,525,420**	**$ 346,290**	**-$ 19,745,488**	**$ 31,145,011**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]						$ 20,829			
		Total						**-$ 1,504,591**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 1,504,591

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

File Number:	2017-0038
Exhibit:	2
Tab:	1
Schedule:	1
Page:	
Date:	September 6, 2017

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS
Year **2016**

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 1,446,052	$ 27,000		$ 1,473,052	-$ 968,746	-$ 139,054		-$ 1,107,800	$ 365,252
CEC	1612	Land Rights (Formally known as Account 1906)	$ 43,879	$ 1,800		$ 45,679	$ -			$ -	$ 45,679
N/A	1805	Land	$ 104,039	$ 74,505		$ 178,544	$ -			$ -	$ 178,544
47	1808	Buildings	$ 253,270	$ 3,194		$ 256,463	-$ 83,321	-$ 4,522		-$ 87,843	$ 168,620
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 566,197			$ 566,197	-$ 201,826	-$ 9,728		-$ 211,553	$ 354,644
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 8,389,746	$ 548,837	-$ 77,577	$ 8,861,005	-$ 2,744,057	-$ 173,283	$ 77,577	-$ 2,839,763	$ 6,021,242
47	1835	Overhead Conductors & Devices	$ 14,325,844	$ 887,131	-$ 340,364	$ 14,872,610	-$ 7,465,468	-$ 246,157	$ 340,364	-$ 7,371,260	$ 7,501,350
47	1840	Underground Conduit	$ 2,877,038	$ 221,003		$ 3,098,041	-$ 490,307	-$ 72,085		-$ 562,392	$ 2,535,649
47	1845	Underground Conductors & Devices	$ 7,017,532	$ 659,042	-$ 256,441	$ 7,420,132	-$ 1,283,508	-$ 181,522	$ 256,441	-$ 1,208,589	$ 6,211,543
47	1850	Line Transformers	$ 8,898,199	$ 535,551	-$ 187,548	$ 9,246,202	-$ 1,487,577	-$ 229,149	$ 187,548	-$ 1,529,179	$ 7,717,024
47	1855	Services (Overhead & Underground)	$ 5,340,994	$ 591,581		$ 5,932,575	-$ 1,644,807	-$ 93,946		-$ 1,738,753	$ 4,193,822
47	1860	Meters	$ -			$ -	$ -			$ -	$ -
47	1860	Meters (Smart Meters)	$ 5,133,176	$ 246,046		$ 5,379,222	-$ 1,783,927	-$ 341,033		-$ 2,124,961	$ 3,254,261
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ 414,833	$ 41,813		$ 456,646	-$ 28,283	-$ 7,923		-$ 36,205	$ 420,441
8	1915	Office Furniture & Equipment (10 years)	$ 97,709			$ 97,709	-$ 74,855	-$ 4,111		-$ 78,965	$ 18,744
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 97,941			$ 97,941	-$ 97,941			-$ 97,941	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 3,892			$ 3,892	-$ 3,892			-$ 3,892	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 148,529	$ 22,003		$ 170,532	-$ 72,041	-$ 31,906		-$ 103,947	$ 66,585
10	1930	Transportation Equipment	$ 3,193,997	$ 346,258	-$ 487,093	$ 3,053,163	-$ 2,135,667	-$ 192,984	$ 487,093	-$ 1,841,558	$ 1,211,605
8	1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 228,294	$ 15,489		$ 243,783	-$ 155,133	-$ 16,743		-$ 171,876	$ 71,907
8	1945	Measurement & Testing Equipment	$ 31,082			$ 31,082	-$ 9,923	-$ 3,885		-$ 13,809	$ 17,274
8	1950	Power Operated Equipment	$ 223,086	$ 1,574		$ 224,659	-$ 26,261	-$ 27,665		-$ 53,926	$ 170,734
8	1955	Communications Equipment	$ -	$ 31,915		$ 31,915	$ -	-$ 3,192		-$ 3,192	$ 28,724
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 324,269	$ 188,030		$ 512,299	-$ 116,143	-$ 83,657		-$ 199,800	$ 312,499
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 6,790,435			-$ 6,790,435	$ 1,197,358	$ 113,174		$ 1,310,532	-$ 5,479,902
47	2440	Deferred Revenue[5]	-$ 1,478,665	-$ 1,192,751		-$ 2,671,415	$ 125,496	$ 10,843		$ 136,339	-$ 2,535,076
			$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 50,890,499**	**$ 3,250,021**	**-$ 1,349,023**	**$ 52,791,497**	**-$ 19,550,830**	**-$ 1,738,527**	**$ 1,349,023**	**-$ 19,940,333**	**$ 32,851,164**
		Less Socialized Renewable Energy Generation Investments (input as negative)								$ -	
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*				$ -				$ -	$ -
		Total PP&E	**$ 50,890,499**	**$ 3,086,091**	**-$ 1,349,023**	**$ 52,627,568**	**-$ 19,550,830**	**-$ 1,738,527**	**$ 1,349,023**	**-$ 19,940,333**	**$ 32,687,234**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 1,738,527**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	
Stores Equipment	
Net Depreciation	-$ 1,738,527

Notes:

-$ 110,247.72

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

File Number:	2017-0038
Exhibit:	2
Tab:	1
Schedule:	1
Page:	
Date:	September 6, 2017

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)	$ 1,473,052	$ 35,000		$ 1,508,052	-$ 1,107,800	-$ 144,887.52		-$ 1,252,688	$ 255,364
CEC	1612	Land Rights (Formally known as Account 1906)	$ 45,679			$ 45,679	$ -	$ -		$ -	$ 45,679
N/A	1805	Land	$ 178,544			$ 178,544	$ -	$ -		$ -	$ 178,544
47	1808	Buildings	$ 256,463	$ 748,343		$ 1,004,806	-$ 87,843	-$ 11,325		-$ 99,168	$ 905,638
13	1810	Leasehold Improvements	$ -			$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -	$ -		$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 566,197			$ 566,197	-$ 211,553	-$ 9,728		-$ 221,281	$ 344,916
47	1825	Storage Battery Equipment	$ -			$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 8,861,005	$ 360,362.57		$ 9,221,368	-$ 2,839,763	-$ 176,887		-$ 3,016,650	$ 6,204,718
47	1835	Overhead Conductors & Devices	$ 14,872,610	$ 604,844.70		$ 15,477,455	-$ 7,371,260	-$ 251,197		-$ 7,622,457	$ 7,854,998
47	1840	Underground Conduit	$ 3,098,041	$ 125,992.26		$ 3,224,033	-$ 562,392	-$ 73,485		-$ 635,876	$ 2,588,157
47	1845	Underground Conductors & Devices	$ 7,420,132	$ 301,764.61		$ 7,721,897	-$ 1,208,589	-$ 184,875		-$ 1,393,465	$ 6,328,432
47	1850	Line Transformers	$ 9,246,202	$ 376,027.90		$ 9,622,230	-$ 1,529,179	-$ 233,850		-$ 1,763,028	$ 7,859,202
47	1855	Services (Overhead & Underground)	$ 5,932,575	$ 1,087,500		$ 7,020,075	-$ 1,738,753	-$ 103,009		-$ 1,841,762	$ 5,178,313
47	1860	Meters	$ -			$ -	$ -	$ -		$ -	$ -
47	1860	Meters (Smart Meters)	$ 5,379,222	$ 248,628		$ 5,627,850	-$ 2,124,961	-$ 351,393		-$ 2,476,354	$ 3,151,496
N/A	1905	Land	$ -			$ -	$ -	$ -		$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -	$ -		$ -	$ -
13	1910	Leasehold Improvements	$ 456,646	$ 49,000		$ 505,646	-$ 36,205	-$ 8,368		-$ 44,573	$ 461,073
8	1915	Office Furniture & Equipment (10 years)	$ 97,709			$ 97,709	-$ 78,965	-$ 4,111		-$ 83,076	$ 14,634
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -	$ -		$ -	$ -
10	1920	Computer Equipment - Hardware	$ 97,941			$ 97,941	-$ 97,941	$ -		-$ 97,941	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 3,892			$ 3,892	-$ 3,892	$ -		-$ 3,892	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 170,532	$ 44,950		$ 215,482	-$ 103,947	-$ 36,401		-$ 140,348	$ 75,134
10	1930	Transportation Equipment	$ 3,053,163	$ 135,000		$ 3,188,163	-$ 1,841,558	-$ 201,421		-$ 2,042,979	$ 1,145,184
8	1935	Stores Equipment	$ -			$ -	$ -	$ -		$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 243,783	$ 35,000		$ 278,783	-$ 171,876	-$ 18,930		-$ 190,806	$ 87,977
8	1945	Measurement & Testing Equipment	$ 31,082			$ 31,082	-$ 13,809	-$ 3,885		-$ 17,694	$ 13,388
8	1950	Power Operated Equipment	$ 224,659			$ 224,659	-$ 53,926	-$ 27,665		-$ 81,591	$ 143,069
8	1955	Communications Equipment	$ 31,915			$ 31,915	-$ 3,192	-$ 3,192		-$ 6,383	$ 25,532
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -	$ -		$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -	$ -		$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisor Equipment	$ 512,299	$ 50,000		$ 562,299	-$ 199,800	-$ 88,657		-$ 288,457	$ 273,842
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -	$ -		$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants	-$ 6,790,435			-$ 6,790,435	$ 1,310,532	$ 113,174		$ 1,423,706	-$ 5,366,728
47	2440	Deferred Revenue[5]	-$ 2,671,415	-$ 652,500		-$ 3,323,915	$ 136,339	$ 25,673		$ 162,012	-$ 3,161,903
						$ -				$ -	$ -
		Sub-Total	**$ 52,791,497**	**$ 3,549,913**	**$ -**	**$ 56,341,410**	**-$ 19,940,333**	**-$ 1,794,418**	**$ -**	**-$ 21,734,751**	**$ 34,606,659**
		Less Socialized Renewable Energy Generation Investments (input as negative)	-$ 163,929			-$ 163,929	$ -	$ -		$ -	-$ 163,929
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 52,627,568**	**$ 3,549,913**	**$ -**	**$ 56,177,481**	**-$ 19,940,333**	**-$ 1,794,418**	**$ -**	**-$ 21,734,751**	**$ 34,442,729**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 1,794,418**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 1,794,418

Notes:

1. Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2. The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3. The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4. The additions in column (E) must not include construction work in progress (CWIP).

5. Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6. The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

File Number:	2017-0038
Exhibit:	2
Tab:	1
Schedule:	1
Page:	
Date:	September 6, 2017

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS
Year **2018**

			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)	$ 1,508,052	$ 35,000		$ 1,543,052	-$ 1,252,688	-$ 150,720.86		-$ 1,403,409	$ 139,643
CEC	1612	Land Rights (Formally known as Account 1906)	$ 45,679			$ 45,679	$ -	$ -		$ -	$ 45,679
N/A	1805	Land	$ 178,544			$ 178,544	$ -	$ -		$ -	$ 178,544
47	1808	Buildings	$ 1,004,806	$ 8,000		$ 1,012,806	-$ 99,168	-$ 11,391.48		-$ 110,559	$ 902,247
13	1810	Leasehold Improvements	$ -			$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -	$ -		$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 566,197			$ 566,197	-$ 221,281	-$ 9,728		-$ 231,009	$ 335,189
47	1825	Storage Battery Equipment	$ -			$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 9,221,368	$ 477,590		$ 9,698,957	-$ 3,016,650	-$ 181,662.80		-$ 3,198,313	$ 6,500,645
47	1835	Overhead Conductors & Devices	$ 15,477,455	$ 801,602		$ 16,279,057	-$ 7,622,457	-$ 257,877.22		-$ 7,880,335	$ 8,398,723
47	1840	Underground Conduit	$ 3,224,033	$ 166,978		$ 3,391,011	-$ 635,876	-$ 75,339.92		-$ 711,216	$ 2,679,795
47	1845	Underground Conductors & Devices	$ 7,721,897	$ 399,929		$ 8,121,826	-$ 1,393,465	-$ 189,874.22		-$ 1,583,339	$ 6,538,487
47	1850	Line Transformers	$ 9,622,230	$ 498,351		$ 10,120,581	-$ 1,763,028	-$ 240,079.09		-$ 2,003,108	$ 8,117,473
47	1855	Services (Overhead & Underground)	$ 7,020,075	$ 1,087,500		$ 8,107,575	-$ 1,841,762	-$ 112,071.41		-$ 1,953,834	$ 6,153,741
47	1860	Meters	$ -			$ -	$ -	$ -		$ -	$ -
47	1860	Meters (Smart Meters)	$ 5,627,850	$ 234,500		$ 5,862,350	-$ 2,476,354	-$ 361,163.80		-$ 2,837,518	$ 3,024,832
N/A	1905	Land	$ -			$ -	$ -	$ -		$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -	$ -		$ -	$ -
13	1910	Leasehold Improvements	$ 505,646	$ 35,000		$ 540,646	-$ 44,573	-$ 8,686.18		-$ 53,260	$ 487,386
8	1915	Office Furniture & Equipment (10 years)	$ 97,709			$ 97,709	-$ 83,076	-$ 4,111		-$ 87,186	$ 10,523
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -	$ -		$ -	$ -
10	1920	Computer Equipment - Hardware	$ 97,941			$ 97,941	-$ 97,941	$ -		-$ 97,941	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 3,892			$ 3,892	-$ 3,892	$ -		-$ 3,892	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 215,482	$ 21,000		$ 236,482	-$ 140,348	-$ 38,501.00		-$ 178,849	$ 57,633
10	1930	Transportation Equipment	$ 3,188,163	$ 20,000		$ 3,208,163	-$ 2,042,979	-$ 202,671.06		-$ 2,245,650	$ 962,513
8	1935	Stores Equipment	$ -			$ -	$ -	$ -		$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 278,783	$ 20,000		$ 298,783	-$ 190,806	-$ 20,180.06		-$ 210,986	$ 87,797
8	1945	Measurement & Testing Equipment	$ 31,082			$ 31,082	-$ 17,694	-$ 3,885		-$ 21,579	$ 9,503
8	1950	Power Operated Equipment	$ 224,659			$ 224,659	-$ 81,591	-$ 27,665		-$ 109,256	$ 115,404
8	1955	Communications Equipment	$ 31,915			$ 31,915	-$ 6,383	-$ 3,192		-$ 9,575	$ 22,341
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -	$ -		$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -	$ -		$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisor Equipment	$ 562,299	$ 90,000		$ 652,299	-$ 288,457	-$ 97,656.84		-$ 386,114	$ 266,186
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -	$ -		$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants	-$ 6,790,435			-$ 6,790,435	$ 1,423,706	$ 113,174		$ 1,536,880	-$ 5,253,554
47	2440	Deferred Revenue[5]	-$ 3,323,915	-$ 652,500		-$ 3,976,415	$ 162,012	$ 40,502		$ 202,514	-$ 3,773,901
						$ -				$ -	$ -
		Sub-Total	**$ 56,341,410**	**$ 3,242,950**	**$ -**	**$ 59,584,360**	**-$ 21,734,751**	**-$ 1,842,780**	**$ -**	**-$ 23,577,531**	**$ 36,006,829**
		Less Socialized Renewable Energy Generation Investments (input as negative)	-$ 163,929			-$ 163,929	$ -			$ -	-$ 163,929
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 56,177,481**	**$ 3,242,950**	**$ -**	**$ 59,420,431**	**-$ 21,734,751**	**-$ 1,842,780**	**$ -**	**-$ 23,577,531**	**$ 35,842,900**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 1,842,780**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	
Stores Equipment	
Net Depreciation	-$ 1,842,780

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Attachment 2 (of 8):

2-B Appendix 2-C Depreciation and Amortization Expense

Appendix 2-C
Depreciation and Amortization Expense

This appendix is to be completed in conjunction with the accounting instructions in Appendix 2-B

Scenario that applies	Applicable Years and Accounting Standard	Year Reflected in Schedule Below	Accounting Standard Reflected in Schedule Below
Rebasing for the first time with depreciation policy changes made in 2012. ☐	This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Rebasing for the first time with depreciation policy changes made in 2013. ☑	This appendix must be duplicated and completed for the years 2013 to 2018. The appendix for 2013 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2013 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).	2013	CGAAP
Already rebased with depreciation policy changes in a prior rate application ☐	This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		

		Book Values							Service Lives				Depreciation Expense					
Account	**Description**	**Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]**	**Less Fully Depreciated [7]**	**Net Amount of Existing Assets Before Policy Change to be Depreciated**	**Opening Gross Book Value of Assets Acquired After Policy Change [2]**	**Less Fully Depreciated [8]**	**Net Amount of Assets Acquired After Policy Change to be Depreciated**	**Current Year Additions**	**Average Remaining Life of Assets Existing Before Policy Change [3]**	**Depreciation Rate Assets Acquired After Policy Change**	**Life of Assets Acquired After Policy Change [4]**	**Depreciation Rate on New Additions**	**Depreciation Expense on Assets Existing Before Policy Change**	**Depreciation Expense on Assets Acquired After Policy Change**	**Depreciation Expense on Current Year Additions [5]**	**Total Current Year Depreciation Expense**	**Depreciation Expense per Appendix 2-BA Fixed Assets, Column J**	**Variance [6]**
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 455,376	$ 8,216	$ 447,160	$ 54,671		$ 54,671	$ 54,671	1.26	79.46%	3.00	33.33%	$ 355,293	$ 18,224	$ 9,112	$ 382,628	$ 737,541	$ 354,913
1612	Land Rights (Formally known as Account 1906)	$ 42,932		$ 42,932	$ 947		$ 947	$ 947		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1805	Land	$ 103,344		$ 103,344	$ 695		$ 695	$ 695		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings	$ 124,624		$ 124,624	$ 24,917		$ 24,917	$ 24,917	38.16	2.62%	60.00	1.67%	$ 3,266	$ 415	$ 208	$ 3,889	$ 75,074	$ 71,185
1810	Leasehold Improvements	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 416,939		$ 416,939	$ 16,591		$ 16,591	$ 16,591	41.37	2.42%	60.00	1.67%	$ 10,078	$ 277	$ 138	$ 10,493	$ 198,234	$ 187,742
1825	Storage Battery Equipment	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 3,625,291		$ 3,625,291	$ 508,874		$ 508,874	$ 508,874	29.95	3.34%	50.00	2.00%	$ 121,035	$ 10,177	$ 5,089	$ 136,301	$ 2,544,985	$ 2,408,684
1835	Overhead Conductors & Devices	$ 3,973,943		$ 3,973,943	$ 770,131		$ 770,131	$ 770,131	21.07	4.75%	60.00	1.67%	$ 188,573	$ 12,836	$ 6,418	$ 207,827	$ 7,035,076	$ 6,827,249
1840	Underground Conduit	$ 2,397,565		$ 2,397,565	$ 46,781		$ 46,781	$ 46,781	40.15	2.49%	45.00	2.22%	$ 59,715	$ 1,040	$ 520	$ 61,274	$ 355,354	$ 294,079
1845	Underground Conductors & Devices	$ 4,872,045		$ 4,872,045	$ 379,360		$ 379,360	$ 379,360	38.61	2.59%	45.00	2.22%	$ 126,171	$ 8,430	$ 4,215	$ 138,816	$ 953,898	$ 815,082
1850	Line Transformers	$ 6,053,932		$ 6,053,932	$ 649,661		$ 649,661	$ 649,661	33.26	3.01%	40.00	2.50%	$ 182,002	$ 16,242	$ 8,121	$ 206,364	$ 1,267,670	$ 1,061,306
1855	Services (Overhead & Underground)	$ 2,484,788		$ 2,484,788	$ 332,065		$ 332,065	$ 332,065	38.19	2.62%	60.00	1.67%	$ 65,057	$ 5,534	$ 2,767	$ 73,359	$ 1,486,280	$ 1,412,921
1860	Meters	$ 2,475,116		$ 2,475,116	$ 35,278		$ 35,278	$ 35,278	37.91	2.64%	25.00	4.00%	$ 65,289	$ 1,411	$ 706	$ 67,406	$ 1,198,433	$ 1,131,027
1860	Meters (Smart Meters)	$ -		$ -	$ 229,651		$ 229,651	$ 229,651	-	0.00%	12.00	8.33%	$ -	$ 19,138	$ 9,569	$ 28,706		-$ 28,706
1905	Land	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1910	Leasehold Improvements	$ 174,259		$ 174,259	$ 53,273		$ 53,273	$ 53,273	51.13	1.96%	55.00	1.82%	$ 3,408	$ 969	$ 484	$ 4,861	$ 17,091	$ 12,230
1915	Office Furniture & Equipment (10 years)	$ 23,165		$ 23,165	$ 3,059		$ 3,059	$ 3,059	2.68	37.28%	10.00	10.00%	$ 8,636	$ 306	$ 153	$ 9,095	$ 68,291	$ 59,196
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ -		$ -	$ -		$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ 3,892	$ 3,892
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -		$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ 19,443	$ 19,443
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 41,332		$ 41,332	$ 57,214		$ 57,214	$ 57,214	4.50	22.22%	5.00	20.00%	$ 9,185	$ 11,443	$ 5,721	$ 26,349	$ 97,941	$ 71,592
1930	Transportation Equipment	$ 925,955		$ 925,955	$ 386,632		$ 386,632	$ 386,632	2.77	36.07%	8.00	12.50%	$ 333,978	$ 48,329	$ 24,164	$ 406,472	$ 1,960,132	$ 1,553,660
1935	Stores Equipment	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 79,940		$ 79,940	$ 16,442		$ 16,442	$ 16,442	4.55	21.99%	10.00	10.00%	$ 17,580	$ 1,644	$ 822	$ 20,046	$ 117,688	$ 97,642
1945	Measurement & Testing Equipment	$ 11,001		$ 11,001	$ -		$ -	$ -	6.09	16.43%	8.00	12.50%	$ 1,808	$ -	$ -	$ 1,808	$ 5,269	$ 3,461
1950	Power Operated Equipment	$ 51,894		$ 51,894	$ -		$ -	$ -	6.48	15.44%	8.00	12.50%	$ 8,011	$ -	$ -	$ 8,011	$ 20,209	$ 12,197
1955	Communications Equipment	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1970	Load Management Controls Customer Premises	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 203,267		$ 203,267	$ 42,216		$ 42,216	$ 42,216	4.75	21.05%	5.00	20.00%	$ 42,793	$ 8,443	$ 4,222	$ 55,458	$ 57,713	$ 2,255
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1990	Other Tangible Property	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1995	Contributions & Grants	-$ 4,479,752		-$ 4,479,752	-$ 1,446,296		-$ 1,446,296	-$ 1,446,296	20.96	4.77%	25.00	4.00%	-$ 213,766	-$ 57,852	-$ 28,926	-$ 300,543	-$ 971,011	-$ 670,467
	Total	**$ 24,056,954**	**$ 8,216**	**$ 24,048,738**	**$ 2,162,162**	**$ -**	**$ 2,162,162**	**$ 2,162,162**					**$ 1,388,113**	**$ 107,005**	**$ 53,502**	**$ 1,548,620**	**$ 17,249,204**	**$ 15,700,583**

General: Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial Statements.

Notes:

1 This is the net book value of assets that existed as at the date of the utility's change in depreciation policies (i.e. as at Jan. 1, 2012 or Jan. 1, 2013). These assets are to be depreciated at the average remaining service life. This amount will not change in years subsequent to the date of the utility's change in depreciation policies. This column is expected to be used until the assets that existed as at the date of the utility's change in depreciation policies are fully depreciated.

2 This is the opening gross book value of assets that have been acquired after the date of the utilities change in depreciation policies (i.e. additions starting in 2012/2013 for those who changed policies Jan. 1, 2012/2013). These assets are to be depreciated at the revised service life. The amount is expected to be equal to the gross book value of the prior year plus the prior year's additions.

3 A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated. As a result, Asset A would have a remaining service life of 17 years (20 years less 3 years) as at January 1 of the year of policy changes. Due to making the change in policies under CGAAP, management re-assessed the asset useful lives and concluded that the revised useful life of Asset A is now 30 years. Therefore, the average remaining useful life of the opening balance of Asset A is determined to be 27 years (30 years less 3 years) under the revised CGAAP as at January 1 of the year of policy changes.

4 The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.

5 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

6 The applicant must provide an explanation of material variances in evidence.

7 This should include assets in column a (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change

8 This should include assets in column d (excel column f) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

Scenario that applies		Applicable Years and Accounting Standard	Year Reflected in Schedule Below	Accounting Standard Reflected in Schedule Below
Rebasing for the first time with depreciation policy changes made in 2012	☐	This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Rebasing for the first time with depreciation policy changes made in 2013	☑	This appendix must be duplicated and completed for the years 2013 to 2018. The appendix for 2013 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2013 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).	2013	Revised CGAAP
Already rebased with depreciation policy changes in a prior rate application	☐	This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		

		Book Values							Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 402,593		$ 402,593	$ 54,671		$ 54,671	$ 54,671	1.11	89.87%	3.00	33.33%	$ 361,821	$ 18,224	$ 9,112	$ 389,156	$ 737,541	$ 348,385
1612	Land Rights (Formally known as Account 1906)	$ 43,879		$ 43,879	$ 947		$ 947	$ 947		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1805	Land	$ 104,039		$ 104,039	$ 695		$ 695	$ 695		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings	$ 145,794		$ 145,794	$ 24,917		$ 24,917	$ 24,917	44.64	2.24%	60.00	1.67%	$ 3,266	$ 415	$ 208	$ 3,889	$ 75,074	$ 71,185
1810	Leasehold Improvements	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 419,329		$ 419,329	$ 12,875		$ 12,875	$ 12,875	41.61	2.40%	60.00	1.67%	$ 10,078	$ 215	$ 107	$ 10,400	$ 198,234	$ 187,834
1825	Storage Battery Equipment	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 3,978,438		$ 3,978,438	$ 471,688		$ 471,688	$ 471,688	32.87	3.04%	50.00	2.00%	$ 121,035	$ 9,434	$ 4,717	$ 135,185	$ 2,544,985	$ 2,409,800
1835	Overhead Conductors & Devices	$ 4,979,931		$ 4,979,931	$ 700,608		$ 700,608	$ 700,608	26.41	3.79%	60.00	1.67%	$ 188,573	$ 11,677	$ 5,838	$ 206,089	$ 7,035,076	$ 6,828,987
1840	Underground Conduit	$ 2,362,088		$ 2,362,088	$ 30,270		$ 30,270	$ 30,270	39.56	2.53%	45.00	2.22%	$ 59,715	$ 673	$ 336	$ 60,724	$ 355,354	$ 294,630
1845	Underground Conductors & Devices	$ 5,068,258		$ 5,068,258	$ 344,473		$ 344,473	$ 344,473	40.17	2.49%	45.00	2.22%	$ 126,171	$ 7,655	$ 3,827	$ 137,653	$ 953,898	$ 816,245
1850	Line Transformers	$ 6,507,209		$ 6,507,209	$ 604,928		$ 604,928	$ 604,928	35.75	2.80%	40.00	2.50%	$ 182,002	$ 15,123	$ 7,562	$ 204,687	$ 1,267,670	$ 1,062,984
1855	Services (Overhead & Underground)	$ 2,725,243		$ 2,725,243	$ 308,080		$ 308,080	$ 308,080	41.89	2.39%	60.00	1.67%	$ 65,057	$ 5,135	$ 2,567	$ 72,759	$ 1,486,280	$ 1,413,521
1860	Meters	$ 459,052		$ 459,052	$ 25,249		$ 25,249	$ 25,249	7.03	14.22%	25.00	4.00%	$ 65,289	$ 1,010	$ 505	$ 66,804	$ 1,198,433	$ 1,131,629
1860	Meters (Smart Meters)	$ 3,099,642		$ 3,099,642	$ 211,907		$ 211,907	$ 211,907	12.88	7.76%	12.00	8.33%	$ 240,645	$ 17,659	$ 8,829	$ 267,133		-$ 267,133
1905	Land	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1910	Leasehold Improvements	$ 223,639		$ 223,639	$ 53,273		$ 53,273	$ 53,273	65.62	1.52%	55.00	1.82%	$ 3,408	$ 969	$ 484	$ 4,861	$ 17,091	$ 12,230
1915	Office Furniture & Equipment (10 years)	$ 21,131		$ 21,131	$ 3,059		$ 3,059	$ 3,059	2.45	40.87%	10.00	10.00%	$ 8,636	$ 306	$ 153	$ 9,095	$ 68,291	$ 59,196
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ -		$ -	$ -		$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ 97,941	$ 97,941
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -		$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ 3,892	$ 3,892
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 83,696		$ 83,696	$ 57,214		$ 57,214	$ 57,214	9.11	10.97%	5.00	20.00%	$ 9,185	$ 11,443	$ 5,721	$ 26,349	$ 19,443	-$ 6,906
1930	Transportation Equipment	$ 1,051,728		$ 1,051,728	$ 386,632		$ 386,632	$ 386,632	3.15	31.76%	8.00	12.50%	$ 333,978	$ 48,329	$ 24,164	$ 406,472	$ 1,960,132	$ 1,553,660
1935	Stores Equipment	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 74,551		$ 74,551	$ 16,442		$ 16,442	$ 16,442	4.24	23.58%	10.00	10.00%	$ 17,580	$ 1,644	$ 822	$ 20,046	$ 117,688	$ 97,642
1945	Measurement & Testing Equipment	$ 9,193		$ 9,193	$ -		$ -	$ -	5.09	19.66%	8.00	12.50%	$ 1,808	$ -	$ -	$ 1,808	$ 5,269	$ 3,461
1950	Power Operated Equipment	$ 43,882		$ 43,882	$ -		$ -	$ -	5.48	18.26%	8.00	12.50%	$ 8,011	$ -	$ -	$ 8,011	$ 20,209	$ 12,197
1955	Communications Equipment	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1970	Load Management Controls Customer Premises	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 198,468		$ 198,468	$ 42,216		$ 42,216	$ 42,216	4.64	21.56%	5.00	20.00%	$ 42,793	$ 8,443	$ 4,222	$ 55,458	$ 57,713	$ 2,255
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1990	Other Tangible Property	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1995	Contributions & Grants	-$ 5,819,424		-$ 5,819,424	-$ 1,446,296		-$ 1,446,296	-$ 1,446,296	27.22	3.67%	25.00	4.00%	-$ 213,766	-$ 57,852	-$ 28,926	-$ 300,543	-$ 971,011	-$ 670,467
	Total	**$ 26,182,359**	**$ -**	**$ 26,182,359**	**$ 1,903,847**	**$ -**	**$ 1,903,847**	**$ 1,903,847**					**$ 1,635,286**	**$ 100,500**	**$ 50,250**	**$ 1,786,036**	**$ 17,249,204**	**$ 15,463,167**

General: Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial Statements.

Notes:

1 This is the net book value of assets that existed as at the date of the utility's change in depreciation policies (i.e. as at Jan. 1, 2012 or Jan. 1, 2013). These assets are to be depreciated at the average remaining service life. This amount will not change in years subsequent to the date of the utility's change in depreciation policies. This column is expected to be used

2 This is the opening gross book value of assets that have been acquired after the date of the utilities change in depreciation policies (i.e. additions starting in 2012/2013 for those who changed policies Jan. 1, 2012/2013). These assets are to be depreciated at the revised service life. The amount is expected to be equal to the gross book value of the prior year plus the

3 A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated. As

4 The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.

5 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

6 The applicant must provide an explanation of material variances in evidence.

7 This should include assets in column a (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change

8 This should include assets in column d (excel column f) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

Scenario that applies		Applicable Years and Accounting Standard	Year Reflected in Schedule Below	Accounting Standard Reflected in Schedule Below
Rebasing for the first time with depreciation policy changes made in 2012	☐	This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Rebasing for the first time with depreciation policy changes made in 2013	☑	This appendix must be duplicated and completed for the years 2013 to 2018. The appendix for 2013 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2013 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).	2014	Revised CGAAP
Already rebased with depreciation policy changes in a prior rate application	☐	This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		

		Book Values							Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 402,593		$ 402,593	$ 87,557		$ 87,557	$ 87,557	1.06	94.40%	3.00	33.33%	$ 380,044	$ 29,186	$ 14,593	$ 423,823	$ 817,283	$ 393,460
1612	Land Rights (Formally known as Account 1906)	$ 43,879		$ 43,879	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1805	Land	$ 104,039		$ 104,039	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings	$ 145,794		$ 145,794	$ 4,014		$ 4,014	$ 4,014	39.61	2.52%	60.00	1.67%	$ 3,681	$ 67	$ 33	$ 3,781	$ 83,989	$ 80,208
1810	Leasehold Improvements	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 423,045		$ 423,045	$ 3,665		$ 3,665	$ 3,665	41.10	2.43%	60.00	1.67%	$ 10,293	$ 61	$ 31	$ 10,384	$ 222,937	$ 212,553
1825	Storage Battery Equipment	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 4,015,623		$ 4,015,623	$ 1,270,813		$ 1,270,813	$ 1,270,813	30.78	3.25%	50.00	2.00%	$ 130,468	$ 25,416	$ 12,708	$ 168,593	$ 2,788,948	$ 2,620,355
1835	Overhead Conductors & Devices	$ 5,049,454		$ 5,049,454	$ 1,410,235		$ 1,410,235	$ 1,410,235	25.22	3.97%	60.00	1.67%	$ 200,250	$ 23,504	$ 11,752	$ 235,506	$ 7,540,555	$ 7,305,049
1840	Underground Conduit	$ 2,378,600		$ 2,378,600	$ 61,799		$ 61,799	$ 61,799	39.39	2.54%	45.00	2.22%	$ 60,388	$ 1,373	$ 687	$ 62,448	$ 464,965	$ 402,517
1845	Underground Conductors & Devices	$ 5,103,145		$ 5,103,145	$ 734,039		$ 734,039	$ 734,039	38.13	2.62%	45.00	2.22%	$ 133,826	$ 16,312	$ 8,156	$ 158,294	$ 1,207,629	$ 1,049,335
1850	Line Transformers	$ 6,551,943		$ 6,551,943	$ 598,730		$ 598,730	$ 598,730	33.71	2.97%	40.00	2.50%	$ 194,372	$ 14,968	$ 7,484	$ 216,824	$ 1,520,711	$ 1,303,887
1855	Services (Overhead & Underground)	$ 2,749,228		$ 2,749,228	$ 548,804		$ 548,804	$ 548,804	39.17	2.55%	60.00	1.67%	$ 70,192	$ 9,147	$ 4,573	$ 83,912	$ 1,665,218	$ 1,581,305
1860	Meters	$ 469,081		$ 469,081	$ -		$ -	$ -		0.00%	25.00	4.00%	$ -	$ -	$ -	$ -	$ -	$ -
1860	Meters (Smart Meters)	$ 3,117,386		$ 3,117,386	$ 162,463		$ 162,463	$ 162,463	7.86	12.72%	12.00	8.33%	$ 396,427	$ 13,539	$ 6,769	$ 416,735	$ 1,508,385	$ 1,091,650
1905	Land	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1910	Leasehold Improvements	$ 223,639		$ 223,639	$ 47,056		$ 47,056	$ 47,056	51.10	1.96%	55.00	1.82%	$ 4,377	$ 856	$ 428	$ 5,660	$ 27,661	$ 22,001
1915	Office Furniture & Equipment (10 years)	$ 21,131		$ 21,131	$ 2,395		$ 2,395	$ 2,395	2.36	42.32%	10.00	10.00%	$ 8,942	$ 240	$ 120	$ 9,302	$ 72,339	$ 63,038
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ 97,941	$ 97,941
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ 3,892	$ 3,892
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 83,696		$ 83,696	$ 34,018		$ 34,018	$ 34,018	4.06	24.65%	5.00	20.00%	$ 20,628	$ 6,804	$ 3,402	$ 30,833	$ 43,473	$ 12,639
1930	Transportation Equipment	$ 1,051,728	$ 23,326	$ 1,028,402	$ 137,334		$ 137,334	$ 137,334	2.79	35.80%	8.00	12.50%	$ 368,133	$ 17,167	$ 8,583	$ 393,883	$ 2,168,467	$ 1,774,585
1935	Stores Equipment	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 74,551		$ 74,551	$ 23,803		$ 23,803	$ 23,803	3.88	25.79%	10.00	10.00%	$ 19,224	$ 2,380	$ 1,190	$ 22,794	$ 137,164	$ 114,369
1945	Measurement & Testing Equipment	$ 9,193		$ 9,193	$ -		$ -	$ -	5.09	19.66%	8.00	12.50%	$ 1,808	$ -	$ -	$ 1,808	$ 6,715	$ 4,907
1950	Power Operated Equipment	$ 43,882		$ 43,882	$ -		$ -	$ -	5.48	18.26%	8.00	12.50%	$ 8,011	$ -	$ -	$ 8,011	$ 26,618	$ 18,607
1955	Communications Equipment	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1970	Load Management Controls Customer Premises	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 198,468		$ 198,468	$ 3,856		$ 3,856	$ 3,856	3.87	25.82%	5.00	20.00%	$ 51,236	$ 771	$ 386	$ 52,393	$ 83,331	$ 30,938
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1990	Other Tangible Property	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1995	Contributions & Grants	-$ 5,819,424		-$ 5,819,424	-$ 810,946		-$ 810,946	-$ 810,946	21.43	4.67%	25.00	4.00%	-$ 271,617	-$ 32,438	-$ 16,219	-$ 320,274	-$ 1,258,847	-$ 938,573
	Total	$ 26,440,674	$ 23,326	$ 26,417,348	$ 4,319,638	$ -	$ 4,319,638	$ 4,319,638					$ 1,790,683	$ 129,352	$ 64,676	$ 1,984,711	$ 19,229,374	$ 17,244,663

General: Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial Statements.

Notes:

1 This is the net book value of assets that existed as at the date of the utility's change in depreciation policies (i.e. as at Jan. 1, 2012 or Jan. 1, 2013). These assets are to be depreciated at the average remaining service life. This amount will not change in years subsequent to the date of the utility's change in depreciation policies. This column is expected to be used

2 This is the opening gross book value of assets that have been acquired after the date of the utilities change in depreciation policies (i.e. additions starting in 2012/2013 for those who changed policies Jan. 1, 2012/2013). These assets are to be depreciated at the revised service life. The amount is expected to be equal to the gross book value of the prior year plus the

3 A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated. As

4 The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.

5 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

6 The applicant must provide an explanation of material variances in evidence.

7 This should include assets in column a (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change

8 This should include assets in column d (excel column f) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

Scenario that applies		Applicable Years and Accounting Standard	Year Reflected in Schedule Below	Accounting Standard Reflected in Schedule Below
Rebasing for the first time with depreciation policy changes made in 2012	☐	This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Rebasing for the first time with depreciation policy changes made in 2013	☐	This appendix must be duplicated and completed for the years 2013 to 2018. The appendix for 2013 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2013 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).	2014	MIFRS
Already rebased with depreciation policy changes in a prior rate application	☑	This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		

		Book Values							Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 402,593	$ 8,268	$ 394,324	$ 87,557		$ 87,557	$ 87,557	1.06	94.40%	3.00	33.33%	$ 372,239	$ 29,186	$ 14,593	$ 416,018	$ 896,781	$ 480,764
1612	Land Rights (Formally known as Account 1906)	$ 43,879		$ 43,879	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1805	Land	$ 104,039		$ 104,039	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings	$ 145,794		$ 145,794	$ 4,014		$ 4,014	$ 4,014	39.61	2.52%	60.00	1.67%	$ 3,681	$ 67	$ 33	$ 3,781	$ 79,063	$ 75,281
1810	Leasehold Improvements	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 423,045		$ 423,045	$ -		$ -	$ -	41.10	2.43%	60.00	1.67%	$ 10,293	$ -	$ -	$ 10,293	$ 208,826	$ 198,533
1825	Storage Battery Equipment	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 4,015,623		$ 4,015,623	$ 1,232,100		$ 1,232,100	$ 1,232,100	30.78	3.25%	50.00	2.00%	$ 130,468	$ 24,642	$ 12,321	$ 167,431	$ 2,646,159	$ 2,478,727
1835	Overhead Conductors & Devices	$ 5,049,454		$ 5,049,454	$ 1,338,932		$ 1,338,932	$ 1,338,932	25.22	3.97%	60.00	1.67%	$ 200,250	$ 22,316	$ 11,158	$ 233,723	$ 7,244,584	$ 7,010,861
1840	Underground Conduit	$ 2,378,600		$ 2,378,600	$ 45,672		$ 45,672	$ 45,672	39.39	2.54%	45.00	2.22%	$ 60,388	$ 1,015	$ 507	$ 61,910	$ 421,944	$ 360,034
1845	Underground Conductors & Devices	$ 5,103,145		$ 5,103,145	$ 698,300		$ 698,300	$ 698,300	38.13	2.62%	45.00	2.22%	$ 133,826	$ 15,518	$ 7,759	$ 157,102	$ 1,112,622	$ 955,520
1850	Line Transformers	$ 6,551,943		$ 6,551,943	$ 552,591		$ 552,591	$ 552,591	33.71	2.97%	40.00	2.50%	$ 194,372	$ 13,815	$ 6,907	$ 215,094	$ 1,359,688	$ 1,144,594
1855	Services (Overhead & Underground)	$ 2,749,228		$ 2,749,228	$ 523,811		$ 523,811	$ 523,811	39.17	2.55%	60.00	1.67%	$ 70,192	$ 8,730	$ 4,365	$ 83,287	$ 1,560,838	$ 1,477,550
1860	Meters	$ 469,081		$ 469,081	$ -		$ -	$ -		0.00%	25.00	4.00%	$ -	$ -	$ -	$ -	$ 1,198,433	$ 1,198,433
1860	Meters (Smart Meters)	$ 3,117,386		$ 3,117,386	$ 134,232		$ 134,232	$ 134,232	12.07	8.29%	12.00	8.33%	$ 258,304	$ 11,186	$ 5,593	$ 275,083	$ 309,952	$ 34,870
1905	Land	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1910	Leasehold Improvements	$ 223,639		$ 223,639	$ 47,056		$ 47,056	$ 47,056	51.10	1.96%	55.00	1.82%	$ 4,377	$ 856	$ 428	$ 5,660	$ 21,895	$ 16,235
1915	Office Furniture & Equipment (10 years)	$ 21,131		$ 21,131	$ 2,395		$ 2,395	$ 2,395	2.36	42.32%	10.00	10.00%	$ 8,942	$ 240	$ 120	$ 9,302	$ 70,716	$ 61,414
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ 97,941	$ 97,941
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ 3,892	$ 3,892
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 83,696		$ 83,696	$ 34,018		$ 34,018	$ 34,018	4.06	24.65%	5.00	20.00%	$ 20,628	$ 6,804	$ 3,402	$ 30,833	$ 43,473	$ 12,639
1930	Transportation Equipment	$ 1,051,728	$ 13,809	$ 1,037,919	$ 137,334		$ 137,334	$ 137,334	2.79	35.80%	8.00	12.50%	$ 371,539	$ 17,167	$ 8,583	$ 397,289	$ 2,148,461	$ 1,751,171
1935	Stores Equipment	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 74,551	$ 7,203	$ 67,348	$ 23,803		$ 23,803	$ 23,803	3.88	25.79%	10.00	10.00%	$ 17,366	$ 2,380	$ 1,190	$ 20,937	$ 139,024	$ 118,087
1945	Measurement & Testing Equipment	$ 9,193		$ 9,193	$ -		$ -	$ -	5.09	19.66%	8.00	12.50%	$ 1,808	$ -	$ -	$ 1,808	$ 7,077	$ 5,269
1950	Power Operated Equipment	$ 43,882		$ 43,882	$ -		$ -	$ -	5.48	18.26%	8.00	12.50%	$ 8,011	$ -	$ -	$ 8,011	$ 28,220	$ 20,209
1955	Communications Equipment	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1970	Load Management Controls Customer Premises	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 198,468		$ 198,468	$ 3,856		$ 3,856	$ 3,856	3.87	25.82%	5.00	20.00%	$ 51,236	$ 771	$ 386	$ 52,393	$ 57,713	$ 5,320
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1990	Other Tangible Property	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1995	Contributions & Grants	-$ 5,819,424		-$ 5,819,424	$ -		$ -	$ -	21.43	4.67%	25.00	4.00%	-$ 271,617	$ -	$ -	-$ 271,617	-$ 971,011	-$ 699,393
2440	Deferred Revenue				-$ 810,946		-$ 810,946	-$ 810,946	60.00	1.67%	60.00	1.67%	$ -	-$ 13,516	-$ 6,758	-$ 20,274	-$ 119,932	-$ 99,658
	Total	**$ 26,440,674**	**$ 29,281**	**$ 26,411,393**	**$ 4,054,728**	**$ -**	**$ 4,054,728**	**$ 4,054,728**					**$ 1,646,303**	**$ 141,175**	**$ 70,588**	**$ 1,858,066**	**$ 18,566,358**	**$ 16,708,292**

General: Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial Statements.

Notes:

1. This is the net book value of assets that existed as at the date of the utility's change in depreciation policies (i.e. as at Jan. 1, 2012 or Jan. 1, 2013). These assets are to be depreciated at the average remaining service life. This amount will not change in years subsequent to the date of the utility's change in depreciation policies. This column is expected to be used
2. This is the opening gross book value of assets that have been acquired after the date of the utilities change in depreciation policies (i.e. additions starting in 2012/2013 for those who changed policies Jan. 1, 2012/2013). These assets are to be depreciated at the revised service life. The amount is expected to be equal to the gross book value of the prior year plus the
3. A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated. As
4. The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.
5. Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.
6. The applicant must provide an explanation of material variances in evidence.
7. This should include assets in column a (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change
8. This should include assets in column d (excel column f) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

Scenario that applies	Applicable Years and Accounting Standard	Year Reflected in Schedule Below	Accounting Standard Reflected in Schedule Below
Rebasing for the first time with depreciation policy changes made in 2012 ☐	This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Rebasing for the first time with depreciation policy changes made in 2013 ☑	This appendix must be duplicated and completed for the years 2013 to 2018. The appendix for 2013 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2013 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).	2015	MIFRS
Already rebased with depreciation policy changes in a prior rate application ☐	This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		

		Book Values							Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 330,909	$ 13,365	$ 317,544	$ 218,361		$ 218,361	$ 218,361	0.81	123.67%	3.00	33.33%	$ 392,702	$ 72,787	$ 36,393	$ 501,882	$ 1,020,368	$ 518,486
1612	Land Rights (Formally known as Account 1906)	$ 43,879		$ 43,879	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1805	Land	$ 104,039		$ 104,039	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings	$ 145,820		$ 145,820	$ 28,387		$ 28,387	$ 28,387	38.91	2.57%	60.00	1.67%	$ 3,748	$ 473	$ 237	$ 4,458	$ 83,321	$ 78,863
1810	Leasehold Improvements	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 408,738		$ 408,738	$ 0		$ 0	$ 0	39.71	2.52%	60.00	1.67%	$ 10,293	$ 0	$ 0	$ 10,293	$ 201,826	$ 191,533
1825	Storage Battery Equipment	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 5,064,968		$ 5,064,968	$ 706,809		$ 706,809	$ 706,809	32.84	3.04%	50.00	2.00%	$ 154,223	$ 14,136	$ 7,068	$ 175,427	$ 2,744,057	$ 2,568,630
1835	Overhead Conductors & Devices	$ 6,107,456		$ 6,107,456	$ 983,489		$ 983,489	$ 983,489	27.45	3.64%	60.00	1.67%	$ 222,534	$ 16,391	$ 8,196	$ 247,121	$ 7,465,468	$ 7,218,346
1840	Underground Conduit	$ 2,341,171		$ 2,341,171	$ 113,924		$ 113,924	$ 113,924	38.13	2.62%	45.00	2.22%	$ 61,403	$ 2,532	$ 1,266	$ 65,200	$ 490,307	$ 425,107
1845	Underground Conductors & Devices	$ 5,606,712		$ 5,606,712	$ 298,197		$ 298,197	$ 298,197	37.55	2.66%	45.00	2.22%	$ 149,319	$ 6,627	$ 3,313	$ 159,258	$ 1,283,508	$ 1,124,250
1850	Line Transformers	$ 6,898,776		$ 6,898,776	$ 725,235		$ 725,235	$ 725,235	33.41	2.99%	40.00	2.50%	$ 206,462	$ 18,131	$ 9,065	$ 233,658	$ 1,487,577	$ 1,253,919
1855	Services (Overhead & Underground)	$ 3,174,497		$ 3,174,497	$ 605,660		$ 605,660	$ 605,660	40.22	2.49%	60.00	1.67%	$ 78,922	$ 10,094	$ 5,047	$ 94,064	$ 1,644,807	$ 1,550,744
1860	Meters	$ 459,052		$ 459,052	$ -		$ -	$ -		0.00%	25.00	4.00%	$ -	$ -	$ -	$ -	$ -	$ -
1860	Meters (Smart Meters)	$ 2,900,903		$ 2,900,903	$ 353,471		$ 353,471	$ 353,471	7.15	13.99%	12.00	8.33%	$ 405,695	$ 29,456	$ 14,728	$ 449,879	$ 1,783,927	$ 1,334,048
1905	Land	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1910	Leasehold Improvements	$ 265,890		$ 265,890	$ 127,047		$ 127,047	$ 127,047	3.00	33.29%	55.00	1.82%	$ 88,515	$ 2,310	$ 1,155	$ 91,980	$ 28,283	-$ 63,697
1915	Office Furniture & Equipment (10 years)	$ 21,102	$ 323	$ 20,779	$ 5,892		$ 5,892	$ 5,892	2.30	43.51%	10.00	10.00%	$ 9,041	$ 589	$ 295	$ 9,925	$ 74,855	$ 64,930
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ 97,941	$ 97,941
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ 3,892	$ 3,892
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 93,685		$ 93,685	$ 11,372		$ 11,372	$ 11,372	3.42	29.28%	5.00	20.00%	$ 27,431	$ 2,274	$ 1,137	$ 30,843	$ 72,041	$ 41,198
1930	Transportation Equipment	$ 958,290	$ 833	$ 957,457	$ 212,573		$ 212,573	$ 212,573	2.47	40.52%	8.00	12.50%	$ 388,006	$ 26,572	$ 13,286	$ 427,864	$ 2,179,045	$ 1,751,181
1935	Stores Equipment	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 77,019	$ 1,101	$ 75,918	$ 12,251		$ 12,251	$ 12,251	3.56	28.05%	10.00	10.00%	$ 21,296	$ 1,225	$ 613	$ 23,133	$ 155,133	$ 132,000
1945	Measurement & Testing Equipment	$ 7,385		$ 7,385	$ 16,620		$ 16,620	$ 16,620	4.09	24.48%	8.00	12.50%	$ 1,808	$ 2,078	$ 1,039	$ 4,924	$ 9,923	$ 4,999
1950	Power Operated Equipment	$ 35,870		$ 35,870	$ 158,995		$ 158,995	$ 158,995	4.48	22.33%	8.00	12.50%	$ 8,011	$ 19,874	$ 9,937	$ 37,823	$ 26,261	-$ 11,562
1955	Communications Equipment	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1970	Load Management Controls Customer Premises	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 202,324		$ 202,324	$ 64,232		$ 64,232	$ 64,232	3.89	25.70%	5.00	20.00%	$ 52,007	$ 12,846	$ 6,423	$ 71,277	$ 116,143	$ 44,866
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1990	Other Tangible Property	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1995	Contributions & Grants	-$ 5,819,424		-$ 5,819,424	$ -		$ -	$ -	21.43	4.67%	25.00	4.00%	-$ 271,617	$ -	$ -	-$ 271,617	-$ 1,097,700	-$ 826,082
2440	Deferred Revenue	-$ 691,014			-$ 667,719		-$ 667,719	-$ 667,719	60.00	1.67%	60.00	1.67%	$ -	-$ 11,129	-$ 5,564	-$ 16,693	-$ 125,496	-$ 108,803
	Total	**$ 28,738,047**	**$ 15,622**	**$ 29,413,440**	**$ 3,974,797**	**$ -**	**$ 3,974,797**	**$ 3,974,797**					**$ 2,009,798**	**$ 227,267**	**$ 113,633**	**$ 2,350,698**	**$ 19,745,488**	**$ 17,394,790**

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Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial Statements.

Notes:

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2. This is the opening gross book value of assets that have been acquired after the date of the utilities change in depreciation policies (i.e. additions starting in 2012/2013 for those who changed policies Jan. 1, 2012/2013). These assets are to be depreciated at the revised service life. The amount is expected to be equal to the gross book value of the prior year plus the
3. A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated. As
4. The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.
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7. This should include assets in column a (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change
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Scenario that applies	Applicable Years and Accounting Standard	Year Reflected in Schedule Below	Accounting Standard Reflected in Schedule Below
Rebasing for the first time with depreciation policy changes made in 2012 ☐	This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
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Already rebased with depreciation policy changes in a prior rate application ☐	This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		

		Book Values							Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 425,684	$ 9,205	$ 416,478	$ 27,000		$ 27,000	$ 27,000	0.88	113.23%	3.00	33.33%	$ 471,594	$ 9,000	$ 4,500	$ 485,094	$ 1,107,800	$ 622,706
1612	Land Rights (Formally known as Account 1906)	$ 43,879		$ 43,879	$ 1,800		$ 1,800	$ 1,800	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1805	Land	$ 104,039		$ 104,039	$ 74,505		$ 74,505	$ 74,505	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings	$ 169,948		$ 169,948	$ 3,194		$ 3,194	$ 3,194	40.26	2.48%	60.00	1.67%	$ 4,221	$ 53	$ 27	$ 4,301	$ 87,843	$ 83,542
1810	Leasehold Improvements	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 364,372		$ 364,372	$ -		$ -	$ -	38.61	2.59%	60.00	1.67%	$ 9,437	$ -	$ -	$ 9,437	$ 211,553	$ 202,117
1825	Storage Battery Equipment	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 5,645,689		$ 5,645,689	$ 548,837		$ 548,837	$ 548,837	33.65	2.97%	50.00	2.00%	$ 167,795	$ 10,977	$ 5,488	$ 184,260	$ 2,839,763	$ 2,655,503
1835	Overhead Conductors & Devices	$ 6,860,376		$ 6,860,376	$ 887,131		$ 887,131	$ 887,131	28.73	3.48%	60.00	1.67%	$ 238,764	$ 14,786	$ 7,393	$ 260,942	$ 7,371,260	$ 7,110,318
1840	Underground Conduit	$ 2,386,731		$ 2,386,731	$ 221,003		$ 221,003	$ 221,003	37.33	2.68%	45.00	2.22%	$ 63,934	$ 4,911	$ 2,456	$ 71,301	$ 562,392	$ 491,091
1845	Underground Conductors & Devices	$ 5,734,023		$ 5,734,023	$ 659,042		$ 659,042	$ 659,042	36.77	2.72%	45.00	2.22%	$ 155,945	$ 14,645	$ 7,323	$ 177,913	$ 1,208,589	$ 1,030,676
1850	Line Transformers	$ 7,410,622		$ 7,410,622	$ 535,551		$ 535,551	$ 535,551	33.31	3.00%	40.00	2.50%	$ 222,455	$ 13,389	$ 6,694	$ 242,538	$ 1,529,179	$ 1,286,641
1855	Services (Overhead & Underground)	$ 3,696,187		$ 3,696,187	$ 591,581		$ 591,581	$ 591,581	41.52	2.41%	60.00	1.67%	$ 89,017	$ 9,860	$ 4,930	$ 103,806	$ 1,738,753	$ 1,634,947
1860	Meters	$ -		$ -	$ -		$ -	$ -		0.00%	25.00	4.00%	$ -	$ -	$ -	$ -	$ -	$ -
1860	Meters (Smart Meters)	$ 3,349,249		$ 3,349,249	$ 246,046		$ 246,046	$ 246,046	7.83	12.77%	12.00	8.33%	$ 427,765	$ 20,504	$ 10,252	$ 458,520	$ 2,124,961	$ 1,666,440
1905	Land	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1910	Leasehold Improvements	$ 386,550		$ 386,550	$ 41,813		$ 41,813	$ 41,813	51.25	1.95%	55.00	1.82%	$ 7,542	$ 760	$ 380	$ 8,683	$ 36,205	$ 27,523
1915	Office Furniture & Equipment (10 years)	$ 22,855		$ 22,855	$ -		$ -	$ -	2.34	42.75%	10.00	10.00%	$ 9,771	$ -	$ -	$ 9,771	$ 78,965	$ 69,194
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ -		$ -	$ -		$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ 97,941	$ 97,941
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -		$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ 3,892	$ 3,892
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 76,488		$ 76,488	$ 22,003		$ 22,003	$ 22,003	2.57	38.84%	5.00	20.00%	$ 29,706	$ 4,401	$ 2,200	$ 36,307	$ 103,947	$ 67,640
1930	Transportation Equipment	$ 1,014,952	$ 6,792	$ 1,008,160	$ 346,258		$ 346,258	$ 346,258	2.54	39.34%	8.00	12.50%	$ 396,578	$ 43,282	$ 21,641	$ 461,501	$ 1,841,558	$ 1,380,057
1935	Stores Equipment	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 73,160		$ 73,160	$ 15,489		$ 15,489	$ 15,489	3.20	31.20%	10.00	10.00%	$ 22,829	$ 1,549	$ 774	$ 25,153	$ 171,876	$ 146,723
1945	Measurement & Testing Equipment	$ 21,159		$ 21,159	$ -		$ -	$ -	5.45	18.36%	8.00	12.50%	$ 3,885	$ -	$ -	$ 3,885	$ 13,809	$ 9,923
1950	Power Operated Equipment	$ 196,825		$ 196,825	$ 1,574		$ 1,574	$ 1,574	7.06	14.17%	8.00	12.50%	$ 27,886	$ 197	$ 98	$ 28,181	$ 53,926	$ 25,745
1955	Communications Equipment	$ -		$ -	$ 31,915		$ 31,915	$ 31,915		0.00%		0.00%	$ -	$ -	$ -	$ -	$ 3,192	$ 3,192
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1970	Load Management Controls Customer Premises	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 208,126		$ 208,126	$ 188,030		$ 188,030	$ 188,030	3.21	31.16%	5.00	20.00%	$ 64,854	$ 37,606	$ 18,803	$ 121,263	$ 199,800	$ 78,537
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1990	Other Tangible Property	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1995	Contributions & Grants	-$ 5,692,735		-$ 5,692,735	$ -		$ -	$ -	20.96	4.77%	25.00	4.00%	-$ 271,617	$ -	$ -	-$ 271,617	-$ 1,310,532	-$ 1,038,915
2440	Deferred Revenue	-$ 1,353,169			-$ 1,192,751		-$ 1,192,751	-$ 1,192,751	54.91	1.82%	60.00	1.67%	$ -	-$ 19,879	-$ 9,940	-$ 29,819	-$ 136,339	-$ 106,521
	Total	**$ 31,145,011**	**$ 15,998**	**$ 32,482,182**	**$ 3,250,021**	**$ -**	**$ 3,250,021**	**$ 3,250,021**					**$ 2,142,360**	**$ 166,040**	**$ 83,020**	**$ 2,391,420**	**$ 19,940,333**	**$ 17,548,913**

General: Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial Statements.

Notes:

1. This is the net book value of assets that existed as at the date of the utility's change in depreciation policies (i.e. as at Jan. 1, 2012 or Jan. 1, 2013). These assets are to be depreciated at the average remaining service life. This amount will not change in years subsequent to the date of the utility's change in depreciation policies. This column is expected to be used
2. This is the opening gross book value of assets that have been acquired after the date of the utilities change in depreciation policies (i.e. additions starting in 2012/2013 for those who changed policies Jan. 1, 2012/2013). These assets are to be depreciated at the revised service life. The amount is expected to be equal to the gross book value of the prior year plus the
3. A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated. As
4. The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.
5. Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.
6. The applicant must provide an explanation of material variances in evidence.
7. This should include assets in column a (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change
8. This should include assets in column d (excel column f) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

Scenario that applies	Applicable Years and Accounting Standard	Year Reflected in Schedule Below	Accounting Standard Reflected in Schedule Below
Rebasing for the first time with depreciation policy changes made in 2012 ☐	This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Rebasing for the first time with depreciation policy changes made in 2013 ☑	This appendix must be duplicated and completed for the years 2013 to 2018. The appendix for 2013 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2013 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).	2017	MIFRS
Already rebased with depreciation policy changes in a prior rate application ☐	This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		

		Book Values							Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 365,252		$ 365,252	$ 35,000		$ 35,000	$ 35,000	0.74	134.43%	3.00	33.33%	$ 491,017	$ 11,667	$ 5,833	$ 508,517	$ 1,252,688	$ 744,171
1612	Land Rights (Formally known as Account 1906)	$ 45,679		$ 45,679	$ -		$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1805	Land	$ 178,544		$ 178,544	$ -		$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings	$ 168,620		$ 168,620	$ 748,343		$ 748,343	$ 748,343	39.45	2.53%	60.00	1.67%	$ 4,274	$ 12,472	$ 6,236	$ 22,983	$ 99,168	$ 76,185
1810	Leasehold Improvements	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 354,644		$ 354,644	$ -		$ -	$ -	37.58	2.66%	60.00	1.67%	$ 9,437	$ -	$ -	$ 9,437	$ 221,281	$ 211,845
1825	Storage Battery Equipment	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 6,021,242		$ 6,021,242	$ 360,363		$ 360,363	$ 360,363	33.98	2.94%	50.00	2.00%	$ 177,220	$ 7,207	$ 3,604	$ 188,031	$ 3,016,650	$ 2,828,619
1835	Overhead Conductors & Devices	$ 7,501,350		$ 7,501,350	$ 604,845		$ 604,845	$ 604,845	30.26	3.30%	60.00	1.67%	$ 247,877	$ 10,081	$ 5,040	$ 262,998	$ 7,622,457	$ 7,359,459
1840	Underground Conduit	$ 2,535,649		$ 2,535,649	$ 125,992		$ 125,992	$ 125,992	36.83	2.72%	45.00	2.22%	$ 68,845	$ 2,800	$ 1,400	$ 73,045	$ 635,876	$ 562,831
1845	Underground Conductors & Devices	$ 6,211,543		$ 6,211,543	$ 301,765		$ 301,765	$ 301,765	37.67	2.65%	45.00	2.22%	$ 164,892	$ 6,706	$ 3,353	$ 174,951	$ 1,393,465	$ 1,218,514
1850	Line Transformers	$ 7,717,024		$ 7,717,024	$ 376,028		$ 376,028	$ 376,028	33.38	3.00%	40.00	2.50%	$ 231,155	$ 9,401	$ 4,700	$ 245,256	$ 1,763,028	$ 1,517,772
1855	Services (Overhead & Underground)	$ 4,193,822		$ 4,193,822	$ 1,087,500		$ 1,087,500	$ 1,087,500	42.41	2.36%	60.00	1.67%	$ 98,876	$ 18,125	$ 9,063	$ 126,064	$ 1,841,762	$ 1,715,699
1860	Meters	$ -		$ -	$ -		$ -	$ -		0.00%	25.00	4.00%	$ -	$ -	$ -	$ -	$ -	$ -
1860	Meters (Smart Meters)	$ 3,254,261		$ 3,254,261	$ 248,628		$ 248,628	$ 248,628	7.26	13.77%	12.00	8.33%	$ 448,268	$ 20,719	$ 10,360	$ 479,347	$ 2,476,354	$ 1,997,007
1905	Land	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1910	Leasehold Improvements	$ 420,441		$ 420,441	$ 49,000		$ 49,000	$ 49,000	50.64	1.97%	55.00	1.82%	$ 8,303	$ 891	$ 445	$ 9,639	$ 44,573	$ 34,934
1915	Office Furniture & Equipment (10 years)	$ 18,744		$ 18,744	$ -		$ -	$ -	1.92	52.13%	10.00	10.00%	$ 9,771	$ -	$ -	$ 9,771	$ 83,076	$ 73,305
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ -		$ -	$ -		$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ 97,941	$ 97,941
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -		$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ 3,892	$ 3,892
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 66,585		$ 66,585	$ 44,950		$ 44,950	$ 44,950	1.95	51.22%	5.00	20.00%	$ 34,106	$ 8,990	$ 4,495	$ 47,591	$ 140,348	$ 92,757
1930	Transportation Equipment	$ 1,211,605		$ 1,211,605	$ 135,000		$ 135,000	$ 135,000	3.17	31.50%	8.00	12.50%	$ 381,645	$ 16,875	$ 8,438	$ 406,958	$ 2,042,979	$ 1,636,021
1935	Stores Equipment	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 71,907		$ 71,907	$ 35,000		$ 35,000	$ 35,000	2.95	33.90%	10.00	10.00%	$ 24,378	$ 3,500	$ 1,750	$ 29,628	$ 190,806	$ 161,178
1945	Measurement & Testing Equipment	$ 17,274		$ 17,274	$ -		$ -	$ -	4.45	22.49%	8.00	12.50%	$ 3,885	$ -	$ -	$ 3,885	$ 17,694	$ 13,809
1950	Power Operated Equipment	$ 170,734		$ 170,734	$ -		$ -	$ -	6.08	16.45%	8.00	12.50%	$ 28,082	$ -	$ -	$ 28,082	$ 81,591	$ 53,508
1955	Communications Equipment	$ 28,724		$ 28,724	$ -		$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ 6,383	$ 6,383
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1970	Load Management Controls Customer Premises	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 312,499		$ 312,499	$ 50,000		$ 50,000	$ 50,000	3.05	32.79%	5.00	20.00%	$ 102,460	$ 10,000	$ 5,000	$ 117,460	$ 288,457	$ 170,997
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1990	Other Tangible Property	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1995	Contributions & Grants	-$ 5,479,902		-$ 5,479,902	$ -		$ -	$ -	20.18	4.96%	25.00	4.00%	-$ 271,617	$ -	$ -	-$ 271,617	-$ 1,423,706	-$ 1,152,089
2440	Deferred Revenue	-$ 2,535,076			-$ 652,500		-$ 652,500	-$ 652,500	56.94	1.76%	60.00	1.67%	$ -	-$ 10,875	-$ 5,438	-$ 16,313	-$ 162,012	-$ 145,700
	Total	**$ 32,851,164**	**$ -**	**$ 35,386,240**	**$ 3,549,913**	**$ -**	**$ 3,549,913**	**$ 3,549,913**					**$ 2,262,876**	**$ 128,558**	**$ 64,279**	**$ 2,455,714**	**$ 21,734,751**	**$ 19,279,038**

General: Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial Statements.

Notes:

1 This is the net book value of assets that existed as at the date of the utility's change in depreciation policies (i.e. as at Jan. 1, 2012 or Jan. 1, 2013). These assets are to be depreciated at the average remaining service life. This amount will not change in years subsequent to the date of the utility's change in depreciation policies. This column is expected to be used

2 This is the opening gross book value of assets that have been acquired after the date of the utilities change in depreciation policies (i.e. additions starting in 2012/2013 for those who changed policies Jan. 1, 2012/2013). These assets are to be depreciated at the revised service life. The amount is expected to be equal to the gross book value of the prior year plus the

3 A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated. As

4 The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.

5 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

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7 This should include assets in column a (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change

8 This should include assets in column d (excel column f) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

Scenario that applies		Applicable Years and Accounting Standard	Year Reflected in Schedule Below	Accounting Standard Reflected in Schedule Below
Rebasing for the first time with depreciation policy changes made in 2012	☐	This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Rebasing for the first time with depreciation policy changes made in 2013	☑	This appendix must be duplicated and completed for the years 2013 to 2018. The appendix for 2013 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2013 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).	2018	MIFRS
Already rebased with depreciation policy changes in a prior rate application	☐	This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		

		Book Values							Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 255,364		$ 255,364	$ 35,000		$ 35,000	$ 35,000	0.51	196.85%	3.00	33.33%	$ 502,684	$ 11,667	$ 5,833	$ 520,184	$ 1,403,409	$ 883,225
1612	Land Rights (Formally known as Account 1906)	$ 45,679		$ 45,679	$ -		$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1805	Land	$ 178,544		$ 178,544	$ -		$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings	$ 905,638		$ 905,638	$ 8,000		$ 8,000	$ 8,000	54.08	1.85%	60.00	1.67%	$ 16,747	$ 133	$ 67	$ 16,947	$ 110,559	$ 93,612
1810	Leasehold Improvements	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 344,916		$ 344,916	$ -		$ -	$ -	36.55	2.74%	60.00	1.67%	$ 9,437	$ -	$ -	$ 9,437	$ 231,009	$ 221,572
1825	Storage Battery Equipment	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 6,204,718		$ 6,204,718	$ 477,590		$ 477,590	$ 477,590	33.64	2.97%	50.00	2.00%	$ 184,427	$ 9,552	$ 4,776	$ 198,755	$ 3,198,313	$ 2,999,558
1835	Overhead Conductors & Devices	$ 7,854,998		$ 7,854,998	$ 801,602		$ 801,602	$ 801,602	30.45	3.28%	60.00	1.67%	$ 257,958	$ 13,360	$ 6,680	$ 277,998	$ 7,880,335	$ 7,602,337
1840	Underground Conduit	$ 2,588,157		$ 2,588,157	$ 166,978		$ 166,978	$ 166,978	36.12	2.77%	45.00	2.22%	$ 71,645	$ 3,711	$ 1,855	$ 77,211	$ 711,216	$ 634,005
1845	Underground Conductors & Devices	$ 6,328,432		$ 6,328,432	$ 399,929		$ 399,929	$ 399,929	36.88	2.71%	45.00	2.22%	$ 171,598	$ 8,887	$ 4,444	$ 184,929	$ 1,583,339	$ 1,398,410
1850	Line Transformers	$ 7,859,202		$ 7,859,202	$ 498,351		$ 498,351	$ 498,351	32.67	3.06%	40.00	2.50%	$ 240,556	$ 12,459	$ 6,229	$ 259,244	$ 2,003,108	$ 1,743,864
1855	Services (Overhead & Underground)	$ 5,178,313		$ 5,178,313	$ 1,087,500		$ 1,087,500	$ 1,087,500	44.26	2.26%	60.00	1.67%	$ 117,001	$ 18,125	$ 9,063	$ 144,189	$ 1,953,834	$ 1,809,645
1860	Meters	$ -		$ -	$ -		$ -	$ -		0.00%	25.00	4.00%	$ -	$ -	$ -	$ -	$ -	$ -
1860	Meters (Smart Meters)	$ 3,151,496		$ 3,151,496	$ 234,500		$ 234,500	$ 234,500	6.72	14.88%	12.00	8.33%	$ 468,987	$ 19,542	$ 9,771	$ 498,300	$ 2,837,518	$ 2,339,218
1905	Land	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1910	Leasehold Improvements	$ 461,073		$ 461,073	$ 35,000		$ 35,000	$ 35,000	50.15	1.99%	55.00	1.82%	$ 9,194	$ 636	$ 318	$ 10,148	$ 53,260	$ 43,111
1915	Office Furniture & Equipment (10 years)	$ 14,634		$ 14,634	$ -		$ -	$ -	1.50	66.77%	10.00	10.00%	$ 9,771	$ -	$ -	$ 9,771	$ 87,186	$ 77,415
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ -		$ -	$ -		$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ 97,941	$ 97,941
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -		$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ 3,892	$ 3,892
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 75,134		$ 75,134	$ 21,000		$ 21,000	$ 21,000	1.74	57.36%	5.00	20.00%	$ 43,096	$ 4,200	$ 2,100	$ 49,396	$ 178,849	$ 129,453
1930	Transportation Equipment	$ 1,145,184		$ 1,145,184	$ 20,000		$ 20,000	$ 20,000	2.87	34.80%	8.00	12.50%	$ 398,520	$ 2,500	$ 1,250	$ 402,270	$ 2,245,650	$ 1,843,380
1935	Stores Equipment	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 87,977		$ 87,977	$ 20,000		$ 20,000	$ 20,000	3.16	31.69%	10.00	10.00%	$ 27,878	$ 2,000	$ 1,000	$ 30,878	$ 210,986	$ 180,108
1945	Measurement & Testing Equipment	$ 13,388		$ 13,388	$ -		$ -	$ -	3.45	29.02%	8.00	12.50%	$ 3,885	$ -	$ -	$ 3,885	$ 21,579	$ 17,694
1950	Power Operated Equipment	$ 143,069		$ 143,069	$ -		$ -	$ -	5.09	19.63%	8.00	12.50%	$ 28,082	$ -	$ -	$ 28,082	$ 109,256	$ 81,173
1955	Communications Equipment	$ 25,532		$ 25,532	$ -		$ -	$ -	-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ 9,575	$ 9,575
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1970	Load Management Controls Customer Premises	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 273,842		$ 273,842	$ 90,000		$ 90,000	$ 90,000	2.44	41.07%	5.00	20.00%	$ 112,460	$ 18,000	$ 9,000	$ 139,460	$ 386,114	$ 246,654
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1990	Other Tangible Property	$ -		$ -	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1995	Contributions & Grants	-$ 5,366,728		-$ 5,366,728	$ -		$ -	$ -	19.76	5.06%	25.00	4.00%	-$ 271,617	$ -	$ -	-$ 271,617	-$ 1,536,880	-$ 1,265,263
2440	Deferred Revenue	-$ 3,161,903			-$ 652,500		-$ 652,500	-$ 652,500	57.08	1.75%	60.00	1.67%	$ -	-$ 10,875	-$ 5,438	-$ 16,313	-$ 202,514	-$ 186,202
	Total	**$ 34,606,659**	**$ -**	**$ 37,768,562**	**$ 3,242,950**	**$ -**	**$ 3,242,950**	**$ 3,242,950**					**$ 2,402,310**	**$ 113,897**	**$ 56,948**	**$ 2,573,154**	**$ 23,577,531**	**$ 21,004,377**

General: Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial Statements.

Notes:

1 This is the net book value of assets that existed as at the date of the utility's change in depreciation policies (i.e. as at Jan. 1, 2012 or Jan. 1, 2013). These assets are to be depreciated at the average remaining service life. This amount will not change in years subsequent to the date of the utility's change in depreciation policies. This column is expected to be used

2 This is the opening gross book value of assets that have been acquired after the date of the utilities change in depreciation policies (i.e. additions starting in 2012/2013 for those who changed policies Jan. 1, 2012/2013). These assets are to be depreciated at the revised service life. The amount is expected to be equal to the gross book value of the prior year plus the

3 A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated. As

4 The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.

5 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

6 The applicant must provide an explanation of material variances in evidence.

7 This should include assets in column a (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change

8 This should include assets in column d (excel column f) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

Attachment 3 (of 8):

2-C 2017 Distribution System Plan

ERIE THAMES POWERLINES

Distribution System Plan (DSP)

This document details Erie Thames Powerlines Asset Management Process and Capital Expenditure Plan as required by the OEB filing requirements set out in the 'Chapter 5 Consolidated Distribution System Plan Filing Requirements'

UPDATED:
July
2017

TABLE OF CONTENTS

TABLE OF FIGURES

TABLE OF TABLES

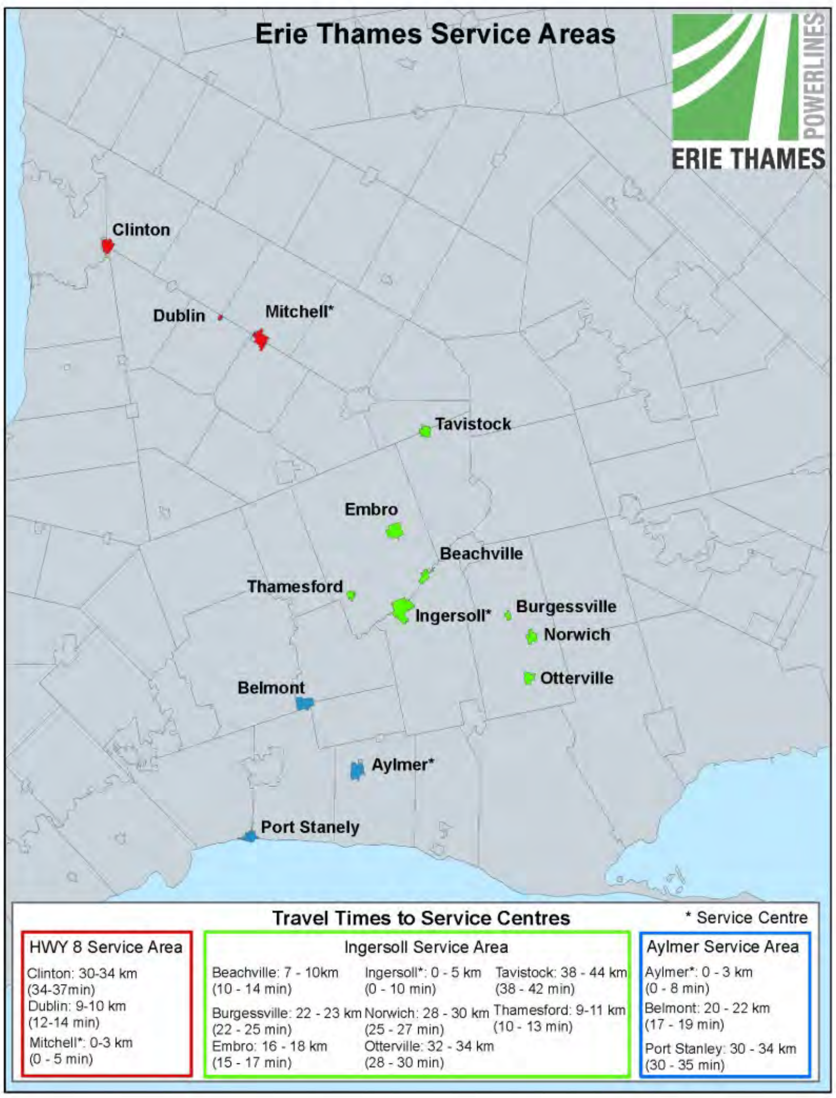
LIST OF ACRONYMS & ABBREVIATIONS

ETPL	Erie Thames Powerlines
DSP	Distribution System Plan
AMP	Asset Management Plan
ACA	Asset Condition Assessment
OEB	Ontario Energy Board
ESA	Electrical Safety Authority
TS	Transmission Station (primary 115kV or 230kV, secondary 28kV)
DS	Distribution Station (primary 28kV, secondary 4kV or 8kV)
DX	Distribution System
TX	Transmission System

UTILITY ABSTRACT

Erie Thames Powerlines (ETPL) is a local distribution company located in Southwestern Ontario representing the amalgamation of nine (9) Public Utilities Commissions and currently services 18,265 customers in the municipalities of Port Stanley, Aylmer, Belmont, Ingersoll, Thamesford, Otterville, Norwich, Burgessville, Beachville, Embro, Tavistock, Mitchell, Dublin and Clinton. ETPL's service territory spans north to south a distance of approximately 120km and all municipalities are embedded within Hydro One service territory. ETPL has three operations centers located in Aylmer, Mitchell and Ingersoll with the later retaining all executive, administration, finance, customer service, metering and engineering departments. Figure 1 below illustrates the ETPL service territory along with operations centers and approximate travel times.

Figure 1: ETPL Service Area Map

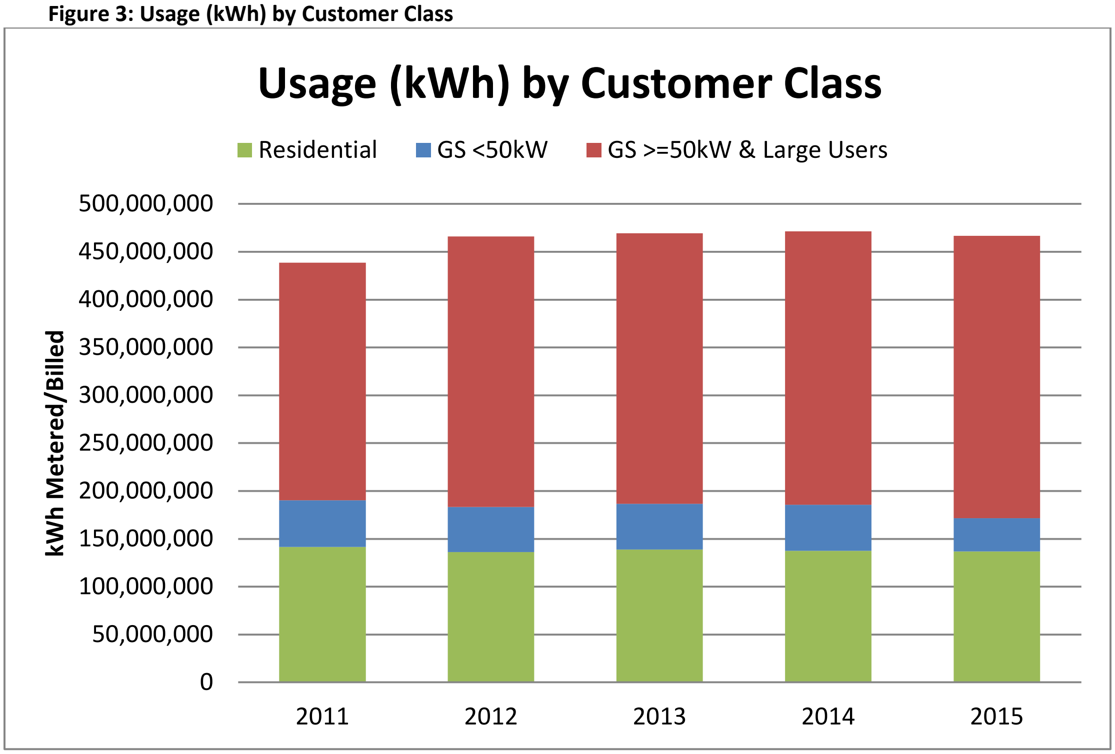


ETPL's customer base has remained relatively constant over the past five (5) years with an increase in customer base of approximately 2% total over the past five years as shown below in Figure 2.

Figure 2: Customer Count by Class

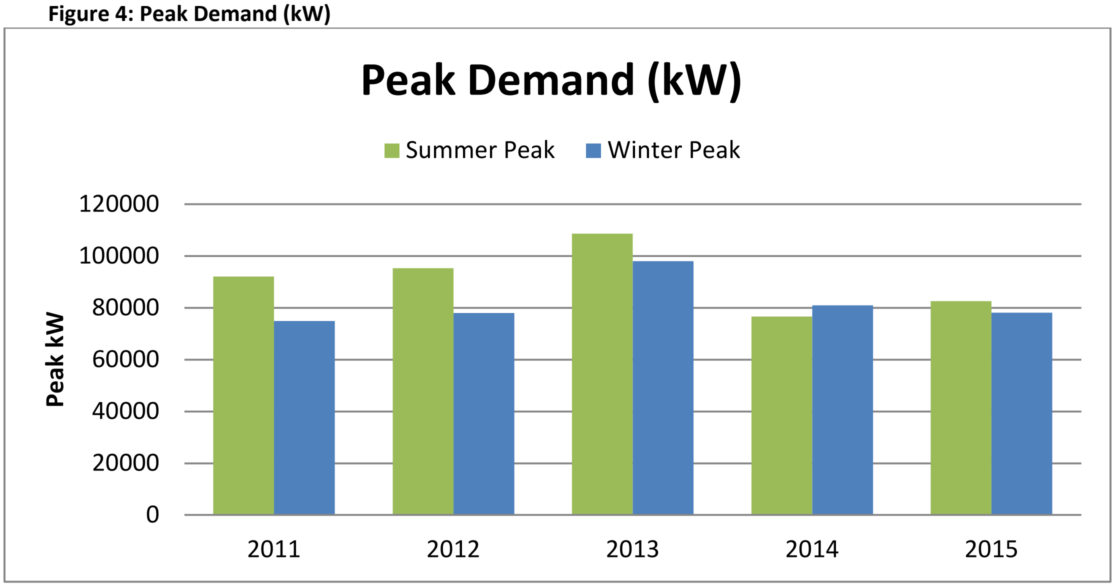
As indicated in Figure 3 below, ETPL has seen an increase in kWh consumption of approximately 6.4% total over the past five (5) years with a 2015 usage of 466,660,752kWh. Of this consumption GS>50kW customers & one (1) large user account for approximately 63% of the usage however only account for 1% of the customer base.

Figure 3: Usage (kWh) by Customer Class



ETPL has typically been a summer peaking utility with a 2015 peak demand of 82,552kW. This demand has dropped significantly from the 2013 demand of 108,683kW as shown below in Figure 4.

Figure 4: Peak Demand (kW)



5.0 INTRODUCTION

This document details Erie Thames Powerlines Asset Management Process and Capital Expenditure Plan as required by the OEB filing requirements set out in the 'Chapter 5 Consolidated Distribution System Plan Filing Requirements'

The structure of this DS Plan has followed the headings provided by the OEB in their filing requirements and all pertinent information is contained within Sections 5.2 to 5.4 and related appendices.

5.1 GENERAL AND ADMINISTRATIVE MATTERS

As required by the filling requirements all internal asset management and capital expenditure planning has been consolidated within the DS Plan and formatted to use the proper terminology and formats.

5.1.1 Investment Categories

All investment projects and activities have been grouped under the following categories as required:

- **System Access** - customer service requests, third party infrastructure requirements, mandated service obligations
- **System Renewal** - asset/asset systems at end of service life due to failure, failure risk, substandard performance, high performance risk, functional obsolescence
- **System Service** - expected changes in load that will constrain the ability of the system to provide consistent service delivery & system operational objectives such as safety, reliability, power quality, system efficiency and other performance/functionality
- **General Plant** - system capital investment support, system maintenance support, business operations efficiency and non-system physical plant.

Table 1 below shows how ETPL has assigned its typical expenditures into the OEB required categories.

Table 1: ETPL Expenditure Categorization

SYSTEM ACCESS	SYSTEM RENEWAL	SYSTEM SERVICE	GENERAL PLANT
▪ Residential Connections ▪ C&I Connections ▪ Meter Management ▪ Facility Relocations	▪ Fixed Distribution Assets ▪ Maps & Records ▪ Substation Upgrades	▪ System Automation ▪ Capacity Upgrades	▪ Leasehold Improvements ▪ Fleet Sustainment ▪ Tools & Equipment ▪ IT Hardware/Software

5.1.2 Investments Related to Renewable Energy Generation

ETPL has included its Renewable Energy Generation (REG) Plan in *Appendix N* and at this time does not forecast any substantial investments will be required to facilitate the connection of renewable energy generation.

5.1.3 Time of Filing

This DSP is filed as part of ETPL's Cost of Service application.

5.1.4 Planning in Consultation with Third Parties

5.1.4.1 REGIONAL PLANNING AND CONSULTATIONS

ETPL communities are included in two Regional Planning Areas; the London and Greater Bruce/Huron regions which are both in the Local Wires Planning stages. Erie Thames will continue to actively participate in all regional planning activities and currently does not expect any investments as a result. Comment letters provided by Hydro One Networks Inc. (HONI) have been included in *Appendix E & F*.

Outside of the regional planning framework ETPL frequently coordinates operations and planning activities with HONI and will continue to do so moving forward.

5.1.4.2 RENEWABLE ENERGY GENERATION INVESTMENTS

ETPL has submitted its REG Plan to the IESO for comment and the resulting letter has been included as *Appendix G*. At this time, ETPL does not forecast any substantial investments will be required to facilitate the connection of renewable energy generation.

5.1.5 Performance Reporting

Erie Thames monitors and adjusts distribution system investments based on various performance metrics. These include the OEB required scorecard metrics along with other measures such as worst performing feeder analysis and others which are detailed in section 5.2.3 of the DS Plan.

5.2 DISTRIBUTION SYSTEM PLANS

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.***

A) KEY ELEMENTS OF THE DS PLAN THAT AFFECT ITS RATES PROPOSAL

- ***This section includes 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.***

ETPL's mission statement included in Section 5.3 outlines the desire to provide safe, reliable and cost effective service to our customers. These core objectives guide proposed capital investments and ensure that planning objectives are met, consistent with customer and corporate goals within the required regulatory framework.

The following outlines the key elements combined in the DS Plan and how they relate to the OEB defined investment categories:

- **Maintaining Public and Employee Safety**
  - *System Access* projects are rarely if ever driven by public or employee safety.
  - *System Renewal* projects which look to replace/refurbish assets at the end of their useful service life due to condition, performance and risk of failure ensure that both public and employee safety are prioritized by reducing failure risks and ensuring that systems are built to current industry standards. The DS Plan uses inputs from various testing and maintenance programs to inform decisions related to system renewal type projects. The DS Plan prioritizes safety related projects above all other drivers when selecting and prioritizing capital investments and capital projects are often driven by safety related concerns.
  - *System Service* projects are not primarily driven by safety related objectives however installation of automated switches and other technology often inherently provide safety benefits in the form of improved electrical protection and coordination.
  - *General Plant* investments are often geared towards employee safety ensuring that the proper fleet, tools and equipment are available to safely construct, operate and maintain the distribution system. Investments made to provide employees with the proper tools,

equipment, policies, and procedures also benefit customers through reduced costs associated with lost time injuries, lost productivity, and efficient work execution.

- **Maintaining/Improving Reliability (Performance Evaluation)**

Customers consistently value reliability as an important aspect of the service provided to them, and investments that maintain or slightly improve reliability allow ETPL to meet this expectation.

- *System Access* investments are rarely if ever driven by the need to maintain reliability.
- *System Renewal* projects are selected, prioritized and paced through the AM and DS Plans to ensure that assets are replaced prior to failures that would result in poor reliability to customers. ETPL uses typical performance evaluation such as SAIDI, SAIFI and worst performing feeder analysis to target capital investments and monitor trends in reliability to evaluate the effectiveness of investment levels.
- *System Service* type investments are primarily focused on improving customer reliability through the implementation of various technologies such as automated switches, SCADA and OMS solutions.
- *General Plant* investments are not typically made as a result of reliability.

- **Cost Effective Service aimed at Reducing Financial Impacts to Customers**

ETPL considers the total lifecycle cost of an asset and seeks to minimize the total cost to customers by repairing, maintaining, and/or refurbishing assets before replacing them, and then replacing them only when it makes economic sense to do so.

- *System Access* spending is rarely if ever driven by the need to minimize customer financial impacts.
- *System Renewal* projects are not typically undertaken by the need to minimize financial impacts to customers however the pace of system renewal spending is an important factor. The AMP looks to forecast the level of asset replacement required to maintain the condition of the distribution system and recommends a smoothed spending level. This approach ensures that capital spending is paced effectively, reducing financial impacts to customers by mitigating drastic changes and maintaining a reasonable spending level.
- *System Service* investments are not primarily focused on customer financial impacts however like most projects the implementation of technology will provide operational efficiencies and provide cost reduction long term.

- *General Plant* projects are somewhat driven by a need to maintain fleet, tools and equipment in line with best industry practices which provide small gains in efficiencies.

- **Customer Service Requests & Growth**

ETPL follows our Conditions of Service document and the Distribution System Code to ensure that work resulting from customer service requests does not adversely impact the rest of the customer base through added costs or poor service quality.

- *System Access* investments are primarily related to customer service requests and the number, frequency, scope etc. are typically customer dependent and out of the control of the utility. The capital investments planned as a result of these requests are budgeted based on historical values and adjusted if any known developments exist.
- *System Renewal* projects are not typically completed as a result of customer service requests.
- *System Service* projects are not typically completed as a result of customer service requests.
- *General Plant* projects are not typically completed as a result of customer service requests.

- **Maintaining Compliance with Mandated Service Obligations**

- *System Access* investments that are related to mandated service obligations are primarily metering related spending and are again planned for based on historical levels combined with reverification schedules. System modifications such as facility relocations for municipal road widening are also included in the system access category. Spending as a result of these requests is developed through consultation with local municipal partners and historical experience; despite best efforts these investments are difficult to properly plan for as they are largely dependent on municipal budgets, grants and other external factors.
- *System Renewal* projects are not typically completed as a result of customer service requests.
- *System Service* projects are not typically completed as a result of customer service requests.
- *General Plant* projects are not typically completed as a result of customer service requests.

- **Responding to Customer Feedback**
  - *System Access, System Renewal, System Service & General Plant* capital investments all take into consideration the feedback that is obtained from customers. Through a number of customer engagement activities, described in Section 5.4.1f) and detailed in customer survey results included as *Appendix A & B*, ETPL has determined that the majority of customers prioritize cost and reliability as primary concerns. The DS Plan takes this feedback into consideration when determining appropriate spending levels

- **Regional Planning Outcomes**
  - No capital investments are currently expected as a result of the transmission level regional planning process as required by the OEB.
  - As a result of the on-going Long Term Load Transfer (LTLT) negotiations with Hydro One Inc. (HONI) Erie Thames Powerlines expects a capital investment of approximately $50,000 to fall into Q4 - 2017 to purchase LTLT assets from HONI. This will result in ETPL adding approximately 60 customers.
  - ETPL actively engages our upstream distributor Hydro One Networks Inc. (HONI) to discuss local issues and reliability concerns. No capital investments are expected prior to 2019 however there are a few upcoming projects tentatively scheduled beyond 2019 in Norwich, Mitchell and Beachville. The financial contribution required for these projects are currently unknown as the project scopes have yet to be determined. Each of these projects addresses local reliability or capacity issues and ETPL will have only partial control over the scope, timing, costs etc.

- **Renewable Energy Generation**
  - No capital investments are currently expected as a result of the Renewable Energy Generation Plan.

B) SOURCES OF COST SAVINGS

- ***This section includes the sources of cost savings expected to be achieved over the forecast period through good planning and DS Plan execution.***

ETPL expects that a number of capital investments over the forecast period will result in increased efficiency operating and maintaining the distribution system. O&M spending have also been positively affected by a reduction in loss factor throughout the forecast period. The financial impacts of these efficiencies are difficult to isolate and quantify however the following investments are anticipated to reduce system O&M costs moving forward.

- **Voltage Conversion Initiatives**

A large driver of ETPL capital projects is the conversion of existing 4kV and 8kV systems to the preferred 28kV distribution voltage. Voltage conversion projects are primarily completed in conjunction with system renewal type projects targeted to areas with end of life assets and increased risk associated to them. Voltage conversion provides a number of benefits related to O&M costs moving forward, including the removal of ETPL owned and operated substations, the reduction of line losses & reduced inventory requirements associated with multiple operating voltages. The approximate annual costs to maintain a municipal substation is detailed below:

Table 2: Yearly Substation Costs

Yearly Substation Costs (approximate)	
O&M Expenses	
5 Year Maintenance	$4000 per station x 2 per year = $8000
Bi-Annual Inspections	$558 per station x 9 stations = $5022
Monthly Inspection	$2475 per station x 9 stations = $22,280
Yearly Oil Sample & Analysis	$391 per station x 9 stations = $3520
Lawn Maintenance & Weed Control	$300 per station x 9 stations = $2700
Utilities, Property Taxes & Amortization	$3399 per station x 9 stations = $30,588
Capital Costs	
Miscellaneous Substation Upgrades (Fence repairs, gravel etc.)	$1667 x 9 stations = $15,000
	$87,110 TOTAL / 9 stations = $9679 per station, per year

- **Fault Indicators Installation**

Fault indicators have and will continue to be installed within the distribution system in strategic locations to aid in troubleshooting system faults reducing the number of truck rolls, and the time required to patrol lines and restore customers. Fault Indicators also provide valuable real-time data to aid more efficient system operation and planning.

- **Automated Switch Installation**

ETPL plans to install automated switches in strategic locations throughout its distribution system having the ability to be remotely controlled through SCADA and able to automatically sectionalize and restore load depending on system conditions. This will again aid in troubleshooting system faults reducing truck rolls and the time required to complete switching.

- **Transition to Electronic Formats**

Within the forecast period ETPL plans to transition the majority of its operations to an electronic format using tablets, laptops, smart phones etc. to modify and view data in the field. This will include items such as inspection forms, job packages, and operational maps linked to the OMS system. This is geared towards the elimination of multiple points of entry from the field to the system of record. In addition, the implementation of the OMS system tied to smart meter data will provide both inside and outside staff with valuable information regarding the state of the distribution system reducing restoration efforts.

Additional information in electronic formats will also aid engineering and operations staffs in capital planning; enabling more accurate assessments of the system and ensuring capital projects are chosen that provide the greatest benefit.

- **Removal of Legacy Issues through Improved Standards**

Through the continual improvement in construction standards and planning initiatives, legacy issues that result in high O&M costs will eventually be eliminated. Some of these improvements include:

  - Direct buried primary cable replaced with TRXLPE primary cable in duct.
  - Removal of “pole-trans” which typically carry a high risk of failure and safety concerns.
  - Removal of backyard infrastructure that is difficult & costly to operate and maintain.

Replacement of legacy assets constructed to current standards will improve the overall operational efficiency of the system through proper clearances, improved equipment, animal guarding etc.

C) PERIOD COVERED BY THE DSP

- ***This section details the period covered by the DS Plan (historical and forecast)***

The DSP covers the historical period of 2013 to 2017 and a forecasted period of 2018 to 2022.

D) VINTAGE OF THE INFORMATION USED TO JUSTIFY INVESTMENTS

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

The information used within this report is current as of January 1st, 2017; with that being said the ACA & AMP were developed with asset information accurate as of January 1st, 2015.

E) IMPORTANT CHANGES TO THE DISTRIBUTORS ASSET MANAGEMENT PROCESS (IF APPLICABLE)

- ***This section details changes to the asset management process since the last DS Plan filing.***

This is ETPL's first DS Plan filed under the Ontario Energy Boards Chapter 5 Consolidated Distribution System Plan Filing Requirements, however ETPL previously filed an Asset Management Plan (AMP) as a part of the 2011 COS application, and since a number of improvements have been made to the process.

The first notable change from 2011 is that customer input has been formally incorporated as part of the decision framework and risk analysis process moving forward. There are a number of means where customer input is gathered ranging from formal customer surveys, meetings with large customers and informal interactions throughout a given year.

Since 2011 ETPL has worked to obtain more accurate data with respect to its major assets and the following are comparisons of the age data used in the 2011 report and the 2015 update.

Table 3: Asset Data Accuracy

Asset Type	2011	2015
	Data Accuracy (%)	
Poles	83%	94%
Pole Mounted Transformers	0%	44%
Pad Mounted Transformers	0%	72%
Underground Medium Voltage Cable	0%	0% **

** More accurate padmounted transformer data in 2015 led to the age profile for medium voltage cable to be a more accurate representation as padmounted ages were used as a proxy.

Since 2011 ETPL has implemented a formal pole testing program that it intends to repeat on a consistent cycle moving forward. For the past three years (2014-2016) we have tested 1/3 of our system per year ensuring that our entire system has recently been tested. This has allowed us to fill the majority of holes in pole related data and condition assessments. Moving forward we plan to repeat inspections on a nine (9) year cycle revisiting poles with a remaining strength less than 80% on a three year cycle. The consistent cycle will aim to provide more detailed condition based information for poles and associated hardware and in turn will allow for capital expenditures to be targeted to areas that age related data alone does not identify.

- **Areas for Improvement**

ETPL will continue to improve the accuracy of data used to make decisions regarding capital spending levels. The goal of using a complete set of condition based evaluations for all major assets will be accomplished with the movement to electronic inspections that are easily compiled and flagged for each asset.

The implementation of an OMS system and further utilization of smart meter data will allow for a more granular analysis of loading and outage causes.

F) ASPECTS OF DS PLAN CONTINGENT ON ONGOING OR FUTURE EVENTS

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

Aspects of the DS Plan that are/could be affected by the outcomes of the following future events:

- Regional Planning process (formal Transmission Level & non-formal Distribution Level)

- Renewable Energy Generation - contingent on program updates.
- Customer Service & Municipal Facility Relocation requests

ETPL communities are included in two Regional Planning Areas; the London and Greater Bruce/Huron regions which are both in the Local Wires Planning stages. Currently no substantial financial investments are expected.

ETPL also actively engages our upstream distributor Hydro One Networks Inc. (HONI) to discuss local issues and reliability concerns. No capital investments are expected prior to 2019 however there are a few upcoming projects tentatively scheduled beyond 2019 in Norwich, Mitchell and Beachville. The financial contribution required for these projects are currently unknown as the project scopes have yet to be determined. Each of these projects addresses local reliability or capacity issues and ETPL will have only partial control over the scope, timing, costs etc.

Currently ETPL does not envision any investments or changes to the DS Plan as a result of REG.

ETPL actively participates with our various communities to determine upcoming municipal work that will affect the DS Plan, or any reasons for unexpected customer growth. Even with these discussions the majority of system access spending is based on historical values, driven by customer demand and largely uncontrollable by ETPL. ETPL does not predict a marked change in customer driven projects over the forecast period, and spending is projected to be comparable to historical levels.

5.2.2 Coordinated Planning with Third Parties

- ***This section demonstrates that a distributor has met the Boards expectations in relation to coordinating infrastructure planning with customers, the transmitter, other distributors and/or the OPA or other third parties where appropriate.***

A) DESCRIPTION OF CONSULTATIONS

- ***This section details the consultations including, the purpose of the consultation, whether the distributor initiated the consultation or was invited to participate, the other participants, the nature and final deliverables that are expected to result from or otherwise be informed by the consultations (e.g. RIP, IRRP) and an indication of whether the consultation(s) have or are expected to affect the distributors DS Plan as filed.***

A description of consultations with the following third parties is detailed below.

- Residential & Small Business Customer Surveys
- Large Customer/Group Consultations
- Municipal Planning Committee
- Regional Planning
- Host Transmitter/Distributor (HONI)

▪ Residential & Small Business Customer Surveys

ETPL began surveying customers in 2014; the premise of our first survey was based on our customers' opinion of service reliability and costs, and was targeted at our residential and small business classes.

Another survey in 2016 was again used to collect data from customers regarding their satisfaction, knowledge and preferences however in addition was used to provide customers with a better understanding of where ETPL fits within the provincial electricity system and found that the majority of customers do not have a great understanding of the system and what Erie Thames controls and does not control.

ETPL had 1136 customers respond to the customer survey in 2016 as compared to 897 in the 2014 customer survey. The 2014 survey did not use email as a medium and found that the number of responses jumped substantially when customers were contacted via email in 2016.

The survey as a whole shows our customers are s with the level of service which they receive from ETPL and feel that we are managing costs effectively. Both surveys reflect that customers are most concerned with total price and reliability, with the majority of respondents indicating that they find the existing level of reliability to be acceptable. These results are reflected in the DSP with a relatively flat level of capital spending aimed at maintaining the existing level of reliability. Customer surveys, results and further detail is included in Section 5.4.1f) and *Appendix A & B.*

▪ Large Customer/Group Consultations

ETPL has met and will continue to engage its large customers or customer groups to address any concerns and obtain feedback regarding customer preferences and performance evaluation of the utility. ETPL endeavours to meet with its sole "large user" on a yearly basis to discuss the past year, any upcoming projects affecting their service, and coordination required for maintenance. An example of meeting minutes, and an agenda is included as *Appendix D.* ETPL is also very receptive to meeting with other groups and large customer to discuss their hydro supply and any related issues. An example is a presentation done to the Norwich BIA regarding reliability issues, included in *Appendix D.*

- **Regional Planning Process (based on OEB framework, RIP/IRRP process)**

ETPL communities are included in two Regional Planning Areas; the London and Greater Bruce/Huron regions which both in the Local Wires Planning stage. Regional planning for the London Region has identified a number of needs affecting ETPL communities resulting in capacity concerns at the Tillsonburg TS and the 115kV W8T circuit supplying the station. The transformer capacity is expected to reach its 10 day LTR in the near term (5 years) and the W8T circuit is expected to reach its thermal capacity within the medium term (10 years). These concerns will be monitored through the RPP and no material financial investments are expected by ETPL as a result of either regional planning process.

- **Municipal Planning Committee**

On a bi-annual basis ETPL participates in the Utility Coordinating Committee (UCC) initiated by the Town of Ingersoll. The UCC typically includes other utilities such as Bell, Rogers & Union Gas and is intended to have all parties kept up to date on municipal driven projects in construction and planned for the future. It allows for high level planning between all parties and provides ETPL with a better understanding of facility relocate projects for the upcoming year. A sample agenda is provided as *Appendix D.*
ETPL also receives possible zoning changes and certain building applications to provide comment with regards to any servicing issues. This again provides insight into upcoming projects and helps to inform system access budget levels.

Other municipalities serviced by ETPL do not currently have formalized UCC meetings however ETPL maintains a good working relationship with all municipalities and discusses upcoming projects throughout the year.

- **Host Transmitter/Distributor (HONI)**

In the majority of ETPL service territories the supply point is a wholesale metered distribution connection to the Hydro One system. As a result ETPL and HONI are frequently in discussion regarding operational and planning objectives. These discussions are initiated by either party as needed and ensure that outages, construction projects and maintenance are coordinated to reduce outages and maintain efficiency.

ETPL also frequently communicates with our Account Executive at Hydro One to address any ongoing concerns or issues. This often includes supply point reliability and any operational issues and contact is typically initiated by ETPL. An example set of meeting minutes is included in *Appendix D.*

B) REGIONAL PLANNING PROCESS DELIVERABLE(S)

- ***This section includes final deliverables of the RPP if available or the role of distributor in the process, the status of the process, and where applicable the expected dates on which final deliverables are expected to be issued.***

ETPL communities are included in two Regional Planning Areas; the London and Greater Bruce/Huron regions which are both in the Local Wires Planning stages.

A planning status letter for both the London and Greater Bruce/Huron Regions are included as *Appendices E & F* respectively.

C) OPA/IESO COMMENT LETTER FOR REG INVESTMENTS

- ***This section includes the OPA/IESO comment letter provided in relation to REG investments included in the DS Plan, along with any written response to the letter from the distributor, if applicable.***

The comment letter provided by the IESO is included in *Appendix G.*

5.2.3 Performance Measurement for Continuous Improvement

- ***This 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) METHODS AND MEASURES USED TO MEASURE PLANNING PERFORMANCE

- ***This section identifies and defines the methods and measures 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 are expected to address at a minimum the following:

- ***customer oriented performance (e.g. 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)***
- ***asset and/or system operations performance***

ETPL monitors a number of measures to evaluate its yearly performance which allows us to target capital and operational spending; these are identified and defined below. Along with evaluating our yearly performance trends ETPL benchmarks its performance against comparable utilities and the industry as a whole.

- **OEB Scorecard Metrics**

The OEB scorecards "measure how well Ontario's electricity distributors are performing each year. It is designed to encourage electricity distributors to operate effectively, continually seek ways to improve productivity and focus on improvements that their customers value. The scorecard includes traditional metrics for assessing a distributor's services, such as frequency of power outages, financial performance and costs per customer." [1] ETPL monitors our scorecard and adjustments are made based on year over year trends.

- **Customer Engagement**

Historically customer feedback has been used to help target capital spending and adjust overall spending levels however in a more informal manner. Moving forward customer engagement will be more formally tracked through customer surveys, and other customer engagement metrics will be developed to help trend preferences over time.

- **Customer Bill Impacts**

Customer Bill impacts are always considered when setting the high level spending envelope on a yearly basis. Both senior management and the board of directors approve the spending level and aim to minimize customer bill impacts from year to year; primarily this entails ensuring that year over year spending remains relatively consistent.

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[1] Electricity Distributor Scorecards. (2015-10-01) OEB Website. Retrieved May 31, 2016, from http://www.ontarioenergyboard.ca/OEB/Industry/Rules+and+Requirements/Electricity+Distributor+Scorecards

- **Operational Efficiency Metrics**

Erie Thames looks at the Total Cost ($) per Customer, Total Cost ($) per km of Line and the Efficiency Assessment as indicators of overall operational efficiency. Although these metrics are part of the OEB Scorecard mentioned above they are important factors when considering how the utility is performing from a high level.

- **Yearly Project Optimization**

As detailed in section 5.3.1a) ETPL utilizes a software based optimization tool that assists in choosing a portfolio of projects within a given year that finds an optimal balance between mitigating risk and providing value within the constraints of defined strategic objectives. The optimization process provides a value indicating the percentage of strategic objectives that are met by a given portfolio. ETPL consistently chooses a mix of projects that achieve approximately 80% of strategic objectives for a given year.

- **Reliability Metrics**

SAIFI[2]

The SAIFI measure is used as an indicator of the frequency of outages that a customer experiences in a given year. ETPL aims to achieve a downward trend in all reliability metrics, and looks to be below the industry average.

$$SAIFI = \frac{Total\ Customer\ Interruptions}{Average\ Number\ of\ Customers\ Served}$$

SAIDI[3]

The SAIDI measure is used as an indicator of the duration of outages that a customer experiences in a given year. ETPL aims to achieve a downward trend in all reliability metrics, and looks to be below the industry average.

$$SAIDI = \frac{Total\ Customer\ Hours\ of\ Interruption}{Average\ Number\ of\ Customers\ Served}$$

[2] SAIFI - System Average Interruption Frequency Index
[3] SAIDI - System Average Interruption Duration Index

CAIDI[4]

The CAIDI measure is used as an indicator of the average outage duration that a customer would expect to experience. It also is an indication of the average restoration time. ETPL aims to achieve a downward trend in all reliability metrics, and looks to be below the industry average.

$$CAIDI = \frac{SAIDI}{SAIFI}$$

SAIFI - excluding Loss of Supply

The SAIFI measure is used as an indicator of the frequency of outages that a customer experiences in a given year. ETPL typically considers the SAIFI metric excluding Loss of Supply to establish the performance levels as a result of our distribution system.

$$SAIFI = \frac{(Total\ Customer\ Interruptions - Interruptions\ Caused\ by\ Loss\ of\ Supply)}{Average\ Number\ of\ Customers\ Served}$$

SAIDI - excluding Loss of Supply

The SAIDI measure is used as an indicator of the duration of outages that a customer experiences in a given year. Again ETPL typically considers the SAIDI metric excluding Loss of Supply to establish the performance levels as a result of our distribution system.

$$SAIDI = \frac{(Total\ Customer\ Hours\ of\ Interruptions - Total\ Customer\ Hours\ of\ Interruptions\ Caused\ by\ Loss\ of\ Supply)}{Average\ Number\ of\ Customers\ Served}$$

CAIDI - excluding Loss of Supply

The CAIDI measure is used as an indicator of the average outage duration that a customer would expect to experience. It also is an indication of the average restoration time. Again ETPL typically considers the CAIDI metric excluding Loss of Supply to establish the performance levels as a result of our distribution system.

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[4] CAIDI - Customer Average Interruption Duration Index
(CAIDI can be a flawed metric and is no longer included on the OEB scorecard, due to the fact that more frequent outages or higher SAIFI values will create artificially low CAIDI values. In ETPL's case, our LOS adjusted SAIFI values are typically low compared to industry averages and therefore the CAIDI metric provides some valuable information.

SAIFI - excluding Loss of Supply by Feeder

The SAIFI measure, as described above, is considered for each distribution feeder allowing ETPL to identify its worst performing feeders allowing capital spending to be targeted to specific areas and improve reliability metrics as a whole.

SAIDI - excluding Loss of Supply by Feeder

The SAIFI measure for each distribution feeder is considered and allows ETPL to identify its worst performing feeders allowing capital spending to be targeted to specific areas and improve reliability metrics as a whole.

CAIDI - excluding loss of Supply by Feeder

The CAIDI measure for each distribution feeder is considered and allows ETPL to identify its worst performing feeders allowing capital spending to be targeted to specific areas and improve reliability metrics as a whole.

B) HISTORICAL PERFORMANCE AND TRENDS

- ***This section includes a summary of performance and performance trends over the historical period using the methods and measures (metrics/targets) identified and described above. It must include data on the historical period including all interruptions and interruptions excluding loss of supply for the SAIDI, SAIFI and CAIDI metrics.***

▪ OEB Scorecard Metrics

The 2016 scorecard is shown below and indicates primarily positive trends over the past 5 years.

Figure 5: 2016 OEB Scorecard

Scorecard - Erie Thames Powerlines Corporation 8/17/2017

Performance Outcomes	Performance Categories	Measures		2012	2013	2014	2015	2016	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		98.80%	98.80%	99.40%	98.40%	99.60%	↑	90.00%	
		Scheduled Appointments Met On Time		100.00%	100.00%	100.00%	100.00%	100.00%	→	90.00%	
		Telephone Calls Answered On Time		94.60%	95.80%	95.50%	98.40%	98.40%	↑	65.00%	
	Customer Satisfaction	First Contact Resolution				99.7%	99.85	99.54			
		Billing Accuracy				99.85%	99.46%	99.50%	↓	98.00%	
		Customer Satisfaction Survey Results				100 %	89%	89			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness					83.40%	83.40%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	NI	C	C	C	→		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	0	→		0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000	→		0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		1.47	0.41	0.59	0.73	1.46	↓		0.99
		Average Number of Times that Power to a Customer is Interrupted [2]		0.31	0.20	0.30	0.48	0.24	↓		0.41
	Asset Management	Distribution System Plan Implementation Progress				In Progress	94%	104			
	Cost Control	Efficiency Assessment		4	3	3	3	3			
		Total Cost per Customer [3]		$564	$610	$631	$656	$676			
		Total Cost per Km of Line [3]		$30,891	$32,792	$33,707	$34,342	$36,550			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Cumulative Energy Savings [4]					18.75%	31.33%			27.63 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		100.00%			100.00%	100.00%			
		New Micro-embedded Generation Facilities Connected On Time			100.00%	92.86%	100.00%	100.00%	↑	90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.78	0.75	0.58	0.85	0.88			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.23	1.19	1.05	1.59	1.55			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.12%	9.12%	9.12%	9.12%	9.12%			
			Achieved	8.43%	11.80%	10.63%	9.39%	9.33%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the fixed 5-year (2010 to 2014) average distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the new 2015-2020 Conservation First Framework.

Legend: 5-year trend: ↑ up ↓ down → flat
Current year: target met; target not met

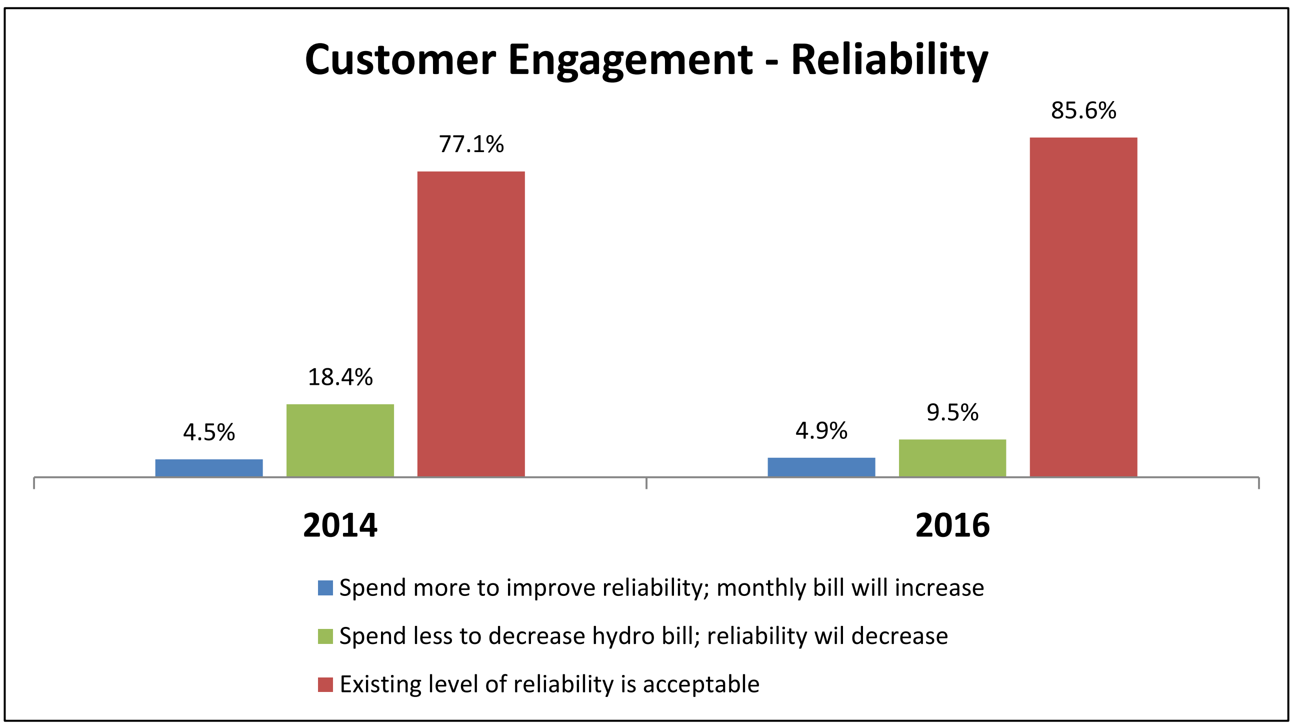
- **Customer Engagement**

ETPL completed a formal customer survey in 2014 & 2016 and will continue with formal customer surveys moving forward. This will allow more definitive trends in customer satisfaction to be developed using the same benchmark questions every year.

The following chart illustrates customer satisfaction with regards to reliability when asked to respond to the following question. It can be seen that there was a slight increase in the number of respondents who choose that the existing level of reliability is acceptable from 2014 to 2016.

"Erie Thames Powerlines understands that a reliable supply of electricity is important to our customers, and that the primary focus of our construction and maintenance work is maintaining or improving the reliability of our system. However, we recognize that customers are also concerned about rising electricity prices. With that in mind, please select one of the following statements that best represents your view."

Figure 6: Customer Engagement - Reliability



- **Operational Efficiency Metrics**

Figure 7: Total Cost ($) Per Customer

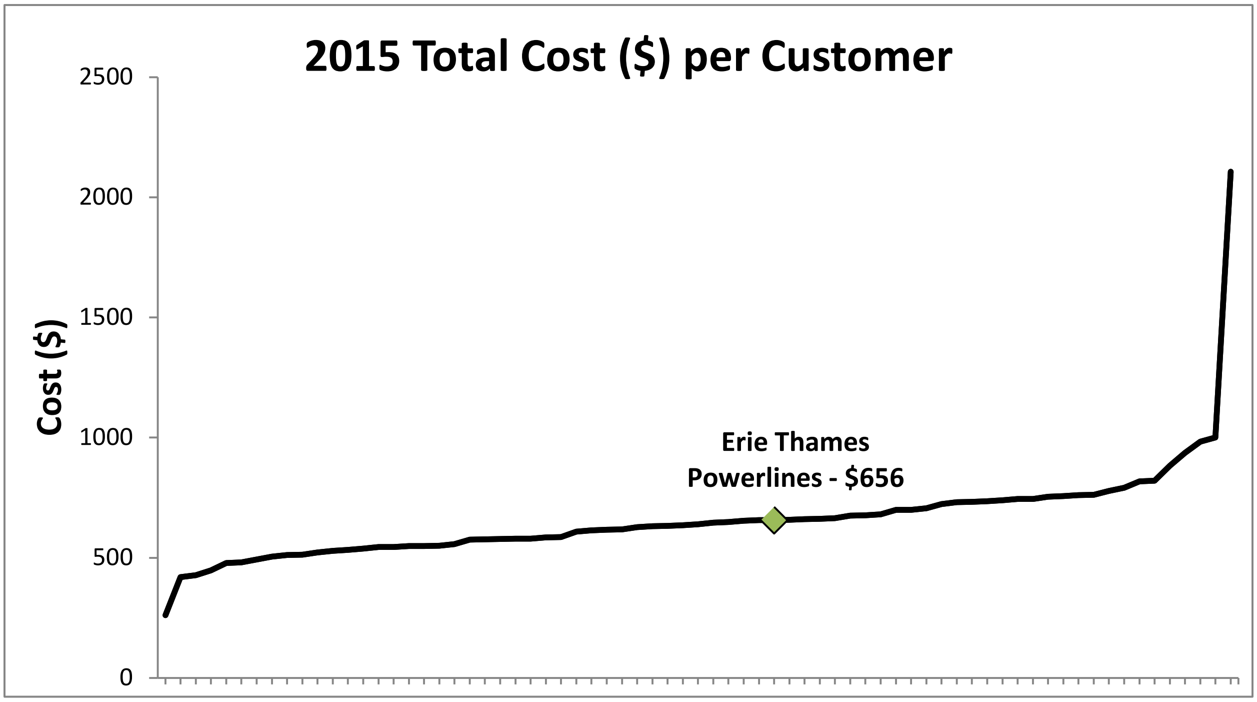


Figure 8: Total Cost ($) Per km of Line

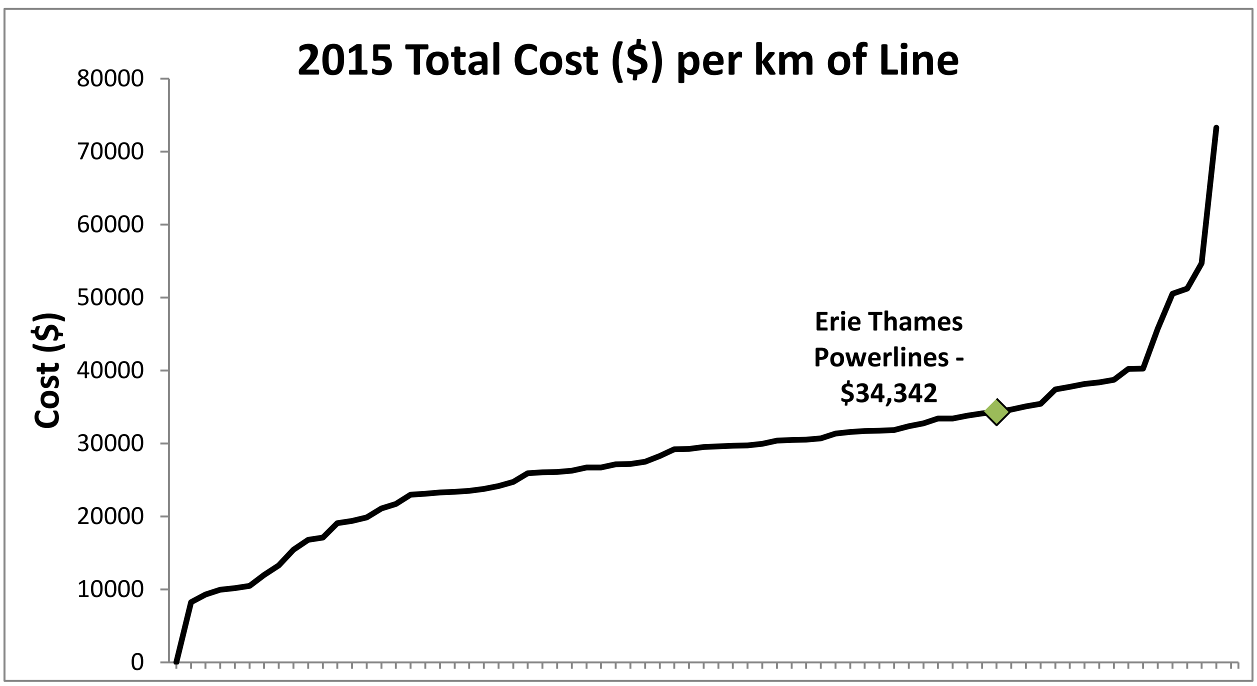
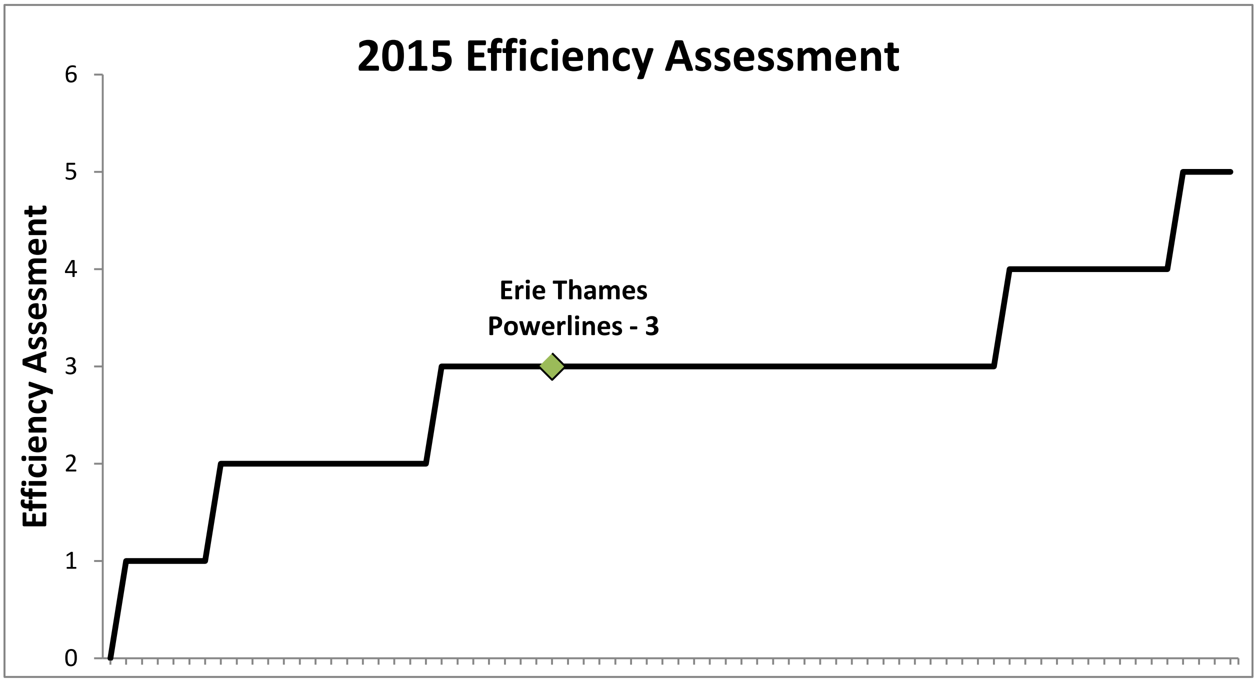


Figure 9: Efficiency Assessment



- **Yearly Project Optimization**

Table 4: Yearly Project Optimization Levels

BUDGET YEAR	STRATEGIC OBJECTIVES MET
2013	82%
2014	89%
2015	82%
2016	83%
2017	78%
2018	81%

- **Reliability Metrics**

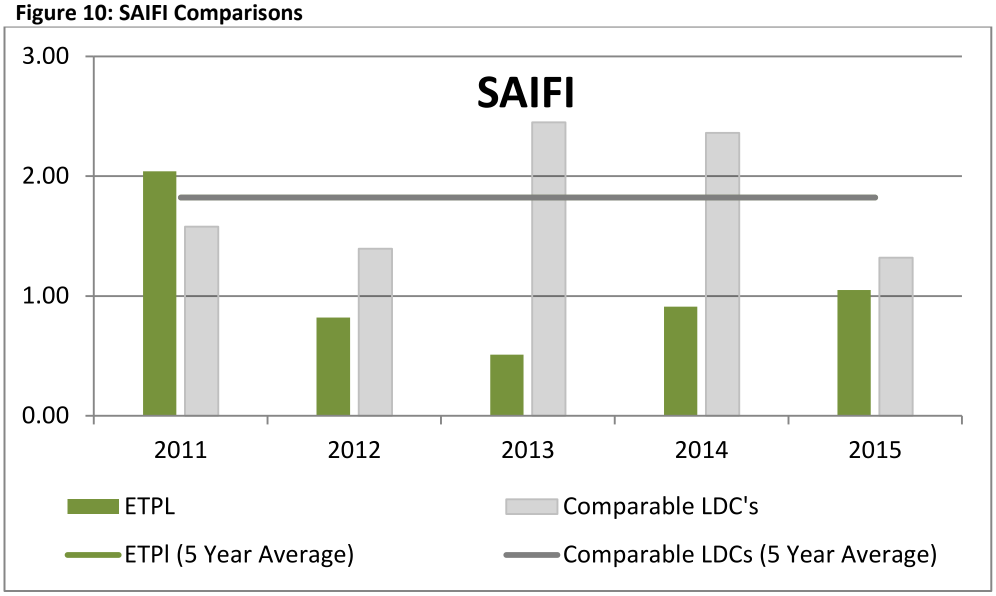
For each of the following reliability metrics ETPL has included the reliability measure for comparable LDCs[5]. The selections of comparable LDCs were based primarily on customer count ranging from 15,000 to 21,000. The varying characteristics of each utility make it difficult to make a direct comparison

[5] Comparable LDC's were selected based on a customer base between 15,000 and 21,000. The specific LDCs were Collus Powerstream, Festival Hydro, Halton Hills, InnPower and St. Thomas Energy.

however still allow for a more valuable benchmarking assessment and any marked adverse deviations from the trend are highlighted. Also included is a comparison of ETPL SAIDI and SAIFI metrics as compared to the industry as a whole.

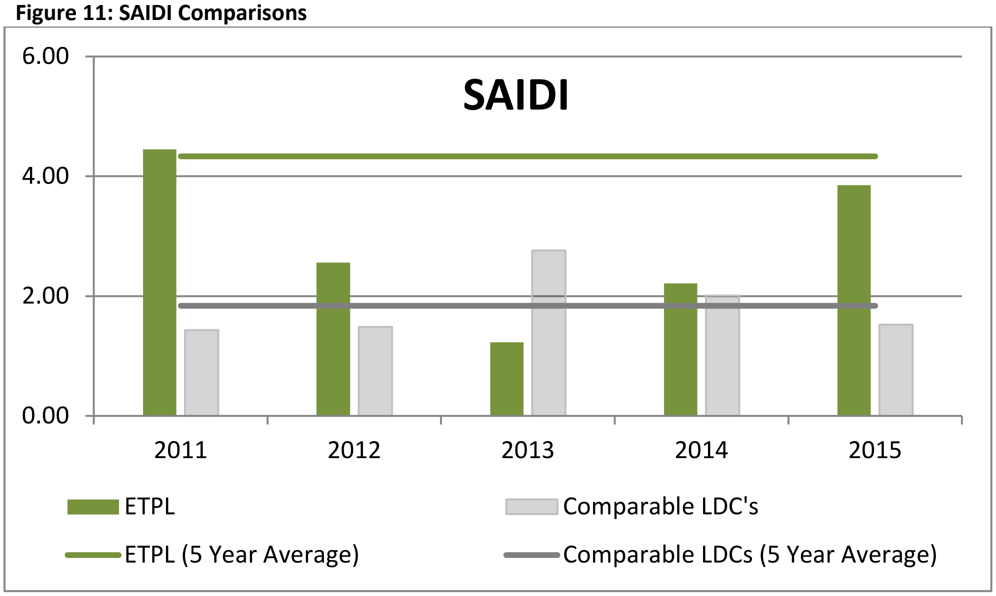
SAIFI

Figure 10: SAIFI Comparisons



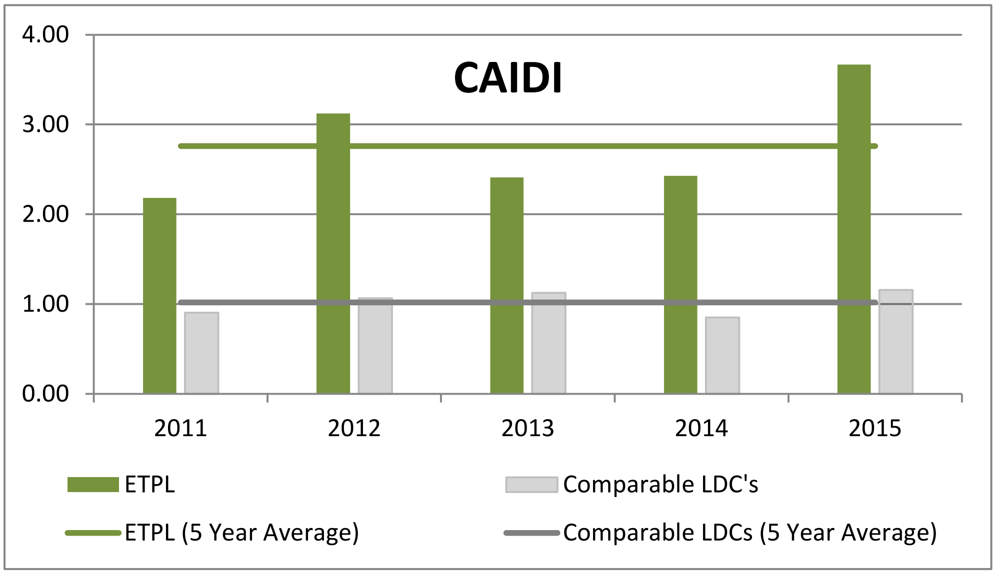
SAIDI

Figure 11: SAIDI Comparisons



CAIDI

Figure 12: CAIDI Comparisons



SAIFI - excluding Loss of Supply

Figure 13: SAIFI (LOS adjusted) Comparisons

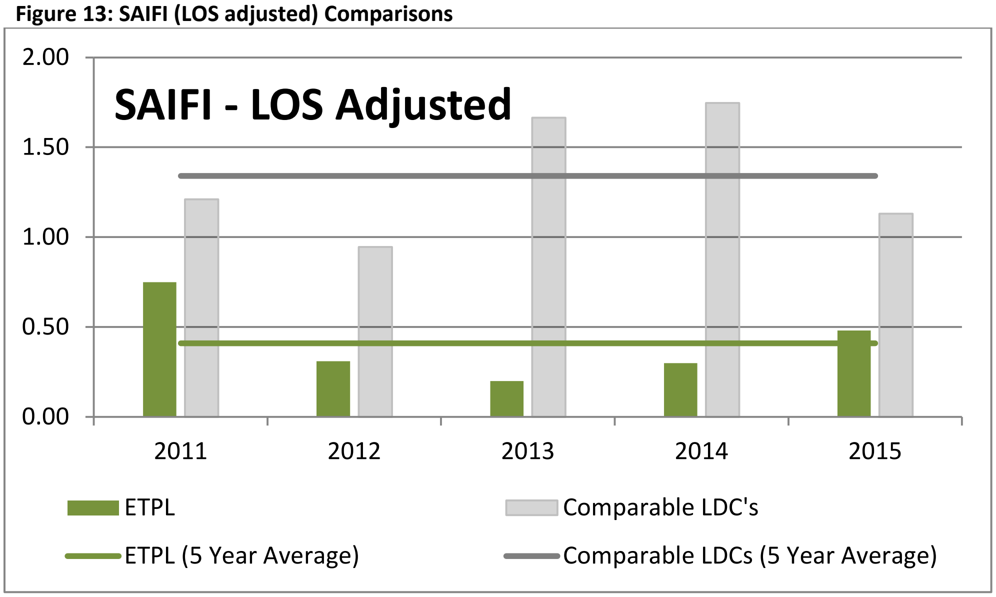
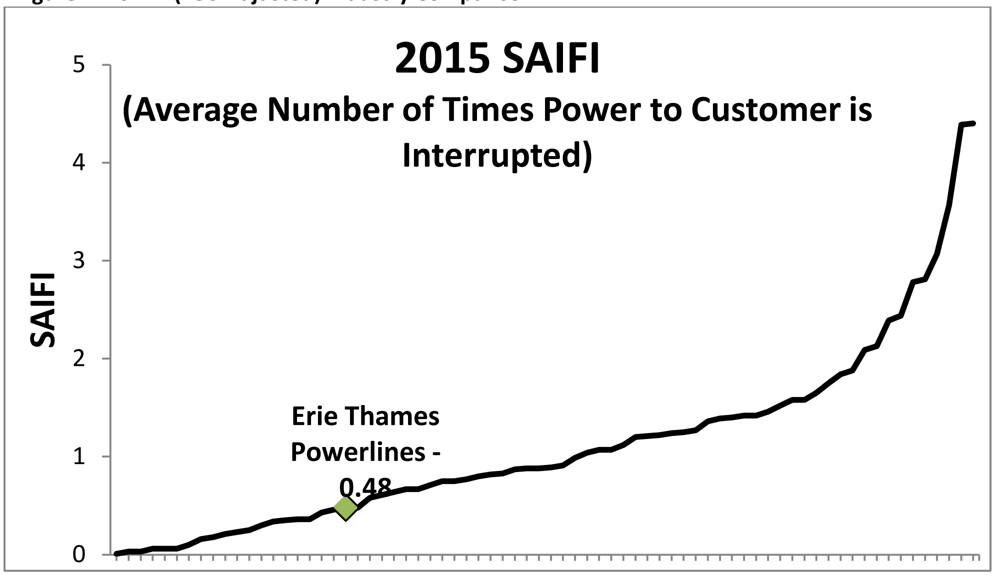


Figure 14: SAIFI (LOS Adjusted) Industry Comparison



SAIDI - excluding Loss of Supply

Figure 15: SAIDI (LOS Adjusted) Comparison

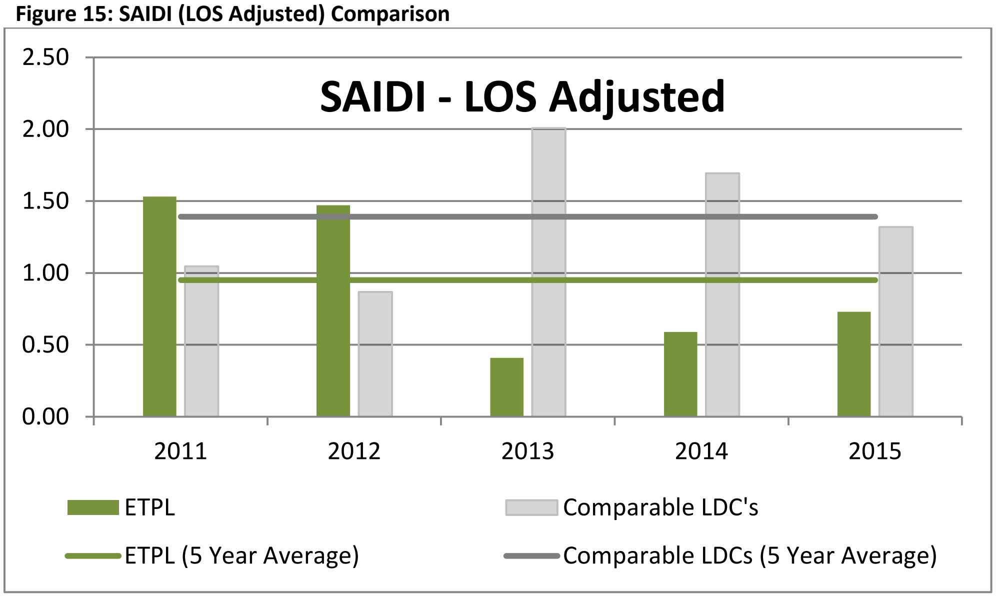
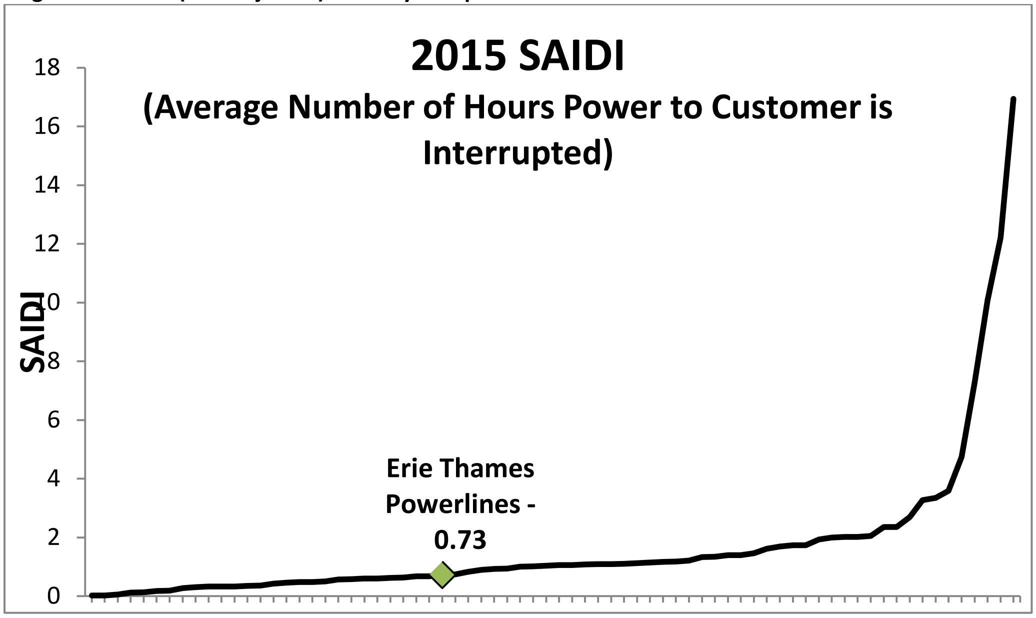


Figure 16: SAIDI (LOS Adjusted) Industry Comparison



CAIDI - excluding Loss of Supply

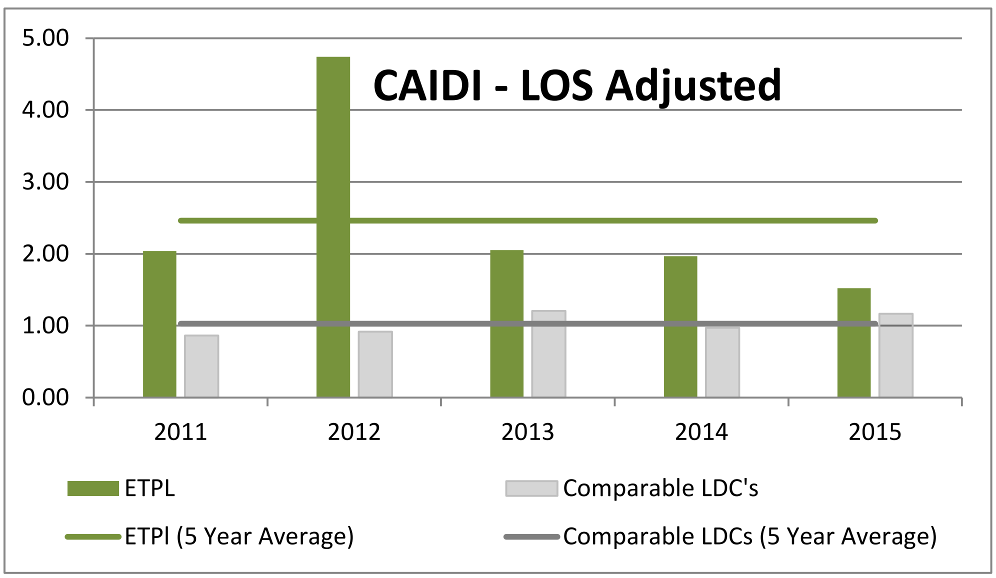
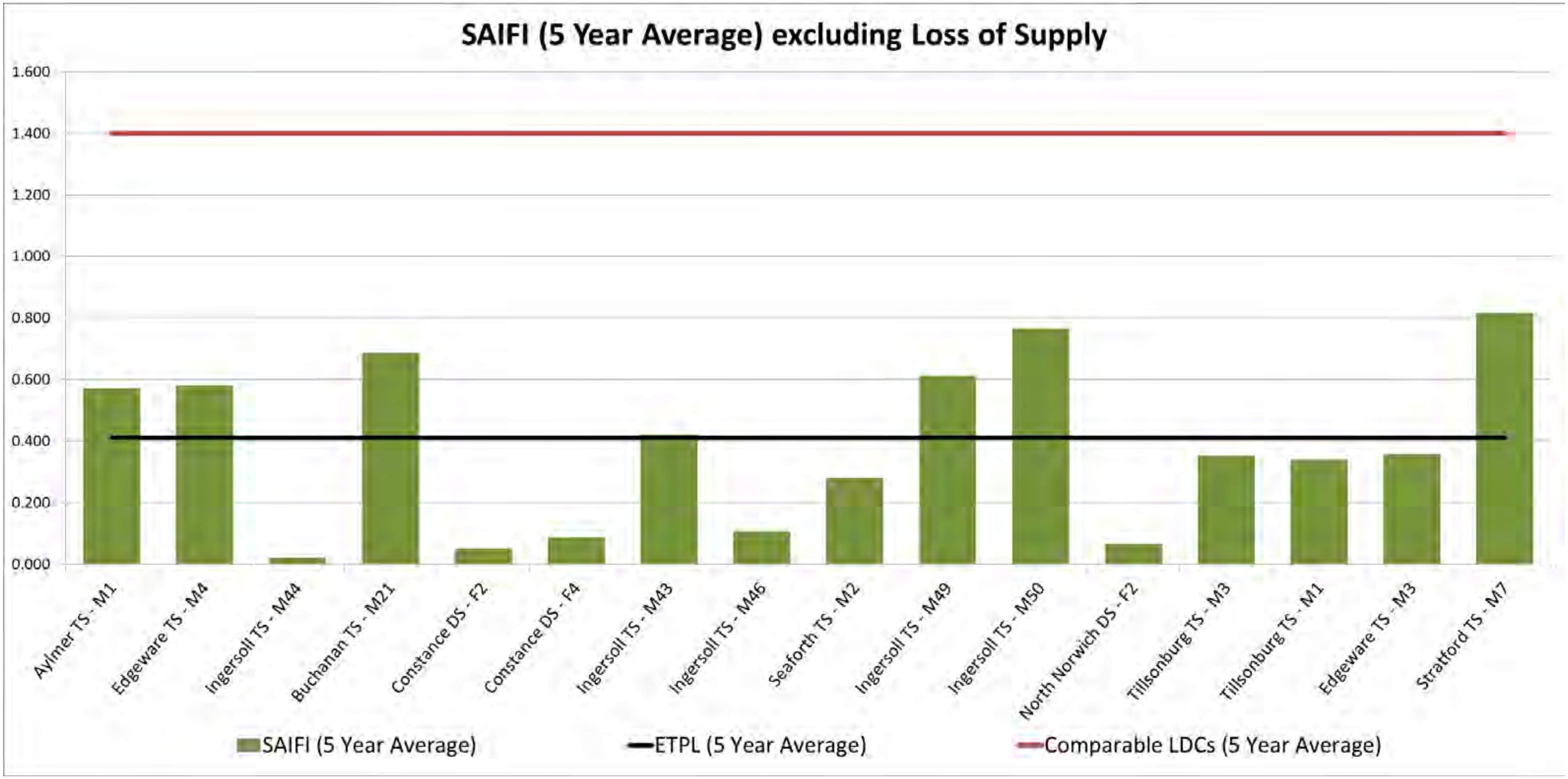


Figure 17: CAIDI (LOS Adjusted) Comparison

In 2012 ETPL reported a drastic increase in LOS adjusted CAIDI. This was a result of a 4kV substation transformer failure caused by a direct lightning strike to a high voltage bushing. The transformer was subsequently replaced resulting in outages to 1200 customers totalling 103,390 hours of customer outage duration.

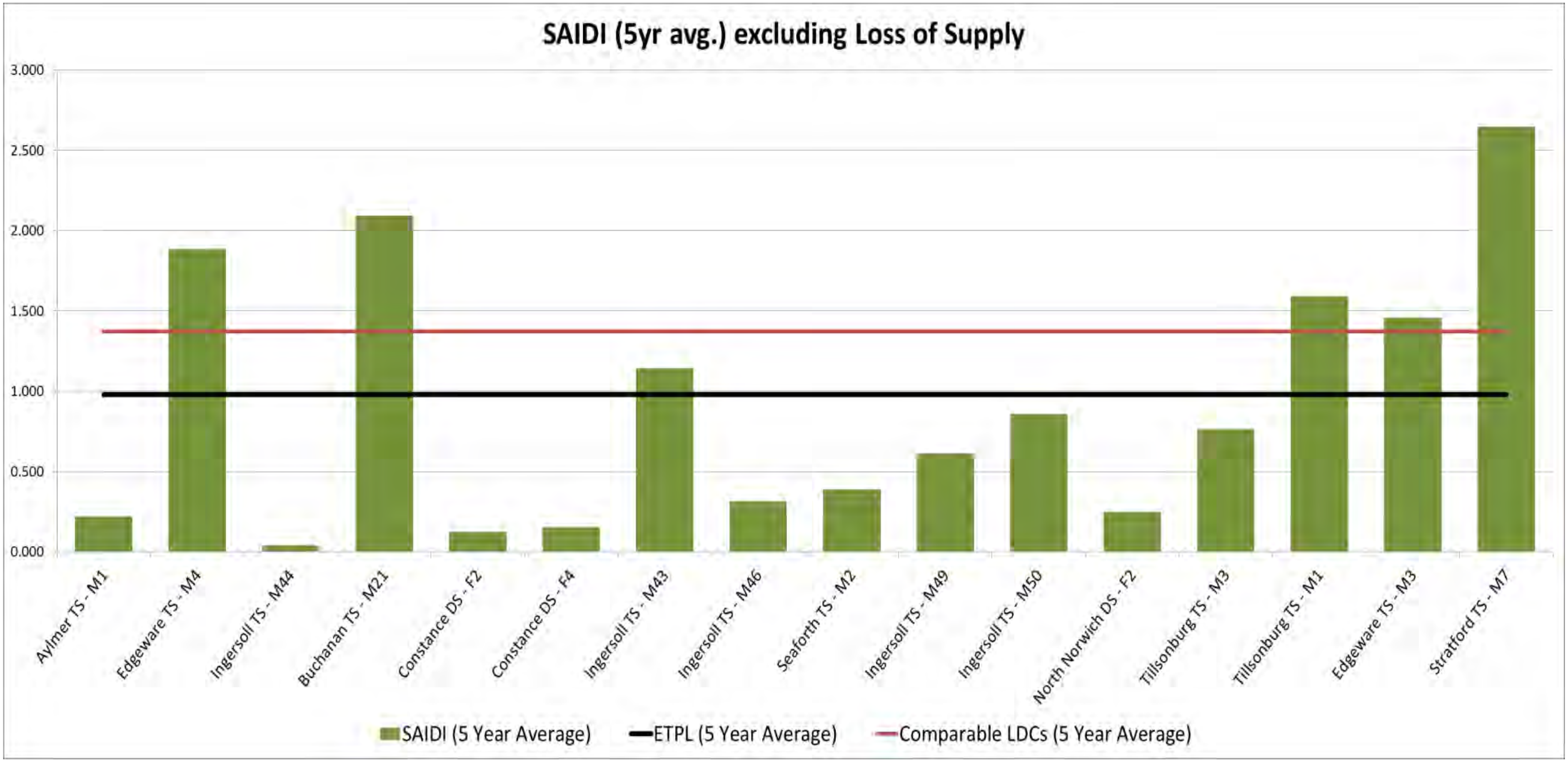
SAIFI - excluding Loss of Supply by Feeder

Figure 18: SAIFI - Worst Performing Feeder



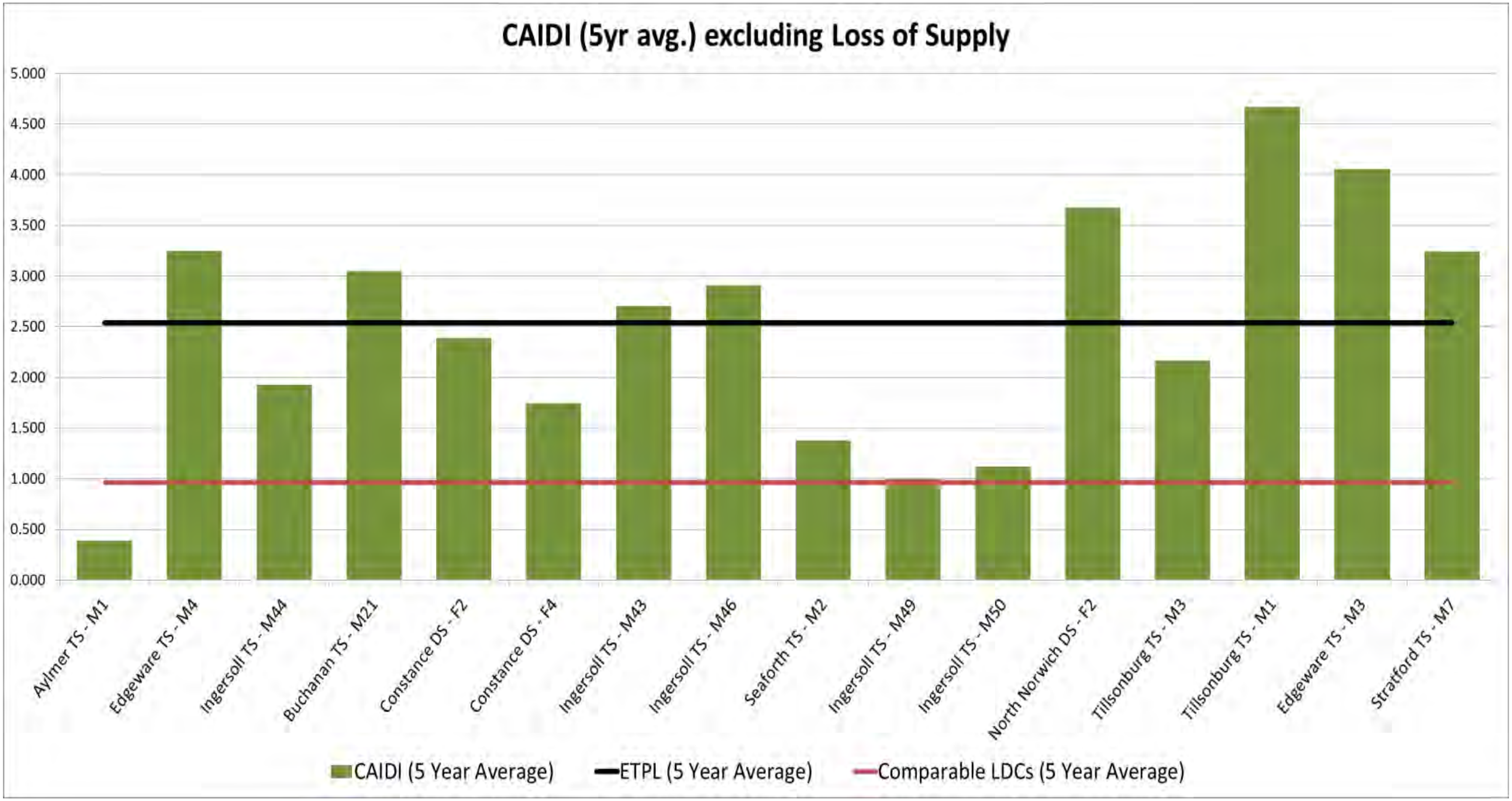
SAIDI - excluding Loss of Supply by Feeder

Figure 19: SAIDI - Worst Performing Feeder



CAIDI - excluding loss of Supply Feeder

Figure 20: CAIDI - Worst Performing Feeder



ETPL understands that CAIDI can be a flawed metric and is no longer included on the OEB scorecard, due to the fact that more frequent outages or higher SAIFI values will create artificially low CAIDI values. In ETPL's case, our LOS adjusted SAIFI values are typically low compared to industry averages and therefore the CAIDI metric provides some valuable information.

Historically Erie Thames Powerlines CAIDI reliability metrics have been higher than industry levels indicating that the average restoration time is longer than industry standards. This can primarily be explained by the geographic makeup of our service territory with significant driving distances between a number of our communities and service centers. It can be seen that restoration times tend to be greater in communities further from ETPL service centers.

- ***Tillsonburg TS - M1 services Otterville which is a driving distance of approximately 30mins***
- ***Edgeware TS - M3 service Port Stanley which is a driving distance of approximately 35mins***
- ***North Norwich DS - F2 services Burgessville which is a driving distance of approximately 25 mins***
- ***Stratford TS - M7 service Tavistock which is a driving distance of approximately 40 mins.***

An outlier from this reasoning is the Edgeware TS - M4 feeder which supplies the southern half of Aylmer. The vast majority of this area is older underground subdivisions and rear yard construction which typically require longer outages due to troubleshooting and access issues. Although CAIDI values are historically higher than industry levels, ETPL has been able to maintain SAIDI & SAIFI values below industry levels ensuring that customers are experiencing fewer outages. Various investments have been made to improve restoration efforts and are detailed in subsequent sections.

C) EFFECTS OF PERFORMANCE MEASUREMENTS ON THE DS PLAN

- ***This section explains how the information provided above 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.***

In general, evaluation of the performance measurements detailed above ensures that the DS Plan is being implemented in such a way that the objectives identified by the Asset Management Plan and key elements detailed in Section 5.2.1 are achieved. This typically focuses on maintaining a safe, reliable and cost effective supply to customers.

It can be seen that ETPL operates in the mid-high level with respect to the operational efficiency metrics such as cost ($) per customer and cost ($) per km of line. This type of benchmarking analysis is reflected in ETPL's capital plan which has forecasted a spending level below the recommend spend in the AMP. This downward pressure on CAPEX spending is a result benchmarking along with the desire to respond to customers who prioritize the cost of hydro as one of their most important preferences.

Reliability measures (SAIDI, SAIFI & CAIDI) are used to benchmark ETPL reliability against industry levels and confirm that ETPL customers are provided a reliable hydro supply. Typically a balance must be struck between recommended spending levels determined purely by AM practices and spending levels established with financial implications such as customer bill impacts in mind. Analysis of reliability trends allows ETPL to justify spending level decisions ensuring that compromises are not adversely affecting customer reliability.

Analysis of reliability measures by feeder is an important performance indicator used to target capital spending. Projects in areas with poor reliability are assigned higher risk and probability of failure when entering the given project into the optimization software. This provides a more accurate assessment of the risks associated with a given project and ensures that capital spending is focused on areas of the greatest need with reliability in mind.

As noted Erie Thames has experienced CAIDI values above industry levels which tends to reflect longer restoration times. This can primarily be explained by the geographic makeup of the utility however our DS Plan includes multiple investments that look to improve restoration times. These include:

- Fault Indicator Installation - fault indicators connected to the SCADA system will provide additional feedback to ETPL staff and aid in determining the location of faults.
- OMS Implementation - the implementation of the OMS will provide Customer Service Representatives (CSRs) the ability to enter customer calls directly onto a distribution map and will receive intuitive feedback regarding the cause of the issue allowing crews to be dispatched quickly to the correct location.
- Automated Switch Installations - Over the planning period ETPL plans to install automated switches at strategic locations controllable from the SCADA system. Depending on the installation multiple switches may be installed and programmed to automatically sectionalize an outage resulting in fewer customers being affected by an event.

5.3 ASSET MANAGEMENT PROCESS

- ***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.***

ETPL's Asset Management practices were formalized in 2011 when it engaged METSCO Energy Solutions to develop an Asset Condition Assessment (ACA) and Asset Management Plan (AMP - included in DSP Appendix H) which was included in the 2012 Cost of Service Rate Application (EB-2012-0121). This formed the basis for more effective Asset Management moving forward and has since been updated with the 2015 AMP (included in DSP Appendix I). It was created to provide an overview of the assets managed by ETPL and outlines the purpose, strategy, objectives and expenditures required to provide safe, reliable and cost effective hydro to our customers. Prior to formalizing the Asset Management Process in 2011, ETPL had been following good utility practices by replacing assets that had or would be reaching end of life, or otherwise identified as potential failure risks during inspection or testing. The engagement of a third party to formalize the process revealed that ETPL had been potentially under-investing in asset replacement although this had not resulted in sub-standard performance (reliability) of the distribution system. As noted in the 2012 Cost of Service Rate Application (EB-2012-0121), ETPL considered the potential rate impact to customers and opted to gradually increase the investment in asset replacement over a number of years. This decision was supported by the OEB and intervenors through the proceeding and no change was required with the proposed level of spending on capital for 2013 (OEB Decision and Order November 29, 2012).

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 distributors asset management process including key elements of the process that have informed the preparation of the distributors capital expenditure plan.***

5.3.1A) DESCRIPTION OF ASSET MANAGEMENT OBJECTIVES AND RELATIONSHIP WITH CORPORATE GOALS

- ***A description of the distributor's asset management objectives and related corporate goals, and the relationship between them; where applicable, show and explain how the distributor ranks asset management objectives for the purpose of prioritizing investments.***

ETPL's corporate structure[6] requires it to prudently manage its resources to balance the needs of customers with the objectives of the shareholder. The sole shareholder of ETPL is ERTH Corporation, which is owned by eight of the municipalities where ETPL provides service. The Directors of ERTH Corporation (Shareholder) are representatives of each of the eight municipalities (typically elected officials), who are responsible to represent their respective municipalities (residents/customers) as an investor (Shareholder) and a provider of affordable essential distribution services. Thus, the performance and planning of ETPL is regularly reviewed by municipal representatives who provide direct input to the ETPL Board and Senior Management regarding customer concerns in their respective municipalities.

- **ERTH's Sustainability Commitment:**

ERTH Corporation is a dynamic group of companies that delivers products and services within the energy, water and municipal sectors. Given our involvement in providing essential services and the key role we play in our local communities, we recognize the importance of sustainable business practices.

Since our inception in 2000, sustainability has been ingrained in our founding principles, which include local presence and employment and a commitment to the social, environmental and economic needs of our customers, employees and shareholder communities. We believe that these principles are key ingredients in building stronger communities and a more sustainable business.

[6] Additional information about ETPL's corporate structure is available in COS Exhibit 1.

We understand that our actions impact the communities in which we operate. We also understand that this impact will affect future generations and the prosperity of our shareholder communities. It is important to recognize that the scope of sustainability stretches much further than simply conservation and environmental preservation. Therefore, sustainability to ERTH means promoting business practices that are sustainable from an environmental, social and economic perspective.

- **ETPL's Mission:**

"As Your *Home Town Utility* we provide you, our valued customers, with safe and reliable power line services. Our mission and pledge to our customers is to provide exceptional, cost effective electrical service. We distribute and maintain the flow of electricity to our customers from Ontario's energy grid. We take pride in providing our customers with knowledgeable staff and a dependable and reliable energy distribution system."

- **Asset Management Objectives:**

As an infrastructure based organization ETPL recognizes that our assets are the key element to providing safe, reliable and cost effective hydro to our customers. ETPL implements a risk based asset management plan (AMP) enabling the following **(OBJECTIVES)** to be realized through informed asset based decisions.

- The ability to maintain or improve the reliability of our distribution system
- Long term planning horizons resulting in stabilized financial impacts to customers
- The proper balance between capital investments in new infrastructure and O&M costs ensuring that the total cost over the life of the asset is minimized.

- **Ranking and Prioritizing Investments:**

ETPL uses a software based investment optimization process ("optimizer") to ensure that planned projects are targeted at portions of the distribution system that have the highest risk and consequence. This allows the objectives set out in the Mission Statement and Sustainability Commitment to be realized while minimizing risk to customers, employees and shareholders.

Each project being considered for capital expenditure is assigned risk based on consequence and probability for a number of categories. The categories as defined in the investment optimizer are explained in detail below, with the associated weighting in percentage.

Financial (11%)

Value - The financial category aims to quantify any financial impacts as a result of the project completion. Consideration is given to the project cost, revenue and cost savings in the form of reduced maintenance, or operating costs.

Risk - the risk assigned under this category is based on the loss of revenue and/or cost avoidance as a result of not completing the particular project. The financial consequences are linked to the probability of an event occurring on a scale ranging from four (4) events a year to one (1) event every ten (10) years.

Service Quality (13% total) - SAIFI (6.5%)

Value - SAIFI quantifies the number of times a customer experiences a power interruption and consideration is given to the current SAIFI trend in the proposed project area.

Risk - risk for SAIFI considers the potential impact to outage frequency resulting from asset failure if the project is not completed. The consequences assigned to the project range from individual customers (<50kW) to transmission feeders (>50% of customers) experiencing an outage and the probability range from four (4) events a year to one (1) event every ten (10) years.

Service Quality (13% total) - SAIDI (6.5%)

Value - SAIDI quantifies the duration of outages experienced by a customer and consideration is given to the current SAIDI trend in the proposed project area.

Risk - risk for SAIDI considers the potential impact to outage duration resulting from asset failure if the project is not completed. The consequences assigned to the project range from a momentary outage (<3min) to a sustained outage (>12 hours) and the probability ranges from four (4) events a year to one (1) event every ten (10) years.

Company Image (8%)

Value - The company image category looks to address any formal complaints made to ETPL as a result of a particular portion of the distribution system related to a proposed project.

Risk - the risk assigned under the company image category is based on the consequences of a formal complaint ranging from individual concerns made to the company to general public outcry - national media coverage and again is assigned a probability ranging from four (4) events a year to one (1) event every ten (10) years.

Legal (8%)

Value - the legal category looks to consider the litigation costs related to a particular project.

Risk - the risk assigned to a project under the legal category is based on the litigation costs that may result of a project not being completed. The consequences range from litigation costs of less than $1000 to greater than $500,000, and are assigned a probability ranging from four (4) events a year to one (1) event every ten (10) years.

Regulatory (18%)

Value - The value assigned under the regulatory category looks to consider the impacts of a project on compliance to regulatory requirements.

Risk - the consequences as a result of not completing the proposed project range from non-reportable compliance issues to damaging OEB regulatory impacts resulting in the loss of licence and are assigned a probability ranging from four (4) events a year to one (1) event every ten (10) years.

Public Safety (13%)

Value - The value considered in this category is specific to public safety and looks to quantify the possibility of a safety incident related to a member of the public.

Risk - If the potential project is not completed the consequences range from the potential of a non-life threatening injury with no prior history to a potentially life threatening hazard with a known history and assigned a probability ranging from four (4) events a year to one (1) event every ten (10) years.

Employee Safety (13%)

Value - The value considered in this category is specific to employee safety and looks to quantify the possibility of a safety incident related to a utility worker.

Risk - If the potential project is not completed the consequences range from a minor employee injury with internal reporting required to a major loss time injury or fatality and assigned a probability ranging from four (4) events a year to one (1) event every ten (10) years.

Environmental (16%)

Value - the environmental category aims to consider the environmental impacts of the distribution system and to ensure any environmental concerns are mitigated.

Risk - the risk assigned under the environmental category if a project is not completed range in consequence from a minor disturbance with environmental documentation not necessary to a disturbance requiring MOE and third party environmental assistance. The possible consequences under this category are assigned probability ranging from four (4) events a year to one (1) event every ten (10) years.

The investment optimizer requires that all categories be assigned importance and the following figure demonstrates the weighting that has been adopted by ETPL[7] in line with our internal and corporate objectives.

[7] The categories and weights are reviewed and confirmed by the ETPL Board of Directors every two to three years.

Figure 21: Risk Analysis Weighting

Currently ETPL utilizes the investment optimizer to complete a yearly optimization of all capital expenditures involving fixed distribution assets. This requires approximately 2-3 years of potential projects to be defined, budgeted and assigned risk. The optimizer then analyzes the available projects and chooses a mix of projects that not only minimize risk but fall within prescribed spending levels. This ensures that projects are identified, selected and prioritized using disciplined risk based analysis. Projects that are considered mandatory (such as connecting new customers) are excluded from the optimization process.

The relationships between the corporate goals (ERTH Sustainability Commitment, ETPL Mission), asset management objectives, the Optimizer categories, and the OEB Outcomes[8] are summarized in the table below.

[8] Section 5.0.4 of OEB Filing Requirements

Table 5: OEB & ETPL Relationships

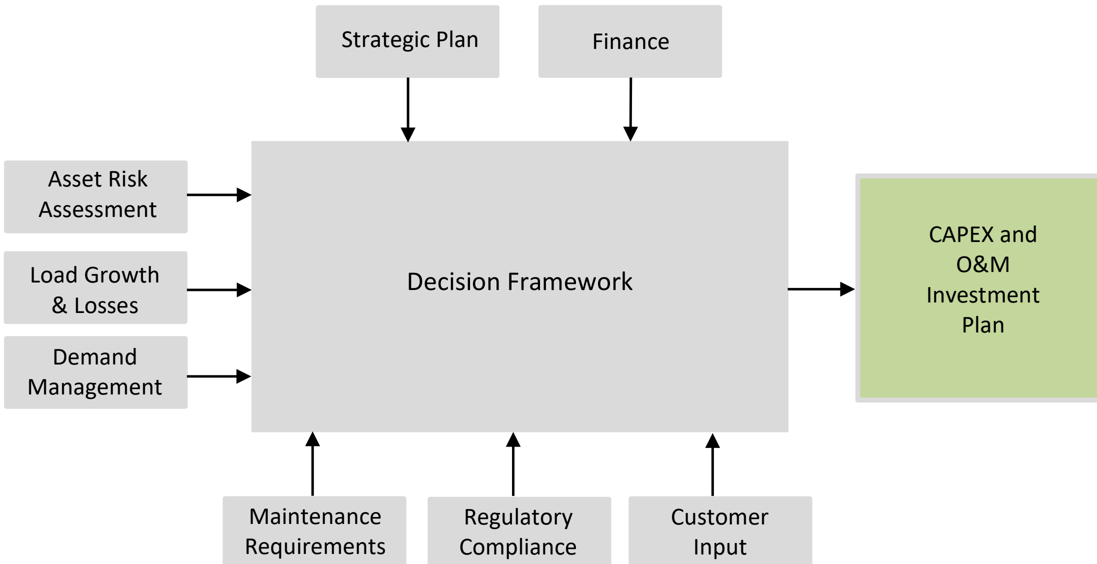
OEB OUTCOMES				
CUSTOMER FOCUS	OPERATIONAL EFFECTIVENESS	PUBLIC POLICY RESPONSIVENESS	FINANCIAL PERFORMANCE	
local presence, needs of customers	economic needs of customers, sustainable business practices	social and environmental needs, conservation, environmental preservation	sustainable business practices, needs of shareholder	**ERTH SUSTAINABILITY COMMITMENT**
home town utility, valued customers, safe and reliable powerline services	exceptional electrical service, knowledgeable staff	exceptional electrical service	cost effective electrical service	**ETPL MISSION**
maintain or improve reliability, stabilized financial impacts to customers	maintain or improve reliability, long term planning horizons, balance capex and O&M costs	long term planning horizons	stabilized financial impacts to customers, balance capex and O&M costs, total cost over life of asset is minimized	**ASSET MANAGEMENT OBJECTIVES**
public safety, SAIFI, SAIDI, financial	SAIFI, SAIDI, employee safety	legal, regulatory, environmental	financial, company image	**OPTIMIZER CATEGORIES**

5.3.1B) ASSET MANAGEMENT PROCESS COMPONENTS

- ***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.***

To create the annual capital, operating and maintenance plan, ETPL uses a risk based strategy as recommended by METSCO in the original 2011 Asset Management Plan. The diagram below illustrates the various inputs that go into the process used to create the capital plan.

Figure 22: ETPL Decision Framework



- ***Finance***

The ETPL Board of Directors, in consultation with Senior Management, provide input regarding the overall envelop of spending that is considered appropriate, given the potential impact to customers' rates, shareholder return, and the present and future financial health of the company[9]. This "top down" approach ensures that the resulting investment plan is reasonable and sustainable.

- **Strategic Plan**

The ETPL Board and Senior Management Team identify special projects (such as a website update) or areas of focus (such as distribution automation) that may impact the overall investment plan for the coming year. This direction is conveyed to the management team during preliminary budget meetings.

[9] This includes a review of the current and forecast ranking using the metrics developed by the Pacific Economics Group LLC (PEG) for the OEB

- **Asset Risk Assessment**

Assets are evaluated (some individually, some by sample set, others using age as a proxy) to determine the risk of failure and impact. From this, an average yearly capex replacement amount is created, which forms a starting point for the capital and O&M plan.

- **Load Growth & Losses**

Using historical trend analysis and input from municipal planners and local developers, an estimate is made regarding the amount of load growth (or loss) that will occur in each area. This is typically expressed as the number of new or upgraded customers by type, and an approximate dollar amount is assigned for the expected workload. In some cases, load growth in a specific area may initiate a project to increase capacity or provide an alternate supply.

- **Demand Management**

Coupled with the load growth analysis, consideration is given to the amount of load that could potentially be reduced by the various conservation and demand management initiatives, or offset with distributed generation (including load displacement). Historically, the overall impact of various demand management initiatives has slowed growth such that increased capacity is not normally required, although new customers are added every year.

- **Maintenance Requirements**

Various components of the system require regular maintenance, dictated by asset condition, utilization, manufacturers' recommendations, or good utility practice. Generally, the costs of maintenance increases as the assets age and as the assets are used.

- **Regulatory Compliance**

LDCs must comply with several regulations that directly or indirectly result in capital or O&M work. Some examples include connecting new customers, upgrading meters, making changes to billing systems, inspecting the distribution system, and providing safety training to workers. In many cases, these types of projects do not go through the optimizing process as they must be completed regardless of the ranking results.

- **Customer Input**

ETPL regularly solicits input from customers through surveys to assist with developing the annual investment plan. Informal input is also received as employees interact with customers through routine activities such as billing inquiries or when participating in community events or when hosting events such as Conservation Seminars.

- **Decision Framework**

The "decision framework" is essentially the optimizer program as detailed in Section 5.3.1 (a), coupled with internal discussion and prioritization.

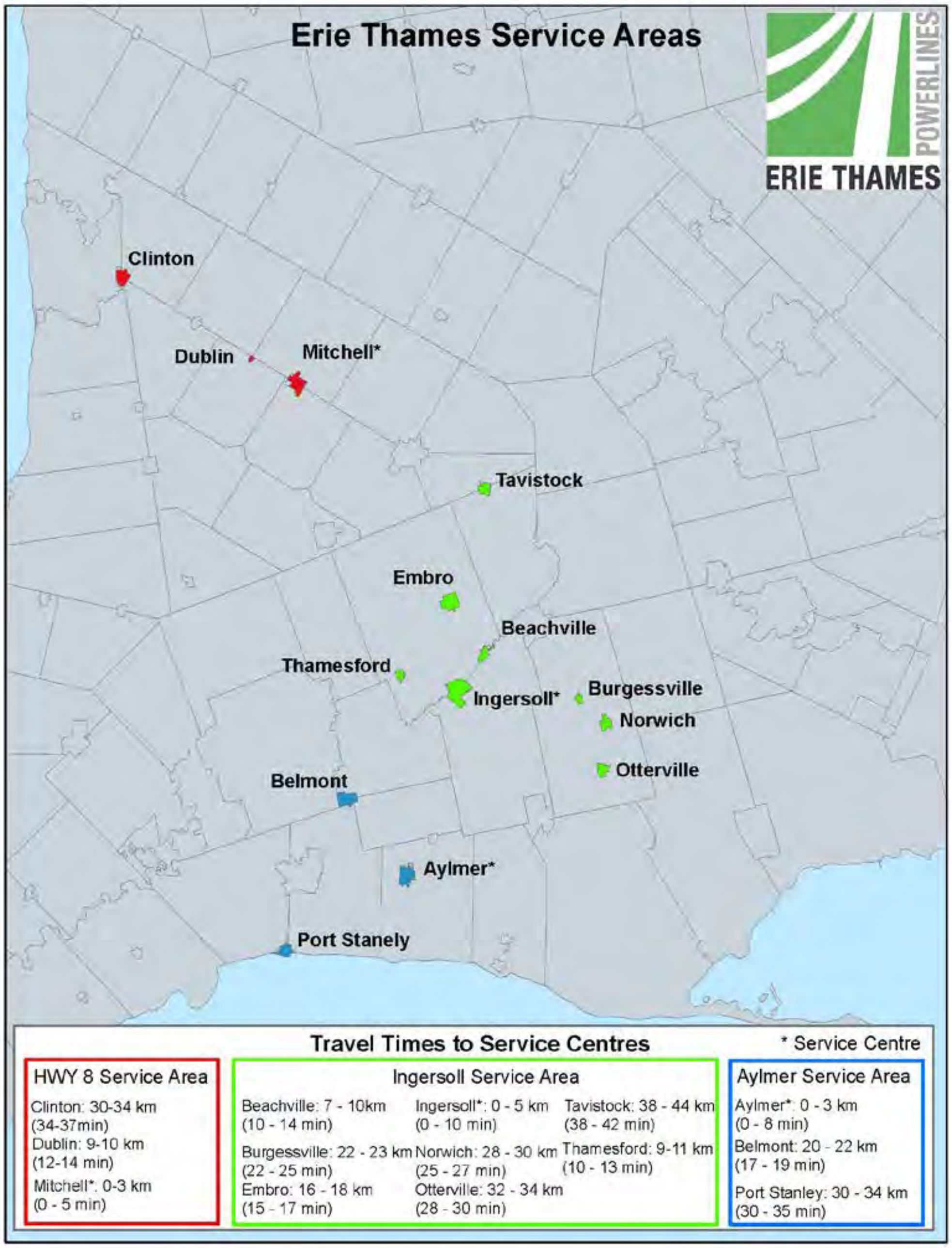
5.3.2 Overview of Assets Managed

5.3.2A) DESCRIPTION AND EXPLANATION OF SERVICE AREA FEATURES

- ***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.***

Erie Thames Powerlines (ETPL) is a local distribution company located in Southwestern Ontario representing the amalgamation of nine Public Utilities Commissions and currently services 18,265 customers in the municipalities of Port Stanley, Aylmer, Belmont, Ingersoll, Thamesford, Otterville, Norwich, Burgessville, Beachville, Embro, Tavistock, Mitchell, Dublin and Clinton. ETPL's service territory spans north to south a distance of approximately 120km and all municipalities are embedded within Hydro One service territory. ETPL has three operations centers located in Aylmer, Mitchell and Ingersoll with the later retaining all executive, administration, finance, customer service, metering and engineering departments. Figure 23 below illustrates the ETPL service territory along with operations centers and approximate travel times.

Figure 23: ETPL Service Area Map



The communities serviced by ETPL have varying degrees of customer density and the majority are classified as rural based on the guidelines set out in Appendix C of the Distribution System Code. ETPL however considers and operates all communities as urban centers with respect to inspection and maintenance requirements.

Table 6: Customer Density

MUNICIPALITY	# OF CUSTOMERS	KM OF LINES	CUSTOMER DENSITY
Norwich	1198	14.923	80.3
Port Stanley	1576	26.248	60.0
Clinton	1724	28.787	59.9
Tavistock	1183	20.402	58.0
Ingersoll	5238	89.668	58.4
Thamesford	603	11.614	51.9
Aylmer	3066	52.868	58.0
Dublin	125	2.702	46.3
Mitchell	2023	44.136	45.8
Beachville	411	9.716	42.3
Otterville	438	10.603	41.3
Burgessville	178	4.857	36.6
Belmont	775	20.713	37.4
Embro	356	10.595	33.6[10]

The weather in Southwestern, Ontario, "brings warm or hot summers with normal thunderstorm occurrences. Some of these storms are severe, with damaging winds, hail and tornadoes all possible during peak season, May through September. The most likely areas for these kinds of weather events are within the Windsor - London corridor and north up to about Huron County. Winters are cold with less snowfall in the south towards Essex County and higher amounts north towards Bruce County. London receives approximately 30% more snowfall than Windsor, owing to its relative position to Lake Huron and the resulting snowbelt in Bruce and Middlesex counties." [11]

During the December 2013 ice storm ETPL experienced mostly minor damage to our overhead infrastructure in various regions of our service territory. Areas affected included Clinton, Mitchell, Tavistock Embro, Ingersoll, Thamesford, Burgessville, Otterville and Norwich.

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[10] Two (2) dedicated 27.6kV feeders service the GM-CAMI industrial facility in Ingersoll and were not considered in the calculations of customer density.

[11] Southwestern Ontario. (n.d.). From Wikipedia. Retrieved January 14, 2015, from https://en.wikipedia.org/wiki/Southwestern_Ontario

All ETPL Line Dept. staff from our three operations centers worked from early morning on the 22nd until late in the day to restore power to as many customers as possible. The entire town of Tavistock was without power from 9:00 am until 1:15pm due to a loss of supply caused by the 68M7 circuit being tripped at the Stratford TS as a result of fallen limbs and trees due to ice buildup. Burgessville experienced outages caused by a loss of supply from Hydro One distribution resulting in approx. 40 customers without power during the night of Dec.22. Power was restored by 10:30 am on the 23rd. ETPL also provided a crew to Hydro One's Beachville operations center on Dec. 23 to assist in the power restoration of Hydro One customers in the Brantford- Paris area. As a whole ETPL's system responded well to the storm and only experienced a small number of outages; no changes to tree trimming, construction standards etc. are planned as a result.

The ETPL system has approximately 346km of lines with the majority (73%) being overhead lines and only (27%) underground. Each municipality has experienced varying degrees of growth with respect to residential subdivisions and moving forward as small communities see more residential development the mix of overhead to underground is expected to move closer to a 50/50 split.

The economic growth rate in the majority of ETPLs' service territories would be considered slow and in the range of 1%. Maple Leafs Foods who employs approximately 400 people in the town of Thamesford has recently announced that it will be closing its facility and moving a portion of the production to a facility in Mitchell. The timing and affect this will have on ETPL is currently unknown. In addition GM (CAMI) Automotive in Ingersoll has recently announced that it will be moving production of the Terrain to Mexico resulting in a loss of 600 jobs. Again the degree to which this will affect ETPL is unknown at this time; the DSP has been prepared without any specific adjustments based on a material change in economic growth or decline.

5.3.2B) SUMMARY OF SYSTEM CONFIGURATION

- ***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.***

Each of ETPL's communities are embedded and supplied from various Hydro One distribution circuit(s) with the Town of Aylmer having the only dedicated supply point connected directly to the HONI owned

TS. ETPL is supplied by seven (7) Transmission Stations, one (1) high voltage Distribution Station, and three (3) Distribution Stations owned and operated by Hydro One as detailed below in Table 7.

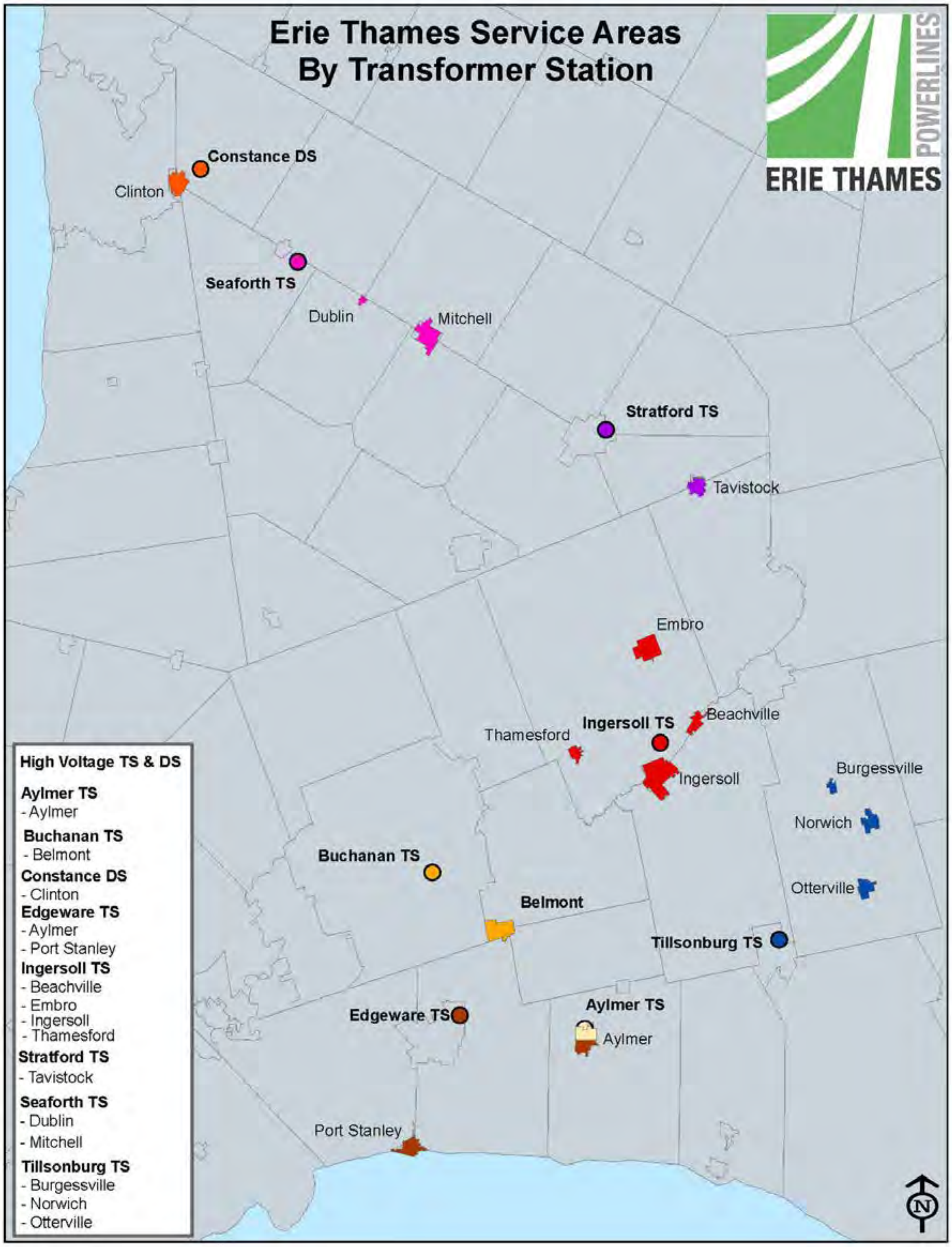
Due to the nature of ETPL's service territory we have 20 wholesale metering installations used at each boundary between our distribution system and HONI's. This equates to approximately one (1) wholesale point for each 922 customers. This obviously creates additional costs as compared to LDC's with large contiguous service territories.

Table 7: ETPL Supply Stations

MUNICIPALITY	HYDRO ONE SUPPLY STATION	ETPL CONNECTED FEEDER ID	SUPPLY VOLTAGE (KV)	CONNECTION TYPE
Aylmer	Aylmer TS	M1	27.6Y/16	Dedicated
	Aylmer TS	Future - 2017	27.6Y/16	Dedicated
	Edgeware TS	M4	27.6Y/16	Embedded
Beachville	Ingersoll TS	M44	27.6Y/16	Embedded
Belmont	Buchanan TS	M21	27.6Y/16	Embedded
Burgessville	North Norwich DS (supplied by Tillsonburg TS)	F2 (Tillsonburg M3)	8.32Y/4.8	Embedded
Clinton	Constance DS	F2	27.6Y/16	Embedded
	Constance DS	F4	27.6Y/16	Embedded
Dublin	Dublin DS (supplied by Seaforth TS)	F1 (Seaforth M2)	8.32Y/4.8	Embedded
Embro	Ingersoll TS	M46	27.6Y/16	Embedded
Ingersoll	Ingersoll TS	M49	27.6Y/16	Embedded
	Ingersoll TS	M50	27.6Y/16	Embedded
	Ingersoll TS	M51	27.6Y/16	Embedded (dedicated to GM-CAMI)
	Ingersoll TS	M52	27.6Y/16	Embedded (dedicated to GM-CAMI)
Mitchell	Seaforth TS	M2	27.6Y/16	Embedded
Norwich	Tillsonburg TS	M3	27.6Y/16	Embedded
Otterville	Tillsonburg TS	M1	27.6Y/16	Embedded
	Otterville DS (supplied by Tillsonburg TS)	F1 (Tillsonburg M1)	8.32Y/4.8	Embedded
Port Stanley	Edgeware TS	M3	27.6Y/16	Embedded
Tavistock	Stratford TS	M7	27.6Y/16	Embedded
Thamesford	Ingersoll TS	M43	27.6Y/16	Embedded
	Ingersoll TS	M45	27.6Y/16	Embedded

Figure 25 below shows the location of each municipality relative to the respective Hydro One owned supply station.

Figure 24: ETPL Service Territory by Supply Station



ETPL currently owns and operates nine (9) municipal 4kV substations as listed below. Each station is supplied via a different 27.6Y/16 kV feeder from Hydro One's system; typically embedded in ETPL's service territory downstream of a wholesale primary metering unit.

Table 8: Municipal Station Overview

MUNICIPALITY	STATION ID	# OF FEEDERS
Aylmer	MS1	2
	MS2	4
Beachville	MS1	2
Clinton	MS1	3
Ingersoll	MS1	3
	MS3	3
Mitchell	MS1	1
Port Stanley	MS1	3
Tavistock	MS1	3

Each municipality has its own unique supply configurations with certain advantages and drawbacks depending on local conditions. A brief summary of each system configuration and associated diagram is presented below.

▪ Aylmer (3066 Customers)

Summary: The Town of Aylmer currently has two (2) 28kV feeders; the M1 from the Aylmer TS (only TX connected supply point) and the M4 from the Edgeware TS. The M1 comes into the north end of Aylmer and supplies the Erie Thames owned 4kV municipal station MS1, along with a number of customers directly connected to the 28kV system. The M4 feeder enters the south end of Aylmer and supplies the Erie Thames owned 4kV municipal station MS2 and also has customers connected directly to the 27.6kV system.

Advantages: Multiple 28kV supply points are present however the current configuration does not allow switching between feeders on either the 28kV or 4kV systems. The M1 feeder which is TX connected at the Aylmer TS is a very short feeder with very little line exposure and as a result is a very reliable supply point. Both current & future supply with allow for smart grid self-healing type configurations.

Disadvantages: The M4 feeder from the Edgeware TS is a long rural feeder with a great deal of line exposure and as a result is typically a less reliable supply point.

*** Aylmer TS** is currently being rebuilt by Hydro One and ETPL has secured a second breaker position to improve the reliability and capacity to the Town of Aylmer; the business case for the second feeder can be found in Appendix K.

Figure 25: Aylmer Distribution System

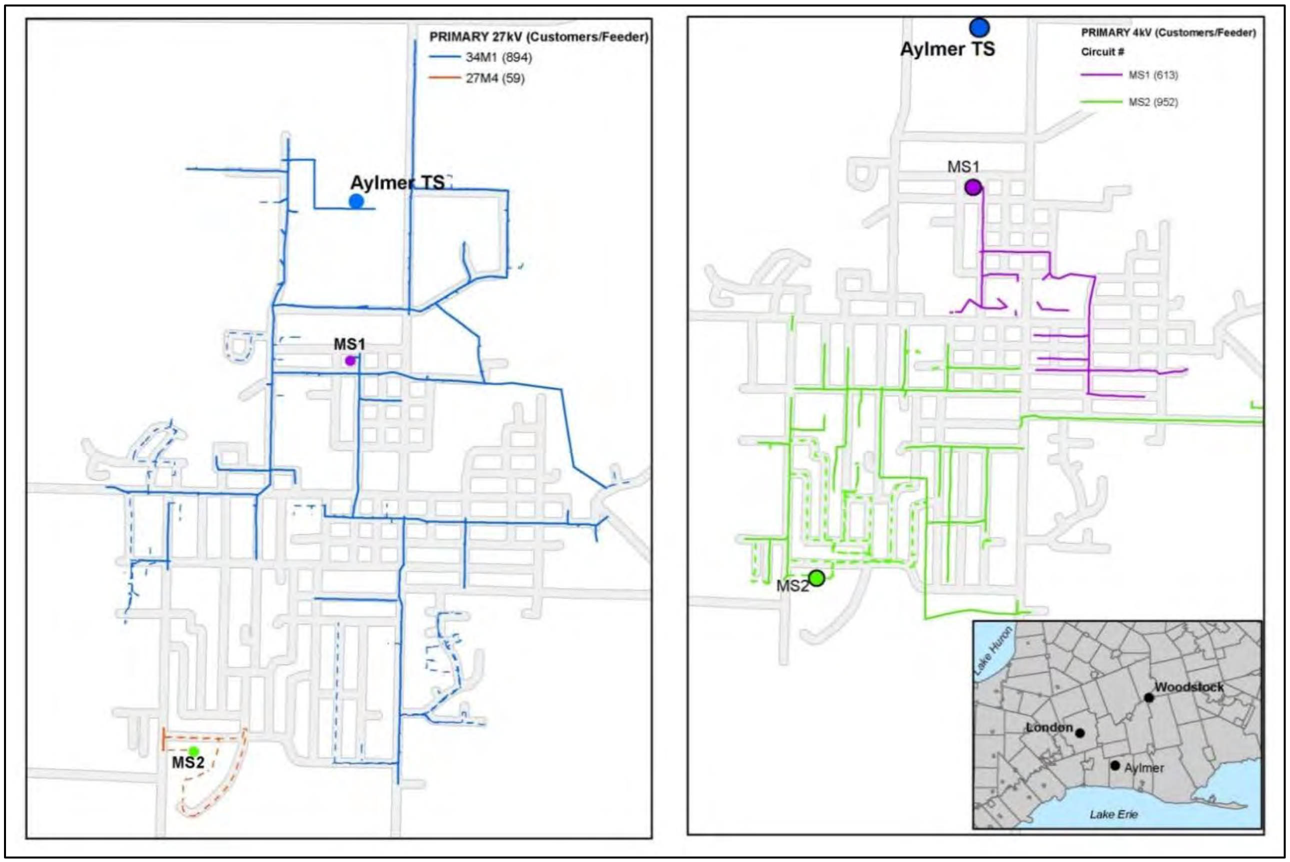
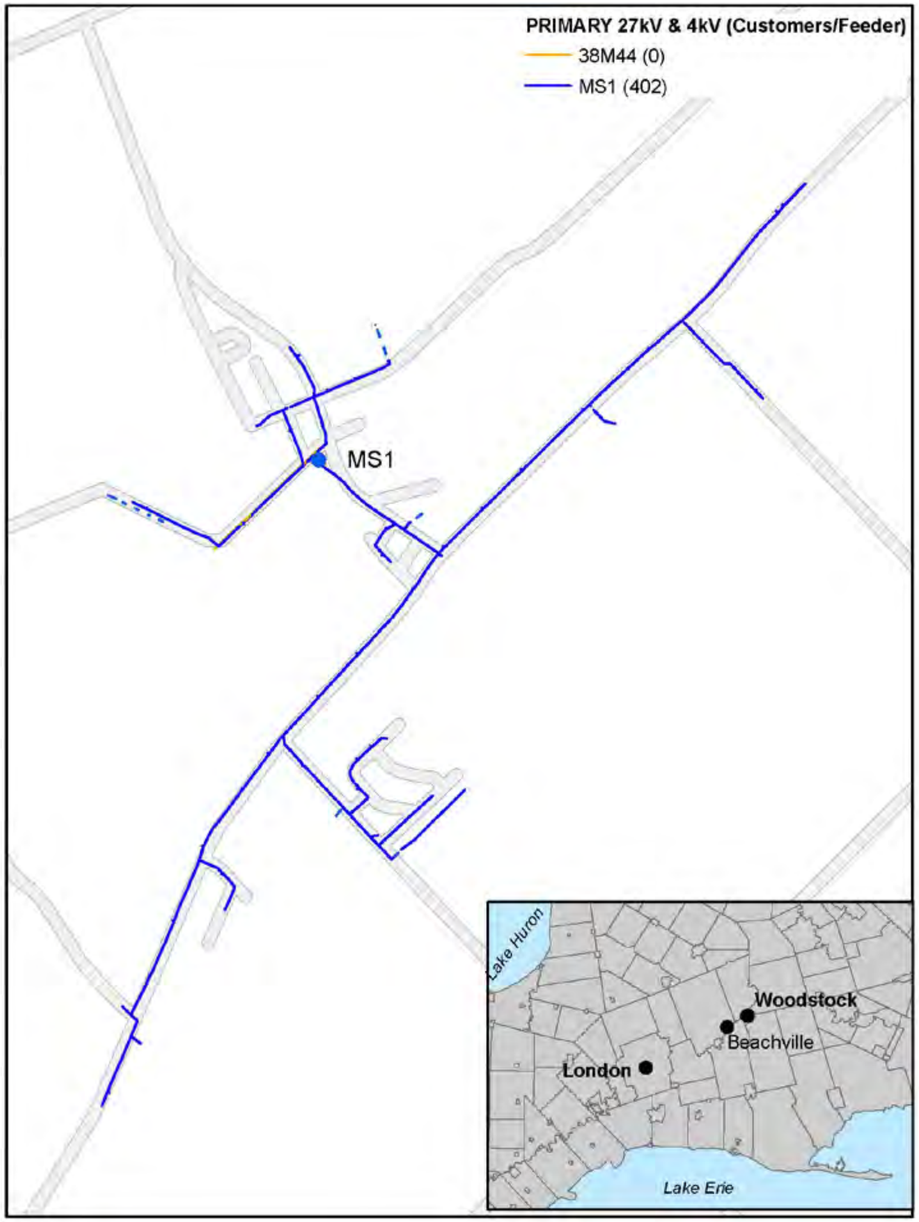


Figure 26: Beachville Distribution System



▪ **Beachville (411 Customers)**

Summary: The town of Beachville is supplied from an ETPL owned 4kV substation which is supplied by the Hydro One Ingersoll TS M44 feeder.

Advantages: 28kV feeder is available for planned voltage conversion.

Disadvantages: One (1) 28kV supply point; no backup supply.

▪ Belmont (775 Customers)

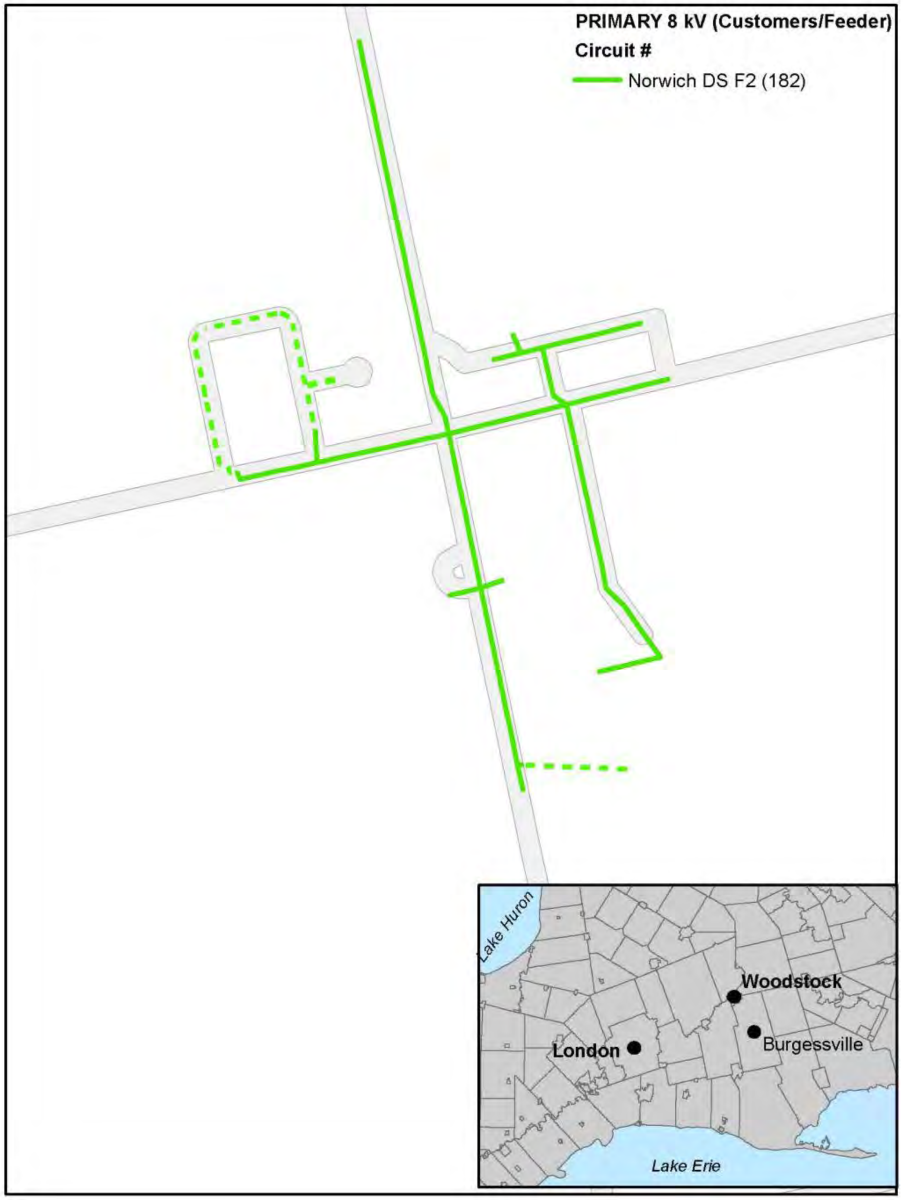
Summary: The town of Belmont is supplied from the Hydro One owned Buchanan M21 feeder at 28kV. The feeder enters from the north end of town with approximately 50% of customers connected directly to the 28kV system. The other half are supplied by the Hydro One owned 8kV Belmont DS at the south end of town which is supplied by the M21 feeder. The town also has a 20MW solar farm connected to the M21 feeder.

Advantages: 28kV feeder is available for planned voltage conversion.

Disadvantages: One (1) 28kV supply point; no backup supply.

Figure 27: Belmont Distribution System

Figure 28: Burgessville Distribution System



▪ Burgessville (178 Customers)

Summary: Burgessville is supplied with a single 8kV feeder from the Hydro One owned North Norwich DS.

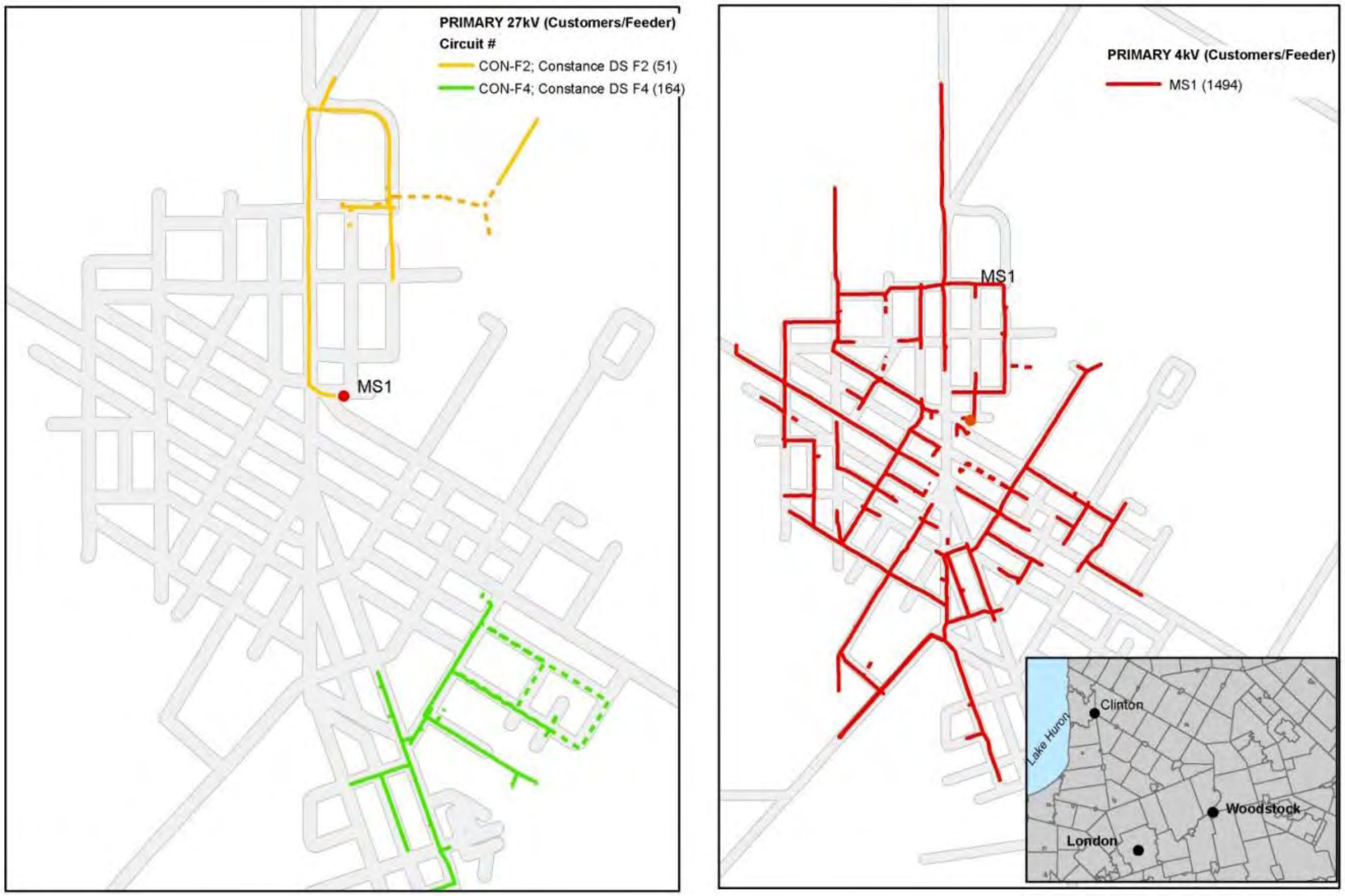
Advantages: There is currently not a 28kV feeder near the town of Burgessville and voltage conversion is therefore not a viable option.

Disadvantages: One (1) 8kV supply point; no backup supply.

▪ Clinton (1724 Customers)

Summary: The town of Clinton is supplied by two (2) 28kV feeders originating at the Hydro One Constance DS. The F2 feeder enters the north end of town and supplies the ETPL owned 4kV substation MS1 along with a number of customers directly connected to the 28kV feeder. The F4 feeder enters the south end of town and has a number of customers directly connected to the feeder at 28kV. ETPLs municipal substation, MS1, currently supplies the majority of the town at 4kV however voltage conversion will eventually eliminate MS1 and tie the F2 and F4 feeders.

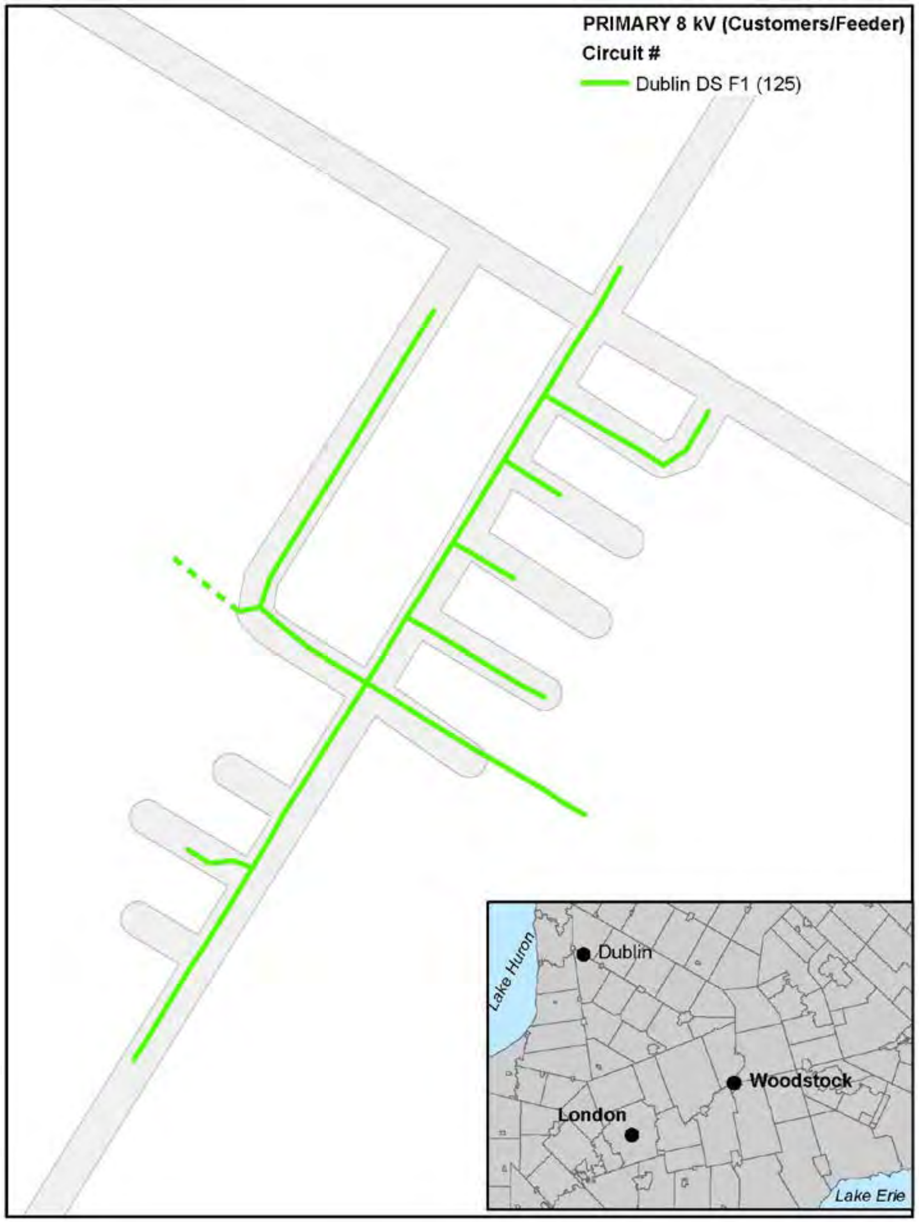
Figure 29: Clinton Distribution System



Advantages: Multiple 28kV supply points are present however the current system does not provide a tie point between the two feeders. Future system configuration will allow for smart grid self-healing type configurations.

Disadvantages: Nothing significant

Figure 30: Dublin Distribution System



▪ Dublin (125 Customers)

Summary: Dublin is supplied with a single 8kV feeder from the Hydro One owned Dublin DS.

Advantages: There is currently not a 28kV feeder near the town of Dublin and voltage conversion is therefore not a viable option.

Disadvantages: One (1) 8kV supply point; no backup supply.

Figure 31: Embro Distribution System

▪ Embro (356 Customers)

Summary: Embro is supplied from the Ingersoll TS M46 feeder at 28kV. ETPL does not have a municipal substation and therefore all customers are connected to the 28kV system.

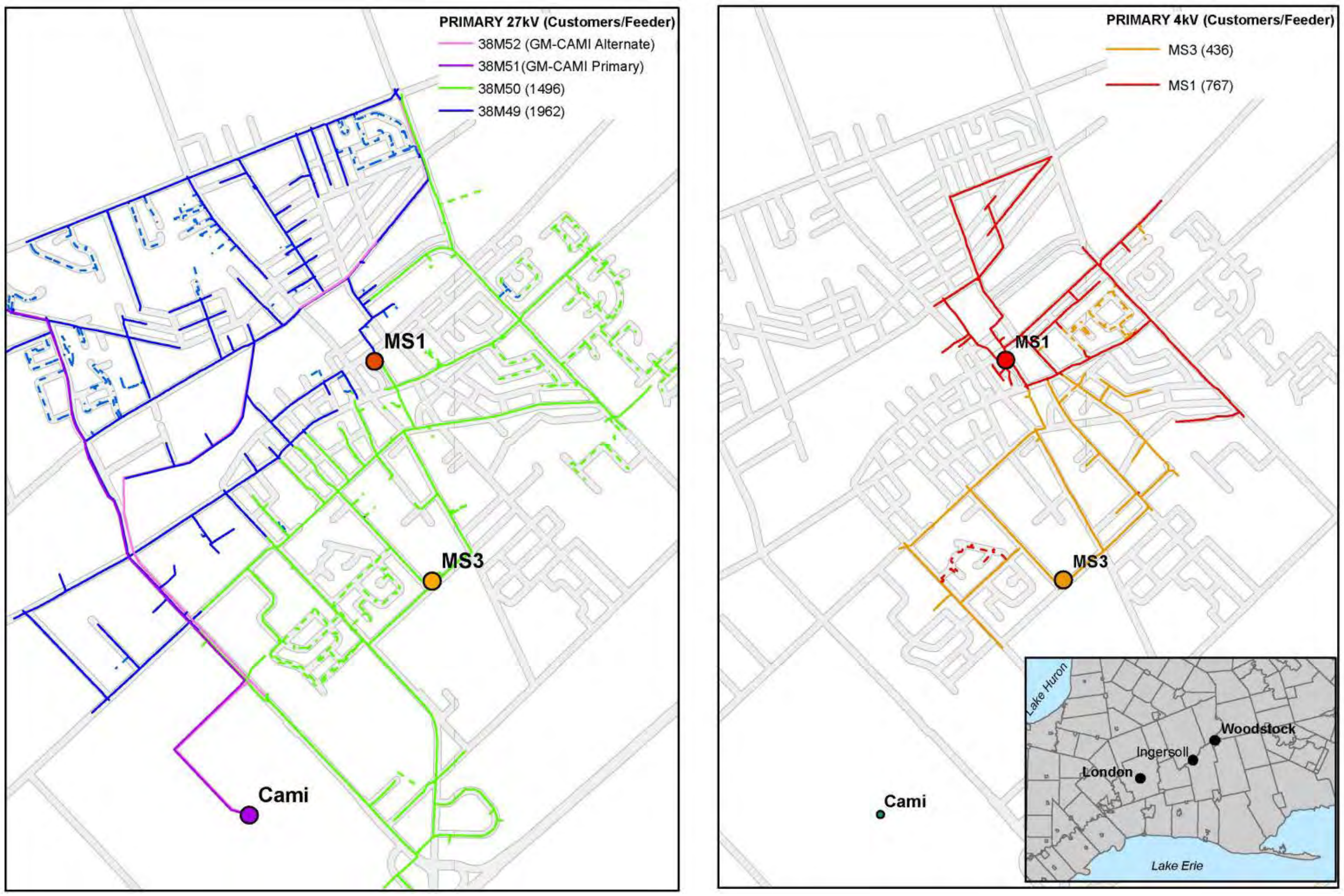
Advantages: 28kV supply; entire town has been converted.

Disadvantages: One (1) 28kV supply point; no backup supply.

▪ Ingersoll (5238 Customers)

Summary: The Town of Ingersoll is supplied with four (4) 28kV feeders from the Hydro One Ingersoll TS. The M49 and M50 feeders supply the town while the M51 & M52 are dedicated to the GM-CAMI facility. ETPL has two (2) 4kV municipal stations, MS1 and MS3, which are tied and able to provide redundancy to each other.

Figure 32: Ingersoll Distribution System



Advantages: Multiple 28kV supply points that are able to be connected within the ETPL system allow for quicker load restoration and switching for construction and maintenance projects. The current supply configuration will allow for smart grid self-healing type configurations.

Disadvantages: Nothing significant.

▪ Mitchell (2023 Customers)

Summary: Mitchell is supplied by the M2 feeder from the Hydro One Seaforth TS at 28kV. The majority of the town is connected to the 28kV system, however a small portion remains connected to the 4kV system supplied from ETPL owned MS2.

Advantages: 28kV supply; nearly the entire town has been converted.

Disadvantages: One (1) 28kV supply point; no backup supply

Figure 33: Mitchell Distribution System

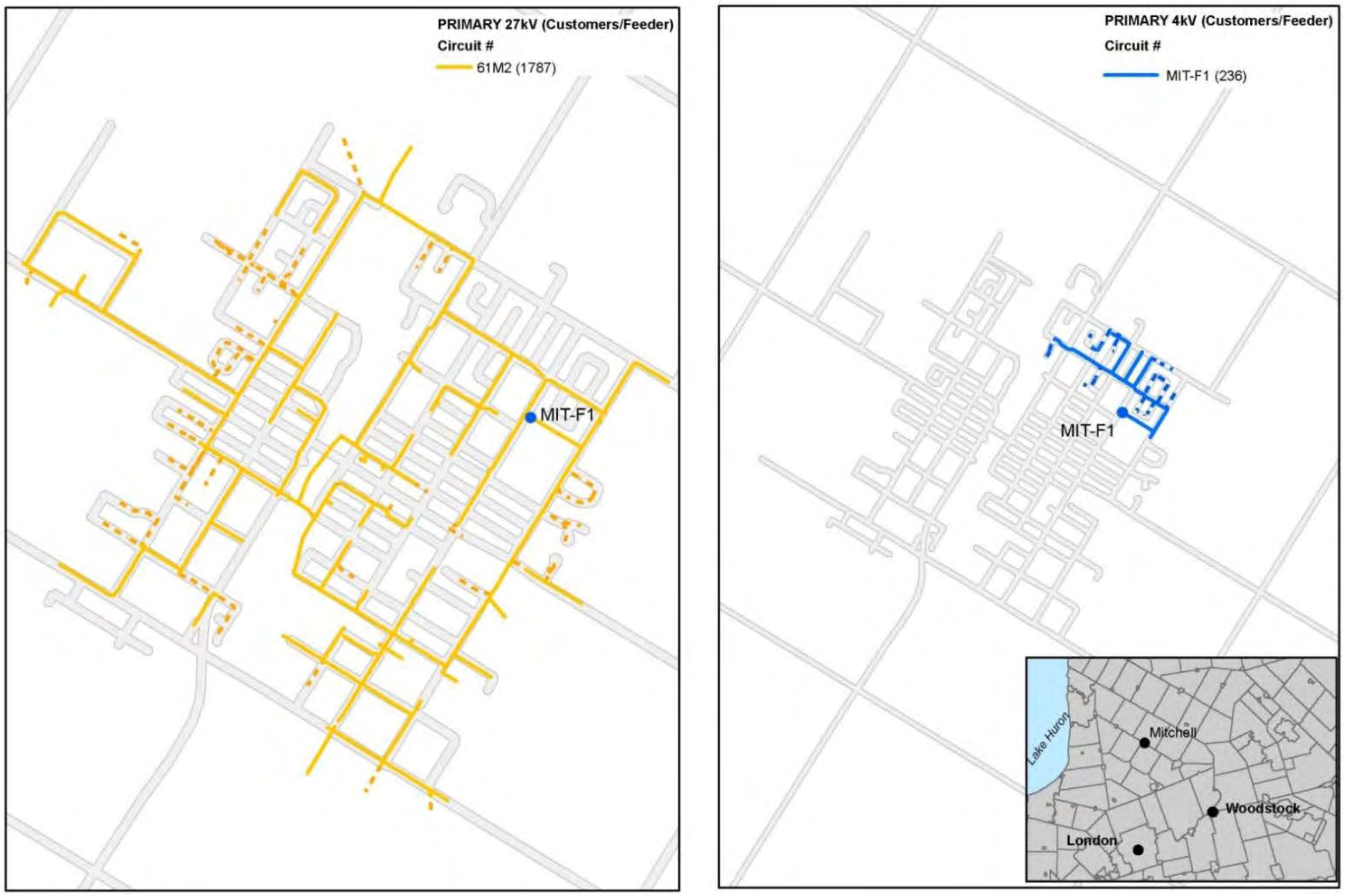


Figure 34: Norwich Distribution System

▪ Norwich (1198 Customers)

Summary: Norwich is currently supplied with the 28kV, M3 feeder originating from the Hydro One Tillsonburg TS. ETPL does not have a municipal station in the town.

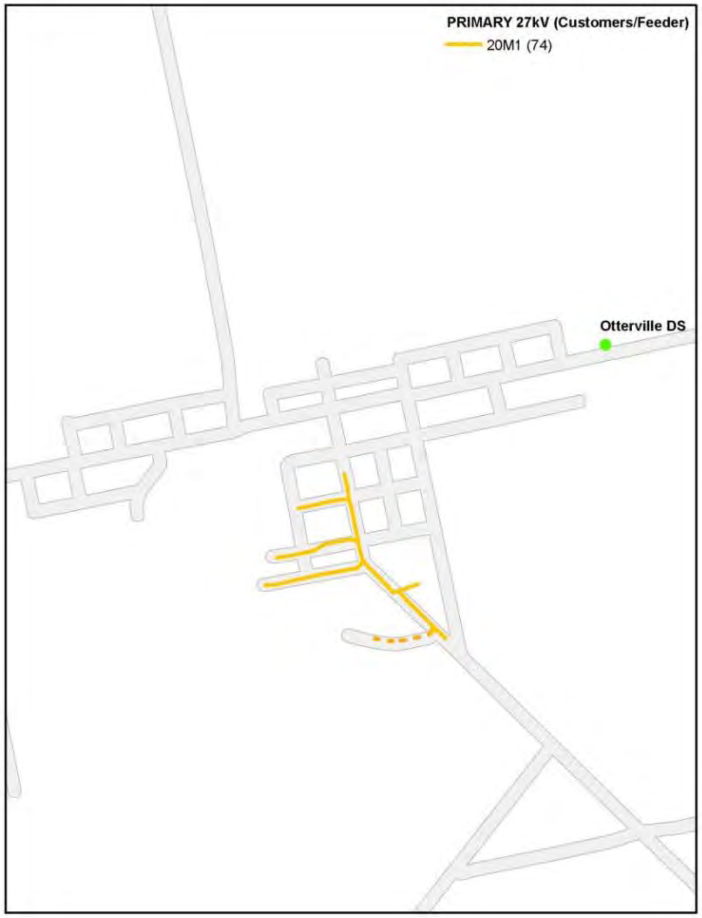
Advantages: 28kV supply point; entire town has been converted.

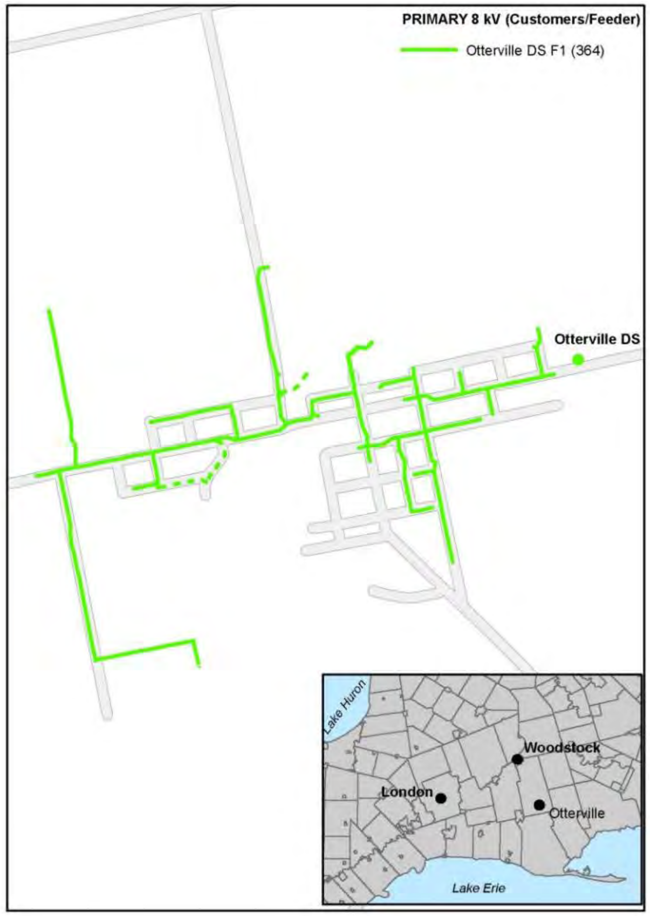
Disadvantages: Due to the location of Norwich in relation to the Tillsonburg TS the M3 feeder is approximately 20km from the TS to the supply point. This has led to a supply with poor reliability and a number of extended outages for the customers in Norwich. Another 28kV feeder from the Tillsonburg TS is relatively close to the town of Norwich and ETPL is exploring the viability of having this feeder extended to provide a second redundant feeder.

▪ Otterville (438 Customers)

Summary: Otterville is supplied primarily from the Hydro One owned Otterville DS via an 8kV feeder. A small portion of town is supplied from the 28kV M1 orginating from the Hydro One Tillsonburg TS and voltage conversion will continue from this supply point eventually eliminating all 8kV connected customers.

Figure 35: Otterville Distribution System





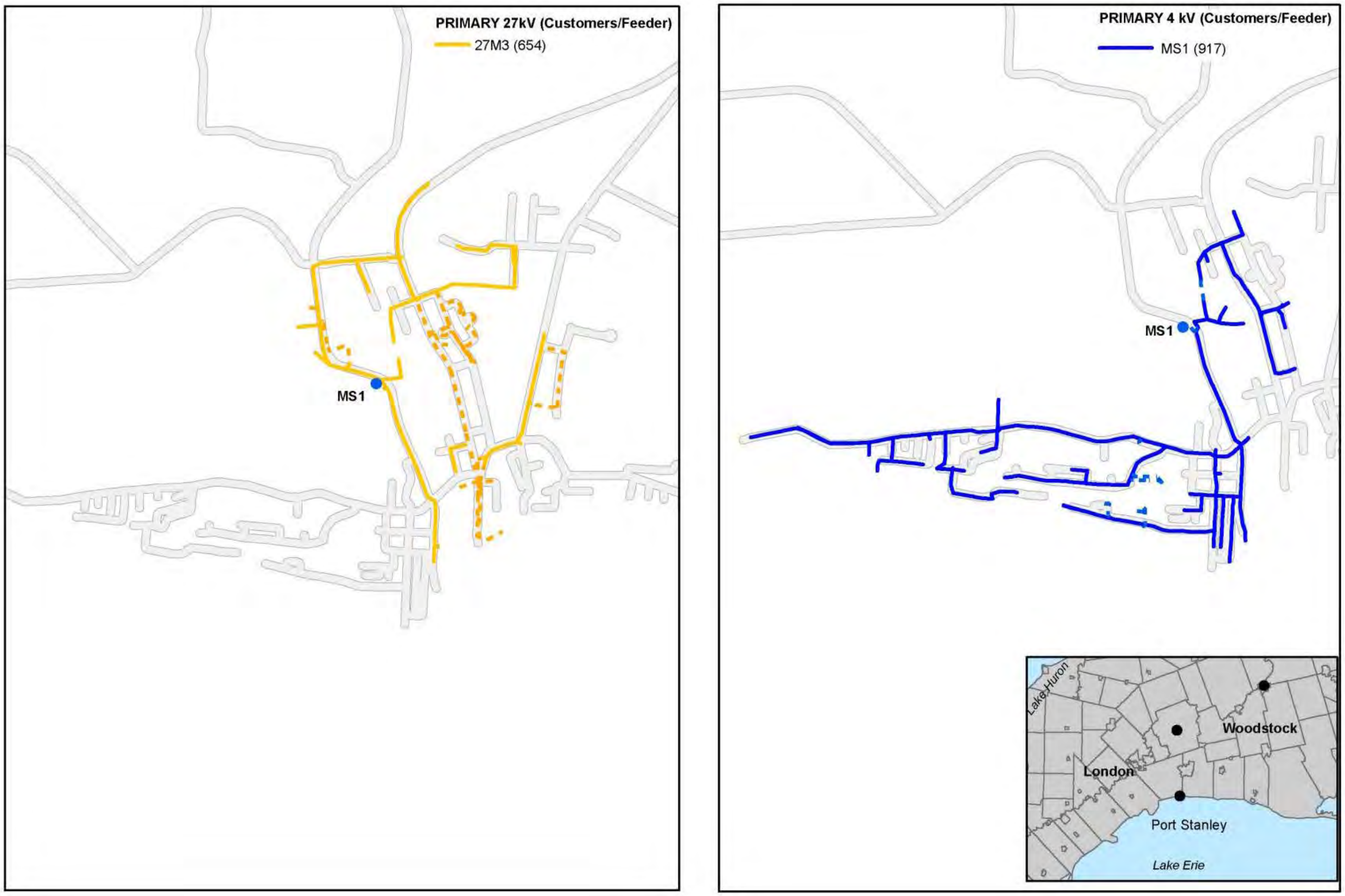
Advantages: 28kV feeder is available for planned voltage conversion.

Disadvantages: One (1) 28kV supply point; no backup supply.

▪ Port Stanley (1576 Customers)

Summary: Port Stanley is supplied from the M3 feeder originating from the Edgeware TS at 28kV. ETPL owns and operates a 4kV substation, MS1, within the town which is supplied from the M3 feeder. Approximately half of the town has been converted and is supplied from the 28kV system.

Figure 36: Port Stanley Distribution System



Advantages: 28kV feeder is available for planned voltage conversion.

Disadvantages: One (1) 28kV supply point; no backup supply.

- ## Tavistock (1183 Customers)

Summary: Tavistock is supplied from the M7 feeder originating from the Stratford TS at 28kV. ETPL owns and operates a 4kV substation, MS1, in the town which is supplied from the M7 feeder. Approximately half of the town has been converted and is supplied from the 28kV system.

Advantages: 28kV feeder is available for planned voltage conversion.

Disadvantages: One (1) 28kV supply point; no backup supply.

Figure 37: Tavistock Distribution System

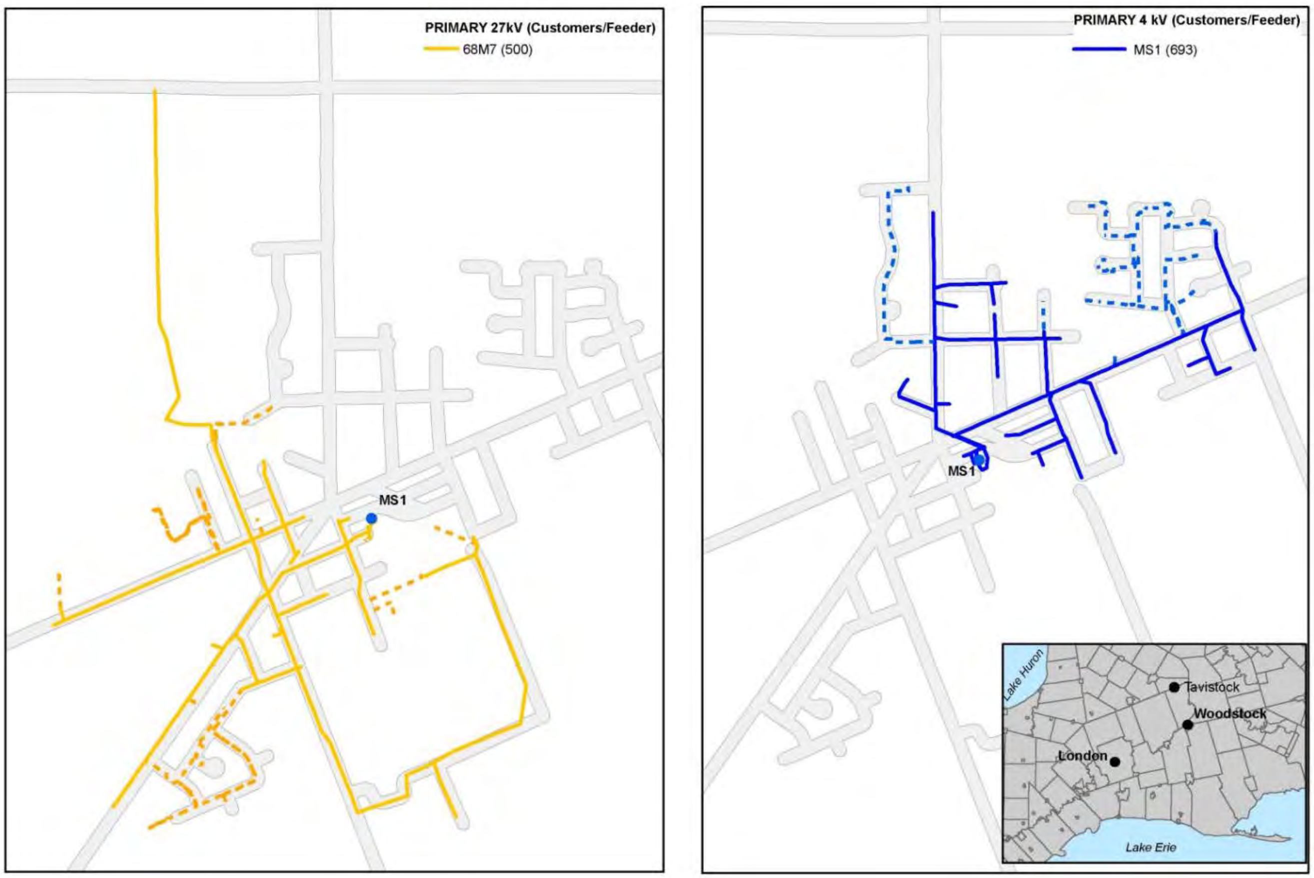


Figure 38: Thamesford Distribution System

▪ Thamesford (603 Customers)

Summary: Thamesford is supplied from the Ingersoll TS M43 feeder at 28kV. ETPL does not have a municipal substation and therefore all customers are connected to the 28kV system.

Advantages: 28kV supply; entire town has been converted. The M43 within Erie Thames service territory also has connections to the M45 from the Ingersoll TS and the M11 from the Highbury TS and therefore possibilities exist with multiple supply points for redundant smart grid self-healing type installations.

Disadvantages: Nothing significant.

Table 9 below details the current mix of overhead and underground lines in each of the 14 municipalities serviced by ETPL.

Table 9: O/H vs. U/G Overview

MUNICIPALITY	OH CONDUCTOR (KM)		UG CABLE (KM)		TOTAL (KM)
Aylmer	34.425	(65%)	18.443	(35%)	52.868
Beachville	9.128	(94%)	0.603	(6%)	9.731
Belmont	12.440	(59%)	8.509	(41%)	20.949
Burgessville	3.765	(78%)	1.092	(22%)	4.857
Clinton	22.088	(77%)	6.721	(23%)	28.809
Dublin	2.599	(96%)	0.102	(4%)	2.701
Embro	10.058	(95%)	0.559	(5%)	10.617
Ingersoll	70.553	(71%)	4.288	(29%)	14.924
Mitchell	23.281	(72%)	9.155	(28%)	32.436
Norwich	10.636	(71%)	4.288	(29%)	14.924
Otterville	9.643	(91%)	0.981	(9%)	10.624
Port Stanley	20.280	(77%)	6.003	(23%)	26.283
Tavistock	12.803	(63%)	7.598	(37%)	20.401
Thamesford	9.808	(84%)	1.805	(16%)	11.613
TOTAL	251.507	(73%)	94.282	(27%)	345.789

Table 10 below details the breakdown of lines by voltage level

Table 10: Voltage Overview

	VOLTAGE (KV)	HYDRO LINES (KM)	%	
"28kV System"	27.6	115.678	32.4%	57.8%
	16.0	90.850	25.4%	
"8kV System"	8.32	10.319	2.9%	7.3%
	4.8	15.772	4.4%	
"4kV System"	4.16	64.676	18.1%	34.9%
	2.4	59.840	16.8%	

There is currently no capacity constraints on the nine (9) municipal substations owned and operated by ETPL. This will continue to be the case for the indefinite future as voltage conversion removes load from each of the substations.

Table 11: Station Characteristics

	STATION CHARACTERISTICS			
DISTRIBUTION STATION	STATION RATING	# OF FEEDERS	# OF CUSTOMERS	LOADING % [12]
Clinton MS1	5MVA	4	1494	66%
Port Stanley MS1	5MVA	3	917	21%
Beachville MS1	3MVA	2	402	40%
Aylmer MS2 - TX1	3MVA	4	992	15%
Mitchell MS2	3MVA	2	236	9%
Ingersoll MS1	5MVA	3	767	23%
Ingersoll MS3	5MVA	3	436	21%
Aylmer MS1	5MVA	2	613	46%
Aylmer MS2 - TX2	3MVA	4	992	30%
Tavistock MS1	5MVA	3	693	38%

Currently there is no known capacity constraints at any embedded distribution supply point connected to Hydro One system.

5.3.2C) ASSET QUANTITY, TYPE & CONDITION

- ***Information (in tables and/or figures) by asset type (where available) on the quantity/years in service profile and condition of the distributors system assets including the date(s) the data was complied.***

The following tables and figures provide information on the quantity and age profile of major assets which are accurate as of February 2015. The age profile for each asset is known with varying degrees of certainty and further detail is provided within the 2015 Asset Management Plan & Asset Condition assessment included in Appendix I

[12] Loading percentage was calculated as an average of the peak phase currents from April 2014 to April 2015 compared to the transformer rating.

▪ Overhead Line Poles

Table 12: Poles - Age Summary

OVERHEAD LINE POLES	8,511	Wood	7964
		Concrete	340
		Steel	207
MAXIMUM AGE		76 years	
AVERAGE AGE		31 years	

Figure 39: Wood Pole Age Distribution

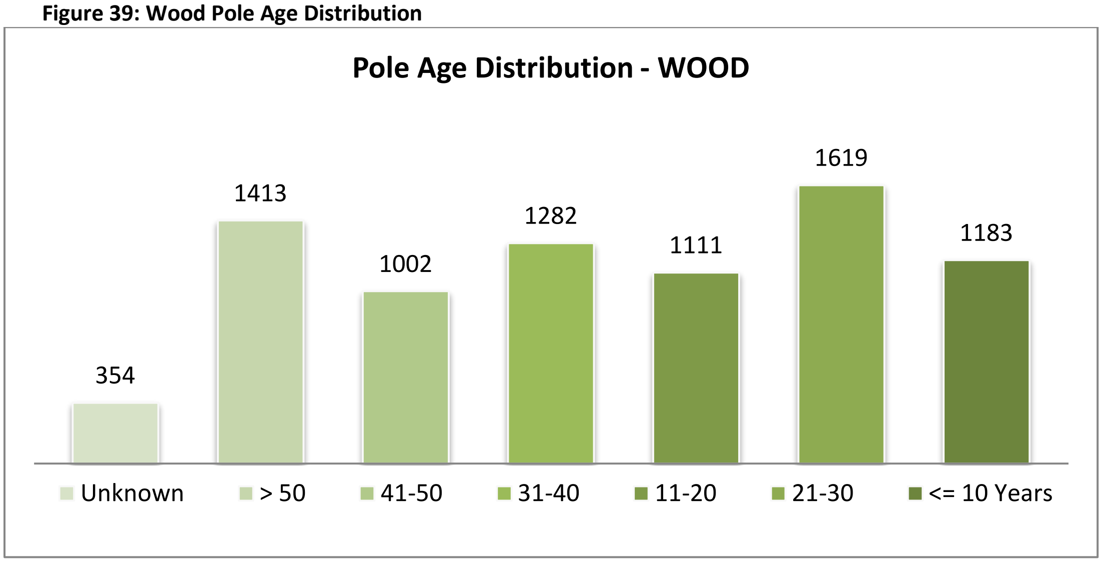


Figure 40: Concrete Pole Age Distribution

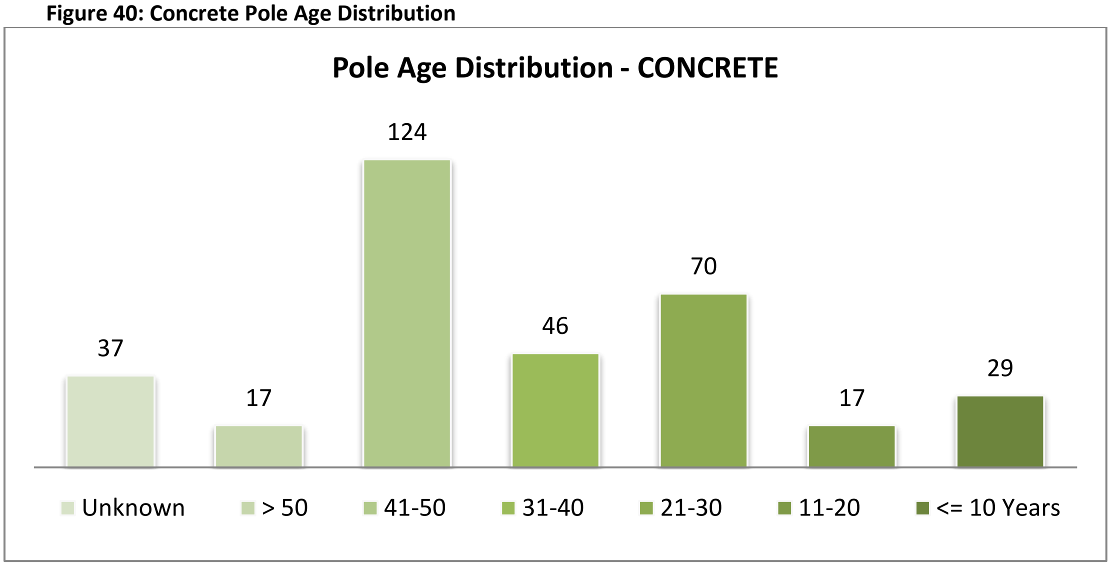
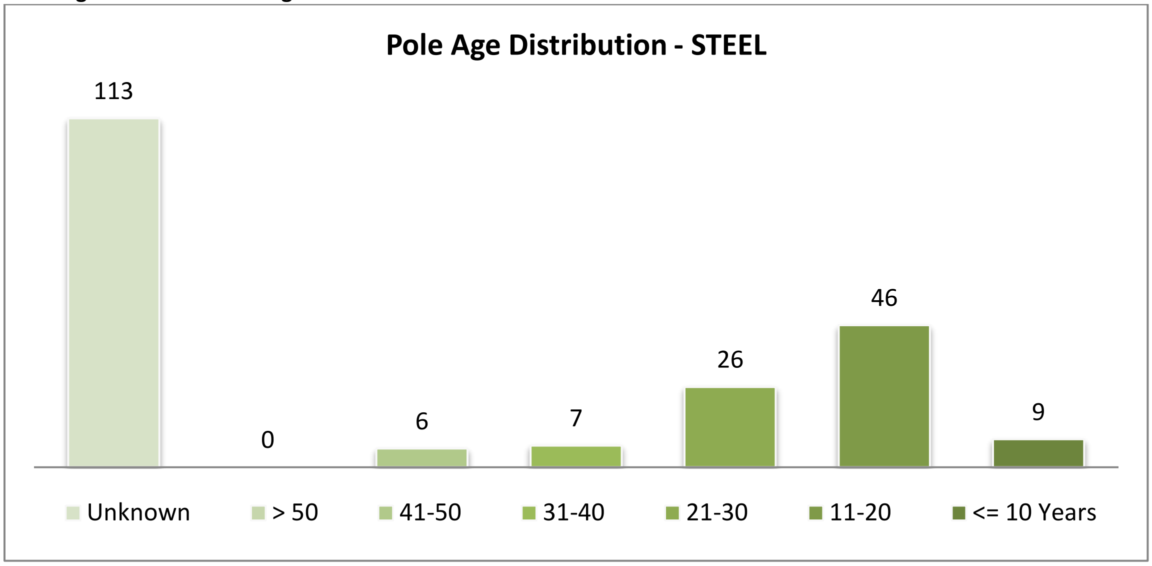


Figure 41: Steel Pole Age Distribution



- **Distribution Transformers**

Table 13: Transformer Age Summary

DISTRIBUTION TRANSFORMERS	3,310	Polemount	2446
		Padmount 1PH	744
		Padmount 3PH	120

Figure 42: Polemount Transformer Age Distribution

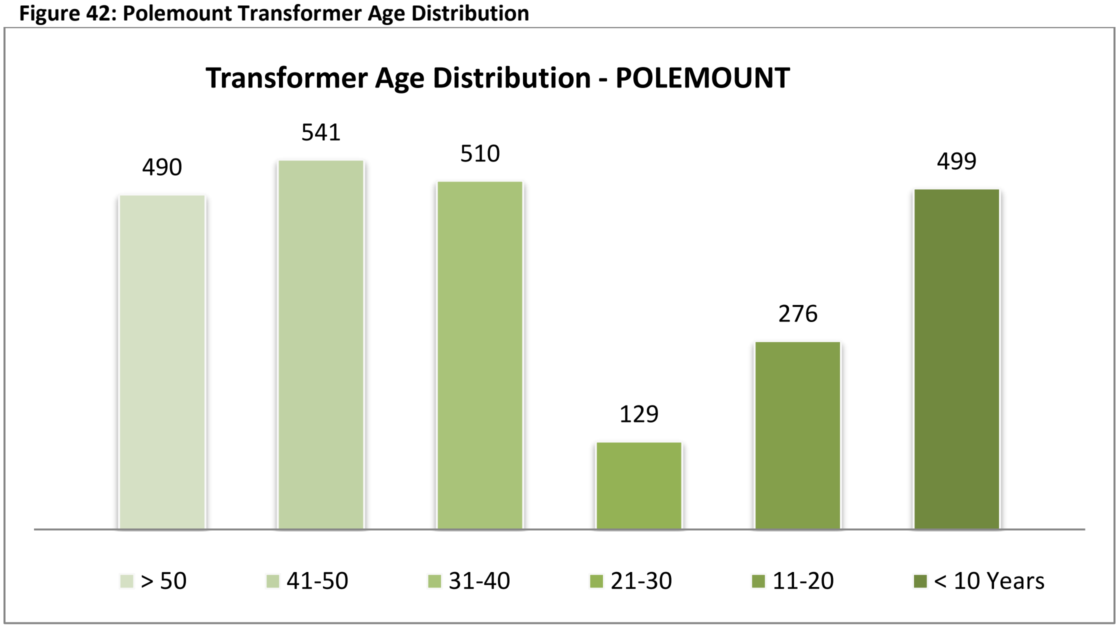


Figure 43: 1Ph Padmount Transformer Age Distribution

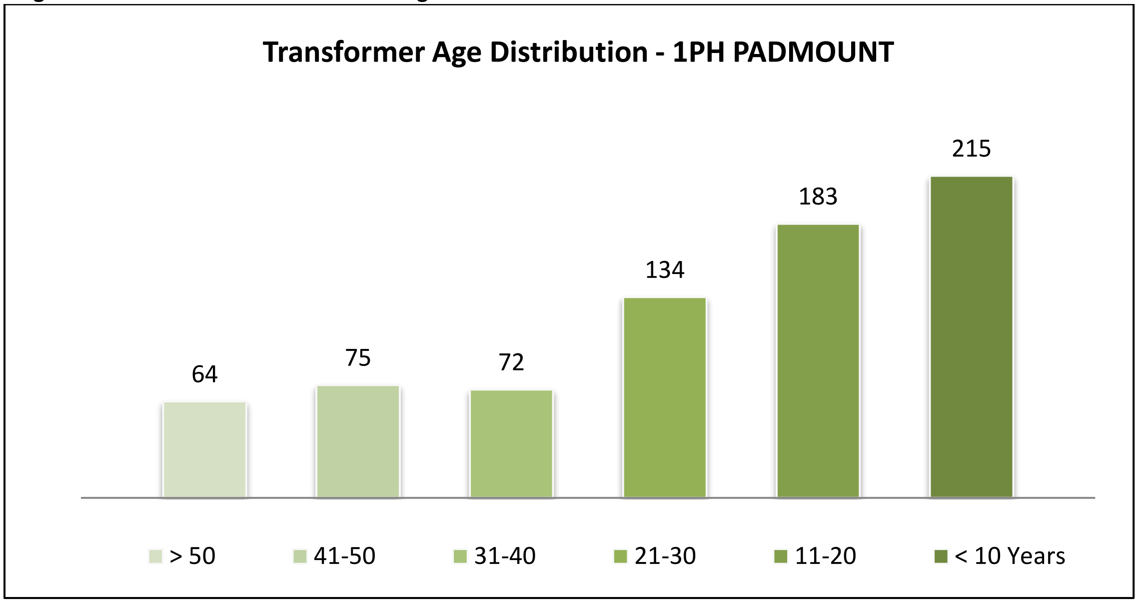
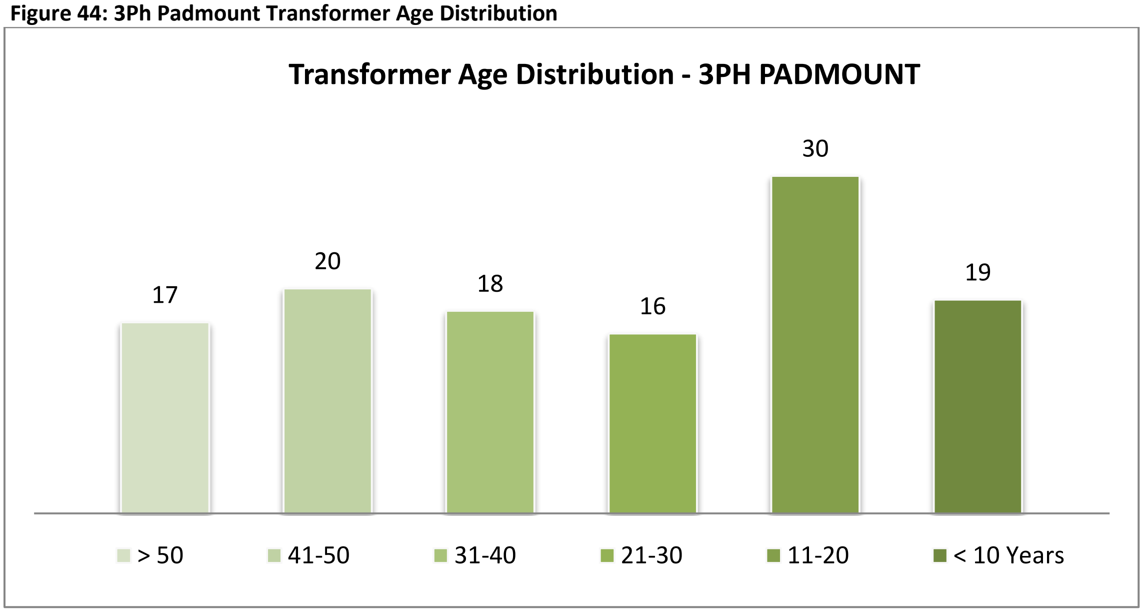


Figure 44: 3Ph Padmount Transformer Age Distribution



- **Medium Voltage Underground Cable**

Table 14: MV Cable Age Summary

MEDIUM VOLTAGE UNDERGROUND CABLE	129 km	1PH 3PH	85.32 km 14.43 km (x3)

Figure 45: 3Ph MV Cable Age Distribution

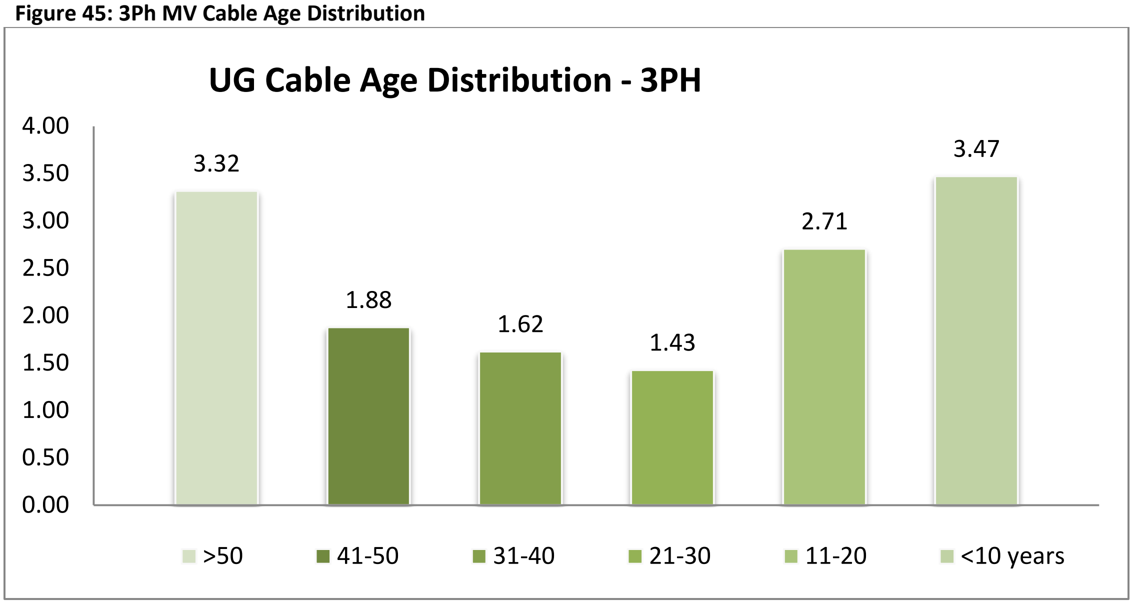
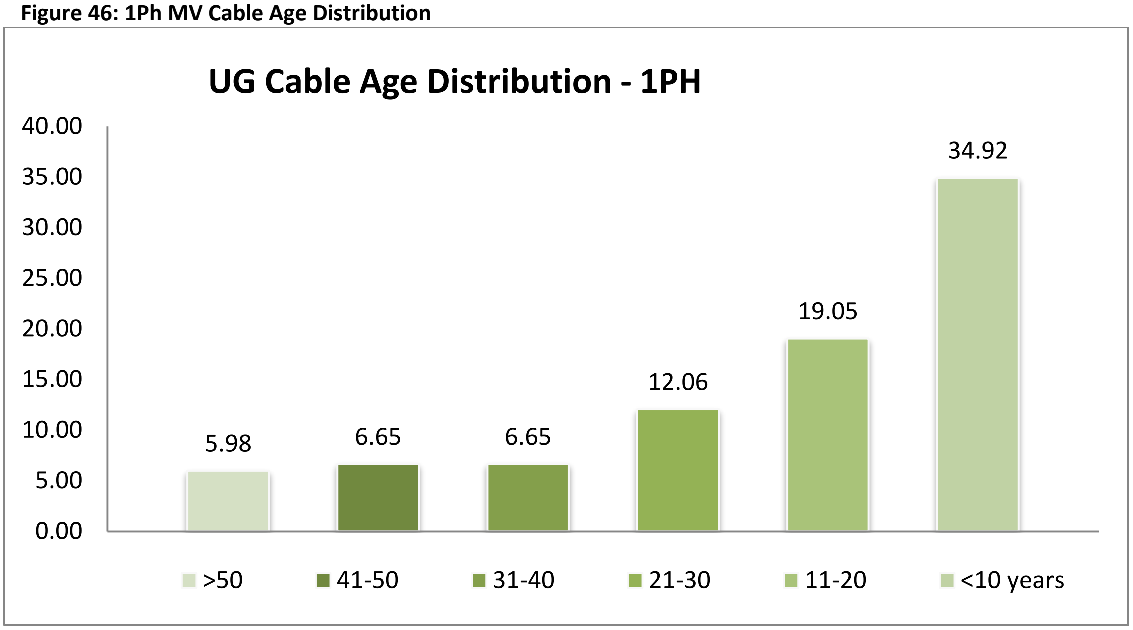


Figure 46: 1Ph MV Cable Age Distribution



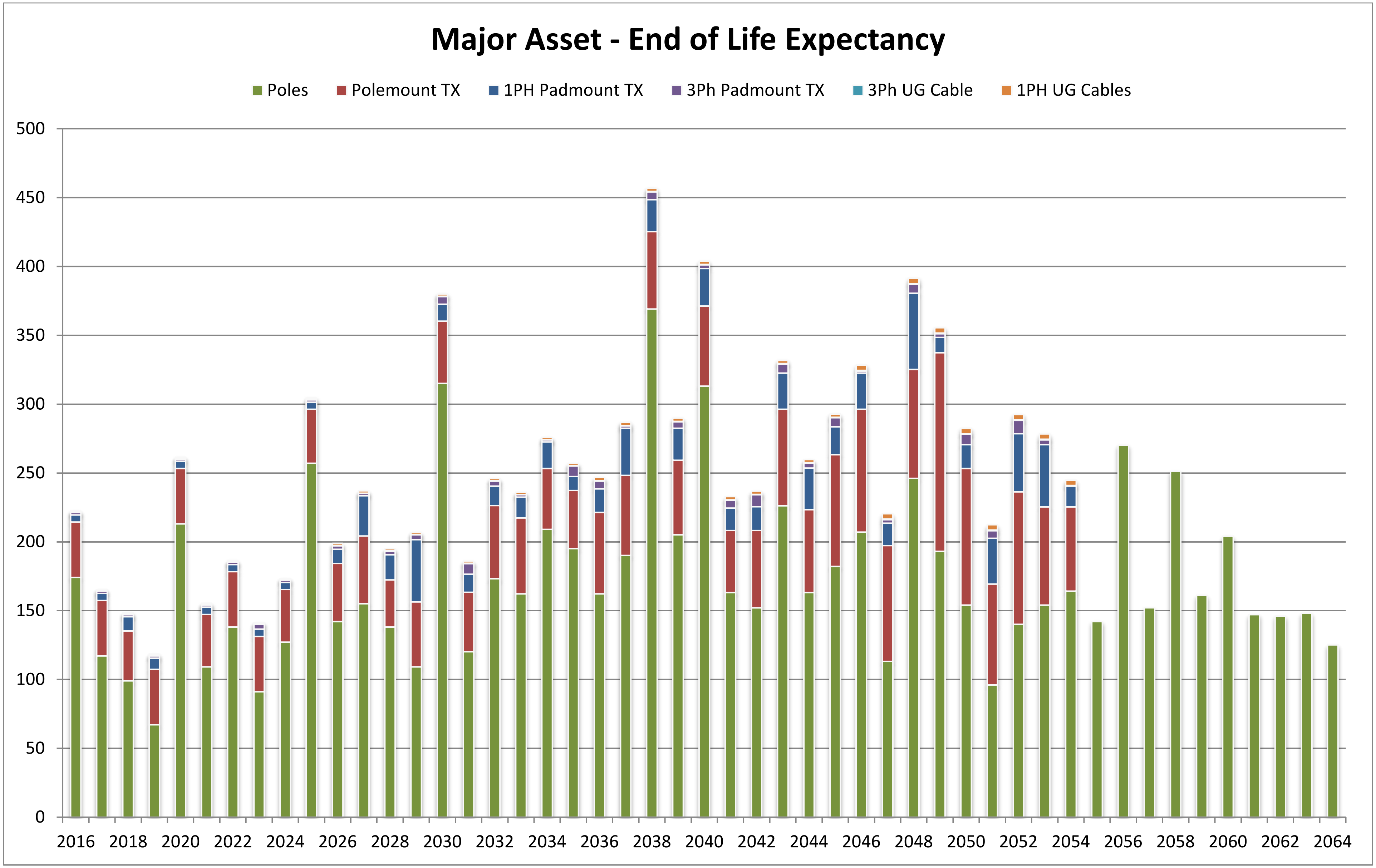
- **Summary**

ETPL has adopted the following useful life estimates based on the OEB - Kinectrics Asset Depreciation Study and are used to determine the expected end of life of major assets.

Table 15: Asset Age Summary

Asset		Typical Useful Life (Years)
Poles	Wood	50
	Concrete	65
	Steel	65
Distribution Transformers	Polemount	40
	1PH Padmount	40
	3PH Padmount	40
Medium Voltage UG Cable		40

Currently the condition assessment of ETPL major assets (excluding substations) is based primarily on age data. Wood poles are tested using a "sound & selective bore" on a nine (9) year cycle with approximately 1% failing each year and <1% in fair to poor condition. The entire distribution system is inspected on a regular basis and any deficiencies identified are addressed on a prioritized basis. Inspection results are starting to be imported to the GIS system which will allow for additional analysis as more inspections cycles are completed. ETPL will continue to improve the accuracy of data with the goal of using a complete set of condition based evaluations for all major assets within 5 years.



Major Asset - End of Life Expectancy
Poles
Polemount TX
1PH Padmount TX
3Ph Padmount TX
3Ph UG Cable
1PH UG Cables
500
450
400
350
300
250
200
150
100
50
0
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
2042
2044
2046
2048
2050
2052
2054
2056
2058
2060
2062
2064

- **Power Transformers**

A full condition based assessment is completed on all substation power transformers yielding the following health index.

Based on these health indices the four (4) worst substations have been prioritized and are expected to reach their end of useful life in the next 5- 10 years, and will be scheduled for retirement or investment within that time period.

Table 16: Substation Health Index

<table>
<tr><th></th><th colspan="4">STATION CHARACTERISTICS</th><th colspan="13">TRANSFORMER HEALTH INDEX SCORES & WEIGHTING</th><th></th></tr>
<tr><th>DISTRIBUTION STATION</th><th>STATION RATING</th><th># OF FEEDERS</th><th># OF CUSTOMERS</th><th>REDUNDANCY</th><th colspan="3">AGE</th><th colspan="3">LOADING %</th><th colspan="3">VISUAL INSPECTION</th><th colspan="3">OIL ANALYSIS</th><th>HEALTH INDEX</th><th>PRIORITY</th></tr>
<tr><td>Clinton MS1</td><td>5MVA</td><td>4</td><td>1494</td><td>N</td><td>44</td><td>2</td><td rowspan="10">6</td><td>66%</td><td>4</td><td rowspan="10">4</td><td>Excellent</td><td>5</td><td rowspan="10">2</td><td>Poor</td><td>2</td><td rowspan="10">8</td><td>54</td><td>1</td></tr>
<tr><td>Port Stanley MS1</td><td>5MVA</td><td>3</td><td>917</td><td>N</td><td>36</td><td>2</td><td>21%</td><td>5</td><td>Good</td><td>4</td><td>Fair</td><td>3</td><td>64</td><td>2</td></tr>
<tr><td>Beachville MS1</td><td>3MVA</td><td>2</td><td>402</td><td>N</td><td>39</td><td>2</td><td>40%</td><td>5</td><td>Excellent</td><td>5</td><td>Fair</td><td>3</td><td>66</td><td>3</td></tr>
<tr><td>Aylmer MS2 - TX1</td><td>3MVA</td><td>4</td><td>992</td><td>Y</td><td>48</td><td>2</td><td>15%</td><td>5</td><td>Excellent</td><td>5</td><td>Fair</td><td>3</td><td>66</td><td>MONITOR</td></tr>
<tr><td>Mitchell MS2</td><td>3MVA</td><td>2</td><td>236</td><td>N</td><td>47</td><td>2</td><td>9%</td><td>5</td><td>Fair</td><td>3</td><td>Good</td><td>4</td><td>70</td><td>4</td></tr>
<tr><td>Ingersoll MS1</td><td>5MVA</td><td>3</td><td>767</td><td>Y</td><td>30</td><td>3</td><td>23%</td><td>5</td><td>Good</td><td>4</td><td>Fair</td><td>3</td><td>70</td><td>MONITOR</td></tr>
<tr><td>Ingersoll MS3</td><td>5MVA</td><td>3</td><td>436</td><td>Y</td><td>48</td><td>2</td><td>21%</td><td>5</td><td>Excellent</td><td>5</td><td>Good</td><td>4</td><td>74</td><td>MONITOR</td></tr>
<tr><td>Aylmer MS1</td><td>5MVA</td><td>2</td><td>613</td><td>N</td><td>41</td><td>2</td><td>46%</td><td>5</td><td>Excellent</td><td>5</td><td>Good</td><td>4</td><td>74</td><td>MONITOR</td></tr>
<tr><td>Aylmer MS2 - TX2</td><td>3MVA</td><td>4</td><td>992</td><td>Y</td><td>23</td><td>3</td><td>30%</td><td>5</td><td>Excellent</td><td>5</td><td>Good</td><td>4</td><td>80</td><td>MONITOR</td></tr>
<tr><td>Tavistock MS1</td><td>5MVA</td><td>3</td><td>693</td><td>N</td><td>10</td><td>5</td><td>38%</td><td>5</td><td>Excellent</td><td>5</td><td>Good</td><td>4</td><td>92</td><td>MONITOR</td></tr>
<tr><td>Clinton MS2</td><td colspan="18">OUT OF SERVICE & DECOMISSIONED</td></tr>
</table>

5.3.2D) ASSET UTILIZATION

- ***An assessment of the degree to which the capacity of the 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 an investment.***

On a local distribution level, there is no known capacity constraints at any embedded distribution supply point connected to Hydro One's system.

Currently there are no capacity constraints on the nine (9) municipal substations owned and operated by ETPL. This will continue to be the case for the indefinite future as voltage conversion removes load from each of the substations.

Table 17: Station Characteristics

	STATION CHARACTERISTICS			
DISTRIBUTION STATION	STATION RATING	# OF FEEDERS	# OF CUSTOMERS	LOADING %
Clinton MS1	5MVA	4	1494	66%
Port Stanley MS1	5MVA	3	917	21%
Beachville MS1	3MVA	2	402	40%
Aylmer MS2 - TX1	3MVA	4	992	15%
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Ingersoll MS1	5MVA	3	767	23%
Ingersoll MS3	5MVA	3	436	21%
Aylmer MS1	5MVA	2	613	46%
Aylmer MS2 - TX2	3MVA	4	992	30%
Tavistock MS1	5MVA	3	693	38%

On a transmission level, ETPL communities are included in two Regional Planning Areas; the London and Greater Bruce/Huron regions which are in the IRRP/RIP and NA stages respectively. Regional planning for the London Region has identified a number of needs affecting ETPL communities resulting in capacity concerns at both the Aylmer TS, Tillsonburg TS and the 115kV W8T circuit supplying these stations. The transformer capacity of the two TS's are expected to reach their 10 day LTR in the near term (5 years) and the W8T circuit is expected to reach its thermal capacity within the medium term (10 years). These concerns will be discussed within the RIP process, and no substantial financial investments are expected.

The transformation capacity at the Aylmer TS is currently being addressed through an end of life replacement by Hydro One. ETPL has secured an additional feeder position for a number of reasons which are detailed in a business plan included in Appendix K; this will result in sufficient capacity, long term for the Town of Aylmer.

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.***

5.3.3A) DESCRIPTION OF ASSET LIFECYCLE OPTIMIZATION POLICIES AND PRACTICES

- ***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 complete description of ETPLs asset lifecycle optimization policies and practices are included within the 2011 and 2015 Asset Management Plan & Asset Condition Assessments included in Appendices H & I.

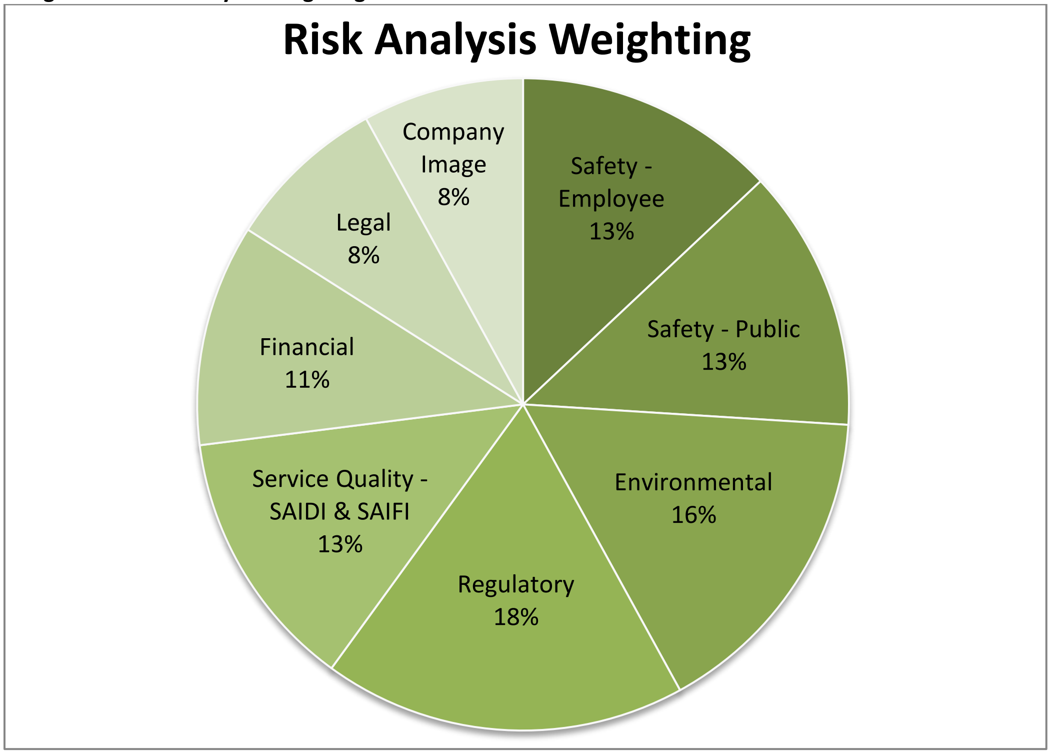
The vast majority of ETPL assets including poles, lines, distribution transformers and associated hardware do not lend themselves to any viable refurbishment options and therefore very few refurbishment practices exist within ETPLs asset management plan. In certain situations when a distribution transformer is retired from service it can be refurbished by the manufacturer and returned to stock as a new unit for unplanned type replacements. This type of refurbishment is evaluated on a transformer by transformer basis and is only completed if there is a need and the costs of refurbishment provide savings over purchasing a new unit.

With regards to asset replacement, decisions are made to achieve the right balance between achieving maximum life expectancy, highest operating performance, lowest initial investment (capital costs) and lowest operating costs. The majority of the investments in fixed assets are triggered by either declining performance in the areas of reliability, power quality and safety; or increasing operating and maintenance costs associated with aging assets; or anticipated growth in demand requiring capacity upgrades. In all cases, investments that are either oversized or made too far in advance of the actual system need may result in non-optimal management. On the other hand, investment not made on time when warranted by the system needs raise the risk of performance targets not being achieved and would also result in non-optimal management. Optimal management of the distribution system is achieved when “right sized” investments into renewal, refurbishment and preventative maintenance are planned and implemented on a “just-in-time” approach.

ETPL implements the use of a software based investment optimizer to ensure that planned projects are targeted to areas of the distribution system most in need. This allows the objectives set out in the mission statement and corporate goals to be realized while minimizing risk to customers, employees and shareholders.

Each project being considered for capital expenditure is assigned risk based on consequence and probability for a number of categories. The investment optimizer requires that all categories be assigned importance and the following figure illustrates the board approved weighting that has been adopted by ETPL in line with our internal and corporate objectives.

Figure 47: Risk Analysis Weighting



Currently ETPL utilizes the investment optimizer to complete a yearly optimization of all capital expenditures involving fixed distribution assets. This requires approximately 2-3 years of potential projects to be defined, budgeted and assigned risk. The optimizer then analyzes the available projects and chooses a mix of projects that not only minimize risk, but fall within prescribed spending levels. This ensures that projects are identified, selected and prioritized using disciplined risk based analysis.

ETPL has been using the investment optimizer since 2012 and the overall result has been that ETPL has been able to spend less on system renewal (sustainment) projects than was suggested by the Asset Condition Assessment (ACA) and Asset Management Plan (AMP) conducted by METSCO Energy Solutions in 2011. METSCO suggested spending an average of $2.3 million[13] annually on capital for sustainment of fixed distribution assets (system renewal). ETPL has spent an average of $1,694,990 on system renewal projects from 2012 to 2016, with a forecast average of $2,080,011 from 2018 to 2022.

[13] Section 5.13 of the METSCO report filed with rate application EB-2012-0121 Exhibit 2 Tab 5 Schedule 1 page 146 of 159

During this time, safety has not been compromised (as noted by zero Serious Incidents) and reliability has not degraded (both SAIDI and SAIFI have improved since 2012[14]).

The direct impact of system renewal type projects on the annual O&M costs is difficult to quantify and a metric has not yet been developed to measure this relationship. Past experience and good utility practice indicate that well planned system renewal projects targeted to areas in need will prevent unplanned reactive repairs, and therefore avoid increasing O&M costs in the long term.

As noted above, reliability has improved which would suggest the pace of system renewal projects is sufficient to avoid unplanned spending in reactive repairs. ETPL will continue to monitor these measures on a yearly basis to ensure the amount of capital spending on system renewal is sufficient to maintain a desirable level of reliability while minimizing O&M costs. As well, overall customer satisfaction, and customer satisfaction with reliability and cost will be tracked (through surveys) to determine if customers continue to be accepting of the reliability and cost trends.

- ***A description of maintenance planning criteria and assumptions;***
- ***A description of routine and preventative inspection and maintenance policies and programmes***
- ***(Can include references to the DSC)***

ETPL implements various preventative inspection and maintenance programs which are in line with the urban inspection requirements as required by the DSC. Additional programs such as pole testing, oil sampling, and infrared scans are aimed at reducing reactive unplanned repairs.

Table 18: Inspection & Maintenance Cycles

INSPECTION & MAINTENANCE CYCLES	
O/H Distribution System	3 year
U/G Distribution System	3 year
Substation Inspection (ETPL)	1 month
Substation Inspection (Contractor)	6 month

[14] See most recent Scorecard

Substation Transformer Oil Sampling	1 year
Substation Maintenance	5 year
Thermograph Scans	2 year
Tree Trimming	3 year
Pole Testing	9 year
Load Break Switch Maintenance	6 year

- **Overhead Distribution System Inspections**

ETPL Cycle: 3 years (DSC Requirement: 3 years)

Currently a visual inspection of approximately 1/3 of the overhead distribution system is completed on an annual basis by ETPL staff. This includes a visual assessment of the integrity of poles, support structures, switching devices, transformers, lightning arrestors, grounding and any associated hardware. Any basic deficiencies such as missing guy guards or ground moulding are immediately addressed while completing the inspection and other issues are documented and provided to the Operations Manager & Lines Supervisor for prioritization and scheduling.

- **Underground Distribution System Inspections**

ETPL Cycle: 3 years (DSC Requirement: 3 years)

Currently ETPL staff complete a visual inspection of approximately 1/3 of its underground distribution system on an annual basis. This includes a visual assessment of the integrity of all padmounted equipment, cables, terminations and associated civil infrastructure. Any basic deficiencies are immediately addressed while completing the inspection and other issues are documented and provided to the Operations Manager & Lines Supervisor for prioritization and scheduling.

- **Distribution Substation Monthly Inspections**

ETPL Cycle: 1 month (DSC Requirement: 1 month)

On a monthly basis ETPL staff complete a visual inspection of all substation equipment including transformers, switches, structures, fence, and yard etc. Temperature and current readings are also recorded for transformers and feeders respectively. Again any basic deficiencies are attended to immediately and other issues are documented and provided to the Operations Manager & Lines Supervisor for prioritization and scheduling as required.

- **Distribution Substation Bi-Yearly Inspections**

ETPL Cycle: 6 month (DSC Requirement: None)

Every six (6) months a visual inspection of all substation equipment including transformers, switches, structures, fence, and yard etc. is completed by a third party contractor. A formal report is created with recommendations for review by ETPL. A sample 2015 report is embedded (Appendix A) in the Asset Condition Assessment and Asset Management Plan included as Appendix I for reference.

- **Distribution Substation Transformer Oil Sampling**

ETPL Cycle: 1 year (DSC Requirement: None)

Oil samples are taken from all distribution station transformers by a third party contractor; Dissolved Gas Analysis (DGA) and Chemical Analysis (ASTM/Water) are completed and compared to previous tests and IEEE limitations. Oil sampling results are the primary condition indicator for station transformers and are used by Engineering and Operations staff to identify and prioritize stations requiring capital or maintenance investment.

- **Distribution Substation Maintenance**

ETPL Cycle: 5 year (DSC Requirement: None)

Substation maintenance is completed by a third party contractor on a five (5) year cycle. This includes inspection, cleaning and service of all electrical and mechanical components, grounding inspection and testing and transformer testing including insulation resistance, capacitance and dissipation factor, turns ratio and winding resistance tests. A formal report is created for review by ETPL; 2014 report is embedded (Appendix C) in the Asset Condition Assessment and Asset Management Plan included as Appendix I for reference.

- **Pole Testing**

ETPL Cycle: 9 year (DSC Requirement: None)

A third party contractor completes "Sound & Selective Bore" testing on poles which includes sounding of the pole (hammer test) and boring as deemed necessary. Poles are then analyzed, assigned a remaining strength value and prioritized for replacement as required. The remaining strength value is determined using tables developed by the testing contractor and is dependent on the field assessment of the poles. The contributing assessment factors include split top, roof rot, woodpecker damage, shell rot, mechanical damage and others. The tables that are used have been compared with software specializing in analysis of wood pole damage and decay.

In conjunction with pole testing, data collection is completed and used to identify other characteristics of the supporting structure. Examples include identifying porcelain insulators, wood cross arms, & pole top extensions. This data is entered into the GIS system and can then be easily queried to help identify specific areas of concern; the image below is a screen capture of a query identifying poles with a remaining strength < 70% in the town of Port Stanley. In this instance you can visually identify that there are no areas with multiple poor tests requiring capital investment.

Figure 48: Pole Testing Results Example

- **Infrared Scans**

ETPL Cycle: 2 year (DSC Requirement: None)

Infrared inspection completed by a contractor to identify thermal anomaly conditions on overhead distribution system equipment. All anomalies are noted and prioritized based on the temperature rise as compared to the ambient temperature; 2014 report is embedded (Appendix B) in the Asset Condition Assessment and Asset Management Plan included in Appendix I for reference.

- **Load Break Switch Maintenance**

ETPL Cycle: 6 year (DSC Requirement: None)

ETPL completes load break switch maintenance on a 6 year cycle which includes a service of all mechanical and electrical components of the switch. Upon completion of the maintenance work each switch is evaluated to determine if it needs to be replaced prior to the next planned maintenance cycle, and if so, the proposed replacement timing is communicated to the Engineering and Operations Managers for further review.

- **Tree Trimming**

ETPL Cycle: 3 year (DSC Requirement: None)

Tree trimming is completed by a third party contractor and aims to remove approximately 3 years of growth from vegetation in proximity to distribution lines and equipment. ETPL staff review conditions before and after to ensure work is completed to recognized standards.

5.3.3B) DESCRIPTION OF ASSET LIFECYCLE RISK MANAGEMENT POLICIES AND PRACTICES

- ***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 analysis are used to select and prioritize capital expenditures.***

A detailed explanation of ETPL risk management policies and practices can be found in the 2015 ACA & AMP included as Appendix I, along with section 5.3.3a) Asset lifecycle risk is managed through a combination of preventative inspection and maintenance and proactive system renewal type projects.

Preventative inspection and maintenance practices identified in section 5.3.3a) are used to target individual assets at or nearing failure and typically result in repairs or replacement of an individual asset (i.e. pole, transformer, insulator, switch, etc.) These repairs and replacements are considered a high priority and budgeted for on a yearly basis based on historical trends.

System renewal projects address asset lifecycle risks with the entire asset base in mind as outlined in the ACA/AMP. They are intended to address end of life assets in a strategic manner accomplishing other objectives such as voltage conversion, and operational flexibility. The spending levels for these types of projects are detailed in the ACA/AMP and look to maintain or slightly improve the asset base as a whole.

The risk management practices detailed above are selected and prioritized with the use of a software optimization tool that is detailed in the ACA/AMP and section 5.3.3a).

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.***
- ***A DS Plan must include information on prospective investments over a minimum five year forecast period, beginning with the test year, 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 the distributor's capital expenditure plan including, by category significant projects and activities to be undertaken and their respective key drivers; the relationship between investments in each category and a distributors objectives and targets; and the primary factors affecting the timing of investment in each category.***

5.4.1A) CAPABILITY TO CONNECT

- ***This section includes 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.***

On a local distribution level, there are no known capacity constraints at any embedded distribution supply point connected to Hydro One's system. There are also no capacity constraints on the nine (9) municipal substations owned and operated by ETPL. This will continue to be the case for the indefinite future as voltage conversion removes load from each of the substations.

On a transmission level, ETPL communities are included in two Regional Planning Areas; the London and Greater Bruce/Huron regions which are both in Local Wires Planning stage. Regional planning for the London Region has identified a number of needs affecting ETPL communities resulting in capacity concerns at the Aylmer TS, Tillsonburg TS and the 115kV W8T circuit supplying these stations. The transformer capacity of the two TS's are expected to reach their 10 day LTR in the near term (5 years) and the W8T circuit is expected to reach its thermal capacity within the medium term (10 years). These concerns will be monitored within the RPP process and no substantial financial investments are expected by ETPL.

The transformation capacity at the Aylmer TS is currently being addressed through an end of life replacement by Hydro One. ETPL has secured an additional feeder position for a number of reasons which are detailed in a business plan included in Appendix K; this will result in sufficient capacity, long term for the Town of Aylmer.

The Buchanan M21 feeder supplying the town of Belmont is unable to connect new generation customers due to feeder generation capacity constraints on the Hydro One portion. No significant investments by ETPL are expected as a result of these constraints or the future ability to connect generation customers in other territories.

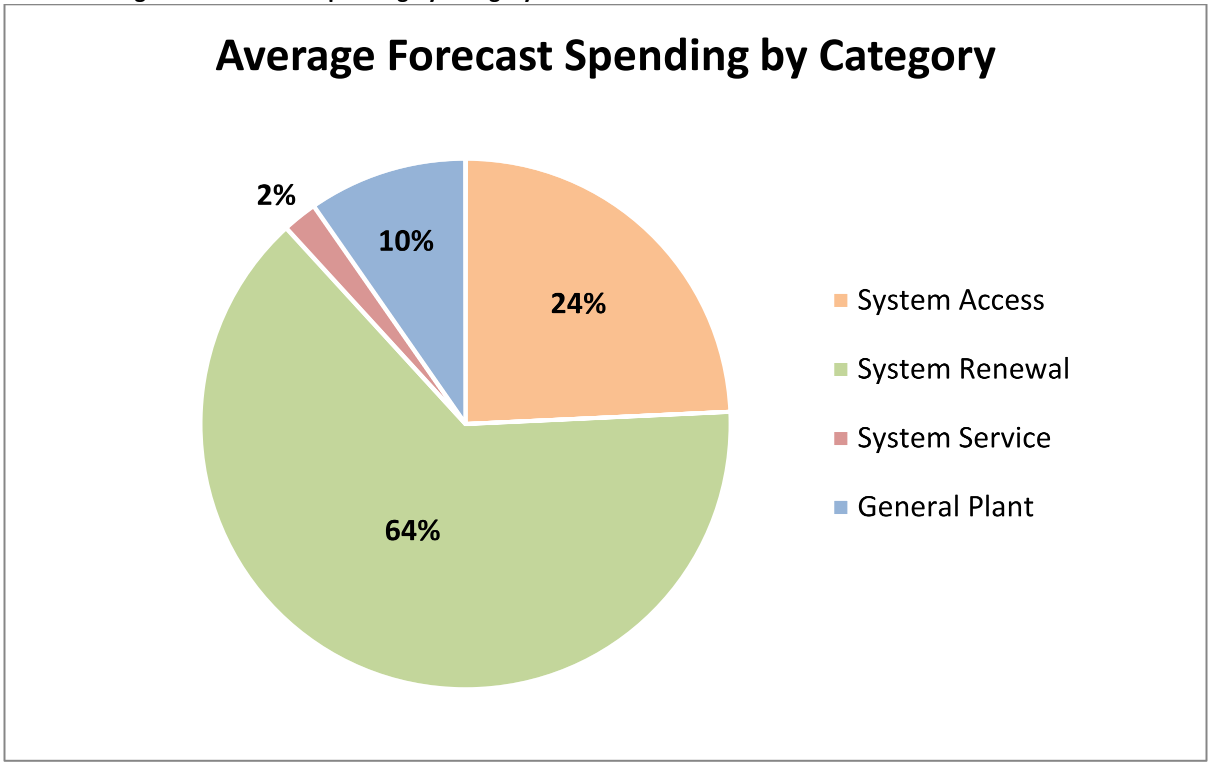
5.4.1B) FORECASTED CAPEX

- ***This section includes the total capital expenditures over the forecast period, by investment category.***

Table 19: Forecast Capital Expenditures

OEB INVESTMENT CATEGORY	2018	2019	2020	2021	2022
System Renewal	$879,500	$920,100	$812,700	$816,300	$819,900
System Access	$2,142,450	$2,002,230	$1,907,040	$2,168,882	$1,879,454
System Service	$73,000	$74,875	$76,750	$55,900	$51,975
General Plant	$148,000	$234,875	$451,750	$223,400	$529,475
TOTAL	$3,242,950	$3,232,080	$3,248,240	$3,264,482	$3,280,804

Figure 49 : Forecast Spending by Category



5.4.1C) EFFECTS OF THE AMP AND CAPEX PLANNING ON CAPITAL EXPENDITURES

- ***This section includes 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.***

ETPL's asset management plan which contains the asset condition assessment of all major assets is used to determine an estimated spending level for the renewal of major assets consistent with the maintenance of a reliable distribution system. With this spending level in mind the capital expenditure planning process uses a risk based assessment of all possible capital expenditures and determines a mix of projects that minimize risk and falls within a prescribed spending level as set by the ETPL board of directors and senior management.

- **System Access**

All system access expenditures are driven by mandated service obligations related to customer service requests, facility relocations and metering requirements. ETPL actively participates with our various communities to determine upcoming municipal work that will affect the distribution system, or any reasons for unexpected customer growth. Even with these discussions the majority of system access spending is based on historical values, driven by customer demand and largely uncontrollable by ETPL. Historically, the annual variances from forecasted demand have been accommodated within the total capital budget without the need to defer or advance other major capital projects.

- **System Renewal**

On a high level, system renewal type projects are driven by the prescribed spending level determined through the asset management plan. These expenditures look to replace aging infrastructure prior to a decline in system reliability, power quality and safety and prior to an increase in operating and maintenance costs that are associated with end of life assets. On a more granular level, specific capital projects are identified by ETPL engineering and operations staff and evaluated using an optimization process that is used to select, prioritize and pace the mix of projects.

- **System Service**

System service type projects comprise a very small portion of the capital expenditures in any given year and are primarily related to system automation. Like all other capital expenditures, projects in this category are evaluated using ETPL's optimization process and selected to achieve strategic objectives. System service projects are primarily driven by a need to maintain reliability and decrease O&M costs moving forward.

- **General Plant**

General plant expenditures include fleet replacements, tools & equipment, IT requirements, and leasehold improvements. Fleet replacements are typically the largest component of general plant spending and are justified through the Fleet Plan included in Appendix M, and evaluated using ETPL's optimization process. Tools and equipment and leasehold improvements are typically smaller non-material investments and are based on historical values. IT requirements are evaluated on a yearly basis with the majority of spending a relatively consistent value based on end of life replacement of hardware. In any given year general plant budgets are adjusted if any large atypical expense is known.

5.4.1D) CAPITAL EXPENDITURE PROJECTS/ACTIVITIES

- ***This section includes a list and brief description including total capital cost (table format recommended) of material capital projects/activities, sorted by category.***

Table 20 below provides a list of ETPL's proposed material capital projects for 2018; detailed descriptions are included in Appendix O as a requirement of section 5.4.5.2.

Table 20: Capital Projects by Category Detailed

OEB CATEGORY	PROJECT	BRIEF DESCRIPTION	CAPITAL COST
System Access	Meter - Stock/Management	Metering and AMI infrastructure replacement as required by failures, reverification etc.	$234,500
	Facility Relocations	Costs associated with municipal/customer facility relocation requirements	$150,000
	Residential Connections	Servicing of residential customers	$231,000
	C&I Connections	Servicing of commercial and industrial customers	$204,000
		TOTAL	**$819,500**
System Renewal	UNPLND - Unplanned Capital Investments	Capital budget associated with any unplanned asset replacement. (ex. MVA's, storm damage, reactive replacements)	$100,000
	OHUPGD - Planned Pole Replacements	Pole replacements identified by pole inspections & testing programs - prioritized and replaced as required.	$200,000
	OHCONV - Bruce & Metcalfe	Overhead conversion in the Town of Ingersoll, Phase 1 of 3 phases targeted to the removal of MS1	$295,000
	UGCONV - Bank of Montreal & Community Living Bldg.	Overhead conversion within the Town of Aylmer driven by end of life assets in the downtown area.	$135,240
	OHCONV - Myrtle to John w/ Pool	Overhead conversion within the Town of Aylmer driven by end of life assets in the downtown area.	$258,840

	OHCONV - Caverly Rd, Anne St. to Fath Ave.	Overhead conversion within the Town of Aylmer, Phase 1 of 3 targeted at creating a tie between McBrien MS and the new feeder out of the Aylmer TS	$82,200
	UGCONV - Davenport School	Overhead conversion within the Town of Aylmer, Phase 1 of 3 targeted at creating a tie between McBrien MS and the new feeder out of the Aylmer TS	$105,450
	OHUPGD - George St. Completion	Completion of a larger overhead conversion project in Port Stanley driven by end of life assets. Project was not completed as a result of property dispute issues which have now been resolved.	$60,000
	OHCONV - Talbot St., Myrtle to Wellington	Overhead conversion within the Town of Aylmer driven by end of life assets in the downtown area.	$200,120
	OHCONV - Princess St., Percival to Schools	Overhead conversion in Clinton driven by the need to remove load from the remaining MS, and create a tie between the two 28kV feeders.	$161,400
	UGCONV - St. Andrews & Maple Crt.	Underground conversion in Mitchell which is one of the last conversion projects required to remove the MS. Also driven by end of life underground cable.	$188,472
	OHCONV - Step Down TX, Arthur St.	Installation of pole-mounted stepdown TX's which will facilitate the removal of the MS.	$46,000
	OHCONV - Princess St. - Percival St. to William St.	Overhead conversion in Clinton driven by the need to remove load from the remaining MS, and create a tie between the two 28kV feeders.	$241,728
	STN - Substation Upgrades	Miscellaneous substation upgrades (ex. fencing, building upgrades, gravel etc.)	$8,000
	MAPS - Maps & Records Updates	Cost associated with updates to GIS maps and other records which are primarily driven by asset renewal.	$120,000

		TOTAL	**$2,202,450**
System Service	System Automation	Costs associated with projects targeted to improving system automation. (i.e. improvements to SCADA, OMS, fault indicators and automated switches)	$90,000
		TOTAL	**$90,000**
General Plant	2018 Fleet Sustainment	Purchases related to small vehicles, large vehicles, trailers, and forklifts.	$20,000
	IT Hardware/Software	Costs associated with computer, server, and related hardware/software purchases.	$56,000
	Leasehold Improvements	Improvements made to buildings & fixtures at each of the three operations centers.	$35,000
	Tools & Equipment	Miscellaneous tools and equipment purchases.	$20,000
		TOTAL	**$131,000**
		TOTAL CAPITAL	**$3,242,080**

5.4.1E) REGIONAL PLANNING PROCESS EFFECTS ON CAPEX

- ***This section details any material effects that the RPP or RIP had on the distributor's capital expenditure plan, with a brief explanation as to how the information is reflected in the plan.***

ETPL communities are included in two Regional Planning Areas; the London and Greater Bruce/Huron regions which are both in the Local Wires Planning stage. Regional planning for the London Region has identified a number of needs affecting ETPL communities resulting in capacity concerns at the Tillsonburg TS and the 115kV W8T circuit supplying these stations. The transformer capacity is expected to reach their 10 day LTR in the near term (5 years) and the W8T circuit is expected to reach its thermal capacity within the medium term (10 years). These concerns will be monitored through the RPP and no material financial investments are expected by ETPL as a result of either regional planning process.

5.4.1F) IMPACTS OF CUSTOMER ENGAGEMENT

- ***This section includes a brief description of customer engagement activities to obtain their preferences and how the results of assessing the information are reflected in the plan.***

ETPL has always endeavoured to provide exceptional services to our customers. With ETPL being an amalgamation of several smaller utilities and the majority of our staff living in these communities, we strive to provide superior service to our neighbours and hometowns while being mindful of the overall cost to our customers for providing this level of service.

ETPL engages our customers regularly by involvement in community events where we encourage and explain conservation and demand management and electrical safety. We also continually provide information on our website, via bill inserts, and bill notes, with regards to explaining customer bills, conservation programs being offered, energy saving tips, and electrical safety. ETPL also holds regular meetings with our largest customer, to ensure reliability of service, conservation, and general concerns of the customer. We also meet with large users to help manage consumption and educate customers about conservation options and programs being offered.

- **Website**

ETPL's website provides a substantial amount of information to our customer, with relation to their utility bills, services available to customer, rates and how bills are calculated, scheduled power outages, conservation, generation, and electrical safety. We also help to promote community events, and general industry information, as well as our RRFE scorecard.

- **Bill inserts and Bill notes**

ETPL takes advantage of our ability to provide information to our customers both through the use of bill inserts and bill notes.

- **Electrical Safety and Community Events**

For several years ETPL has been providing a yearly Electrical Safety program to the Elementary School students within our own territory. We have a service provider go into the class room and demonstrate electrical risks and safety actions to be taken. We have always had a great response from the schools within our service territory, and attempt to cycle through all the schools at least once every four years. We also attend various community events such as The Future Oxford Expo where we provide safety tips, and conservation program information.

- **Conservation and Demand Management**

Our Conservation and Demand Management team is quite active in engaging our customers on a regular basis. We are in regular contact with our largest user (GM-CAMI Automotive) working together to find ways to conserve and review new technical opportunities that would improve their operations.

We also hold topic specific meeting, such as our Compressed Air Efficiencies and Incentives Seminar held in May 2015. Commercial/Industrial customers that use compressed air were invited to attend a meeting which we hosted to discuss how to make compressed air systems more efficient and the incentives available from the save on energy program.

- **Customer Surveys**

ETPL has completed customer surveys in both 2014 & 2016 and will continue this trend moving forward to obtain valuable information regarding customer satisfaction, knowledge and preferences surrounding their electricity supply. Each additional survey will allow ETPL to trend customer satisfaction and make adjustments to its distribution system plan if warranted. A complete report detailing the results of each customer survey is included in Appendix A & B.

ETPL began surveying customers on a yearly basis in 2014. The premise of our first survey was to identify our customers' preferences regarding the existing level of service reliability and costs, and was targeted at our residential and small business classes.

The 2016 survey was again used to collect data from customers regarding their satisfaction, knowledge and preferences however in addition was used to provide customers with a better understanding of where ETPL fits within the provincial electricity system and found that the majority of customers do not have a great understanding of the system and what Erie Thames controls and does not control.

ETPL had 1136 customers respond to the customer survey in 2016 as compared to 897 in the 2014 customer survey. The 2014 survey did not use email as a medium and found that the number of responses jumped substantially when customers were contacted via email in 2016.

The surveys as a whole shows our customers are satisfied with the level of service which they receive from ETPL and feel that we are managing costs effectively. Both surveys reflect that customers are most concerned with total price and reliability, with the majority of respondents indicating that they find the existing level of reliability to be acceptable. These results are reflected in the DSP with a relatively flat level of capital spending aimed at maintaining the existing level of reliability.

5.4.1G) DISTRIBUTION SYSTEM DEVELOPMENT

- ***This section includes 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 developments and/or the accommodation of forecasted renewable energy generation projects.***

▪ Load & Customer Growth

ETPL does not anticipate any abnormal load or customer growth outside of typical totals seen in the historical period; it is estimated somewhere in the range of 1%. This is reflected in the DS Plan with the majority of capital, approximately 64%, being dedicated to renewal of existing infrastructure and 24% to system access which primarily consists of new connections.

▪ Smart Grid Developments

ETPL expects to continue making minor improvements to the smart grid capabilities of our distribution system. This will revolve around the implementation of an OMS (Outage Management System), along with automated switches and fault indicators which will be tied into the existing SCADA system. These improvements are aimed at improving reliability through reduced frequency and duration of outages and will look to leverage smart meter data more effectively.

- **Renewable Projects**

ETPL currently has sufficient capacity to connect renewable energy projects within its distribution system and does not expect substantial capital investments as a result.

5.4.1H) CAPITAL COSTS OF PLANNED PROJECTS/ACTIVITIES

- ***This section includes a list and brief description including total capital cost (table format recommended) of material capital projects/activities planned:***
- ***Table XX below indicates planned capital expenditures and their relationship to customer preference, technology and innovation.***
  - ***In response to customer preferences (e.g. data access and visibility; participation in distributed generation; load management)***
-

OEB Category	Project	1 - Customer Preference 2 - Technology 3 - Innovation	Capital Cost
System Access	Meter - Stock/Management	1	$234,500
	Facility Relocations	1	$150,000
	Residential Connections	1	$231,000
	C&I Connections	1	$204,000
		TOTAL	**$819,500**
System Renewal	UNPLND - Unplanned Capital Investments	1	$100,000
	OHUPGD - Planned Pole Replacements	1	$200,000
	OHCONV - Bruce & Metcalfe	1	$295,000
	UGCONV - Bank of Montreal & Community Living Bldg.	1	$135,240
	OHCONV - Myrtle to John w/ Pool	1	$258,840
	OHCONV - Caverly Rd, Anne St. to Fath Ave.	1	$82,200
	UGCONV - Davenport School	1	$105,450
	OHUPGD - George St. Completion	1	$60,000
	OHCONV - Talbot St., Myrtle to Wellington	1	$200,120
	OHCONV - Princess St., Percival to Schools	1	$161,400
	UGCONV - St. Andrews & Maple Crt.	1	$188,472
	OHCONV - Step Down TX, Arthur St.	1	$46,000
	OHCONV - Princess St. - Percival St. to William St.	1	$241,728
	STN - Substation Upgrades	1	$8,000

	MAPS - Maps & Records Updates	1	$120,000
		TOTAL	**$2,202,450**
System Service	System Automation	1, 2	$90,000
		TOTAL	**$90,000**
General Plant	2018 Fleet Sustainment	1	$20,000
	IT Hardware/Software	1, 2	$56,000
	Leasehold Improvements	1	$35,000
	Tools & Equipment	1	$20,000
		TOTAL	**$131,000**
		TOTAL CAPITAL	**$3,242,950**

Customer preferences clearly indicate that customers are most concerned with cost and reliability. With this in mind the majority of expenditures are related to the renewal of end of life assets as prescribed by the AMP plan included in Appendix I to ensure that system reliability is maintained. Since cost is the primary concern ETPL has reduced the spending levels prescribed by the AMP and will monitor multiple indicators to ensure that safety and reliability are maintained as detailed in section 5.3.3a).

- ***To take advantage of technology-based opportunities to improve operational efficiency, asset management and the integration of distributed generation and complex loads.***

As mentioned above costs are the primary concern for the majority of ETPL customers and therefore technology based opportunities are scaled to a level that will only minimally affect the costs incurred by customers. Over the past number of years and throughout the forecast period, ETPL has focused approximately 2%-6% of its capital expenditures on system automation type projects such as SCADA, OMS, and automated equipment. This level of spending is consistent with customer preferences where value is placed on technology based opportunities only if the costs of delivering reliable service are not compromised.

- ***To study or demonstrate innovative processes, services, business models or technologies.***

Currently no planned expenditures fall into this field.

5.4.2 Capital Expenditure Planning Process Overview

5.4.2A) CAPITAL PLANNING OBJECTIVES, CRITERIA AND ASSUMPTIONS

- ***This section includes a description of the distributors 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.***

ETPL's capital expenditure plans looks to choose a mix of expenditures that achieve a balance of the following objectives:

- Meet mandated service obligations with respect to new customer connections, meter replacements and facility relocations.
- Maintain or improve the safety and reliability of the distribution system to meet customer expectations.
- Effective renewal of end of life assets as prescribed by the ACA & AMP, creating a balance between capital investments in new infrastructure and O&M costs ensuring that the total cost over the life of the asset is minimized.
- Establishment of long term planning horizons to maintain stable financial impacts to customers.
- Provide adequate system capacity for load growth, and connection of REG.
- Ensure that general plant expenditures are sufficient to enable objectives to be achieved in an efficient manner.

The criteria used to select, pace and prioritize projects in a manner that achieve the proper balance of the objectives listed above are detailed in the AMP included in Appendix I and have been summarized below:

- Financial
- Service Quality
- Company Image
- Legal
- Regulatory
- Safety (Public and Employee)
- Environmental

All of these criteria represent various inputs into the decision framework used by ETPL and encompass variables such as customer preference, consultation with municipal government, maintenance requirements, load growth requirements, specific asset condition assessments etc.

There are a number of assumptions that are made during the capital expenditure process primarily focused of third party driven system access type investments which include:

- The capital expenditure level for developer driven projects is typically established on historical trends and adjusted based on information from municipal contacts and developers. This however assumes that historical trends will hold true and adjustments made for known developments come to fruition in a given year.
- The capital expenditure level for municipal facility relocation projects is established through historical trends and adjusted based on consultation with our municipal partners. This assumes that projects tabbed for a given year move forward and the effect on ETPL infrastructure is consistent with initial plans.
- The use of historical growth, CDM and DG rates to establish a forecast for the demand of the distribution system.

ETPL objectives regarding REG look to enable any REG to connect to the system. Currently ETPL has sufficient capacity to connect renewable energy projects within its distribution system and does not expect substantial capital investments as a result. ETPL is working with regional partners to address REG related constraints on the transmission system.

5.4.2B) NON-DISTRIBUTION ALTERNATIVES

- ***This section includes the distributor's policy on and procedure whereby non-distribution alternatives to relieving system capacity or operational constraints are considered, including the role of Regional Planning Processes in identifying and assessing alternatives.***

On a local distribution level, there are no, known capacity constraints at any embedded distribution supply point connected to Hydro One's system and therefore a formal policy to address non-distribution alternatives with regards to capacity constraints has not been developed by ETPL.

On a transmission level, ETPL communities are included in two Regional Planning Areas; the London and Greater Bruce/Huron regions which are in the IRRP/RIP and NA stages respectively. The regional planning process will evaluate non-distribution alternatives with input from LDC's, IESO and Hydro One stakeholders.

5.4.2C) PROCESS TO IDENTIFY, SELECT, PRIORITIZE, AND PACE CAPITAL PROJECTS

- ***This section includes a description of the tools and methods used to identify, select, prioritize, and pace the execution of projects in each investment category.***

ETPL implements the use of a software based investment optimizer to ensure that capital expenditures have been selected, prioritized and paced effectively. This allows the objectives set out in the mission statement and corporate goals to be realized while minimizing risk to customers, employees and shareholders.

Each project being considered for capital expenditure is assigned risk based on consequence and probability for a number of categories. The categories as defined in the investment optimizer are explained in detail below.

- **Financial (11%)**
  - *Value* - The financial category aims to quantify any financial impacts as a result of the project completion. Consideration is given to the project cost, revenue and cost savings in the form of reduced maintenance, or operating costs. Protecting ETPL's financial viability provides value to customers as it ensures ETPL can continue to provide safe, reliable service to customers at a reasonable cost.
  - *Risk* - the risk assigned under this category is based on the loss of revenue and/or cost avoidance as a result of not completing the particular project. The financial consequences are linked to the probability of an event occurring on a scale ranging from four (4) events a year to one (1) event every ten (10) years.

- **Service Quality (13%)**

SAIFI

- *Value* - SAIFI quantifies the number of times a customer experiences a power interruption and consideration is given to the current SAIFI trend in the proposed project area. Customers value a reliable supply of electricity and want ETPL to minimize the frequency of outages at minimal cost.
- *Risk* - risk for SAIFI considers the potential impact to outage frequency resulting from asset failure if the project is not completed. The consequences assigned to the project range from individual customers (<50kW) to transmission feeders (>50% of customers) experiencing an outage and the probability range from four (4) events a year to one (1) event every ten (10) years.

SAIDI

- *Value* - SAIDI quantifies the duration of outages experienced by a customer and consideration is given to the current SAIDI trend in the proposed project area. Customers value a reliable supply of electricity and want ETPL to minimize the duration of outages at minimal cost.
- *Risk* - risk for SAIDI considers the potential impact to outage duration resulting from asset failure if the project is not completed. The consequences assigned to the project range from a momentary outage (<3min) to a sustained outage (>12 hours) and the probability ranges from four (4) events a year to one (1) event every ten (10) years.

- **Company Image (8%)**

- Value - The company image category looks to address any formal complaints made to ETPL as a result of a particular portion of the distribution system related to a proposed project. Maintaining a strong company image by minimizing complaints ensures customers trust ETPL to make the correct decisions, to operate ethically, to be socially responsible, and be a valued contributor to the community. This trust allows customers to focus on using and enjoying the services we provide.
- Risk - the risk assigned under the company image category is based on the consequences of a formal complaint ranging from individual concerns made to the company to general public

outcry - national media coverage and is assigned a probability ranging from four (4) events a year to one (1) event every ten (10) years.

- **Legal (8%)**
  - *Value* - the legal category looks to consider the litigation costs related to a particular project.
  - *Risk* - the risk assigned to a project under the legal category is based on the litigation costs that may result of a project not being completed. The consequences range from litigation costs of less than $1000 to greater than $500,000, and are assigned a probability ranging from four (4) events a year to one (1) event every ten (10) years.

- **Regulatory (18%)**
  - *Value* - The value assigned under the regulatory category looks to consider the impacts of a project on compliance to regulatory requirements. Customers expect ETPL to be fully compliant with all regulations as these regulations are often focused on ensuring the customers are receiving the proper services for a fair price.
  - *Risk* - the consequences as a result of not completing the proposed project range from non-reportable compliance issues to damaging OEB regulatory impacts resulting in the loss of licence and are assigned a probability ranging from four (4) events a year to one (1) event every ten (10) years.

- **Safety (26%)**

  Public
  - *Value* - The value considered in this category is specific to public safety and looks to quantify the possibility of a safety incident related to a member of the public. Many of ETPL's distribution assets are in public spaces (along streets, serving every property) and ensuring the system is safe is ETPL's number one priority.
  - *Risk* - If the potential project is not completed the consequences range from the potential of a non-life threatening injury with no prior history to a potentially life threatening hazard with a known history and assigned a probability ranging from four (4) events a year to one (1) event every ten (10) years.

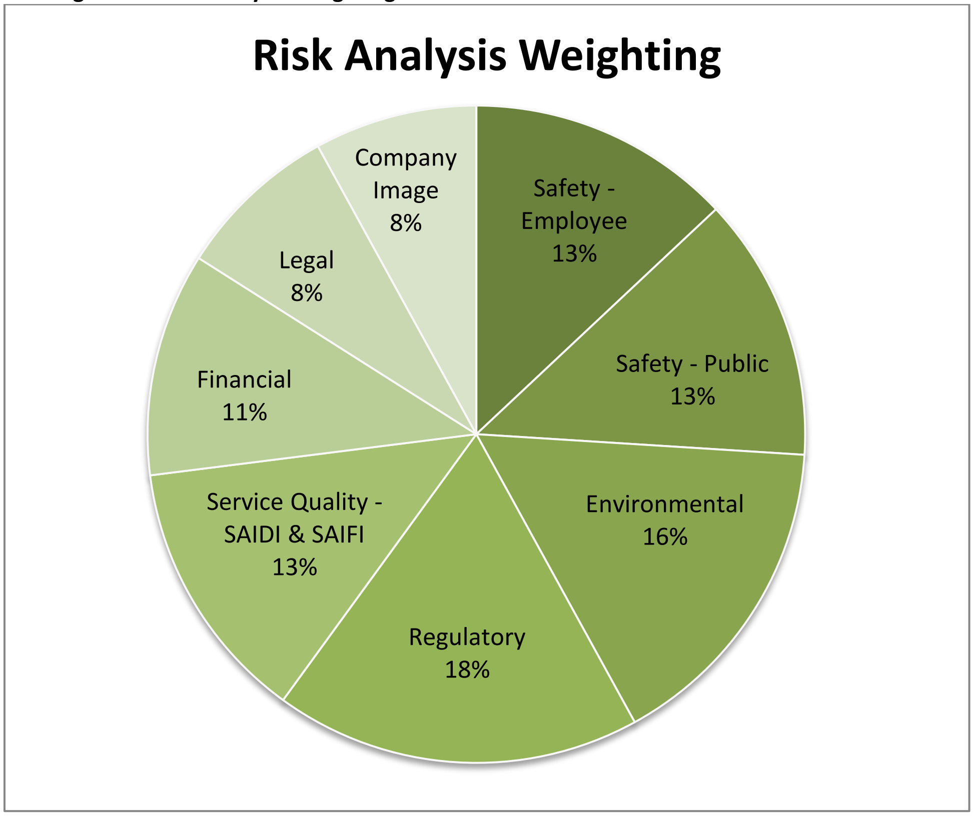
Employee

- *Value* - The value considered in this category is specific to employee safety and looks to quantify the possibility of a safety incident related to a utility worker. A safe workplace is an efficient workplace and prevents costs associated with lost time injuries and lost productivity.
- *Risk* - If the potential project is not completed the consequences range from a minor employee injury with internal reporting required to a major loss time injury or fatality and assigned a probability ranging from four (4) events a year to one (1) event every ten (10) years.

- **Environmental (16%)**
  - *Value* - the environmental category aims to consider the environmental impacts of the distribution system and to ensure any environmental concerns are mitigated. Addressing environmental risks keeps the cost to customers down by preventing expensive clean-ups and soil remediation.
  - *Risk* - the risk assigned under the environmental category if a project is not completed range in consequence from a minor disturbance with environmental documentation not necessary to a disturbance requiring MOE and company environmental assistance. The possible consequences under this category are assigned probability ranging from four (4) events a year to one (1) event every ten (10) years.

The investment optimizer requires that all categories be assigned importance and the following figure demonstrates the weighting that has been adopted by ETPL in line with our internal and corporate objectives.

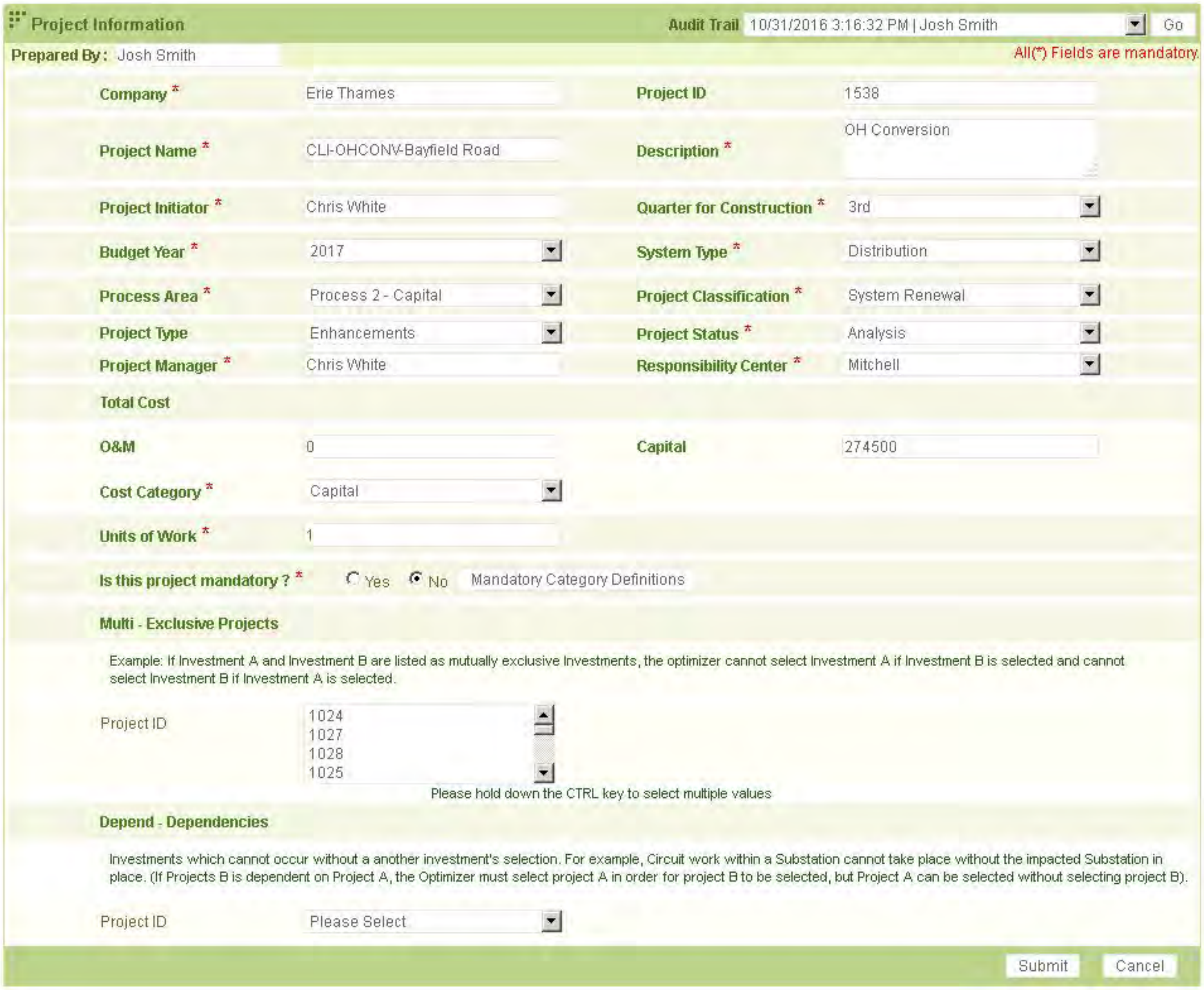
Figure 50: Risk Analysis Weighting



Currently ETPL utilizes the investment optimizer to complete a yearly optimization of all capital expenditures involving fixed distribution assets. This requires approximately 2-3 years of potential projects to be defined, budgeted and assigned risk. The optimizer then analyzes the available projects and chooses a mix of projects that not only minimize risk but fall within prescribed spending levels. This ensures that projects are identified, selected and prioritized using disciplined risk based analysis. The optimizer will identify if the prescribed spending levels are too low which could be exposing EPTL and customers to excessive risk. The management team would then review the total spending envelope to determine if the spending level needs to increase or if additional cost efficiencies need to be found.

The figures below are examples of the investment optimizer interface along with the "risk matrix" output, which is one of multiple deliverables that are used to evaluate the capital portfolio.

Figure 51: Project Information Form


Project Information | Audit Trail 10/31/2016 3:16:32 PM | Josh Smith | Go

Prepared By: Josh Smith | All(*) Fields are mandatory.

Company *	Erie Thames	Project ID	1538
Project Name *	CLI-OHCONV-Bayfield Road	Description *	OH Conversion
Project Initiator *	Chris White	Quarter for Construction *	3rd
Budget Year *	2017	System Type *	Distribution
Process Area *	Process 2 - Capital	Project Classification *	System Renewal
Project Type	Enhancements	Project Status *	Analysis
Project Manager *	Chris White	Responsibility Center *	Mitchell
Total Cost			
O&M	0	Capital	274500
Cost Category *	Capital		
Units of Work *	1		
Is this project mandatory ? *	Yes / No	Mandatory Category Definitions	

Multi - Exclusive Projects

Example: If Investment A and Investment B are listed as mutually exclusive investments, the optimizer cannot select Investment A if Investment B is selected and cannot select Investment B if Investment A is selected.

Project ID: 1024, 1027, 1028, 1025

Please hold down the CTRL key to select multiple values

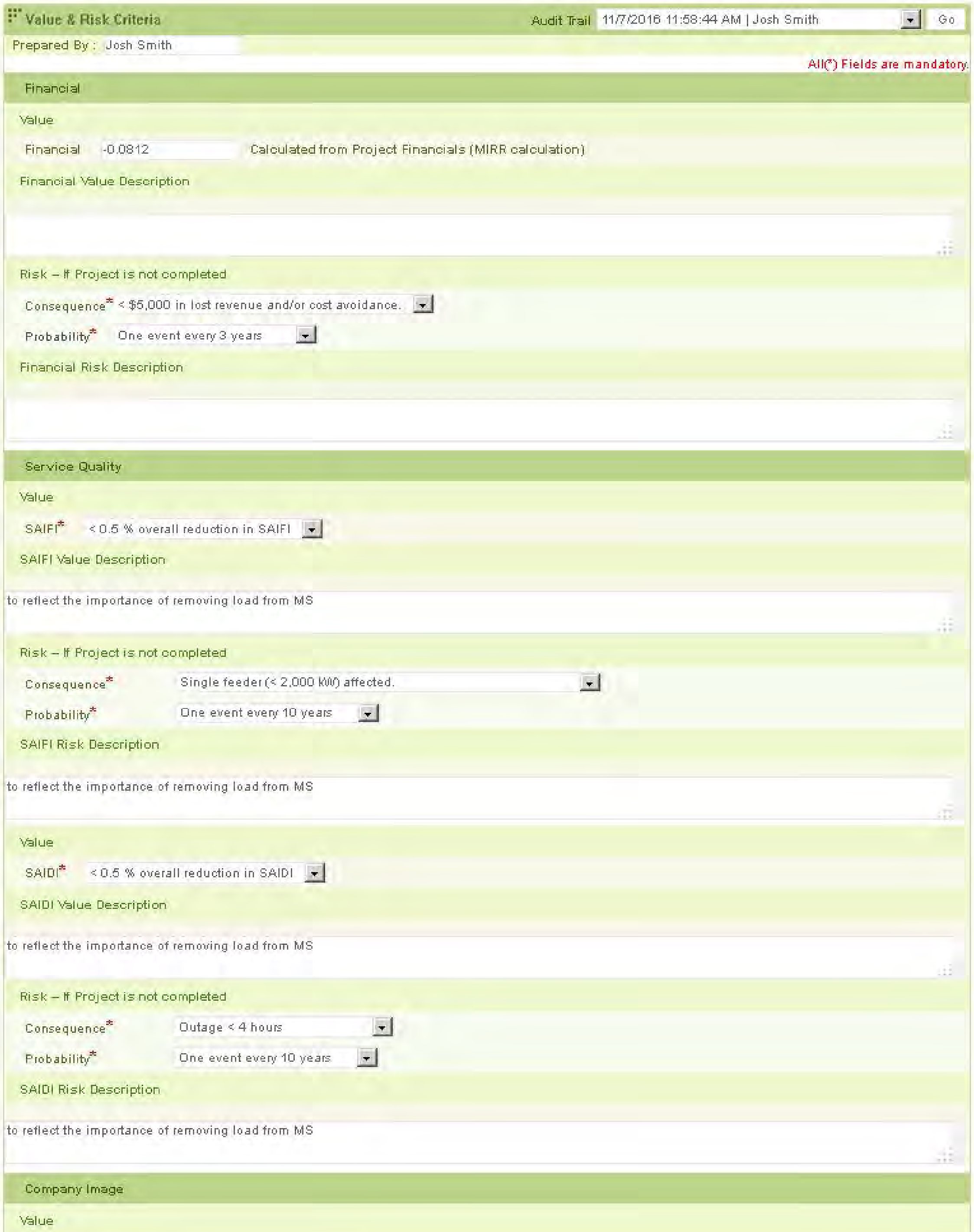
Depend - Dependencies

Investments which cannot occur without a another investment's selection. For example, Circuit work within a Substation cannot take place without the impacted Substation in place. (If Projects B is dependent on Project A, the Optimizer must select project A in order for project B to be selected, but Project A can be selected without selecting project B).

Project ID: Please Select

Submit | Cancel

Figure 52: Value & Risk Criteria Input



Value & Risk Criteria | Audit Trail 11/7/2016 11:58:44 AM | Josh Smith | Go

Prepared By : Josh Smith

All(*) Fields are mandatory

Financial

Value

Financial -0.0812 Calculated from Project Financials (MIRR calculation)

Financial Value Description

Risk – If Project is not completed

Consequence* < $5,000 in lost revenue and/or cost avoidance.

Probability* One event every 3 years

Financial Risk Description

Service Quality

Value

SAIFI* < 0.5 % overall reduction in SAIFI

SAIFI Value Description

to reflect the importance of removing load from MS

Risk – If Project is not completed

Consequence* Single feeder (< 2,000 kW) affected.

Probability* One event every 10 years

SAIFI Risk Description

to reflect the importance of removing load from MS

Value

SAIDI* < 0.5 % overall reduction in SAIDI

SAIDI Value Description

to reflect the importance of removing load from MS

Risk – If Project is not completed

Consequence* Outage < 4 hours

Probability* One event every 10 years

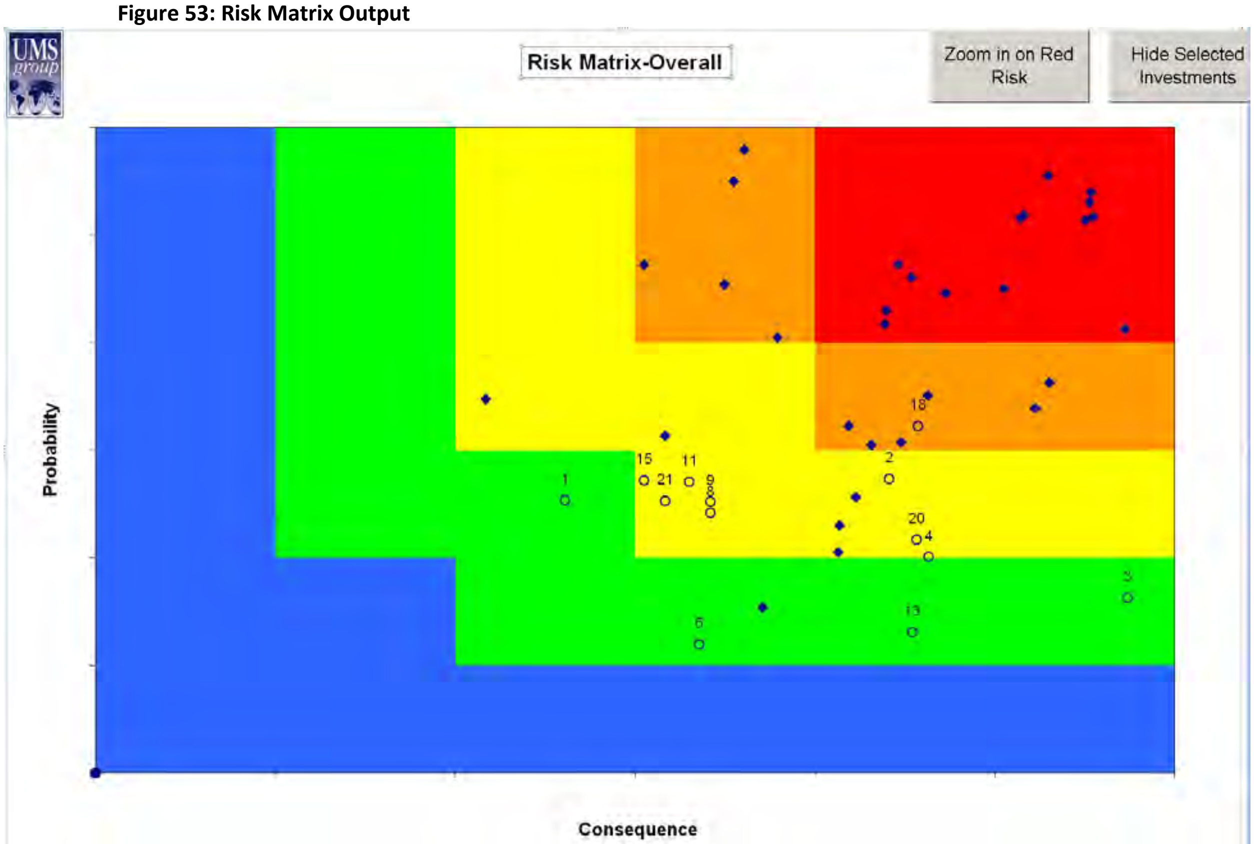
SAIDI Risk Description

to reflect the importance of removing load from MS

Company Image

Value

Figure 53: Risk Matrix Output



- ***Projects within each investment category are included in the optimization process however each category has varying degrees of flexibility within the process. Each project, or category have different means of being identified for input into the optimizer; these variations are detailed below.***

- **System Access**

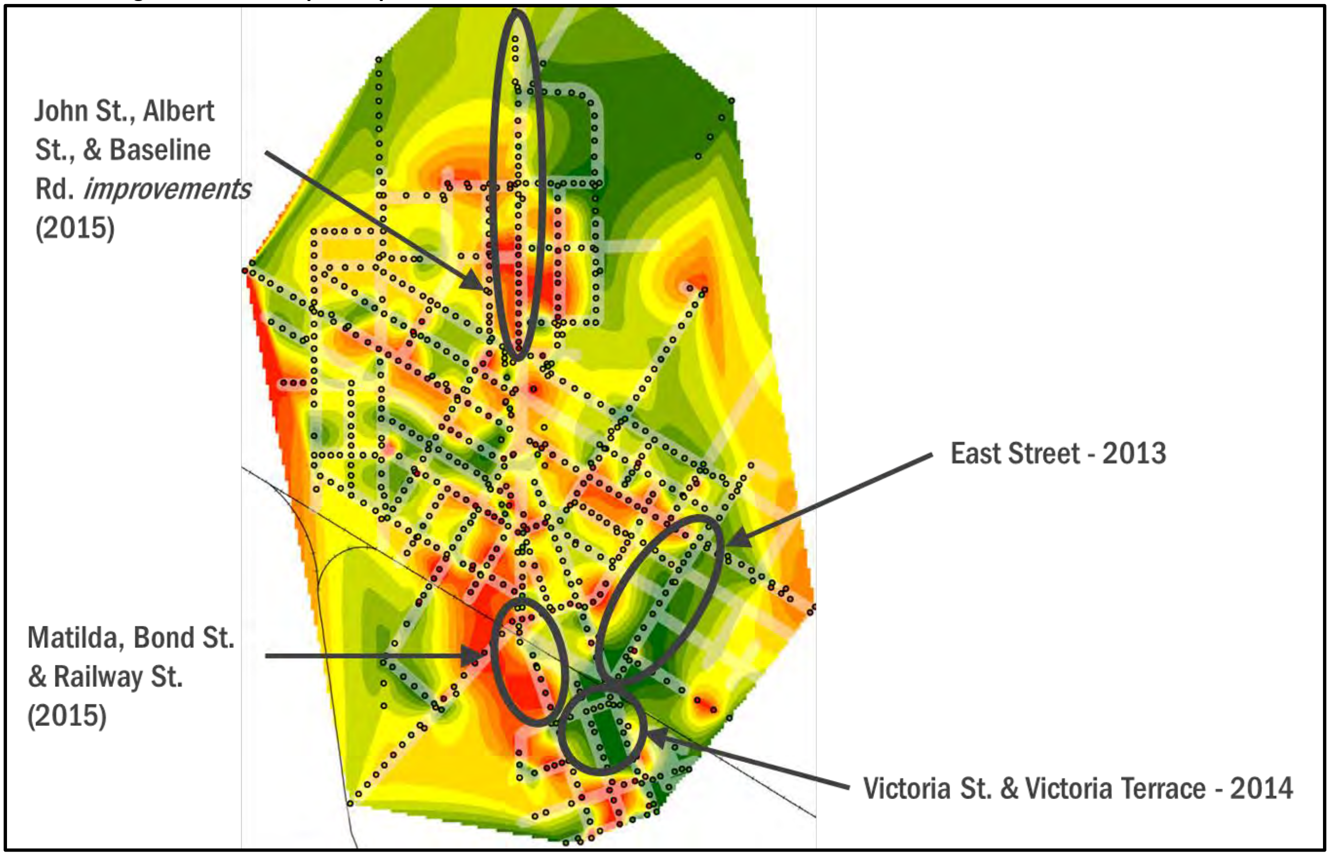
System Access projects are identified through communication with municipal contacts and developers to obtain insight into new developments and road reconstruction. When projects are known in advance they are incorporated into their respective system access budget for a given year. Many system access projects are identified throughout the year and are budgeted using historical trends. Capital expenditures classified as system access projects are considered mandatory within the process due to regulatory mandates and therefore there is minimal effort to select, and pace these investments. System access projects are typically prioritized by ETPL on a first come, first serve basis with consideration given to the in service date provided by municipalities, customers and developers.

- **System Renewal**

System renewal projects are identified through a number of programs, tools and intuitive knowledge of the distribution system by ETPL engineering and operations staff. Pole inspection and testing cycles are used to identify distribution poles in need of replacement and are typically replaced on a one-for-one basis; these replacements are considered mandatory and are budgeted based on historical replacement levels. If a pattern or group of poles is identified in the same area a project will be entered into the optimizer to be compared against other capital expenditures. In a similar fashion, substation inspection and maintenance cycles identify assets requiring replacement and are an input into the optimization process. Typically minor substations assets are replaced on a yearly basis and budgeted for based on historical inspection findings; if a larger scale investment is identified at a substation, the project is entered into the optimization for comparison against other capital expenditures. System reliability is also used to identify system renewal projects; outages are monitored by cause and location, and if patterns or groups of outages occur in the same area then a project will be created and entered into the optimization process.

A key driver for the vast majority of system renewal projects is 4kV conversion, which is aimed at the eventual removal of all ETPL owned 4kV substations. This will avoid capital expenditures for end of life stations and reduce future station related O&M costs. Specific projects for voltage conversion are identified by ETPL staff and entered into the optimization process and are targeted to areas that not only accomplish conversion on particular station feeders but also address end of life assets such as poles, cross arms, insulators, and transformers. Risk and probability for both the distribution assets (i.e. poles, transformers etc.) along with the supply substation are built into the scoring for each project and are selected and prioritized through the investment optimizer discussed above. An example of a "heat map" for the Town of Clinton based on pole age data is shown below and is a tool used to provide a graphical representation of areas of the system with aging infrastructure. Heat maps are used as a supplemental tool for the identification of capital expenditures into system renewal and the future implementation of an OMS system will provide additional tools such as loading analysis and more detailed outage tracking allowing ETPL to correlate all these factors easily when deciding where to target capital expenditures.

Figure 54: Heat Map Example



The ACA and AMP create a high level overview of the needs of the system, establishing target levels for major asset replacement in a given year and prescribe a replacement level that reduce year to year fluctuations in spending. This spending level is used to pace the quantity of system renewal projects in a given year.

- **System Service**

Typically system service projects are a small portion of the capital budget and the only consistent spending year over year is related to system automation projects. These projects have included the installation of FCI's (fault current indicators), implementation of a SCADA system and other projects looking to slowly improve the smart grid capability of the system. They are primarily driven by reliability and operational efficiency and are entered into the optimization process the same as other capital expenditures in order to select, prioritize and pace. Over the past few years and into 2017 there are a number of capital expenditures related to an additional breaker position at the Aylmer TS.

- **General Plant**

Leasehold Improvements are budgeted based on internal knowledge of the facilities owned and operated by ETPL. This knowledge is informed through communication with trade contractors and inspections completed by the Operations Manager. The budget amounts for buildings have historically been a very small portion of the CAPEX budget and there is currently nothing to indicate any changes to this trend throughout the forecast period.

Fleet Replacements are entered into in the optimization process and compared against other capital expenditures to select, prioritize and pace replacements. The inputs into the optimization process are informed by the fleet replacement plan included in Appendix M, which looks at vehicle age, utilization, maintenance costs, etc.

Tools & Equipment are entered into the optimization process and are typically mandatory in nature. The Operations Manager is responsible for spending in this category and is a relatively small component in the capital budget.

IT Systems expenditures are generally evaluated on a yearly basis however the majority of hardware expenditures are scheduled on a 4 year cycle and paced to ensure a relatively flat spending trend. Software related expenditures are typically driven by regulatory compliance or operational efficiency to either update obsolete platforms or implement new programs. These projects are entered into the optimization process through input from both internal and corporate IT staff.

5.4.2D) CUSTOMER NEEDS, PRIORITIES AND PREFERENCES

- ***This section includes 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 affected by this information.***

As noted in Section 5.4.1f) ETPL engages our customers regularly through various activities and providing a number of channels for customers to provide feedback regarding their needs, priorities and preferences.

- **Community Involvement**
    - ETPL attends various community events to promote electrical safety and energy saving initiatives. ETPL presence at community events provides an informal forum for customers to speak with various levels of staff and discuss any concerns they may have.
- **Communications through Call Center, and emails to general information email**
    - Various customer inquiries, complaints and other concerns are documented and assigned to engineering, operations or customer service staff for remediation. Typically communications are related to very specific issues that are addressed immediately if possible.
- **Communications directly through Engineering and Operations Department**
    - The majority of contact directly through engineering and operations revolves around new service or service upgrade requests. These are typically forwarded to the Call Center to ensure that a proper service order is created for tracking purposes. Any customer concerns are generally addressed immediately or documented for input into capital plans as required. Prior to starting a project that may directly impact customers, written notices are given to customers identifying the scope of the project, potential impact to them (short outages to transfer services, excavations in front of their property, traffic flow changes, etc.), and contact information if they have questions or concerns.
- **Social Media**
    - ETPL Facebook and Twitter accounts are monitored to obtain general feedback from customers.
- **Meetings and Information Sessions**
    - Engineering and Operations staff meets with various customers throughout a given year for various reasons including, customers' requests, effects of ETPL capital projects, or yearly planned meetings.

- **CDM Activities**
  - CDM staff regularly initiates contact with medium to large commercial and industrial customers to discuss various initiatives through face-to-face meetings and information sessions. Discussion surrounding distribution related concerns are welcomed and communicated with engineering and operations staff.
- **Customer Survey**
  - A yearly customer survey was completed and targeted towards residential and small commercial customers. This survey was available through online, email, phone and paper mediums.
- **ETPL Board of Directors (5 members)**
  - The Erie Thames Powerlines Board of Directors is comprised of executive management and industry experts who provide insight into customer expectations based on past experience, and current interactions within the industry.
- **Corporate Board of Directors (8 members)**
  - At a corporate level the Board of Directors are selected members of shareholder communities who are able to provide feedback received from constituents regarding distribution related concerns.

The customer engagement activities noted above inform decisions made by ETPL within the capital planning process. Any feedback from customers related to a specific concern or issue are used to identify specific projects which will be entered into the CAPEX optimization process (i.e. broken equipment, power quality issues etc.) The bulk of engagement activities look to develop knowledge about customer preference. The customer surveys included in Appendix A & B, along with other engagement clearly indicate that customers are concerned primarily with the cost of their power and the reliability of the system. These preferences are used primarily to pace the level of capital investment into the system, which is reflected in ETPL's plan to maintain a level of asset renewal to maintain or slightly improve reliability while maintaining cost to customers.

To some degree, some of the customer engagement activities also inform decisions made by ETPL during the execution phase of some projects. Customers may contact ETPL to express a concern about or have a question about the proposed or recently completed project in their area. These concerns and questions are forwarded to the engineering and operations department who will review these with the customer and may adjust the schedule or scope of the project to meet the customers' preferences, provided they do not adversely affect the overall project cost and schedule. These interactions are also reviewed by management as a quality control measure, to ensure the ETPL employees and contractors are doing the work effectively and providing the expected level of customer service.

5.4.2E) PRIORITY OF REG INVESTMENTS

- ***This section details the method and criteria used to prioritize REG investments in accordance with planned development of the system, including the impact if any of the distributor's plans to connect distributor owned renewable generation projects.***

ETPL does not implement a separate prioritization procedure for REG investments and currently does not expect any capital investment within the forecast period as a result of REG. More detail regarding REG connections and capacity can be found in Appendix N.

5.4.3 System Capability Assessment for Renewable Energy Generation

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

5.4.3A) REG OVER 10KW

- ***This section includes any applications from renewable generators over 10kW in the distributor's service area***

5.4.3B) REG FORECAST

- ***This section includes the number and capacity (in MW) of renewable generation connections anticipated over the forecast period based on existing connection applications, information available from IESA/OPA and any other information the distributor has. (a regional breakdown is to be provided for non-contiguous service areas)***

5.4.3C) REG CAPACITY

- ***This section includes the capacity (in MW) of the distributor's distribution system to connect renewable energy generation within its service area.***

5.4.3D) REG SYSTEM CONSTRAINTS

- ***This sections details constraints related to the connection of renewable generation, either within the distributors system or upstream system.***

5.4.3E) EMBEDDED DISTRIBUTOR CONSTRAINTS

- ***This section details the constraints for an embedded distributor that may result from the connections.***

**Please refer to a complete Renewable Energy Generation (REG) Plan included in Appendix N.

5.4.4 Capital Expenditure Summary

- ***The purpose of the information filed under this section in to provide the Board and stakeholders with a 'snapshot' of a distributors capital expenditures over a 10 year period including 5 historical and 5 forecast years.***

A summary of Erie Thames Powerlines historical and forecast capital expenditures are provided below in Tables 21 & 22. ETPL has made best efforts to map 2012-2016 historical actual spending and historical budgets into the OEB defined categories and has provided additional commentary as required.

Table 21: Historical Capital Expenditures

	Historical Capital Expenditures										Actual - Average (2012-2016)
	2012		2013		2014		2015		2016		
CATEGORY	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual	
System Access	$345,000	$929,841	$560,000	$758,310	$405,000	$1,420,455	$680,220	$1,316,968	$806,021	$982,907	$1,071,399
System Renewal	$2,300,000	$2,222,700	$1,986,000	$789,397	$2,198,000	$2,298,252	$1,995,440	$1,830,486	$1,978,591	$1,404,998	$1,694,990
System Service	$200,000	$213,964	$275,775	$42,215	$225,000	$3,856	$530,000	$64,232	$253,430	$188,030	$161,452
General Plant	$480,000	$249,537	$470,000	$572,237	$425,000	$332,164	$468,250	$763,110	$558,900	$674,084	$483,706
TOTAL	$3,325,000	$3,616,044	$3,291,775	$2,162,161	$3,253,000	$4,054,728	$3,673,910	$3,974,796	$3,596,942	$3,250,020	$3,411,548

Table 22: Forecast Capital Expenditures

	Forecast Capital Expenditures						Average (2018-2022)
	2017	2018 (Test)	2019	2020	2021	2022	
CATEGORY	Plan	Plan	Plan	Plan	Plan	Plan	
System Access	$733,628	$819,500	$860,100	$752,700	$756,300	$759,900	$789,700
System Renewal	$1,733,992	$2,202,450	$2,062,230	$1,967,040	$2,228,882	$1,939,454	$2,080,011
System Service	$433,343	$90,000	$90,000	$55,000	$55,000	$55,000	$69,000
General Plant	$648,950	$131,000	$219,750	$473,500	$224,300	$526,450	$315,000
TOTAL	$3,549,913	$3,242,950	$3,232,080	$3,248,240	$3,264,482	$3,280,804	$3,253,711

5.4.4.1.2 YEAR OVER YEAR PLAN VS. ACTUAL VARIANCES

- **2012 Budget vs. Actual**

Table 23: 2012 Budget vs. Actuals

	HISTORICAL		
	2012		
CATEGORY	**BUDGET**	**ACTUAL**	**VARIANCE FROM BUDGET**
System Access	$345,000	$929,841	$584,841 (170%)
System Renewal	$2,300,000	$2,222,700	-$77,300 (-3%)
System Service	$200,000	$213,964	$13,964 (7%)
General Plant	$480,000	$249,537	-$230,463 (-48%)
TOTAL	**$3,325,000**	**$3,616,044**	**9%**

System Access spending was considerably higher than budget and is a result of increased expenditures on C&I services, Residential Services and meters; all of which indicate that the number of services connected were higher than expected. ***System Renewal*** and ***System Service*** were slightly below budget and the variance was not material. General Plant was under budget by -48% as a result of not purchasing a large vehicle which was moved to the 2013 budget. This resulted in the total 2012 spend to be within 9% of budget.

- **2013 Budget vs. Actual**

Table 24: 2013 Budget vs. Actuals

	HISTORICAL		
	2013		
CATEGORY	**BUDGET**	**ACTUAL**	**VARIANCE FROM BUDGET**
System Access	$560,000	$758,310	$198,310 (35%)
System Renewal	$1,986,000	$789,397	-$1,196,603 (-60%)
System Service	$275,775	$42,215	-$233,560 (-85%)
General Plant	$470,000	$572,237	$102,237 (22%)
TOTAL	**$3,291,775**	**$2,162,161**	**-34%**

System Access spending was higher than the budgeted amount; this is primarily the result of a large facility relocation request costing approximately $312,000 which accounts for the entire difference. ***System Renewal*** spending was considerably lower than expected which offset the overspending in System Access and ***General Plant*** which was over budget. ***System Service*** spending was lower than budgeted as a result of less spending than expected in system automation initiatives. This resulted in the total 2013 spend to be within -34% of budget.

- **2014 Budget vs. Actual**

Table 25: 2014 Budget vs. Actuals

	Historical		
	2014		
CATEGORY	**Budget**	**Actual**	**Variance from Budget**
System Access	$405,000	$1,420,455	$1,015,455 (251%)
System Renewal	$2,198,000	$2,298,252	$100,252 (5%)
System Service	$225,000	$3,856	-$221,144 (-98%)
General Plant	$425,000	$332,164	-$92,836 (-22%)
TOTAL	**$3,253,000**	**$4,054,728**	**25%**

In 2014, ***System Access*** spending was considerably higher than budget and is a result of increased expenditures on C&I services, Residential Services and meters; all of which indicate that the number of services connected were higher than expected. In addition, ETPL spent approximately $235,000 more than budgeted on municipal facility relocations. ***System Renewal*** spending was within 5% of budget with minimal adjustments made to account for overages in System Access spending; this was more likely due to reduced spending in 2013. ***System Service*** was again less than budgeted as a result of minimal spending in system automation initiatives. ***General Plant*** spending was less than budget as a result of a large vehicle not being purchased and moved to the 2015 budget. This resulted in the total 2014 spend to be within 25% of budget.

- **2015 Budget vs. Actual**

Table 26: 2015 Budget vs. Actuals

	Historical		
	2015		
CATEGORY	**Budget**	**Actual**	**Variance from Budget**
System Access	$680,220	$1,316,968	$636,748 (94%)
System Renewal	$1,995,440	$1,830,486	-$164,954 (-8%)
System Service	$530,000	$64,232	-$465,768 (-88%)
General Plant	$468,250	$763,110	$294,860 (63%)
TOTAL	**$3,673,910**	**$3,974,796**	**8%**

System Access exceeded the budgeted amount due to two factors; a large municipality facility relocation that was greater than originally expected and new services (both Residential and C&I) which were greater than expected. ***System Renewal*** spending within an acceptable range of budget and reduced slightly to help account for System Access spending. ***System Service*** spending was considerably lower than budgeted as a result of minimal spending on system automation initiatives and changes to the payment schedule with Hydro One regarding the new breaker position at the Aylmer TS. ***General Plant*** spending was higher than budget due to an increase in the purchase price of a large vehicle along with some leasehold improvement aimed at creating efficiencies within our metering department. <u>This resulted in the total 2015 spend to be within 8% of budget.</u>

- **2016 Budget vs. Actual**

Table 27: 2016 Budget vs. Actuals

	HISTORICAL		
	2016		
CATEGORY	**BUDGET**	**ACTUAL**	**VARIANCE FROM BUDGET**
System Access	$806,021	$1,060,304	$254,283 (32%)
System Renewal	$1,978,591	$1,515,632	-$462,959 (-23%)
System Service	$253,430	$188,030	- $65,400 (26%)
General Plant	$558,900	$486,053	- $72,847 (-13%)
TOTAL	**$3,596,942**	**$3,250,020**	**-10%**

System Access spending was again over budget however much closer than previous years as a result of a more realistic budget. Still, both Residential and C&I services exceeded expectations and accounted for the majority of the variance. ***System Renewal*** spending was less than planned as a result of a mid-year reduction in the targeted CAPEX spending level. This coincided with a few developer/municipally driven projects that did not move forward, along with a pole line rebuild that is affected by Hydro One plans in the area and allowed ETPL to obtain a desired spending level of approximately $3.2mil. ***System Service*** spending was slightly below budget as a result of decreased spending on System Automation. ***General Plant*** spending was higher than budget due to small increases in each of fleet, tools, and leasehold improvement expenditures.

- **2017 Budget vs. Actual**

Table 28: 2017 Budget vs. Actuals

	HISTORICAL (BRIDGE YEAR)		
	2017		
CATEGORY	**BUDGET**	**ACTUAL**	**VARIANCE FROM BUDGET**

System Access	$793,628	In progress	T.B.D
System Renewal	$1,673,992	In progress	T.B.D
System Service	$448,318	In progress	T.B.D
General Plant	$633,975	In progress	T.B.D
TOTAL	**$3,199,913**	**In progress**	**T.B.D**

5.4.4.1.1 SHIFTS IN FORECAST VS. HISTORICAL BY CATEGORY

- **System Access**

Table 29: System Access - Forecast vs. Historical

	Average (2012-2016)	Forecast Capital Expenditures						Average (2018-2022)	Variance
		2017	2018 (Test)	2019	2020	2021	2022		
		Plan	Plan	Plan	Plan	Plan	Plan		
System Access	$1,017,399	$733,628	$819,500	$860,100	$752,700	$756,300	$759,900	$789,700	-22%

Erie Thames does not anticipate a drastic change in System Access spending when compared to the average historical spending level. The planned average is 16.5% lower than historical amounts as ETPL expects improved communications with municipalities will reduce the impacts of facility relocation requests. After 2020 required upgrades to ETPL's wholesale metering equipment will be completed and will result in a slight decrease in planned spending in the category. System Access is typically very difficult to predict and adjustments to other categories can be made to help adjust and ensure total spending remains relatively constant from year to year.

- **System Renewal**

Table 30: System Renewal - Forecast vs. Historical

	Average (2012-2016)	Forecast Capital Expenditures						Average (2018-2022)	Variance
		2017	2018 (Test)	2019	2020	2021	2022		
		Plan	Plan	Plan	Plan	Plan	Plan		
System Renewal	$1,694,990	$1,733,992	$2,202,450	$2,062,230	$1,967,040	$2,228,882	$1,939,454	$2,080,011	23%

System Renewal spending will increase by approximately 19% when compared to average historical spending levels. The 2011 and 2015 ACA & AMP plans prepared by Metsco Energy Solutions and Erie

Thames respectively both recommended a higher level of expenditure on fixed distribution assets. In order to balance an increase to historical values and maintaining appropriate asset renewal levels ETPL plans to spend an average of approximately $2,000,000 yearly. This level of renewal spending is much lower than the AMP recommends however ETPL is confident that monitoring of reliability statistics and testing/inspections procedures will ensure no adverse effects will occur.

- **System Service**

Table 31: System Service - Forecast vs. Historical

	Average (2012-2016)	Forecast Capital Expenditures						Average (2018-2022)	Variance
		2017	2018 (Test)	2019	2020	2021	2022		
		Plan	Plan	Plan	Plan	Plan	Plan		
System Service	$161,452	$433,343	$90,000	$90,000	$55,000	$55,000	$55,000	$69,000	-57%

System Service spending has been reduced a great deal compared to historical values as a result of a number of larger system automation projects (SCADA, OMS, automated switches) being completed. In addition ETPL does not expect any substantial spending will be required to increase capacity within our distribution system. Moving forward ETPL intends to implement small scale system automation initiatives such as fault indicators.

- **General Plant**

Table 32: General Plant - Forecast vs. Historical

	Average (2012-2016)	Forecast Capital Expenditures						Average (2018-2022)	Variance
		2017	2018 (Test)	2019	2020	2021	2022		
		Plan	Plan	Plan	Plan	Plan	Plan		
General Plant	$633,975	$648,950	$131,000	$219,750	$473,500	$224,300	$526,450	$315,000	-50%

ETPL is forecasting reduced spending within the General Plant category. Since the merger with West Perth Power and Clinton Power, ETPL has made significant investments to bring our fleet to an optimal level and will be able to scale back spending while still maintaining a capable fleet. No substantial spending is anticipated within Tools & Equipment, Leasehold Improvements, and IT.

- **Total Spend**

Table 33: Total Spend - Forecast vs. Historical

	Average (2012-2016)	Forecast Capital Expenditures						Average (2018-2022)	Variance
		2017	2018 (Test)	2019	2020	2021	2022		
		Plan	Plan	Plan	Plan	Plan	Plan		
Total	$3,411,548	$3,549,913	$3,242,950	$3,232,080	$3,248,240	$3,264,482	$3,280,804	$3,253,711	-5%

The total CAPEX spend is anticipated to be approximately 5% lower than the historical average. In order to increase System Renewal spending to an acceptable level, System Service and General Plant spending has been reduced primarily through reductions in system automation and fleet expenditures. To minimize fluctuations to the overall spend from year to year ETPL has adjusted System Renewal spending when larger System Service/General Plant expenditures are expected. This is illustrated in Figure 56 and detailed in Table 30 below:

Figure 55: Spending Level by Category

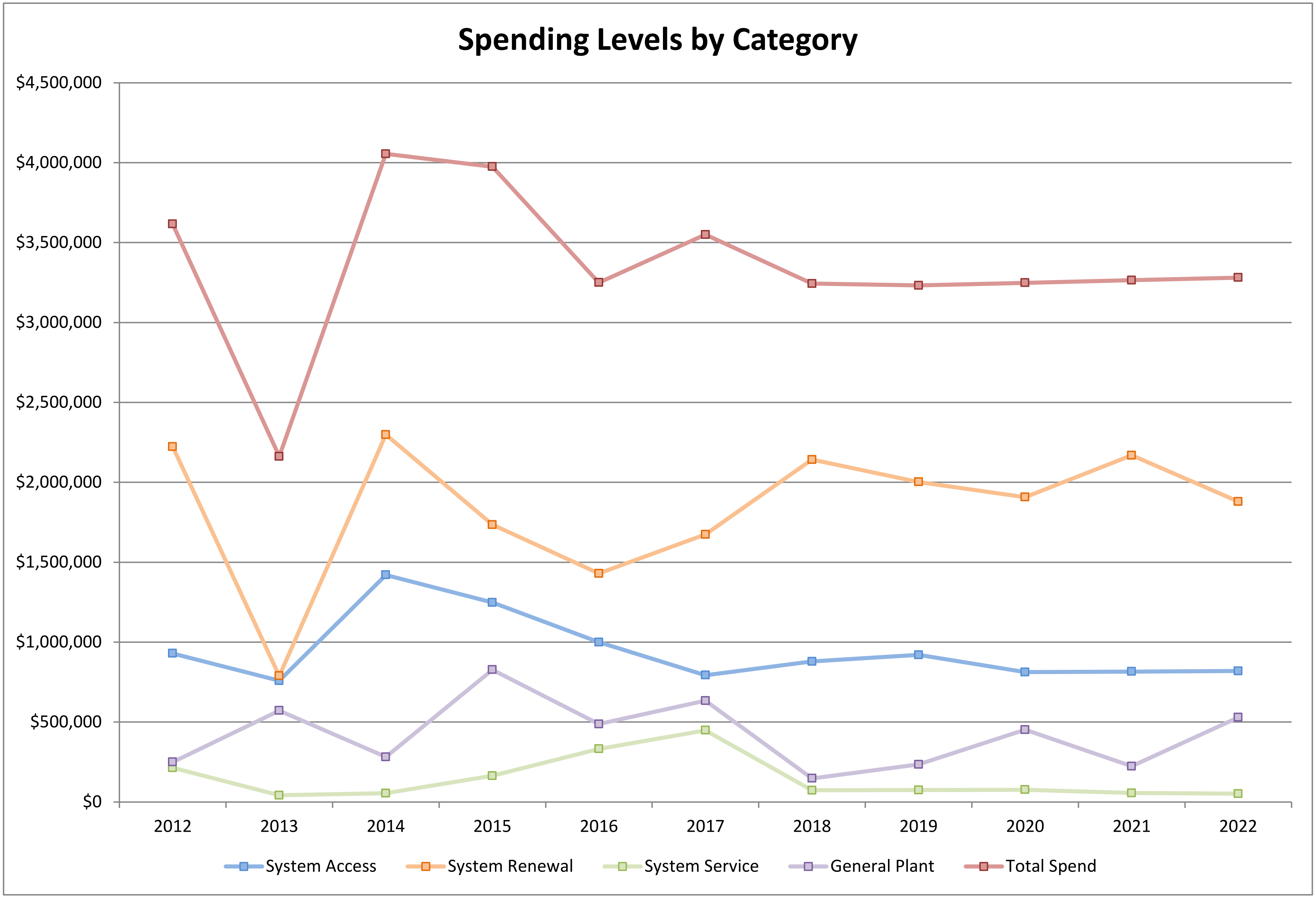


Table 34: Spending Levels by Category Detail

OEB Category	Description	2017	2018	2019	2020	2021	2022
System Access	Residential Connections	$231,000	$231,000	$231,000	$231,000	$231,000	$231,000
	C&I Connections	$204,000	$204,000	$204,000	$204,000	$204,000	$204,000
	Meter Stock/Management	$248,628	$234,500	$275,100	$167,700	$171,300	$174,900
	Facility Relocations	$50,000	$150,000	$150,000	$150,000	$150,000	$150,000
	TOTAL	$733,628	$819,500	$860,100	$752,700	$756,300	$759,900
System Renewal	Fixed Distribution Asset Replacement	$1,598,992	$2,074,450	$1,915,730	$1,839,040	$2,100,881	$1,811,454
	Substation Upgrades	$15,000	$8,000	$26,500	$8,000	$8,000	$8,000
	Maps & Records	$120,000	$120,000	$120,000	$120,000	$120,000	$120,000
	TOTAL	$1,733,992	$2,202,450	$2,062,230	$1,967,040	$2,228,882	$1,939,454
System Service	System Automation	$50,000	$90,000	$90,000	$55,000	$55,000	$55,000
	Aylmer TS Breaker Payment	$383,343	$0	$0	$0	$0	$0
	TOTAL	$433,343	$90,000	$90,000	$55,000	$55,000	$55,000
General Plant	IT Hardware/Software	$79,950	$56,000	$59,750	$98,500	$56,800	$48,950
	Leasehold Improvements	$49,000	$35,000	$35,000	$80,000	$42,500	$42,500
	Tools & Equipment	$35,000	$20,000	$35,000	$20,000	$35,000	$35,000
	Fleet Sustainment	$135,000	$20,000	$90,000	$275,000	$90,000	$400,000
	Buildings & Fixtures	$350,000	$0	$0	$0	$0	$0
	TOTAL	$648,950	$131,000	$219,750	$473,500	$224,300	$526,450
	TOTAL CAPITAL SPEND	**$3,549,913**	**$3,242,950**	**$3,232,080**	**$3,248,240**	**$3,264,482**	**$3,280,804**

5.4.5 Justifying Capital Expenditures

- ***As indicated in Chapter 1, the onus is on the 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***

Refer to Section 5.4.4 above for comparative expenditures by category over the historical years.

- ***The forecast impact of system investment on system O&M costs, including on the direction and timing of expected impacts.***

ETPL expects that a number of capital investments over the forecast period will result in increased efficiency operating and maintaining the distribution system. In general, it is expected that proactively replacing end of life assets before they fail will reduce unplanned and emergency work, thereby reducing some of the O&M costs. However, at the same time, ETPL is putting more resources into analyzing, planning, and reviewing asset performance (through data collection, GIS, AMP updates, etc.) which tends to increase O&M costs. The financial impacts of these efficiencies and additional activities are difficult to isolate and quantify however the following investments are anticipated to reduce system O&M costs moving forward.

- **Voltage Conversion Initiatives**

A large driver of ETPL capital projects is the conversion of existing 4kV and 8kV systems to the preferred 28kV. Voltage conversion projects are primarily completed in conjunction with system renewal type projects targeted to areas with end of life assets and increased risk associated to them. Voltage conversion provides a number of benefits related to O&M costs moving forward, including the reduction of ETPL owned and operated substations and the reduction of line losses.

- **Fault Indicators Installation**

Fault indicators have and will continue to be installed within the distribution system in strategic locations to aid in troubleshooting system faults reducing the number of truck rolls, and the time required to patrol lines and restore customers.

- **Automated Switch Installation**

ETPL plans to install automated switches in strategic locations throughout its distribution system having the ability to be remotely controlled through SCADA and able to automatically sectionalize and restore load depending on system conditions. This will also aid in troubleshooting system faults reducing truck rolls and the time required to complete switching.

- **Transition to Electronic Formats**

Within the forecast period ETPL plans to transition the majority of its operations to an electronic format using tablets, laptops, smart phones etc. to modify and view data in the field. This will include items such as inspection forms, job packages, and operational maps linked to the OMS system. This is geared towards the elimination of multiple points of entry from the field to the system of record. In addition, the implementation of the OMS system tied to smart meter data will provide both inside and outside staff with valuable information regarding the state of the distribution system reducing restoration efforts.

- **Removal of Legacy Issues through Improved Standards**

Through the continual improvement in construction standards, legacy issues that result in high O&M costs will be slowly removed as the distribution system is re-built through end of life renewal. Some of these improvements include:

- Direct buried primary replaced with TRXLPE primary in duct.
- Removal of "pole-trans" which typically carry a high risk of failure and safety concerns.
- Removal of backyard infrastructure that is difficult & costly to operate and maintain.
- Replacement of legacy assets constructed to current standards will improve the overall operational efficiency of the system through proper clearances, improved equipment, animal guarding etc.

- ***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 distributors asset-related performance and performance targets relevant for each category, referencing information provided in section 5.2.3)***

- **System Access**

System access expenditures are primarily driven by mandated service obligations related to customer service requests, facility relocations and metering requirements detailed below.

- *Customer Service Requests* which vary in number, frequency and scope are typically customer dependent and out of the control of the utility. The capital investments planned as a result of these requests are budgeted based on historical values and adjusted if any known developments exist.
- *Maintaining Compliance with Mandated Service Obligations* compels the utility to account for spending in metering and facility relocation requirements. Metering related spending are budgeted based on historical levels combined with reverification schedules. System modifications such as facility relocations for municipal road widening are also included in the system access category; spending levels as a result of these requests are developed through consultation with local municipal partners and historical experience; despite best efforts these investments are difficult to properly plan for as they are largely dependent on municipal budgets, grants and other external factors.

ETPL has experienced a steady increase in spending as a result of customer service requests from 2013 to 2015 and expects this trend to continue however at a slower rate over the forecast period.

Spending on metering obligations is expected to remain relatively constant over the forecast period however changes to regulations may impose unforeseen changes.

Municipal facility relocations historically have been inconsistent and uneven; however the average spending over the historical period is not expected to drastically change through the forecast period.

- **System Renewal**

On a high level, system renewal spending levels are prescribed by the asset management plan. These expenditures look to replace aging infrastructure prior to a decline in system reliability, power quality and safety and prior to an increase in operating and maintenance costs that are associated with end of life assets. On a more granular level, specific capital projects are identified by ETPL engineering and operations staff and evaluated using an optimization process that is used to select, prioritize and pace the mix of projects. Both high level spending levels and specific system renewal projects are driven by the following factors.

- *Maintaining Public and Employee Safety* drive projects which look to replace/refurbish assets at the end of their useful service life due to condition, performance and risk of failure ensuring that both public and employee safety are prioritized by reducing failure risks and ensuring that systems are built to current industry standards. The DS Plan uses inputs from various testing and maintenance programs to inform decisions related to system renewal type projects. The DS Plan prioritizes safety related projects above all other drivers when selecting and prioritizing capital investments and capital projects are most often driven by safety related concerns.

- *Maintaining/Improving Reliability (Performance Evaluation)* ensure projects are selected, prioritized and paced through the AM and DS Plans ensuring that assets are replaced prior to failures that would result in poor reliability to customers. ETPL uses typical performance evaluation such as SAIDI, SAIFI and worst performing feeder analysis. This permits capital spending to be targeted to specific areas and allows ETPL to evaluate the effectiveness of investment levels by monitoring reliability trends.

- *Cost Effective Service aimed at Reducing Financial Impacts to Customers* does not typically drive system renewal projects however the pace of system renewal spending is an important factor. The AMP looks to forecast the level of asset replacement required to maintain the condition of the distribution system and recommends a smoothed spending level. This approach ensures that capital spending is paced effectively, reducing financial impacts to customers by mitigating drastic changes and maintaining a reasonable spending level.

- *Responding to Customer Feedback* is taken into consideration for all spending categories. Through a number of customer engagement activities, described in Section 5.4.1f) and detailed in customer survey results included as Appendices A & B, ETPL has determined that the majority of customers prioritize cost and reliability as primary concerns. The DS Plan takes this feedback into consideration when determining appropriate spending levels and selecting projects.

The spending levels forecast for the next five (5) years are expected to remain relatively flat and in line with the average spending levels over the historical period. The pace of system renewal projects will be monitored using customer feedback, reliability metrics and inspection programs; no changes from the projected levels are expected as a result.

- **System Service**

System service type projects comprise a very small portion of the capital expenditures in any given year and are primarily related to system automation. Like all other capital expenditures, projects in this category are evaluated using ETPL's optimization process and selected to achieve strategic objectives. System service projects are primarily driven by a need to maintain reliability and decrease O&M costs moving forward.

- *Maintaining/Improving Reliability (Performance Evaluation)* is the primary driver for system service type investments which are focused on improving customer reliability through the implementation of various technologies such as automated switches, SCADA and OMS solutions.

Spending on system service projects is expected to remain relatively flat with a slight decrease resulting in the previous implementation of a GIS, SCADA and OMS system.

General Plant

General plant expenditures include fleet replacements, tools & equipment, IT requirements, and leasehold improvements. Fleet replacements are typically the largest component of general plant spending and are justified through the Fleet Plan included in Appendix M. Tools and equipment and leasehold improvements are typically smaller non-material investments and are based on historical values. IT requirements are evaluated on a yearly basis with the majority of spending a relatively consistent value based on end of life replacement of hardware. In any given year general plant budgets are adjusted if any large atypical expense is known.

- *Maintaining Public and Employee Safety* is the main driver of general plant investments focusing on employee safety ensuring that the proper tools and equipment are available to safely construct, operate and maintain the distribution system. This includes fleet replacements, miscellaneous tools and equipment.
- *Cost Effective Service aimed at Reducing Financial Impacts to Customers* drive a need to maintain fleet, tools and equipment in line with best industry practices which can provide small gains in efficiencies.

- ***Information related to the distributor's system capability assessment***

As detailed in the REG Plan included as Appendix N there are a number of system constraints that limit REG connections in certain service territories for ETPL customers. The majority of these constraints are limited to upstream transmission capacity from Hydro One owned stations. The following service territories are constrained as a result of Hydro One station capacity limits:

- Belmont

ETPL has also exceeded 7% of the peak loading requirement for microFIT connections in Clinton on the F2 feeder from the Constance DS. This will result in ETPL not being able to connect microFIT generation to the feeder moving forward. Due to the nature of this constraint ETPL does not expect any capital expenditure into the system as a result.

5.4.5.2) MATERIAL INVESTMENTS

- ***The focus of this section is on Projects/Activities that meet the materiality threshold. 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***
  - ***B. Evaluation criteria and information required for each project/activity***
  - ***C. Category-specific requirements for each project/activity***

Project Assessment forms have been included in Appendix O.

APPENDIX A - 2014 CUSTOMER SURVEY RESULTS AND RECOMMENDATIONS

It is understood that a very small group of our customers have responded to this survey, and therefore although the information provide is valuable we need to determine the merit of the comments provided by the customers, before expending time and funds on each.

Findings

897 customers or 5% of our customers completed our survey, 825 being residential customers, 9 are commercial customers, and 28 have residential and commercial accounts with Erie Thames Powerlines. Reliability and pricing remains the major concerns of our surveyed customers, with 62% of saying that the total hydro bill is the most important aspect of their electricity supply, and 30% say that reliability is the most important.

Customers were informed that our primary focus of construction and maintenance work is to maintain or improve reliability of the supply of electricity to them, 77% felt that our existing level of reliability is acceptable, where 18% stated that would be will to tolerate an increase in outages if it meant a decrease in their monthly hydro bill. Our customers also did not support the idea if implementing a program to start burying hydro lines if it required an increase in their bills.

In regards to web-based outage map system that would be available to our customers, 50% of respondents felt ETPL should focus on decreasing the frequency and length of outages rather than developing a web-based outage map, and 45% felt that Erie Thames Powerlines should not invest in a web-based outage map. Our customers also felt very strongly that although they feel ETPL should be active on social media they would not support the increased cost of manning the service 24 hours per day, 7 days a week.

With regards to notification of planned outages, 88% of those surveyed felt ETPL already made all necessary efforts to inform them in advance of the outage.

Conservation appears to still be the main concept with our customers to reduce usage. 31% of the customers surveyed are considering the purchase of storage systems, Solar or wind generation in the next 5 years to reduce consumption from the grid, and 89% stated they are no considering the purchase of an electric vehicle in that same time frame.

Recommendation

Although some of our customers have a reasonable understanding of the services available to them on our website we need have a educational blitz to our customers of what is available on our website for their use and electronic delivery of bills. The survey shows us that 75% of customers surveyed are not aware that our website provides the following information:

- Energy saving tips and advise
- Time-of-use rates,
- Electric usage of their account
- Ability to order meter reading for the purpose of moving into and out of a property
- Availability of Smart Meter data

Our survey shows that 79% of customers will switch to electronic billing, if we offer them a small monthly discount. We need to calculate the savings to us and then what we could offer to the customers, and again blitz the customers with this info.

On average approximately 1/3 of the customer's surveyed plan on purchasing a major high usage appliance (refrigerators, freezers, dehumidifiers, and hot tubs) within the next 5 years. From a CDM view is there a program that we could promote that encourage our customers the purpose efficient appliances.

We had many customers comment that they would like to have contact and communication with us via email. Another blitz of our customers to obtain email addresses would be beneficial.

Results

Erie Thames Powerlines understands that a reliable supply of electricity is important to our customers, and that the primary focus of our construction and maintenance work is maintaining or improving the reliability of our system. However, we recognize that customers are also concerned about rising electricity prices. With that in mind, please select one of the following statements that best represents your view.

Answer Options	Response Percent	Response Count
Erie Thames Powerlines should be spending more to decrease the frequency and duration of outages and I understand that this will increase my monthly hydro bill.	4.5%	40
I find the existing level of reliability to be acceptable.	77.1%	682
Erie Thames Powerlines should be spending less and I would be willing to tolerate increased outages if it meant a decrease in my monthly hydro bill.	18.4%	163
answered question		885
skipped question		12

Outages happen and when they do, it is important for our customers to know when the power is coming back on. Today, the only way to find this out is to call our office, or view our website for general information. Some utilities have developed interactive websites that showcase outage areas and expected restoration times. For Erie Thames Powerlines to develop a similar website, it would require an increase to monthly hydro bills. With this in mind, please select one of the following statements that best represents your view.		
Answer Options	Response Percent	Response Percent
Erie Thames Powerlines should invest in a web-based outage map and increase my monthly hydro bill to have this application available.	4.6%	40
Erie Thames Powerlines should not invest in a web-based outage map.	45.4%	397
Erie Thames Powerlines should focus on system improvements that decrease the frequency and duration of outages rather than develop a web-	50.1%	438

based outage map.		
answered question		875
skipped question		22

When maintenance work is planned causing your electricity to be off for a period of time, we attempt to contact all affected customers in the following manner: newspaper ads, notices delivered by hand or Canada post, social media, notices on our website, and automated telephone messaging. With that in mind, please select one of the following statements that best represents your view.		
Answer Options	Response Percent	Response Count
I feel that Erie Thames Powerlines already makes all necessary efforts to inform me of planned power outages.	88.0%	748
I feel that Erie Thames Powerlines should also attempt to contact the affected customers by	12.0%	102
(please suggest alternatives):		116
answered question		850
skipped question		47

Converting existing overhead power lines to underground is expensive (between 4 to 10 times the cost). Aside from an improved appearance, burying hydro lines will decrease the number of outages. However,when an outage does occur, it takes longer to repair. Erie Thames Powerlines currently does some overhead to underground conversions if it is financially and physically feasible. With that in mind, please select one of the following statements that best represents your view.		
Answer Options	Response Percent	Response Count

Erie Thames Powerlines should begin a new program to start burying lines in residential areas and I would consider an increase in my monthly hydro bill to be reasonable to begin this type of program.	8.9%	77
Erie Thames Powerlines should begin a new program to start burying lines in major streets and I would consider an increase in my monthly hydro bill to be reasonable to begin this type of program.	8.8%	76
I would not support a program to start burying hydro lines if it means an increase in my monthly hydro bill.	82.3%	709
answered question		862
skipped question		35

Erie Thames Powerlines recognizes that customers are trying to reduce or eliminate their electricity consumption and so with that in mind, please select ALL of the following items that best represent your planned purchases during the next 5 years.		
Answer Options	Response Percent	Response Count
Solar panels for generation	18.3%	125
Storage systems for cost avoidance	8.5%	58
Wind turbine	4.5%	31
Conservation activity	89.0%	607
Other (please specify)		83
answered question		682
skipped question		215

In today's ever changing market, it is important for utilities to understand our customers' future usage plans. With that in mind, please select ALL of the

following items that best represents your planned purchases during the next 5 years.		
Answer Options	Response Percent	Response Count
Pool	12.0%	33
Hot tub	38.0%	105
Additional refrigerator and/or freezer	40.6%	112
Additional dehumidifier	35.1%	97
Other (please specify)		180
answered question		276
skipped question		621

The charging of electric vehicles could add additional strain to the distribution system. Erie Thames Powerlines would like to know if our customers already have or are considering purchasing an electric vehicle (fully electric). Please select a statement that best represents you.		
Answer Options	Response Percent	Response Count
I currently own an electric vehicle.	0.1%	1
I plan to purchase an electric vehicle in the next five years.	1.3%	11
I would purchase an electric vehicle within the next five years if the purchase price difference (between the gas and electric models) decreased to less than $3,000.	9.7%	83
I do not plan to purchase an electric vehicle within the next five years.	89.0%	765
answered question		860
skipped question		37

Erie Thames Powerlines currently uses social media (Facebook and Twitter) to connect with our customers, providing them information about outages, electricity pricing, and conservation tips. To increase our effectiveness with social media would require additional resources, especially for addressing outages outside of normal business hours. Although we do attempt to communicate during large scale after hours outages, we are not regularly posting during non-working hours. With this in mind, please select the following statement that best represent your view.		
Answer Options	Response Percent	Response Count
Erie Thames Powerlines should be active in social media, however it should not increase costs and rates to be active during non-working hours.	92.5%	781
Erie Thames Powerlines should be active in social media 24 hours a day, 7 days a week. I would accept an incremental increase in my monthly hydro bill to have this available to me.	7.5%	63
answered question		844
skipped question		53

Do you receive your Erie Thames Powerlines bill electronically?		
Answer Options	Response Percent	Response Count
Yes	35.0%	302
No	65.0%	562
answered question		864
skipped question		33

Have you accessed your Smart Meter data on line?		
Answer Options	Response Percent	Response Count

No, I was not aware of this option.	49.8%	152
No, I was aware of this option but have not used it.	13.4%	41
Yes, but I did not find it useful.	15.4%	47
Yes, and it has helped me manage my electricity usage.	21.3%	65
answered question		305
skipped question		592

Would you switch to electronic billing if you were provided a small discount to do so?		
Answer Options	Response Percent	Response Count
Yes	79.4%	446
No	20.6%	116
answered question		562
skipped question		335

Erie Thames Powerlines is always trying to improve our online service to our customers. With that in mind, please select ALL of the following statements that best represent your view.		
Answer Options	Response Percent	Response Count
I would use the Erie Thames Powerlines website in order to notify the utility that I was moving into/or out of the service territory.	68.6%	554
I would use the Erie Thames Powerlines website in order to access information about my electricity usage.	83.3%	672
I would use the Erie Thames Powerlines website in order to access information about Time-of-Use rates.	75.0%	605
I would use the Erie Thames Powerlines site in order to access energy saving tips and advice.	73.0%	589
answered question		807
skipped question		90

Please select one of the following:		
Answer Options	Response Percent	Response Count
I am a residential customer	95.7%	825
I am a commercial customer	1.0%	9
I am both a residential and commercial customer	3.2%	28
answered question		862
skipped question		35

What is the most important aspect of your electricity supply? (Select one).		
Answer Options	Response	Response

	Percent	Count
Total price.	61.6%	532
Reliability.	30.5%	263
Customer service.	3.1%	27
Conservation programs.	4.8%	41
answered question		863
skipped question		34

APPENDIX B - 2016 CUSTOMER SURVEY RESULTS AND RECOMMENDATIONS

Although many of the findings and recommendations could be of value we also need to recognise that this information comes from a very small sampling of our customers, and therefore must determine the merit of suggestions provided by customer, before expending a large amount of time and funds on each.

Findings

We had 1136 customers take the survey in 2016 as compared to 897 in our last Customer Survey.
We found that the amount of responses jumped substantially when we contacted the customers via email. We did not use email for the previous survey.

This survey was used as both an education tool, providing customers with average $ that remain with ETPL, as well as what part of the provincial electrical system that ETPL actually has control over, and a data collection tool, to measure satisfaction, concern, and knowledge.

As with our previous survey, on a whole it tells us that most of our customers are quite happy with the service that is provided to them by ETPL, and their focus still remains on low costs and reliability.

When asking our customer what we could do to improve our service to them, 680 customers replied, they identified the following areas:

- 52% lower costs
- 18% Billing/Collections, Call Centre
- 16% outages
- 6% operations issues
- 4% water, sewer or streetlight issues
- 3% Website
- 2% Conservation

We explained how we currently contact customers regarding planned outages and asked for their preferred form on communication in this situation. An overwhelming 69% of the 173 customers that responded asked to be contacted by **email**. The remainder feel that our current forms are sufficient.

Recommendations

The survey does show us a few areas where we could improve. Firstly we could attempt to educate our customers on our roll in the provincial electrical system, and what specifically we are in control of, ie the distribution systems within the municipalities that we serve, but not transmission, generation or rates and other charges.

This survey shows that our customer want to see an improvement in reliability of service, fewer number of outages, less voltage fluctuations, and increase speed of restoring power, when outages occur. I feel these results would improve once Hydro One is able to correct transmission issue to some of our areas. If possible we should also educate the customers on what it takes to find the outage and then move the repairing and restoring the power.

We were able to inform customers that only 16% of what they pay each month for electricity actually stays with ETPL, and the remainder of their bill moves on to other bodies, and therefore they are costs ETPL cannot control.

Another area that ETPL needs to attempt to improve and/or educate customers is with our billing. We only scored an average of 63% on accuracy, payment options, understandability, timely delivery of bills, and communication. Once again education of the customer to understand that we are mandated to provide line items as they appear, and timing of when bills can actually be produced would help alleviate some of their concerns. Other questions we need to ask are:

- Can we improve on our billing accuracy
- Is there any other payment options we can offer
- Can the new bill format be improved on
- How can we deliver bills quicker to the customer
- How can we improve communication with our customers

We may find that we are providing the best service, however a review of the above items would only benefit the customers and ETPL.

I feel that there are several actions that can be taken to improve on many of these issues:

Customer education:

- Water/Sewer and streetlights are not owned, operated or repaired by ETPL. We must make it clear that we do bill for these services and will take repair calls, however we ultimately have no control over the rates charged for these services or when and how they are repaired.

- We need to not only put our website to more use, via notifying customers and providing information on the site but possibly testing all links, as we did have a few comments regarding the ability to move about on the site and finding the information customers are looking for.
- In areas where our customers seem to suffer more frequent and prolonged outages due to our supply from Hydro One, just ensure that customers understand where the issues lies, as well as possibly the difficulties in finding the problem in such areas.
- Blitz the customers for email address' and updated contact information, so that we can then begin sending out educational info regarding, payment options, billing and collections process' and why we need to have the billing schedule we do, as well as providing customers with outage info.
- Conservation topics – via, bill stuffers, emails, social media.
- Payment options – blitz the customers with the payment options and plans available
- Ecare ability, what the customers can see, benefits of information provided on site
- Online billing and other services provided

Internal checks and processes

- Website – we did have a few comments about our website not being user friendly, or not working on all platforms. Customers are also looking more up to date info.
- Do we contact customers when their water usage spikes? Does our VEE process need to be updated
- Late payment calls, do we call customers that have never been late before, and do we call 2-4 days after due date.
- What is our billing accuracy rates. Are they within a tolerable rate, what is cause of billing adjustments.
- Can we or have we compared our bill format to other utilities, is there anything we can do to improve our bill format so that our customers can understand it easily.
- Should a schedule be set up for sending out communications to customers, billing, CDM ….
- It would appear that customers are looking for more frequent updates when there are outages. I would suggest we start posting more regularly to social media during outages, as well as, if possible, using email for planned outages and stating that customers should watch our social media feeds for current updates during time of outage.

- Do we need to continue to use the costly newspaper ads to inform customers of planned outages
- Ensure non-customers (ie apartment bldgs.) are notified of outages, hand delivered notification may be the most effective.

As stated previously these actions would be responding to all comments received from our customers and may not necessarily improve our services that we provide.

Results

1. As you may know, electricity from generating stations located around the province travels over transmissions lines on those large transmissions towers. However, what we want to talk about today is the electricity distribution system in your community that is operated by Erie Thames Powerlines. Their system consists of hydro poles and wires, underground cables, transformer boxes on lawns, substations and smart meters. How familiar are you with Erie Thames Powerlines, which operates the electricity distribution system in your community?		
Answer Options	Response Percent	Response Count
Very familiar	19.2%	218
Somewhat familiar	49.2%	559
Not very familiar	22.9%	260
Not familiar at all	7.0%	79
Don't know	1.2%	14
N/A	0.5%	6
answered question		1136
skipped question		0

2. Overall, how satisfied are you with the service you receive from Erie Thames Powerlines?		
Answer Options	Response Percent	Response Count

100%	51.1%	580
75%	38.1%	433
50%	7.2%	82
25%	2.6%	29
0%	1.1%	12
answered question		1136
skipped question		0

3. Is there anything in particular Erie Thames Powerlines can do to improve their service to you?	
Answer Options	Response Count
	680
answered question	680
skipped question	456

4. For each of the following statements, please select your level of satisfaction.									
Answer Options	Very satisfied	Somewhat satisfied	Neither satisfied nor dissatisfied	Somewhat dissatisfied	Very dissatisfied	Don't know	N/A	Rating Average	Response Count
Providing reliable electricity service, with a minimal number of power outages.	747	276	47	31	15	0	6	5.53	1122
Delivering	762	268	51	23	11	1	6	5.56	1122

good power quality that is free from voltage fluctuations, such as flickering lights.									
Speed to which electrical service is restored when power outages occur.	579	378	83	37	17	15	14	5.28	1123
answered question									1124
skipped question									12

5. The average residential customer pays about $200 a month for electricity of which $32 or approximately 16% goes to Erie Thames Powerlines. The remainder of the electricity portion of your bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies. Before this survey, how familiar were you with the amount of your electricity bill that went to Erie Thames Powerlines?		
Answer Options	Response Percent	Response Count
Very familiar	7.7%	87

Somewhat familiar	17.1%	192
Not very familiar	27.8%	312
Not familiar at all	45.7%	513
Don't know	1.1%	12
N/A	0.6%	7
answered question		1123
skipped question		13

6. For each of the following statements, please tell us your level of satisfaction.

Answer Options	Very satisfied	Somewhat satisfied	Neither satisfied or dissatisfied	Somewhat dissatisfied	Very dissatisfied	Don't know	N/A	Rating Average	Response Count
Providing accurate bills	701	284	70	25	11	17	7	5.43	1115
Providing convenient options to pay my bills	771	221	68	26	20	0	8	5.53	1114
Providing bills that are easy to understand	633	341	67	50	19	0	4	5.37	1114
Providing timely delivery	736	255	65	29	19	1	9	5.50	1114

of bills in advance of their due date	
answered question	1116
skipped question	20

7. Have you ever contacted Erie Thames Powerlines?		
Answer Options	Response Percent	Response Count
Yes	73.3%	818
No	23.1%	258
Don't know	3.0%	34
N/A	0.5%	6
answered question		1116
skipped question		20

8. How many times have you contacted Erie Thames Powerlines in the past 12 months?		
Answer Options	Response Percent	Response Count
Zero	20.9%	171
Once	39.0%	319
2-3 times	28.4%	232
4-5 times	3.9%	32
More than 5 times	4.7%	38
Don't know	3.1%	25
N/A	0.0%	0
answered question		817
skipped question		319

9. Overall, how satisfied are you with the customer service provided by Erie Thames Powerlines?		
Answer Options	Response Percent	Response Count
Very satisfied	64.8%	528
Somewhat satisfied	22.3%	182
Neither satisfied nor dissatisfied	5.9%	48
Somewhat dissatisfied	3.7%	30
Very dissatisfied	2.2%	18
Don't know	1.1%	9
answered question		815
skipped question		321

10. Overall, how well do the communications you receive from Erie Thames Powerlines keep you informed on issues related to your electrical service?		
Answer Options	Response Percent	Response Count
Very well	42.3%	468
Somewhat well	39.2%	433
Not very well	5.6%	62
Not well at all	3.3%	37
Don't know	5.9%	65
N/A	3.7%	41
answered question		1106
skipped question		30

11. Erie Thames Powerlines understands that a reliable supply of electricity is important to our customers, and that the primary focus of our construction and maintenance work is maintaining or improving the reliability of our system. However, we recognize that customers are also concerned about rising electricity

prices. With that in mind, please select one of the following statements that best represents your view.		
Answer Options	Response Percent	Response Count
Erie Thames Powerlines should be spending more to decrease the frequency and duration of outages and I understand that this will increase my monthly hydro bill.	4.9%	54
I find the existing level of reliability to be acceptable.	85.6%	947
Erie Thames Powerlines should be spending less and I would be willing to tolerate increased outages if it meant a decrease in my monthly hydro bill.	9.5%	105
answered question		1106
skipped question		30

12. When maintenance work is planned causing your electricity to be off for a period of time, we attempt to contact all affected customers in the following manner: newspaper ads, notices delivered by hand or Canada Post, social media, notices on our website, and automated telephone messaging. With that in mind, please select one of the following statements that best represents your view.		
Answer Options	Response Percent	Response Count
I feel that Erie Thames Powerlines already makes all necessary efforts to inform me of planned power outages.	85.1%	941
I feel that Erie Thames Powerlines should also attempt to contact the affected customers by (please suggest alternatives below):	14.9%	165

Suggestions	173
answered question	1106
skipped question	30

13. What is the most important aspect of your electricity supply?		
Answer Options	Response Percent	Response Count
Total price	49.7%	550
Reliability	44.5%	492
Customer service	2.7%	30
Conservation programs	3.1%	34
answered question		1106
skipped question		30

APPENDIX C - CUSTOMER INFORMATION NIGHT PRESENTATION

ERIE THAMES POWERLINES

ERIE THAMES POWERLINES
Distribution System Plan

Customer Presentation
March 29, 2017

ERIE THAMES POWERLINES

About ETPL

About Erie Thames

Erie Thames Powerlines Corporation

Your Home Town Utility - A Regulated Electricity Distributor serving 18,500 customers in 14 communities across 4 Counties.

- 352 kms of Distribution Line
- Summer Peak Load -94MW

Total ETPL Employees: 47

About Erie Thames

Erie Thames Powerlines Shareholders

100% Municipally owned by:

- Town of Aylmer
- Municipality of Central Elgin
- Township of East Zorra-Tavistock
- Town of Ingersoll
- Town of Norwich
- Township of Southwest Oxford
- Municipality of West Perth
- Township of Zorra

About Erie Thames

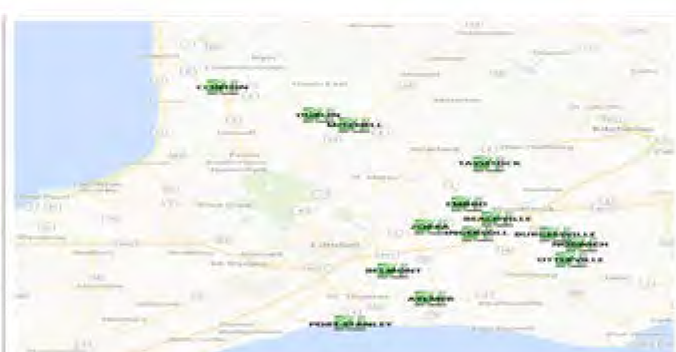
ERIE THAMES POWERLINES

MITCHELL
Service Center
50 Arthur Street

INGERSOLL
Head Office
143 Bell Street

AYLMER
Service Center
280 Elm Street

Community Maps



Introductions

Presenters

- Scott Brooks, Director of Operations and Risk
- Chuck deJong, Director of Engineering and Innovation
- Josh Smith, Electrical Distribution and Planning Engineer
- Graig Pettit, Director – Director of Regulatory, Finance & Customer Relations

Electricity Bill Snapshot

ERIE THAMES POWERLINES

Electricity Bill Snapshot

ETPL - Typical Residential Bill Mock-up for 800 kWh Customer

Billing Summary	
Previous Balance	xx
Payment Received on XXXXXXXX	xx
Balance Forward	xx

Your Electricity Charges			
On Peak TOU - Summer	200 kWh x	$ 0.180000	$ 36.00
Off Peak TOU - Summer	400 kWh x	$ 0.087000	$ 34.80
Mid Peak TOU - Summer	200 kWh x	$ 0.132000	$ 26.40
Delivery			$ 46.42
Regulatory Charges			$ 5.94
H.S.T.			$ 19.44
Current Charges			$ 169.00

ERIE THAMES POWERLINES

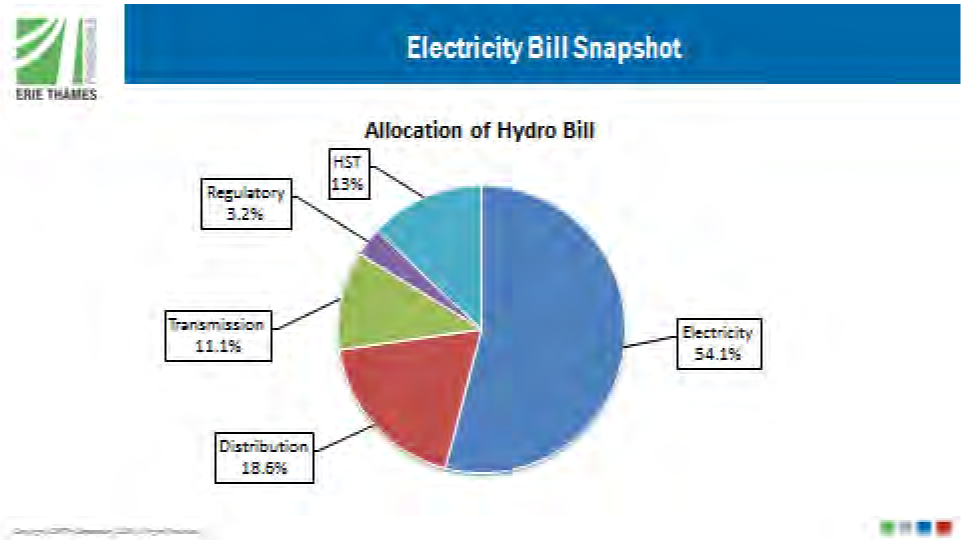
Electricity Bill Snapshot

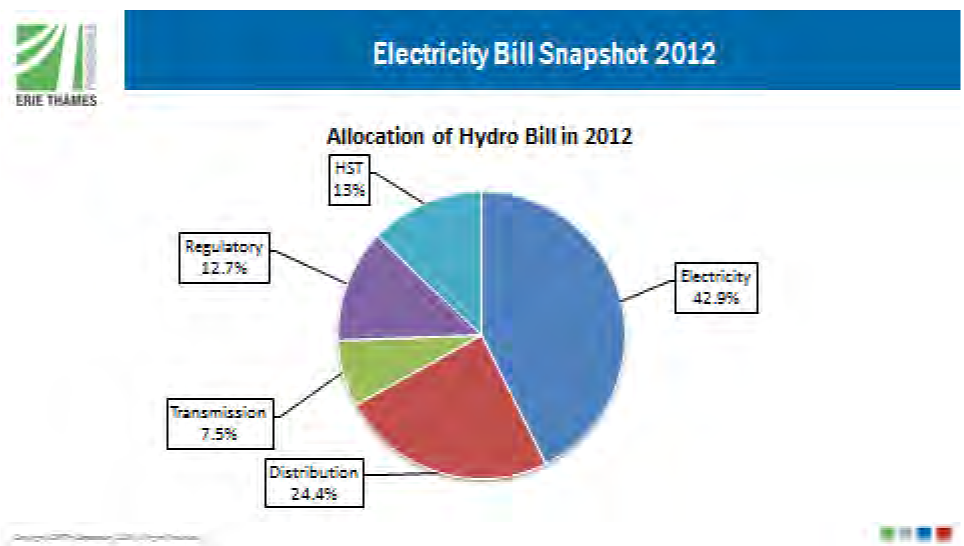
- Electricity Charges is the cost of the commodity that Erie Thames pays on behalf of its customers a month after the energy is consumed.
- Delivery costs are the costs to transfer electricity from the generator to our customers homes,
- Distribution costs are the only amounts that Erie Thames keeps in order to run its entire operation and amounts to $30.84 (18.6% of the total bill) a month on an average bill.
- It is these costs that we wish to focus on to get your feedback on how you would like to see us spend your money.

ERIE THAMES POWERLINES

Electricity Bill Snapshot

- Electricity Charges is the cost of the commodity that Erie Thames pays on behalf of its customers a month after the energy is consumed.
- Delivery costs are the costs to transfer electricity from the generator to our customers homes,
- Distribution costs are the only amounts that Erie Thames keeps in order to run its entire operation and amounts to $30.84 (18.6% of the total bill) a month on an average bill.
- It is these costs that we wish to focus on to get your feedback on how you would like to see us spend your money.


Electricity Bill Snapshot
Allocation of Hydro Bill
HST 13%
Regulatory 3.2%
Transmission 11.1%
Distribution 18.6%
Electricity 54.1%
ERIE THAMES


Electricity Bill Snapshot 2012
Allocation of Hydro Bill in 2012
HST 13%
Regulatory 12.7%
Transmission 7.5%
Distribution 24.4%
Electricity 42.9%
ERIE THAMES

ERIE THAMES POWERLINES

5 Year Bill Change

	2012	2017	Change	Growth
Electricity	$ 46.69	$ 97.20	$ 50.51	108%
Distribution	**$ 26.59**	**$ 30.84**	**$ 4.25**	**16%**
Transmission	$ 8.19	$ 15.58	$ 7.39	90%
Regulatory	$ 14.92	$ 5.94	-$ 8.98	-60%
HST	$ 12.53	$ 19.44	$ 6.91	55%
	$ 108.92	**$ 169.00**	**$ 60.08**	**55%**

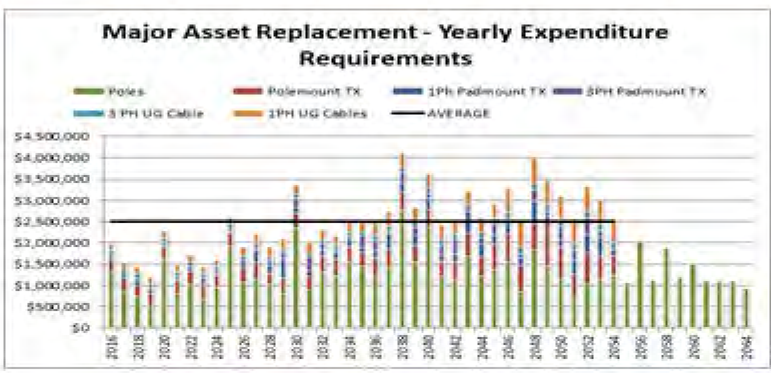
ERIE THAMES POWERLINES

What are our challenges?

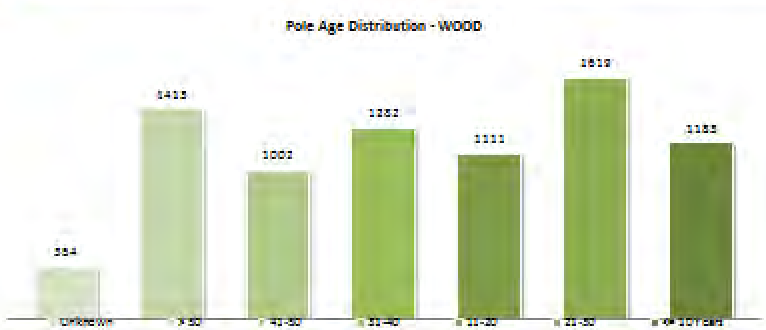
ETPL Challenges

- Aging Assets – 8000 wood poles, average age 31 years – life expectancy only 50 years. Over 1700 wood poles 50 years and older.
- Customer Expectations – lower rates, more services, fewer outages.
- Regulator Expectations – lower rates, better value, more customer engagement, more information to customers.

Aging Assets

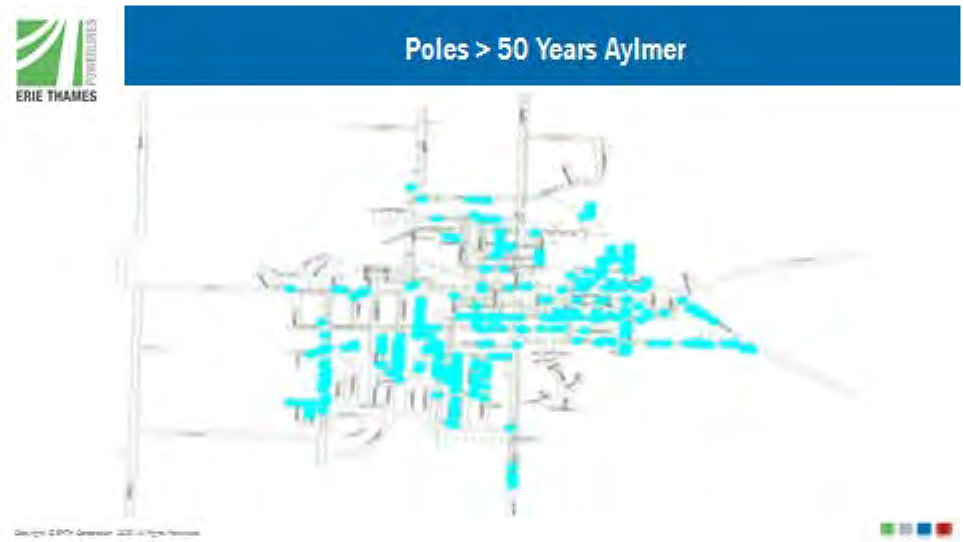


Wood Pole Aging

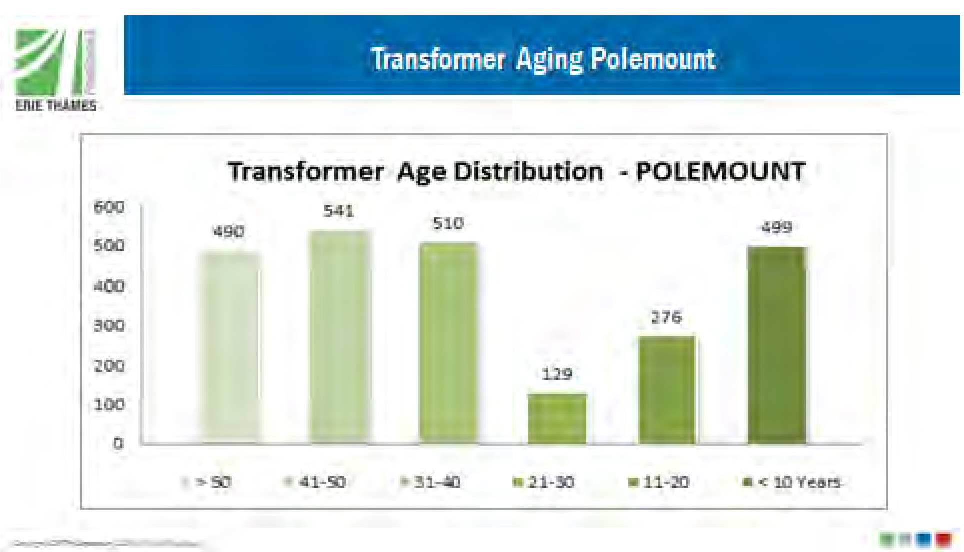


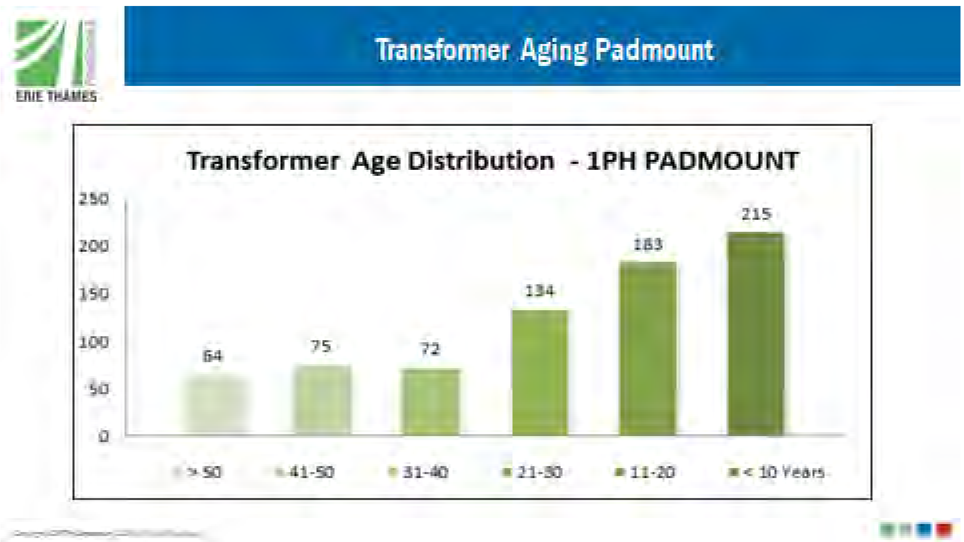
Aging Wood Poles

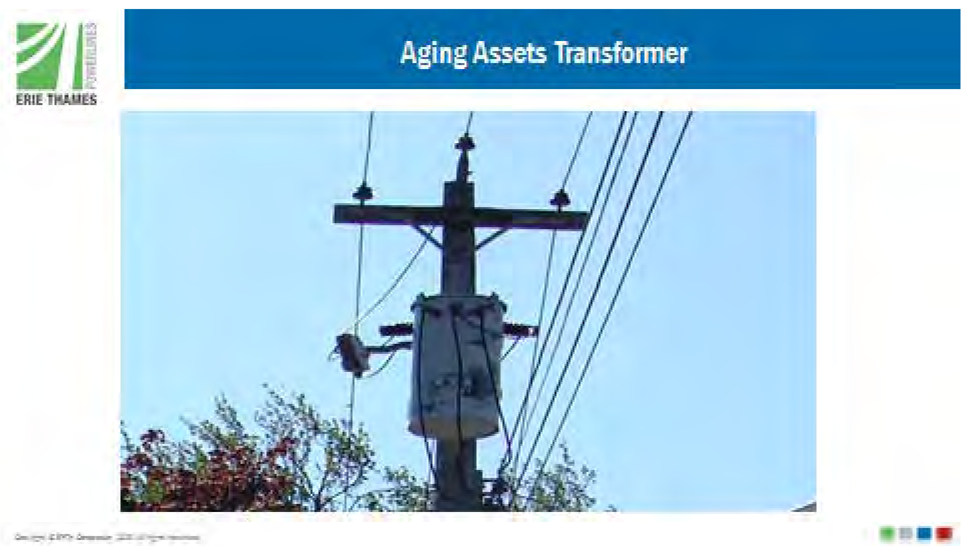
Poles > 50 Years Mitchell

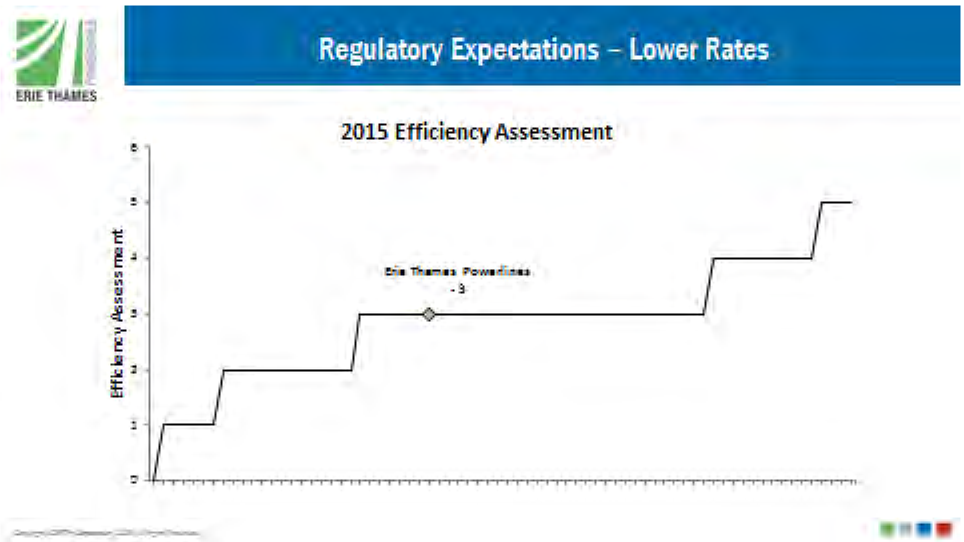

ERIE THAMES
POWERLINES
Poles > 50 Years Aylmer

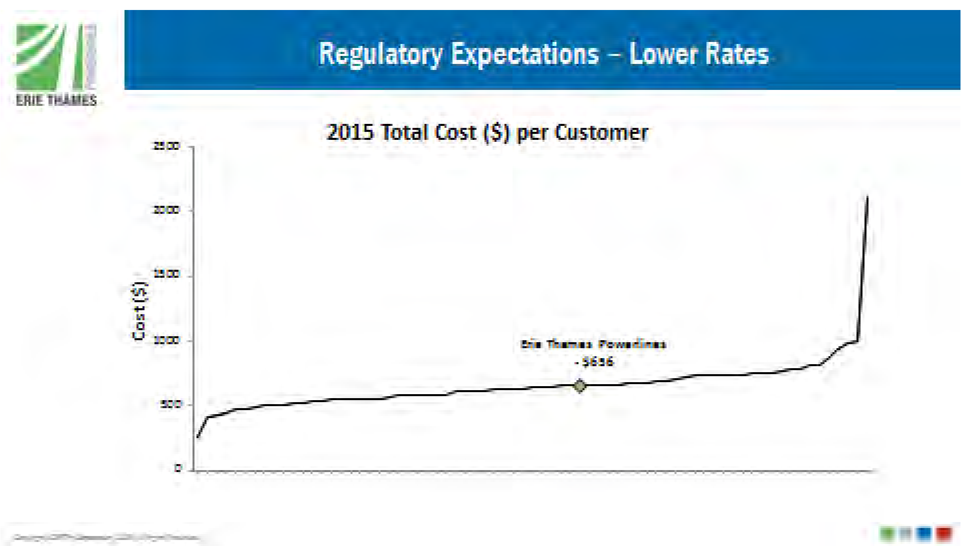

Poles > 50 Years Ingersoll


ERIE THAMES
POWERLINES
Transformer Aging Polemount
Transformer Age Distribution - POLEMOUNT
600
500
400
300
200
100
0
490
541
510
129
276
499
> 50
41-50
31-40
21-30
11-20
< 10 Years


ERIE THAMES
Transformer Aging Padmount
Transformer Age Distribution - 1PH PADMOUNT
250
200
150
100
50
0
64
75
72
134
183
215
> 50
41-50
31-40
21-30
11-20
< 10 Years


ERIE THAMES
Aging Assets Transformer


ERIE THAMES
Regulatory Expectations – Lower Rates
2015 Efficiency Assessment
Efficiency Assessment
Erie Thames Powerlines
- 3

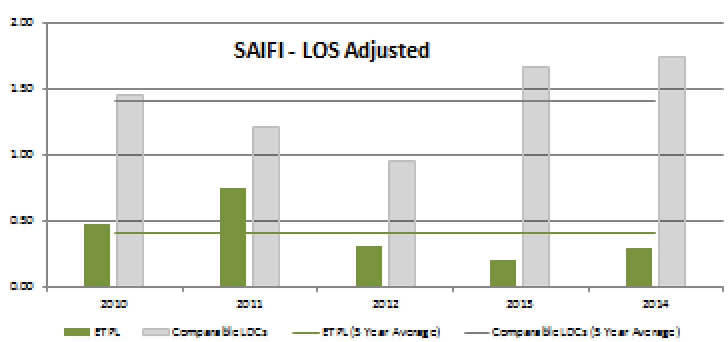

ERIE THAMES
Regulatory Expectations – Lower Rates
2015 Total Cost ($) per Customer
Cost ($)
2500
2000
1500
1000
500
0
Erie Thames Powerlines
- $656

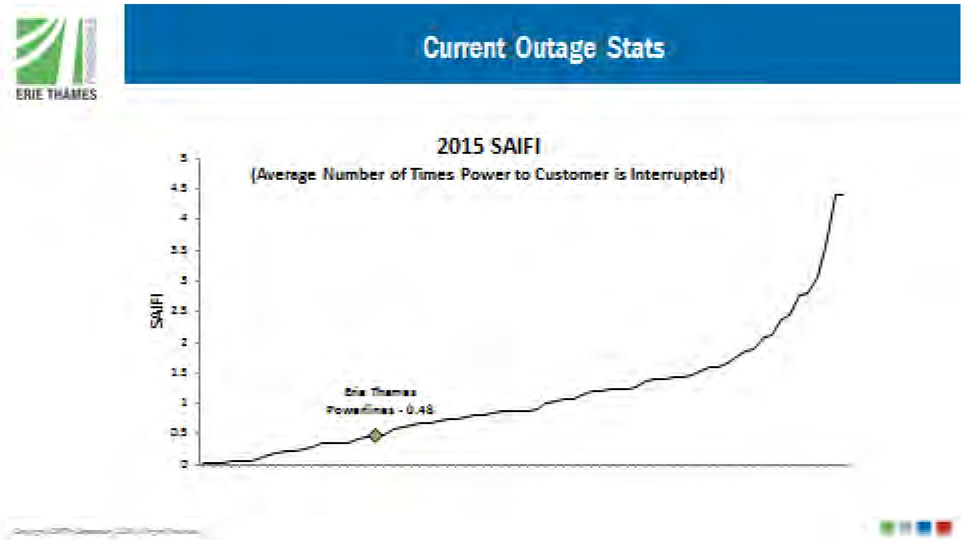
What are our options and plans for 2018 to 2022?

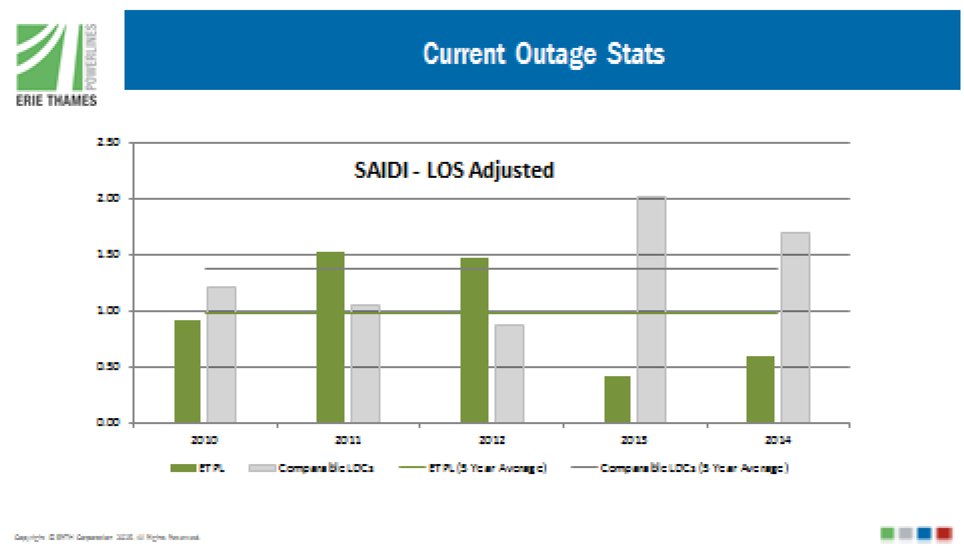
Options – Aging Assets

- Run to Failure – replace assets only when they fail – often results in a power outage and safety concerns
- Replace on Prioritized Basis – inspect and test assets, then replace those that are at greatest risk of failure
- Replace by Section – replace all assets in a specified area to minimize cost and impact to customers
- Asset Management Planning – combination of prioritized spend and section based spend, most cost effective way to refurbish distribution system

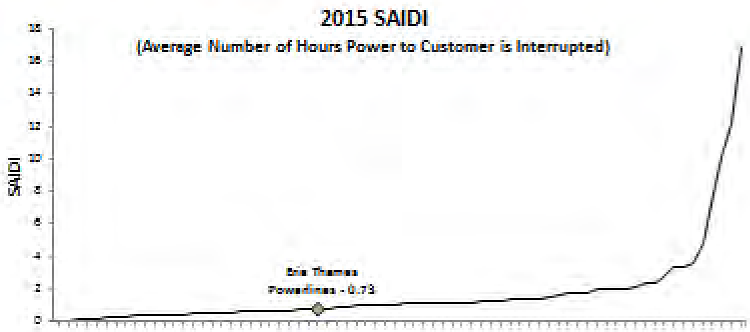
Current Outage Stats




ERIE THAMES
Current Outage Stats
2015 SAIFI
(Average Number of Times Power to Customer is Interrupted)
SAIFI
5
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
Erie Thames Powerlines - 0.48


ERIE THAMES
POWERLINES
Current Outage Stats
SAIDI - LOS Adjusted
2.50
2.00
1.50
1.00
0.50
0.00
2010
2011
2012
2013
2014
ET PL
Comparable LDCs
ET PL (5 Year Average)
Comparable LDCs (5 Year Average)

Current Outage Stats



Tree Trimming a big factor in Reducing Outages

Options – Lower Rates

- Provide Minimal Services – limit customer service to only what is required
- Grow the customer base or Collaborate with other utilities
- Outsource – competitive bids for tasks like customer service call centre

ETPL – Plan for 2018

- Capital – Replace 136 wood poles, replace 64 transformers, replace 2,011m of cables – on priority basis considering risk of failure and impact to customers. Total Cost $3.2M – similar to 2017, less than 2016. Minimize cost and risk of outages.
- Operating, Maintaining, Administration minimal change from 2015, 2016 and 2017 less than 2% increases annually.

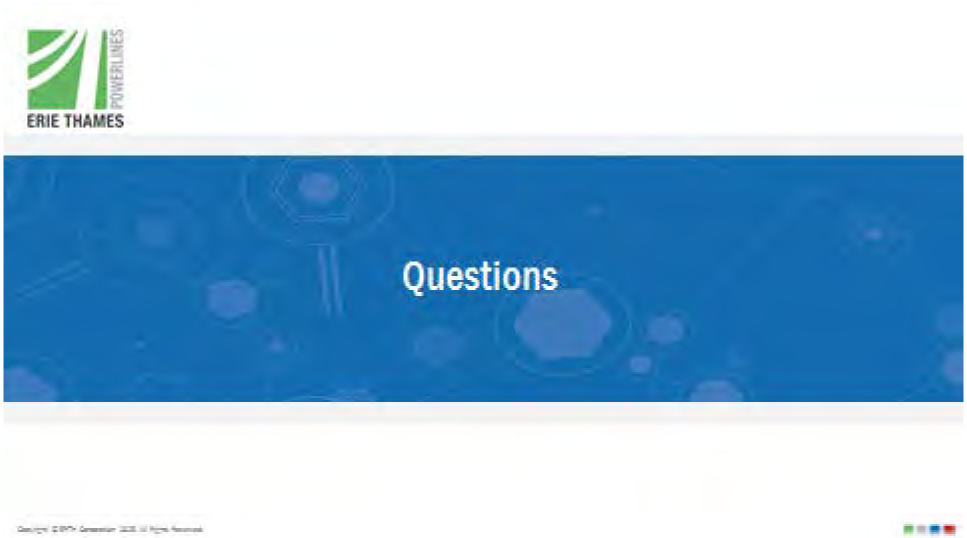
Project Example Before

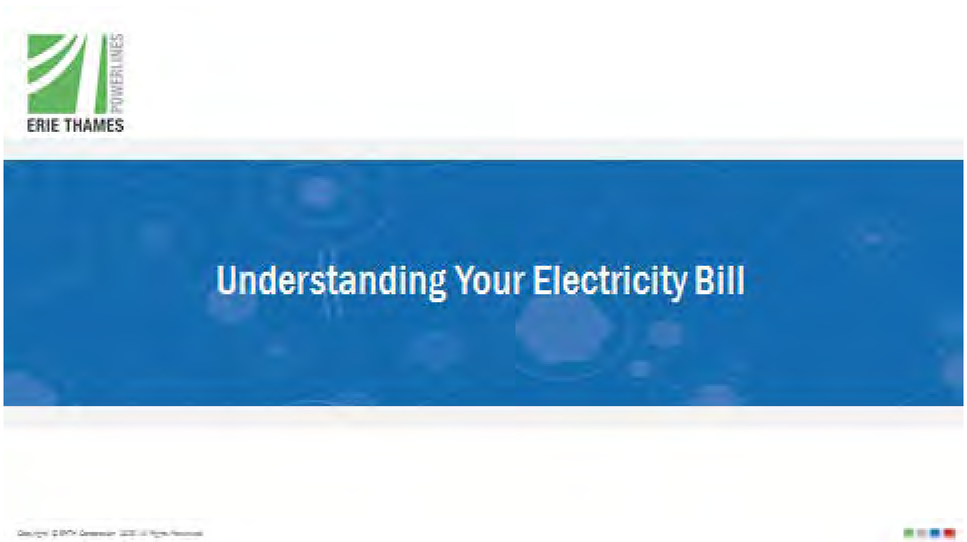
Project Example After

How this impacts you

Customer Impact

- Based on preliminary estimates, the distribution rate for a typical residential customer in 2018 is expected to be approximately $30.54 compared to $30.84 today which is a 1% reduction.
- System Reliability – continue to maintain current reliability levels.
- Customer Service – similar to previous years, some enhancements to customer communications (website, Twitter, customer meetings)


ERIE THAMES
POWERLINES
Questions


ERIE THAMES
POWERLINES
Understanding Your Electricity Bill

Customer Bill Example

- C:\Users\gralgp\Desktop\Erie_Thames_Bill.pdf

Understanding your electricity bill

ETPL - Typical Residential Bill Mock-up for 800 kWh Customer

Billing Summary			
Previous Balance			xx
Payment Received on XXXXXXXX			xx
Balance Forward			xx

Your Electricity Charges			
On Peak TOU - Summer	200 kWh x	$ 0.180000	$ 36.00
Off Peak TOU - Summer	400 kWh x	$ 0.087000	$ 34.80
Mid Peak TOU - Summer	200 kWh x	$ 0.132000	$ 26.40
Delivery			$ 46.42
Regulatory Charges			$ 5.94
H.S.T.			$ 19.44
Current Charges			$ 169.00

Electricity Charges

- This portion of the bill is for the electricity you used – in this example, a total of 800 kWh of electricity was used during the billing period.
- This portion of the bill is collected by your local utility and transferred to the Independent Electricity System Operator (IESO) who in turn, pays the various Generators of electricity.
- These rates are set by the Ontario Energy Board and adjusted on May 1 and November 1 each year. **Your local utility does not retain any of this money**.

Electricity Charges

- The commodity costs we pay are based on set pricing by the IESO and are set to peaks ON OFF and MID
- Currently the pricing is
  - 8.7 cents per kWh off-peak
  - 13.2 cents per kWh mid-peak
  - 18.0 cents per kWh on-peak

Understanding Global Adjustment

- Embedded in the ON OFF and MID peak charges is the cost for the commodity and the Global Adjustment amount that is required to cover the cost of generation in the provinces current supply mix
- Global adjustment can be broken down into 3 categories
  - Current generation facilities with guaranteed contracts (Bruce)
  - OPG Hydro and Nuclear baseload generating stations
  - Renewable, Gas Generation, Biofuel and Nuclear refurbishment projects

Understanding Global Adjustment

- In 2016 the average cost of Global Adjustment was approximately $0.103 per kWh which can be broken down as follows and details can be seen on the following slide:
  - Existing generation facility contracts: $0.007 per kWh
  - OPG Hydroelectric and Nuclear baseload: $0.029 per kWh
  - Renewable, Gas, Bio and Refurbishment: $0.066 per kWh

Understanding Global Adjustment

2016	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Average	Avg /kWh
GA-OEFC-NUG (M$)	$ 74.20	$ 73.30	$ 76.50	$ 61.20	$ 54.10	$ 46.50	$ 40.00	$ 38.90	$ 99.30	$ 119.70	$ 116.10	$ 42.00	$ 70.15	$ 0.007
GA-OPG (M$)	$ 327.90	$ 339.60	$ 378.00	$ 335.10	$ 301.80	$ 261.40	$ 268.40	$ 204.40	$ 273.70	$ 305.60	$ 261.60	$ 258.70	$ 293.02	$ 0.029
GA-OPA (M$)	$ 668.50	$ 650.80	$ 665.60	$ 694.40	$ 704.90	$ 687.40	$ 673.40	$ 635.30	$ 594.70	$ 637.00	$ 698.40	$ 664.80	$ 664.60	$ 0.066
Total GA (M$)	$1,070.60	$1,063.70	$1,120.10	$1,090.70	$1,060.80	$ 995.30	$ 981.80	$ 878.60	$ 967.70	$1,062.30	$1,076.10	$ 965.50	$1,027.77	$ 0.103

2015	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Average	Avg /kWh
GA-OEFC-NUG (M$)	$ 64.10	$ 50.60	$ 66.40	$ 56.20	$ 55.50	$ 57.20	$ 47.10	$ 73.00	$ 45.50	$ 62.50	$ 62.70	$ 82.60	$ 60.28	$ 0.006
GA-OPG (M$)	$ 174.10	$ 29.50	$ 210.50	$ 262.20	$ 279.50	$ 250.40	$ 224.10	$ 227.60	$ 118.70	$ 151.70	$ 328.90	$ 311.70	$ 214.08	$ 0.021
GA-OPA (M$)	$ 389.90	$ 378.60	$ 429.90	$ 610.20	$ 604.10	$ 635.50	$ 632.90	$ 578.60	$ 549.20	$ 528.40	$ 727.70	$ 605.30	$ 555.86	$ 0.056
Total GA (M$)	$ 628.10	$ 458.70	$ 706.80	$ 928.60	$ 939.10	$ 948.10	$ 904.10	$ 879.20	$ 713.40	$ 742.60	$1,119.30	$ 999.60	$ 830.22	$ 0.083

Regulatory Charges

ETPL - Typical Residential Bill Mock-up for 800 kWh Customer

Billing Summary			
Previous Balance			xx
Payment Received on XXXXXXXX			xx
Balance Forward			xx

Your Electricity Charges			
On Peak TOU - Summer	200kWh x	$ 0.180000	$ 36.00
Off Peak TOU - Summer	400kWh x	$ 0.087000	$ 34.80
Mid Peak TOU - Summer	200kWh x	$ 0.132000	$ 26.40
Delivery			$ 46.42
Regulatory Charges			$ 5.94
H.S.T.			$ 19.44
Current Charges			$ 169.00

Regulatory Charges

- This portion of the bill is for costs associated with operating the electrical grid, including:
  - wholesale electricity market (buying/selling generation)
  - Rural and Remote Rate Protection
  - Ontario Electricity Support Program
- This portion of the bill is collected by your local utility and transferred to the Independent Electricity System Operator (IESO).
- These rates are set by the Ontario Energy Board and adjusted each year. **Your local utility does not retain any of this money.**

Delivery Charges

ETPL - Typical Residential Bill Mock-up for 800 kWh Customer

Billing Summary			
Previous Balance			xx
Payment Received on XXXXXXXX			xx
Balance Forward			xx

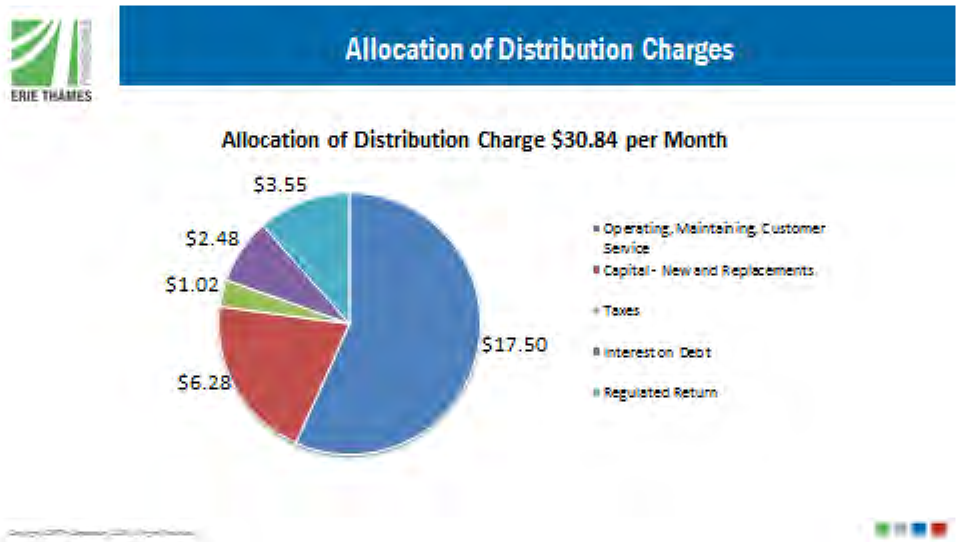
Your Electricity Charges			
On Peak TOU - Summer	200 kWh x	$ 0.180000	$ 36.00
Off Peak TOU - Summer	400 kWh x	$ 0.087000	$ 34.80
Mid Peak TOU - Summer	200 kWh x	$ 0.132000	$ 26.40
Delivery			$ 46.42
Regulatory Charges			$ 5.94
H.S.T.			$ 19.44
Current Charges			$ 169.00

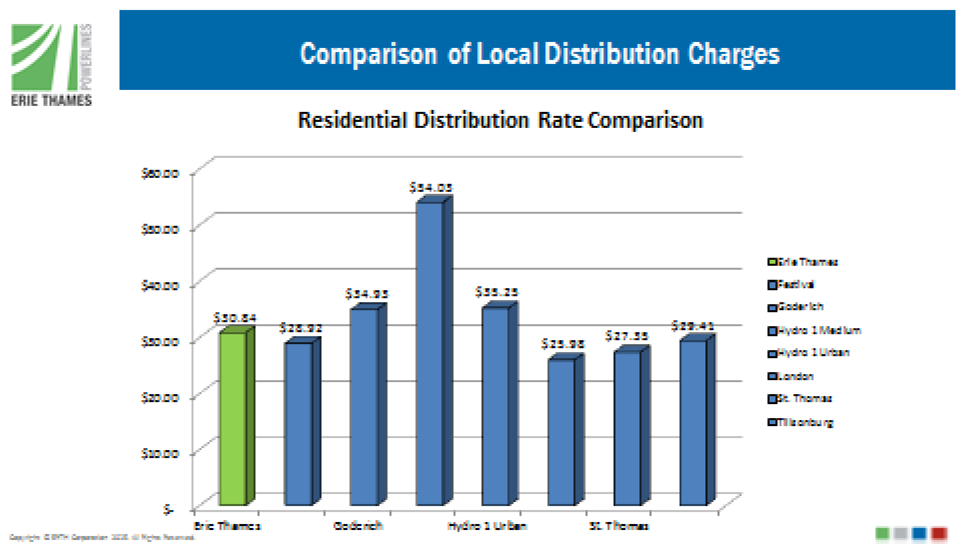
Delivery Charges

- This portion of the bill is for costs associated with delivering the Electricity from the Generators to you:
  - $11.04 or 24% of this charge is for the Transmission System
  - $4.54 or 10% for provincial regulatory costs
  - $30.84 or 66% for the Distribution System.
- This portion of the bill is collected by your local utility and amount for the Transmission System is sent to the Transmitter – Hydro One.
- These rates are set by the Ontario Energy Board and adjusted each year. **Your local utility retains only a portion ($30.84 or 18.6% of the total bill) of this money.**

Distribution Charges

- The $30.84 (18.6%) of your monthly bill is used by your local utility to cover all the costs associated with delivering the electricity to you:
  - Operation and Maintenance of the Distribution System
  - Provide Customer Service (billing and call centre)
  - Replace assets at end of life due to safety and reliability issues
  - Invest in technology to automate the system


ERIE THAMES
Allocation of Distribution Charges
Allocation of Distribution Charge $30.84 per Month
$3.55
$2.48
$1.02
$6.28
$17.50
Operating, Maintaining, Customer Service
Capital - New and Replacements
Taxes
Interest on Debt
Regulated Return


ERIE THAMES
POWERLINES
Comparison of Local Distribution Charges
Residential Distribution Rate Comparison
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$-
$30.84
$54.05
Erie Thames
Goderich
Hydro 1 Urban
St. Thomas
Erie Thames
Festival
Goderich
Hydro 1 Medium
Hydro 1 Urban
London
St. Thomas
Tillsonburg

ERIE THAMES POWERLINES

Questions

ERIE THAMES POWERLINES

Survey

ERIE THAMES POWERLINES

Survey

- Was this presentation helpful? (yes, no, unsure)
- Should ETPL spend more, or less, or as planned for replacing assets?
- Should ETPL spend more, or less, or as planned for Customer Service?
- If you think ETPL should spend less, what areas should spending be reduced?

APPENDIX D - CUSTOMER CONSULTATIONS

GM-CAMI - Agenda & Meeting Minutes

ERIE THAMES POWERLINES
Your Home Town Utility

Meeting Notes
GM/CAMI and Erie Thames Powerlines Corporation
Bell Street Board Room, Ingersoll ON
April 1st, 2014 – 11:00 AM

Attendees:

Adel Ali	GM/CAMI
Michael Ford	GM/CAMI
Mike Demsey	GM/CAMI
Chuck deJong	Erie Thames Powerlines
Scott Brooks	Erie Thames Powerlines
Josh Smith	Erie Thames Powerlines
Pat Zimmer	Erie Thames Powerlines

Purpose of the Meeting:
Adel requested the meeting for introductions and to discuss the CAMI feeders, maintenance programs, backup supply and any issues of either party.

Discussions:
There were introductions and Adel provided background for the GM/CAMI plant. Chuck deJong discussed Erie Thames relationship with CAMI and Hydro One in regards to the M51, M52 feeders and the Ingersoll TS.

Erie Thames provided a drawing of the configuration of the feeder positions at the Ingersoll TS which includes the CAMI dedicated feeders M51 & M52.

GM/CAMI has concerns regarding the backup supply for the plant, such as:

- What if any backup feeds are there if both the M51 and M52 feeders went down?
- How often would the M51 be out of service in a year when the load is on the M52? ***What would be the backup feed for the backup feed?***
- Are there spare parts available if there were any issues at the TS?
- What is Erie Thames maintenance program schedule? i.e. Infrared scan, insulator replacement, arrestor failure.
- What type of insulators in use on the CAMI feeders – porcelain or polymer? How often are they replaced and with which type of insulator? Where is the bypass switch?
- What is Erie Thames coordination with Hydro One regarding Hydro One equipment that would affect Erie Thames?
- Would we have any information on outages caused by arrestor failures?
- Ebuss reliability – would Erie Thames and Hydro One look at this together, especially M51 backup feed?

It was discussed that there have been more insulator issues on the M51 than the M52. The feeders are the same age, not sure why there are more issues on the M51. This situation is making GM/CAMI nervous. GM/CAMI asked if:

- This could be a weather related issue?
- Would it make sense to perform the infrared scan in the winter opposed to current practice conducting the scan in warmer weather?
- Does Erie Thames perform insulator washing?

Erie Thames comments:

- Erie Thames does not perform insulator washing.
- We have a proactive plan to change out the porcelain insulators. We do not wait until they fail.
- There may be an opportunity to use jumpers on the M49 and M50 as a backup if the M51 and M52 were out of service, currently there is no switch in place, this would require Hydro One involvement, it is a Hydro One station.
- The infrared scan is conducted annual from the pole outside the Ingersoll TS up to the CAMI plant. Not inside the Station. Hydro One conducts their own inspections.

- Maintenance projects that require power interruptions are coordination with CAMI and their work schedule, there is not a set time frame to complete the projects, unless the issue requires immediate attention. Insulator changes are approximately 35% completed on Erie Thames plant.
- Erie Thames put pressures on Hydro One to cleanup any known issues on their system that could affect the supply to GM/CAMI.
- Inspection reports are provided to GM/CAMI.

Action Plan: provide Erie Thames schedule for replacing the porcelain insulators
Meet at least twice a year to review maintenance item
Copy Adel on all communications regarding planned maintenance

Other Discussion Items:
GM/CAMI's I-Grid System:

- How does this work?
    - Adel replied that it records the feeder at the time, there are 4 units, if any further information is required by Erie Thames let Adel know and he will assist in supplying the data. Hydro One receives the same information.
- Can Erie Thames add comments on the I-Grid?
    - Adel would not receive the comments.

Erie Thames I-Grid Chart:

- Erie Thames shared the chart, positive comments, helpful for historical tracking and trending, good tool to expand on
- Agreed that it would be beneficial if the ebuss and zbuss was divided

SCADA

- Primary Metering - could Erie Thames add a phone line to bring this information back into SCADA? Collect real time data to correlate with the OGCC – monitor power quality
    - Adel will discuss with Tracy Collins, MSP, to make sure he doesn't have any problems with this.

Erie Thames agreed to get back to Adel no later than a couple of weeks.

Meeting adjourned at 12:20 PM.

TOWN OF INGERSOLL
BI-ANNUAL JOINT UTILITIES MEETING
J.C. HERBERT ROOM – TOWN CENTRE

Tuesday, February 11, 2014
9:30 am

1. Welcome
2. Introductions
3. Additions to Agenda
4. Projects 2014

Ingersoll

1. **Holcroft Street Reconstruction** – This is a project carried over from 2013. JAAR is the contractor and we anticipate construction to start back up in late March early April and continue to the end of June 2014. The sanitary sewer, storm and road work is still left to complete.
2. **Whiting Street Reconstruction** – This project is due to be tendered this spring for summer construction. It is the continuation of sanitary sewers and watermain from Holcroft to just before Brickwood.
3. **King Street East** – Hall to Harris. This is a road reconstruction project and should not affect utilities.
4. **King Street West** – Oxford to Merritt. This is also a road reconstruction project and should not affect utilities.
5. **Charles Street Sidewalk** – Merritt to King Street West. Construction of sidewalk along the ? of the road.

Ingersoll Projects for Oxford County

1. **King Street West** – Thames to Oxford. Sanitary sewer replacement to the business on the south side of King Street West.
2. **Bell Street** – McKeand to Cashel - watermain replacement.
3. **Mutual Street Sanitary Sewers** – CPR tracks to Janes Street.

Subdivisions and Site Plans

1. **Canadian Tire** – Construction of a new storm sewer system around the entire building.
2. **Harrisview** – Sifton Properties
3. **Sinclair Homes** – 175 Ingersoll Street

4. **Clover Ridge North** – Phase II – Oak Country Homes – Walker Road
5. **Clover Ridge South** – Paul Florica
6. **McKeand Ridge** – Len Reeves
7. **Schout Subdivision** – 25 Kerwin
8. **Sharp Bus Lines** – Whiting Street
9. **People's Revival Church** – Kensington Street
10. **Princess Elizabeth School** – William & George Streets

5. Projects 2015 – 2020

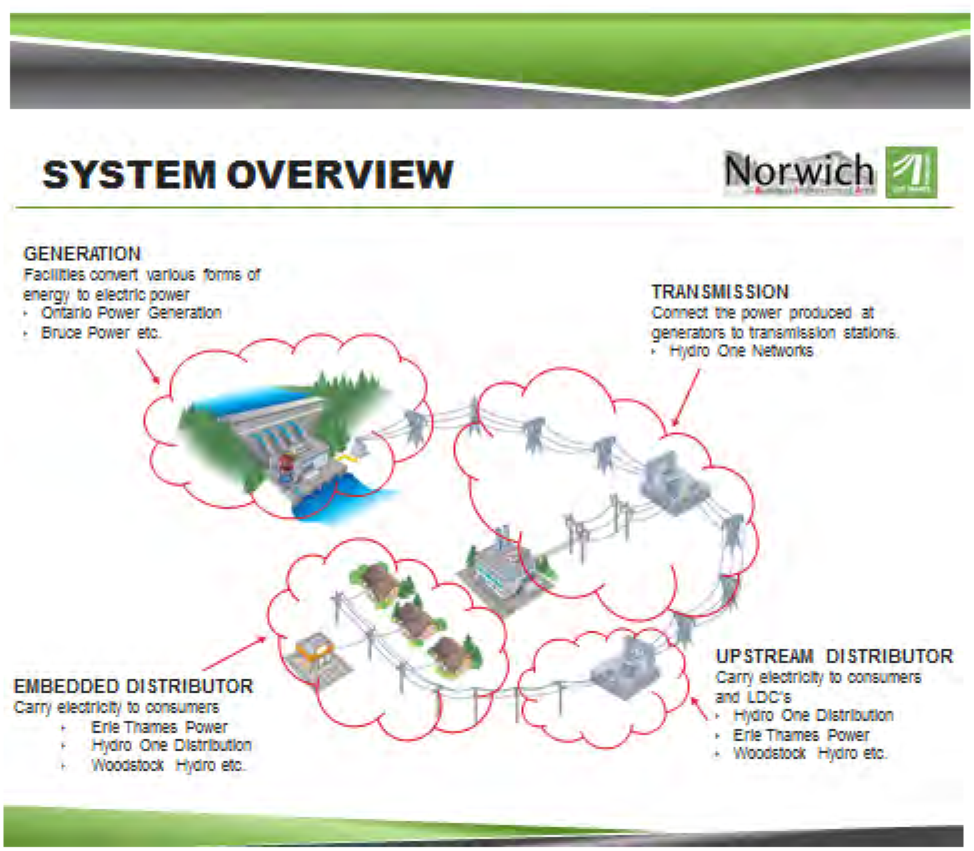
   1. William Street Reconstruction
   2. North Town Line
   3. Catherine Street Reconstruction
   4. Catherine Street Culvert
   5. Brickwood and Maple Lane
   6. Whiting Street
   7. Clark Road West
   8. George Street
   9. Tunis Street Reconstruction (Etna and Centre St)
   10. Thames Street South Reconstruction
   11. Thames Street South Culvert

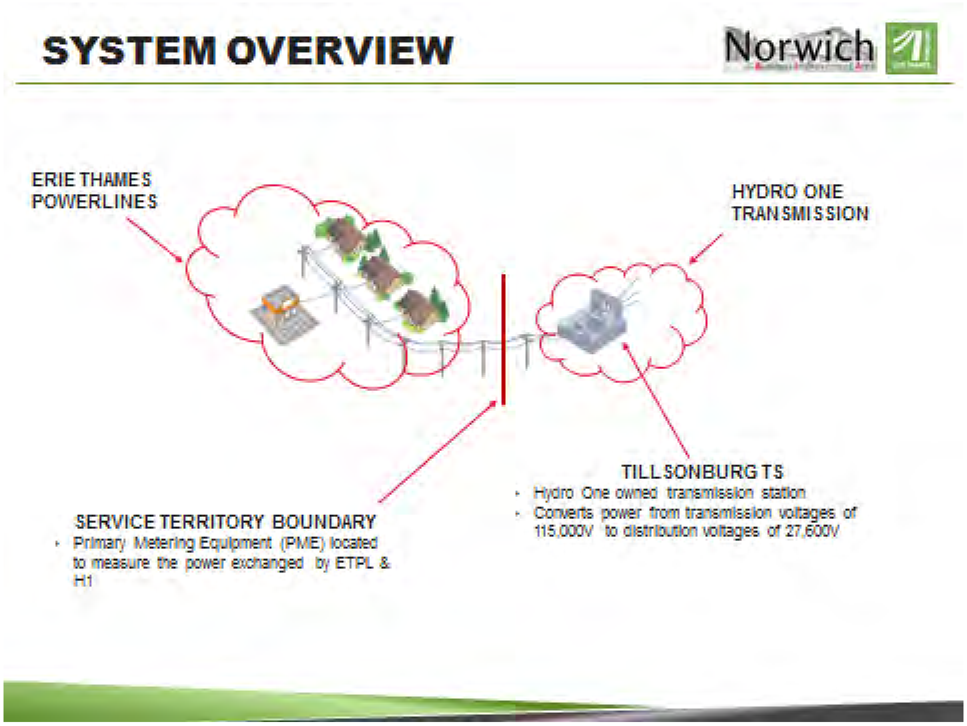
6. Emergency Contact List

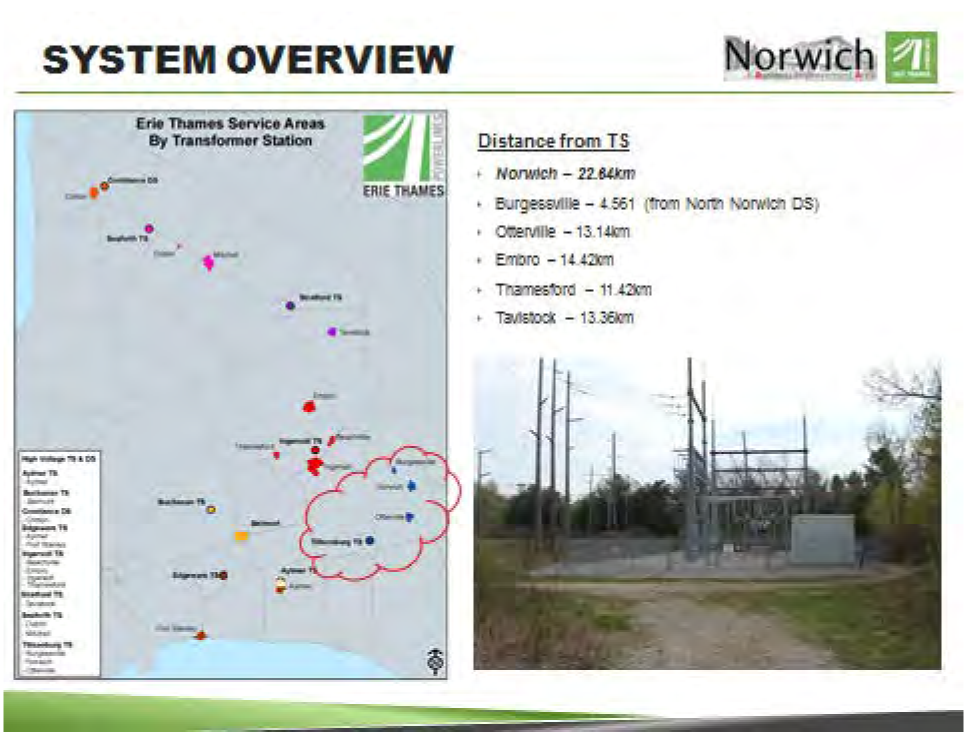
7. Next Meeting

8. Adjournment

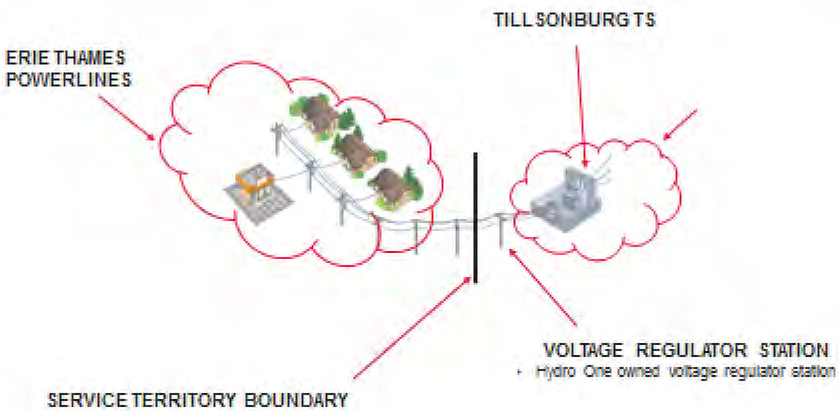
Norwich BIA - Presentation




SYSTEM OVERVIEW
Norwich
ERIE THAMES POWERLINES
HYDRO ONE TRANSMISSION
TILLSONBURG TS
Hydro One owned transmission station
Converts power from transmission voltages of 115,000V to distribution voltages of 27,600V
SERVICE TERRITORY BOUNDARY
Primary Metering Equipment (PME) located to measure the power exchanged by ETPL & H1


SYSTEM OVERVIEW
Norwich
Erie Thames Service Areas
By Transformer Station
ERIE THAMES
POWERLINES
Distance from TS
Norwich – 22.84km
Burgessville – 4.561 (from North Norwich DS)
Otterville – 13.14km
Embro – 14.42km
Thamesford – 11.42km
Tavistock – 13.36km

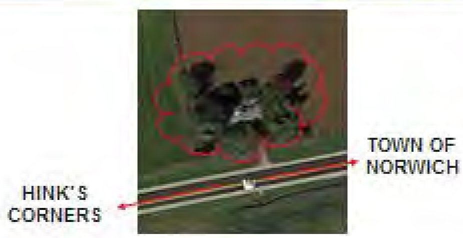
SYSTEM OVERVIEW



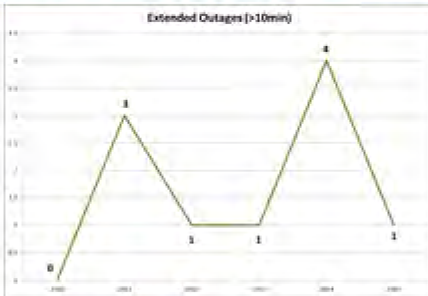
SYSTEM OVERVIEW

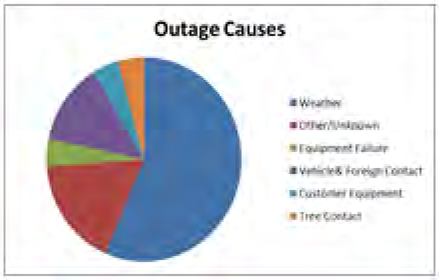
VOLTAGE REGULATOR STATION

- Used to "boost" low voltages as a result of voltage drop caused by line losses over a long distance.



POWER QUALITY ISSUES





Recent Outages

- July 22, 2014 – *10 minutes*
  - Transmission circuit W8T tripped as a result of a protection operation by a connected generator.
- September 5, 2014 – *2 hours 57 minutes*
  - ETPL Equipment Failure
- November 24, 2014 – *1 hour 30 minutes*
  - Weather, Wind
- December 20, 2014 – *3 hour 41 minutes*
  - Foreign Vehicle
- February 15, 2015
  - Equipment Failure at Voltage Regulator Station due to weather conditions.

ETPL CAPITAL PLAN

Stover Street Reconstruction

- Entire Stover Street feeder to be reconstructed in 3 phases over the next 5 years.
  - Phase 1 (2014) - North St. to Elgin St. $235,000
  - Phase 2 (2018) - Elgin St. to Tidey St. $325,000
  - Phase 3 (2020) - Tidey St. to Palmer St. $270,000
- Stover Street feeder supplies approximately ½ of the customer base in Norwich including parts of the downtown core, commercial/industrial customers and residential areas.

SCADA & SMART GRID

- Currently receiving telemetry (data) from the Ontario Grid Control Center (OGCC) including the Tillsonburg TS.
  - Allows us to monitor breaker status, current & voltage levels and better respond to any issues.

- Currently examining options related to "smart" automated switches and fault indicators.
  - Will provide further monitoring of power quality at the ETPL service boundary, and provide more insight into issues arising within the community.

ETPL MAINTENANCE

Pole Testing & Replacement Program

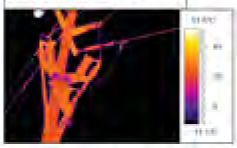
- Distribution System Code requires distribution poles to be tested at a minimum of every 6 years in an urban area.
- ETPL current program includes inspection of every pole on a 3 year cycle.
  - Visual inspection of pole, associated hardware, support structures, etc.
  - "Hammer test" & selective bore to asses internal condition of pole as required.
  - Any suspect poles are analyzed with software to determine remaining strength.

ETPL MAINTENANCE

Identification:	DATE
Dip 38M52-LC	2014-07-18

Description: Feeder Dip Pole

INFRARED IMAGE



PHOTO

IR information	Value
Date of creation	[illegible]
Time of creation	[illegible]
Object parameter	Value
Ambient temperature	[illegible]

INFORMATION:

No anomaly heating was noted

PRIORITY: High Medium Low

ANOMALY:	No problems noted

Tree Trimming Program

- ETPL current program includes tree trimming of entire service territory every three (3) years.

Infrared Inspections

- ETPL currently completes infrared scans of the entire system every two (2) years.

Underground Inspections

- ETPL currently completes underground inspections of the entire system every three (3) years.

Loadbreak Switch Maintenance

- ETPL currently completes load break switch maintenance on all switches every two (2) years.

REGIONAL PLANNING

London Area Planning Region

- On October 18, 2013 the Ontario Energy Board issued it's *Report of the Board – A Renewed Regulatory Framework for Electricity Distributors.*
- The RRFE Board Report concluded a consultation process aimed at promoting the cost-effective development of electricity infrastructure through coordinated planning on a regional basis between licenced distributors and transmitters.
- ETPL has just completed the initial "Needs Assessment" stage as part of the London Area Regional Planning group.

REGIONAL PLANNING

"Needs Assesment Report"

- The needs assessment report is available to the public at http://www.hydroone.com/RegionalPlanning/LondonArea along with all other stages of the process.

- ETPL has just completed the initial "Needs Assessment" stage as part of the London Area Regional Planning group.

System Reliability, Operation and Restoration Review

Based on the net and gross load forecast, the 115 kV voltages at Tillsonburg TS were found to be less than minimum requirements under precontingency conditions in the near term.

Based on the gross and net load forecast, the loss of one element will not result in load interruption greater than 150MW in the London Region. The maximum gross and net load interrupted by configuration due to the loss of two elements is below the load loss limit of 600MW by the end of the 10-year study period.

7. RECOMMENDATIONS

Based on the findings of the Needs Assessment, the study team recommends that:

a) The following needs should be further assessed as part of the Scoping Assessment to determine if CDM/DG can fully or partly address them or wires planning should be undertaken:

- Transformation capacity limitations at Strathroy TS, Tillsonburg TS, Wonderland TS, Clarke TS and Talbot TS
- Thermal and voltage limitations along the 115kV circuit W8T

QUESTIONS?

Consultations with Upstream Distributor (HONI)

Meeting

Date: June 3, 2015.
Attendees: Chuck DeJong, Josh Smith, Jac Vanderbaan and Doug Fraser.
Location: Erie Thames Ingersoll Office.

Norwich Area

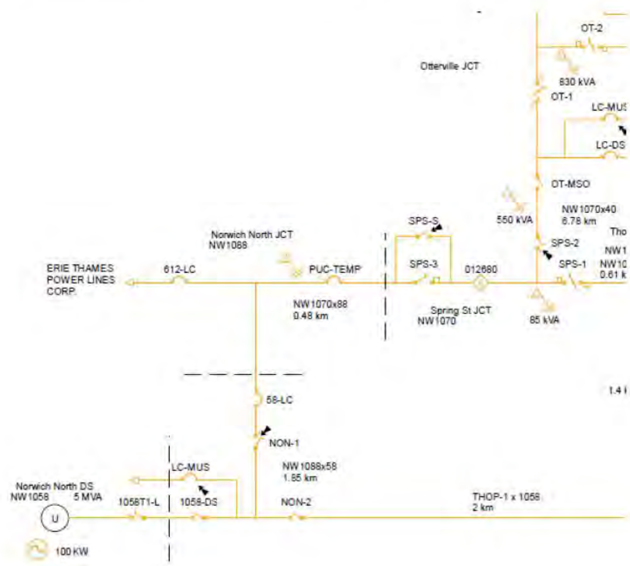
- Identified prolonged outages recently that have been discussed at recent town hall
  - Dating back to 2011
  - Potential causes / issues
    - Newark R.S. – old and problematic; not sure it is operating correctly
    - Electronic Reclosers (NRW3R-S and NRW2R-2S)
      - Recent fault past NRW3R-S tripped entire 20M3 feeder, instead of isolating section past recloser
        - ET to provide outage date for clarity
          - May 20, 2015; 4:41 to 9:55.
        - Josh has requested detailed report from Nick Stimac
      - Restoration time was lengthy (5 hours) and could have been reduced greatly and avoided altogether if recloser operated
      - Additional complication was load could not be quickly shifted to 20M1 via SPS-2 since H1 Lines identified the SPS-1 could not be opened
        - Switch in need of maintenance or replacement?
        - Load was finally picked up via SPS-2, creating an open point at the NRW2R recloser.

- Ownership of Lines and Conductor in Norwich
  - Tillsonburg low tension SLD and Erie Thames' TCA show H1 ownership of poles, conductor and switches past ET's PME

1 of 4

- ET believe they own everything beyond the PME
- SPS-3 is one pole span past the PME within ET territory
- PUC-TEMP is approx. 0.5km within ET territory.
- ET identified concern about H1 ability to move load around (past their PME), potentially without notifying ET… settlements issue, especially if H1 does not install ERAs etc

Tillsonburg TS (NW20)	
Distributor owns the following: **Note: * Indicates Controlling Authority belongs to Customer**	**Customer owns the following:** **Note: * Indicates Controlling Authority belongs to Distributor**
Switches: **Fuses:** **Loops:**	**Switches:** **Fuses:** **Loops:**
Feeders: **NW 20M1** Poles, conductor and line hardware including 16 kV tap (Cornell Jct) up to but not including switch 3002 on the supply to Fleetwood Metals **NW 20M3** Poles, conductor and line hardware including SPS-3 up to but not including loops PUC-TEMP. Hydro One owns from loops 58-LC to North Norwich DS	**Feeders:** **NW 20M1** Poles, conductor and line hardware from and including switch 3002 on the supply to Fleetwood Metals **NW 20M3** Poles, conductor and line hardware from and including PUC-TEMP though and including 612-LC (feeding Norwich) and up to but not including loops 58-LC



- ET inquiry about having a second feed into Norwich from 20M1 circuit… with an operable switch to allow ET to move and restore load
- ET identified there are a number of old ‘cap and pin’ type insulators on the M3 feeder along County Road 18, east of County Road 13… any plans to replace

2 of 4

APPENDIX E- REGIONAL PLANNING STATUS LETTER

Hydro One Networks Inc.
483 Bay Street
13th Floor, North Tower
Toronto, ON M5G 2P5
www.HydroOne.com

Tel: (416) 345-5420
Fax: (416) 345-4141
ajay.garg@HydroOne.com

July 26th, 2017

Josh Smith
Electrical Distribution and Planning Engineer
Erie Thames Power Lines Corporation
143 Bell Street,
PO Box 157
Ingersoll, ON, N5C 3K5

Dear Mr. Smith,

Subject: Regional Planning Status

This letter is in response to your request for a Planning Status letter for your cost of service application. The province has been divided into 21 Regions for the purpose of regional planning, which are assigned to one of the 3 Groups to prioritize and manage the regional planning process. A map showing details with respect to the 21 Regions and the list of LDCs in each Region are attached in Appendix A and B respectively.

Erie Thames Power Lines Corporation belongs to London Area (Group 2 Region) and Greater Bruce/Huron Area (Group 3 Region), in which Hydro One Networks Inc. (HONI) is the lead transmitter.

This letter confirms that the first cycle of regional planning process for both Regions is currently underway and is anticipated to complete by August 2017. An overview of Ontario's regional planning process is available on Hydro One's Regional Planning homepage. Each region's current status and corresponding reports are also published online and can be accessed using the links above. The planning statuses for the two regions of your interest are briefly discussed below.

London Area Region

This region has been divided into 5 sub-regions; Strathroy, Greater London, Woodstock, St. Thomas, and Aylmer-Tillsonburg. Needs Assessment (NA) Report (Appendix C) for London area was completed on April 2, 2015 and Scoping Assessment was completed on August 28, 2015. The Local Planning (LP) Reports (Appendix C) for Strathroy TS and Woodstock Sub-region Restoration were completed in September 2016 and May 2017, respectively.

The Working Group recommended that Integrated Regional Resource Plan (IRRP) was only required for Greater London Sub-Region, which was completed in January this year and is available at IRRP. Regional Infrastructure Planning (RIP) phase for this region is currently underway and anticipated to complete by August 2017.

The IRRP recommends installation of switching devices and feeder extensions for a total cost of $1.8M to address the restoration issues in the London sub region and there is no cost implication for Erie Thames Power Lines Corporation.

There are couple end-of-life asset refurbishments and few development projects in the region underway and/or planned over the next few years. It is expected that there will be little or no cost implications for Erie Thames Power Lines Corporation from these projects. However, if any, it will be incorporated into the Region's RIP report.

Greater Bruce / Huron Area

The NA for the Greater Bruce/Huron region was completed in May 2016 (Appendix D). The Working Group recommended the following needs to be addressed:

- Low power factor at Wingham TS (and resulting voltage deficiency) and Bruce HW Plant B TS
- Thermal overloading on the 115 kV circuit L7S
- Customer Delivery Point Performance

The Working Group concluded that no further regional coordination was required and the plans to mitigate the above needs will be developed via the Local Planning process and Hydro One's OEB-approved process for addressing delivery point performance. Local planning was completed for these needs. Local Planning reports (Appendix D) were developed for needs at Wingham TS, L7S circuit capacity and Bruce HWP B TS. It is expected that that there will be little or no cost implications for Erie Thames Power Lines Corporation. The RIP report for Greater Bruce/Huron Region is expected to be completed in August 2017.

Erie Thames Power Lines Corporation is an active participating member of the Working Group. Further details will be discussed with the Working Group Members and communicated as they become available. Hydro One looks forward to working with Erie Thames Power Lines Corporation in executing the regional planning process.

Please feel free to contact me if you have any questions.

Sincerely,

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

Appendix A: Map of Ontario's Planning Regions

Northern Ontario

Southern Ontario

Greater Toronto Area (GTA)

Group 1	Group 2	Group 3
Burlington to Nanticoke	East Lake Superior	Chatham/Lambton/Sarnia
Greater Ottawa	London area	Greater Bruce/Huron
GTA East	Peterborough to Kingston	Niagara
GTA North	South Georgian Bay/Muskoka	North of Moosonee
GTA West	Sudbury/Algoma	North/East of Sudbury
Kitchener- Waterloo- Cambridge-Guelph (“KWCG”)		Renfrew
Metro Toronto		St. Lawrence
Northwest Ontario		
Windsor-Essex		

Appendix B: List of LDCs for Each Region

[Hydro One as Upstream Transmitter]

Region	LDCs
1. Burlington to Nanticoke	• Energy+ Inc. (formerly Brant County Power Inc.) • Brantford Power Inc. • Burlington Hydro Inc. • Haldimand County Hydro Inc.** • Horizon Utilities Corporation • Hydro One Networks Inc. • Norfolk Power Distribution Inc.** • Oakville Hydro Electricity Distribution Inc.
2. Greater Ottawa	• Hydro 2000 Inc. • Hydro Hawkesbury Inc. • Hydro One Networks Inc. • Hydro Ottawa Limited • Ottawa River Power Corporation • Renfrew Hydro Inc.
3. GTA North	• Enersource Hydro Mississauga Inc. • Hydro One Brampton Networks Inc. • Hydro One Networks Inc. • Newmarket-Tay Power Distribution Ltd. • PowerStream Inc. • PowerStream Inc. [Barrie] • Toronto Hydro Electric System Limited • Veridian Connections Inc.
4. GTA West	• Burlington Hydro Inc. • Enersource Hydro Mississauga Inc. • Halton Hills Hydro Inc. • Hydro One Brampton Networks Inc. • Hydro One Networks Inc. • Milton Hydro Distribution Inc. • Oakville Hydro Electricity Distribution Inc.

5. Kitchener- Waterloo-Cambridge-Guelph (“KWCG”)	• Energy+ Inc. (formerly Cambridge and North Dumfries Hydro Inc.) • Centre Wellington Hydro Ltd. • Guelph Hydro Electric System - Rockwood Division • Guelph Hydro Electric Systems Inc. • Halton Hills Hydro Inc. • Hydro One Networks Inc. • Kitchener-Wilmot Hydro Inc. • Milton Hydro Distribution Inc. • Waterloo North Hydro Inc. • Wellington North Power Inc.
6. Metro Toronto	• Enersource Hydro Mississauga Inc. • Hydro One Networks Inc. • PowerStream Inc. • Toronto Hydro Electric System Limited • Veridian Connections Inc.
7. Northwest Ontario	• Atikokan Hydro Inc. • Chapleau Public Utilities Corporation • Fort Frances Power Corporation • Hydro One Networks Inc. • Kenora Hydro Electric Corporation Ltd. • Sioux Lookout Hydro Inc. • Thunder Bay Hydro Electricity Distribution Inc.
8. Windsor-Essex	• E.L.K. Energy Inc. • Entegrus Power Lines Inc. [Chatham- Kent] • EnWin Utilities Ltd. • Essex Powerlines Corporation • Hydro One Networks Inc.
9. East Lake Superior	N/A → This region is not within Hydro One’s territory
10. GTA East	• Hydro One Networks Inc. • Oshawa PUC Networks Inc. • Veridian Connections Inc. • Whitby Hydro Electric Corporation

11. London area	• Entegrus Power Lines Inc. [Middlesex] • Erie Thames Power Lines Corporation • Hydro One Networks Inc. • London Hydro Inc. • Norfolk Power Distribution Inc.** • St. Thomas Energy Inc. • Tillsonburg Hydro Inc. • Woodstock Hydro Services Inc.**
12. Peterborough to Kingston	• Eastern Ontario Power Inc. • Hydro One Networks Inc. • Kingston Hydro Corporation • Lakefront Utilities Inc. • Peterborough Distribution Inc. • Veridian Connections Inc.
13. South Georgian Bay/Muskoka	• Collingwood PowerStream Utility Services Corp. (COLLUS PowerStream Corp.) • Hydro One Networks Inc. • Innisfil Hydro Distribution Systems Limited • Lakeland Power Distribution Ltd. • Midland Power Utility Corporation • Orangeville Hydro Limited • Orillia Power Distribution Corporation • Parry Sound Power Corp. • Powerstream Inc. [Barrie] • Tay Power • Veridian Connections Inc. • Veridian-Gravenhurst Hydro Electric Inc. • Wasaga Distribution Inc.
14. Sudbury/Algoma	• Espanola Regional Hydro Distribution Corp. • Greater Sudbury Hydro Inc. • Hydro One Networks Inc.
15. Chatham/Lambton/Sarnia	• Bluewater Power Distribution Corporation • Entegrus Power Lines Inc. [Chatham- Kent] • Hydro One Networks Inc.
16. Greater Bruce/Huron	• Entegrus Power Lines Inc. [Middlesex] • Erie Thames Power Lines Corporation • Festival Hydro Inc. • Hydro One Networks Inc. • Wellington North Power Inc. • West Coast Huron Energy Inc. • Westario Power Inc.

17. Niagara	• Canadian Niagara Power Inc. [Port Colborne] • Grimsby Power Inc. • Haldimand County Hydro Inc.** • Horizon Utilities Corporation • Hydro One Networks Inc. • Niagara Peninsula Energy Inc. • Niagara-On-The-Lake Hydro Inc. • Welland Hydro-Electric System Corp. • Niagara West Transformation Corporation* * Changes to the May 17, 2013 OEB Planning Process Working Group Report
18. North of Moosonee	N/A → This region is not within Hydro One's territory
19. North/East of Sudbury	• Greater Sudbury Hydro Inc. • Hearst Power Distribution Company Limited • Hydro One Networks Inc. • North Bay Hydro Distribution Ltd. • Northern Ontario Wires Inc.
20. Renfrew	• Hydro One Networks Inc. • Ottawa River Power Corporation • Renfrew Hydro Inc.
21. St. Lawrence	• Cooperative Hydro Embrun Inc. • Hydro One Networks Inc. • Rideau St. Lawrence Distribution Inc.

**This Local Distribution Company (LDC) has been acquired by Hydro One Networks Inc. Please refer to the letter for a brief description on the acquisition approved by the Ontario Energy Board (OEB).

Appendix C

1) Needs Assessment Report – London Area
2) Local Planning Report – Strathroy TS
3) Local Planning Report – Woodstock TS Restoration

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

NEEDS ASSESSMENT REPORT

Region: London

Date: April 1, 2015

Prepared by: London Area Study Team

London Area Study Team	
Organization	**Name**
Hydro One Networks Inc. (Lead Transmitter)	Kennan Ip Jennifer Li Raymond Zeng
Independent Electricity System Operator	Phillip Woo Kun Xiong Jiya Shoaib
Entegrus Power Lines	Matthew Meloche
Erie Thames Power Lines Corporation	Chuck deJong Josh Smith Tim Collins
London Hydro Inc.	Bill Milroy Ismail Sheikh
St. Thomas Energy Inc.	Larry Martin
Tillsonburg Hydro Inc.	Stephen Gradish
Woodstock Hydro Services Inc.	Jay Heaman
Hydro One Networks Inc. (Distribution)	Alexander Hamlyn

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the London Area 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	London Area		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	February 2, 2015	**END DATE**	April 3, 2015

1. INTRODUCTION

The purpose of this Needs Assessment (NA) report is to undertake an assessment of the London Area 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, the Independent Electricity System Operator (IESO) will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or whether both are required.

2. REGIONAL ISSUE / TRIGGER

The NA for the London Area 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 Regions is completed and has been initiated for Group 2 Regions. The London Area belongs to Group 2. The NA for the London Area was triggered on January 30, 2015 and was completed on March 31, 2015.

3. SCOPE OF NEEDS ASSESSMENT

The scope of the NA study was conducted for the next 10 years as per the recommendations of the Planning Process Working Group (PPWG) Report to the Board. As such, relevant data and information was collected up to the year 2023.

Needs emerging over the next 10 years and requiring coordinated regional planning may be further assessed as part of the IESO-led SA, which will determine the appropriate regional planning approach: IRRP, RIP, and/or local planning.

This NA included a review of transmission system connection facilities capability, which covers station and line loading, thermal and voltage analysis as well as a review of system reliability, operational issues such as load restoration, and assets approaching end-of-useful-life.

4. INPUTS/DATA

Study team participants, including representatives from LDCs, the IESO, and Hydro One Transmission provided information for the London Area. 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. In this region, asset utilization is at the capacity threshold even when LDCs CDM forecast is taken into account. Accordingly, further assessment is required to determine possible targeted CDM activities by feeders and station(s) to ensure CDM will meet load reduction forecasts. See Section 4 for further details.

5. NEEDS ASSESSMENT METHODOLOGY

The assessment's primary objective was to identify the electrical infrastructure needs in the London Area over the study period (2014 to 2023). The assessment reviewed available information and load forecasts and included single contingency analysis to confirm needs, if and when required. See Section 5 for further details.

6. RESULTS

Transmission Capacity Needs

A. 230/115 kV Autotransformers

- The 230/115 kV autotransformers (Buchanan TS and Karn TS) supplying the London Area are adequate over the study period for the loss of a single 230/115 kV autotransformer.

B. 230 kV Transmission Lines

- The 230 kV circuits supplying the London Area are adequate over the study period for the loss of a single 230 kV circuit.
- Under high eastwardly flows and or high generation conditions, W44LC, W45LS, N21W, N22W and S47C may be overloaded under pre-contingency conditions. This issue will be further assessed by IESO as part of bulk system planning.

C. 115kV Transmission Lines

- The 115 kV circuit W8T reaches its continuous rating pre-contingency in 2014 based on the gross load forecast.
- The remaining 115 kV circuits supplying the London Area are adequate over the study period for the loss of a single 115 kV circuit.

D. 230 kV and 115 kV Connection Facilities

- Loadings at Aylmer TS, Strathroy TS and Wonderland TS exceed their transformer 10-Day Long Term Rating (LTR) in 2014 based on the net load forecast. The limitation at Aylmer TS will be addressed through the currently planned sustainment investment. Tillsonburg TS is forecasted to exceed its 10-Day LTR by the end of near term. Clarke TS is forecasted to exceed its 10-Day LTR in 2014 based on the gross load forecast, but is expected to be adequate to meet the net load forecast for the remainder of the study as planned CDM targets and DG contributions continue to offset the load growth.
- Historical data shows that Buchanan DESN power factor may be below Ontario Resource and Transmission Assessment Criteria under peak load conditions.

System Reliability, Operation and Restoration Review

Based on the net and gross load forecast, the 115 kV voltages at Tillsonburg TS were found to be less than minimum requirements under pre-contingency conditions in the near term.

Based on the gross and net load forecast, the loss of one element will not result in load interruption greater than 150MW in the London Region. The maximum gross and net load interrupted by configuration due to the loss of two elements is below the load loss limit of 600MW by the end of the 10-year study period.

For the loss of two elements on the 230kV system, the gross and net load interrupted by configuration at peak conditions will exceed 150 MW and 250 MW.

Under peak load conditions with the Buchanan 115 kV capacitor in-service, the 115 kV voltage reaches its maximum limit. Accordingly, switching in any additional 230 kV capacitors at Buchannan becomes challenging. This is an operational issue and will be discussed between IESO and Hydro One.

Aging Infrastructure / Replacement Plan

During the study period, plans to replace or add equipment do not affect the needs identified.

7. RECOMMENDATIONS

Based on the findings of the Needs Assessment, the study team recommends that:

a) The following needs should be further assessed as part of the Scoping Assessment to determine if CDM/DG can fully or partly address them or wires planning should be undertaken:

- Transformation capacity limitations at Strathroy TS, Tillsonburg TS, Wonderland TS, Clarke TS and Talbot TS
- Thermal and voltage limitations along the 115kV circuit W8T
- Load restoration concerns following the loss of two elements as described in section 6.2

b) No further regional coordination is required and following needs should be further assessed as part of local planning :

- Low power factor at Buchanan DESN

TABLE OF CONTENTS

LIST OF FIGURES AND TABLES

1 INTRODUCTION

This Needs Assessment (NA) report provides a summary of needs that are emerging in the London Area between 2014 – 2023. 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 London Area 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 needs.

This report was prepared by the London Area 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 IESO.

Table 1: Study Team Participants for London Area

No.	Company
1.	Hydro One Networks Inc. (Lead Transmitter, "Hydro One Transmission")
3.	Independent Electricity System Operator ("IESO")
4.	Entegrus Power Lines lnc.
5.	Erie Thames Power Lines Corporation
6.	London Hydro Inc.
7.	St. Thomas Energy Inc.
8.	Tillsonburg Hydro Inc.
9.	Woodstock Hydro Services Inc.
10.	Hydro One Networks Inc. (Distribution)

2 REGIONAL ISSUE / TRIGGER

The NA for the London Area 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 London Area belongs to Group 2. The NA for this area was triggered on January 30, 2015 and was completed on March 31, 2015.

3 SCOPE OF NEEDS ASSESSMENT

This NA covers the London Area over an assessment period of 2014 to 2023. The scope of the NA includes a review of transmission system connection facility capability which covers transformer station and line 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 London Area Description and Connection Configuration

The London Area includes the municipalities of Oxford County (comprising Township of Blandford-Blenheim, Township of East Zorra-Tavistock, Town of Ingersoll, Township of Norwich, Township of South-West Oxford, Town of Tillsonburg, Township of Zorra), City of Woodstock, Middlesex County (comprising Municipality of Adelaide Metcalfe , Municipality of Lucan Biddulph, Municipality of Middlesex Centre, Municipality of North Middlesex, Municipality of Southwest Middlesex, Municipality of Strathroy-Caradoc, Municipality of Thames Centre, Village of Newbury), City of London, Elgin County (comprising Municipality of Town of Aylmer, Municipality of Bayham, Municipality of Central Elgin, Municipality of West Elgin, Municipality of Dutton/Dunwich, Township of Malahide, Township of Southwold), City of St. Thomas. In addition, the facilities located in the London Region supply part of Norfolk County. The boundaries of the London Area are shown below in Figure 1.

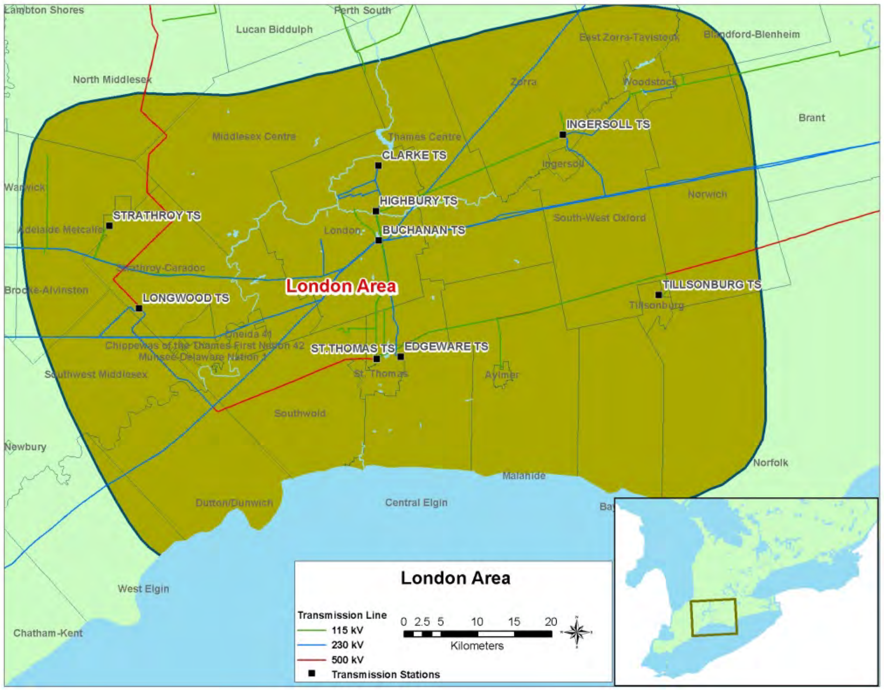


Figure 1: London Area Map

Electrical supply to the London Area is provided through a network of 230 kV and 115 kV circuits supplied by 500/230 kV autotransformers at Longwood Transformer Station (TS) and 230/115 kV autotransformers at Buchanan TS and Karn TS. There are fourteen Hydro One step-down TS's, four direct transmission connected load customers and three transmission connected generators in the London Area. The distribution system consists of voltage levels 27.6 kV and 4.16kV.

The existing facilities in the London Area are summarized below and depicted in the single line diagram shown in Figure 2. The 500kV system is part of the bulk power system and is not studied as part of this Needs Assessment. Also, although depicted, Duart TS is not included in the London Area study and will be studied as part of the Chatham Area Regional Infrastructure Plan.

- Longwood TS is the major transmission station that connects the 500kV network to the 230kV system via two 500/230 kV autotransformers.

- Buchanan TS and Karn TS are the transmission stations that connect the 230kV network to the 115kV system via 230/115 kV autotransformers.

- Fourteen step-down transformer stations supply the London Area load: Aylmer TS, Buchanan TS, Clarke TS, Commerceway TS, Edgeware TS, Highbury TS, Ingersoll

TS, Nelson TS, Strathroy TS, St. Thomas TS, Talbot TS, Tillsonburg TS, Wonderland TS, and Woodstock TS.

- Four Customer Transformer Stations (CTS) are supplied in the London Area: Ford Talbotville CTS, Enbridge Keyser CTS, Lafarge Woodstock CTS, and Toyota Woodstock CTS.

- There are 3 existing Transmission connected generating stations in the London Area as follows:
    - Suncor Adelaide GS is a 40 MW wind farm connected to 115 kV circuit west of Strathroy TS
    - Port Burwell GS is a 99 MW wind farm connected to 115kV circuit near Tillsonburg TS
    - Silver Creek GS is a 10 MW solar generator connected to 115kV circuit near Aylmer TS

- There are a network of 230 kV and 115 kV circuits that provide supply to the London Area, as shown in Table 2 below:

Table 2: Transmission Lines in London Area

Voltage	Circuit Designations	Location
230 kV	N21W, N22W	Scott TS to Buchanan TS
	W42L, W43L	Longwood TS to Buchanan TS
	W44LC	Longwood TS to Chatham TS to Buchanan TS
	W45LS	Longwood TS to Spence SS to Buchanan TS
	W36, W37	Buchanan TS to Talbot TS
	D4W, D5W	Buchanan TS to Detweiler TS
	M31W, M32W	Buchanan TS to Ingersoll TS to Middleport TS
	M33W	Buchanan TS to Brantford TS
115 kV	W2S	Buchanan TS to Strathroy TS
	W5N	Buchanan TS to Nelson TS
	W6NL	Buchanan TS to Highbury TS to Nelson TS
	W9L	Buchanan TS to Highbury TS
	W7, W12 WW1C W8T WT1T W3T, W4T WT1A K7, K12	Buchanan TS to CTS Buchanan TS to CTS Buchanan TS to ESWF JCT ESWF JCT to Tillsonburg TS Buchanan TS to St. Thomas TS Aylmer TS to Lyons JCT Karn TS to Commerce Way TS

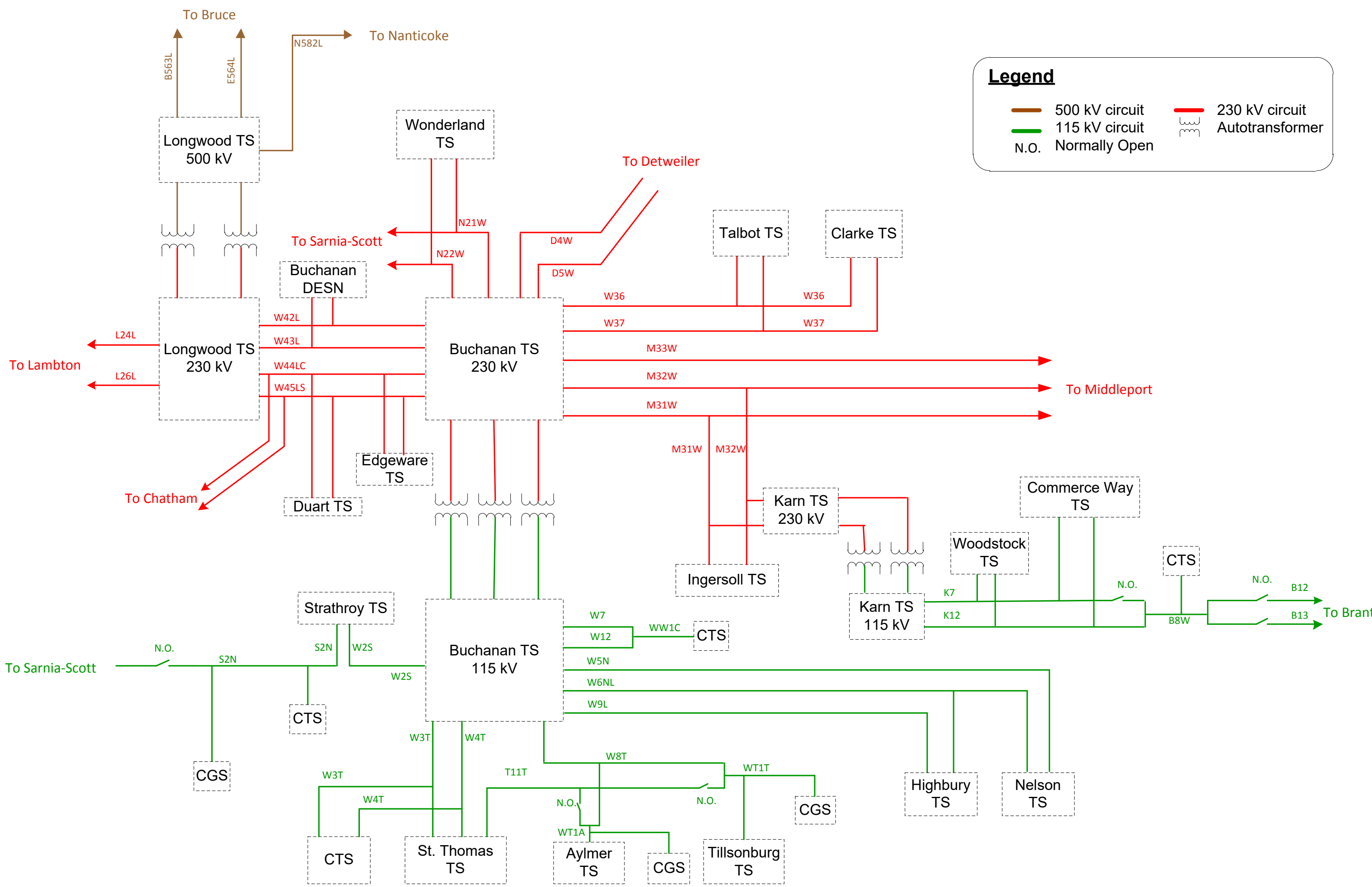


Figure 2: Single Line Diagram – London Area

4 INPUTS AND DATA

In order to conduct this Needs Assessment, study team participants provided the following information and data to Hydro One:

- IESO provided:
  i. Historical 2013 regional coincident peak load and station non-coincident peak load
  ii. List of existing reliability and operational issues
  iii. Conservation and Demand Management (CDM) and Distributed Generation (DG) data
- LDCs provided historical (2011-2013) net load, and gross load forecast (2014-2023)
- Hydro One (Transmission) provided transformer, station, and circuit ratings
- Any relevant planning information, including planned transmission and distribution investments provided by the transmitter and LDCs, etc.

4.1 Gross Load Forecast

The gross load forecast describes the total forecast electrical consumption in the area without considering the combined impact of CDM and DG. As per the data provided by the study team, the gross load in the London Area is expected to grow at an average rate of approximately 0.9% annually from 2014 – 2023.

4.2 Net Load Forecast

The net load forecast builds from the gross load forecast and includes the planned CDM targets and DG contributions. For the London Area, the net load is expected to grow at an average rate of approximately 0.2% annually from 2014 – 2023.

5 NEEDS ASSESSMENT METHODOLOGY

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

1. The assessment is based on summer peak loads.

2. Load data for transmission connected industrial customers in the region was assumed to be consistent with historical peak loads.

3. The LDC's load forecast is translated into load growth rates and is applied onto the 2013 summer peak load as a reference point.

4. Accounting for (2) and (3) mentioned 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 is analyzed to determine if needs can be deferred.

   A coincident version of the gross and net load forecast was used to assess the transformer capacity needs (section 6.1.1), 230 kV transmission line needs (section 6.1.2), 115 kV transmission line needs (6.1.3) and system reliability operation and restoration needs (6.2).

   A non-coincident version of the net load forecast was used to assess the station capacity as presented in section 6.1.4.

   A coincident peak load forecast and a non-coincident peak load forecast were produced for each gross load and net load forecasts.

5. Review impact of any on-going and/or planned development projects in the London Area 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).

8. 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.

9. 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 long-term emergency (LTE) ratings and transformers within their summer or winter 10-Day LTR, as appropriate.
- All voltages must be within pre and post contingency ranges as per Ontario Resource and Transmission Assessment Criteria (ORTAC) (Section 4.2) 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 (Section 7.2) criteria.

6 RESULTS

This section summarizes the results of the Needs Assessment in the London Area.

6.1 Transmission Capacity Needs

6.1.1 230/115 kV Autotransformers

The 230/115 kV autotransformers (Buchanan TS and Karn TS) supplying the London Area are adequate over the study period for the loss of a single 230/115 kV autotransformer.

6.1.2 230 kV Transmission Lines

Overall, the 230 kV circuits supplying the London Area are adequate over the study period for the loss of a single 230 kV circuit in the Region.

Under high eastwardly flows and/or high generation conditions, W44LC, W45LS, N21W, N22W and S47C may be overloaded under pre-contingency conditions. This issue will be further assessed by IESO as part of bulk system planning.

6.1.3 115 kV Transmission Lines

The 115 kV circuit W8T from Buchanan TS to Edgeware JCT reaches its continuous rating under pre-contingency conditions in the near term based on the gross load forecast. Such thermal overload is deferred to the medium term based on the net load forecast. In addition, the 115kV system is also restricted for any new DG connections at Tillsonburg TS because of capacity limitation.

The remaining 115 kV circuits supplying the London Area are adequate over the study period for the loss of a single 115 kV circuit in the area.

6.1.4 230 kV and 115 kV Connection Facilities

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

Aylmer TS
Aylmer TS T2/T3 is forecasted to exceed its 10-Day LTR in 2014 based on the net load forecast (approximately 113% Summer 10-Day LTR in 2014).

Buchanan TS

Historical data shows that Buchanan DESN power factor is below ORTAC criteria under peak load conditions.

Clarke TS

Clarke TS T3/T4 exceeds its 10-Day LTR in 2014 based on the net load forecast (approximately 101% of Summer 10-Day LTR). Although based on the planned CDM targets and DG contributions, the station capacity for Clarke TS T3/T4 is adequate to meet the net forecasted demand over the remainder of the study period, loading at Clarke TS is above its LTR based on gross load.

Strathroy TS

Strathroy TS T1/T2 is forecasted to exceed its 10-Day LTR in 2014 based on the net load forecast (approximately 125% of Summer 10-Day LTR in 2014)

Talbot TS

Talbot TS T1/T2 and T3/T4 DESN is near its 10-Day LTR rating in the near term based on the net load forecast and is above its LTR based on gross load. The load forecast for Talbot TS increases significantly in year 2015 by 17MW based on the ongoing planning activities of the LDC to convert and transfer Nelson TS load to Talbot TS to accommodate the redevelopment plans of Nelson TS. The load transferred to Talbot TS in 2015 is temporary in nature, and will be transferred back to Nelson TS when the redevelopment is expected to be complete in 2019.

Tillsonburg TS

For the loss of T3, Tillsonburg TS T1 is forecasted to exceed its 10-Day LTR towards the end of the near term based on the net load forecast (approximately 102% of Summer 10-Day LTR in 2018) and is above its LTR based on gross load

Wonderland TS

For the loss of T6, Wonderland TS T5 is forecasted to exceed its 10-Day LTR 2014 based on the net load forecast (approximately 112% of Summer 10-Day LTR in 2014).

All the other TSs in the London Area are forecasted to remain within their normal supply capacity during the study period.

6.2 System Reliability, Operation and Restoration Review

Based on the net load forecast, the pre-contingency voltage at Tillsonburg TS 115kV is expected to be less than the minimum voltage level as established in Section 4.3 of the ORTAC.

Under peak load conditions with the Buchanan 115 kV capacitor in-service, the 115 kV voltage reaches its maximum limit. Accordingly, switching in any additional 230 kV capacitors at Buchannan becomes challenging. This is an operational issue and will be discussed between IESO and Hydro One.

Based on the gross and net coincident load forecast, the loss of one element will not result in load interruption greater than 150MW in the London Region. The maximum gross and net load interrupted by configuration due to the loss of two elements is below the load loss limit of 600MW by the end of the 10-year study period.

Based on the gross coincident load forecast at Buchanan TS, the load interrupted by configuration will exceed 150 MW for the loss of double-circuit line W42L and W43L. However, based on the net coincident load forecast, which accounts for CDM and DG, the load interrupted by configuration does not exceed 150 MW. Therefore, no action is required at this time and this will be reviewed in the next planning cycle.

Based on the gross and net coincident load forecast for Ingersoll TS and stations connected along the 115 kV circuits K7/K12/B8W, the load interrupted by configuration at peak will exceed 150 MW for the loss of double-circuit 230kV line M31W and M32W. Similarly, based on the gross and net coincident load forecast at Clarke TS and Talbot TS, the load interrupted by configuration will exceed 250 MW for the loss of double-circuit 230kV line W36 and W37. Furthermore, based on the gross and net coincident load forecast at Wonderland TS and Modeland TS, the load interrupted by configuration will exceed 150 MW for the loss of double-circuit 230kV line N21W and N22W.

6.3 Aging Infrastructure and Replacement Plan of Major Equipment

Hydro One reviewed the sustainment and development initiatives that are currently planned for the replacement of any autotransformers, power transformers and high-voltage cables. These sustainment plans do not affect the results of this NA study. During the study period:

- The existing Aylmer TS will be replaced with a new DESN with two 25/33.3/41.7 MVA transformer and four feeder positions and is scheduled to be completed in 2019. The replacement plan will address the transformer capacity need identified in section 6.1.4.
- The existing Nelson TS DESN will be redeveloped to maintain supply to the area. Final arrangement will depend on the ongoing discussions between the Hydro One and the LDC. This NA study assumes the LDC’s plan to redevelop Nelson TS and convert the station LV from 13.8kV to 27.6kV.

- As part of the Burlington-Nanticoke Area Regional Infrastructure Planning, there is an ongoing plan to replace existing switches on B12/B13 with 115 kV breakers to address the voltage and capacity issue in the Brant area. This project will allow the existing normally-open points on B12/B13 to be operated normally-closed. The breakers cause no adverse impacts to the London Region. As the project is still in its planning phase, the ability to provide backup to the Woodstock area has not yet been confirmed.

7 RECOMMENDATIONS

Based on the findings and discussion in Section 6 of the Needs Assessment report, the study team recommends that the following needs should be further assessed as part of the Scoping Assessment to determine if CDM/DG can fully or partly address them or Wires Planning should be undertaken:

- Transformation capacity limitations at Strathroy TS, Tillsonburg TS, Wonderland TS, Clarke TS and Talbot TS
- Thermal and voltage limitations along the 115kV circuit W8T
- Load restoration concerns following the loss of two elements as described in section 6.2

The following need should be further assessed as part of local planning by Hydro One and relevant LDCs:

- Low power factor at Buchanan DESN

8 NEXT STEPS

IESO and Hydro One will initiate a SA and Local Planning process to address the relevant needs as per the recommendations in Section 7.

9 REFERENCES

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013
ii) IESO 18-Month Outlook: March 2014 – August 2015
iii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0

10 ACRONYMS

BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
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
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

Hydro One Networks Inc.
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LOCAL PLANNING REPORT

Strathroy TS Transformer Capacity
Region: London Area

Date: September 12, 2016
Revision: Final

anning Study Team

This report is prepared on behalf of the Strathroy Sub-region Local Planning study team with the participation of representatives from the following organizations:

Organizations
Hydro One Networks Inc. (Lead Transmitter)
Entegrus Inc.
Hydro One Networks Inc. (Distribution)

Disclaimer

This Local Planning Report was prepared for the purpose of developing wires-only options and recommending a preferred solution(s) to address the local needs identified in the Needs Assessment (NA) report for the London Region that do not require further coordinated regional planning. The preferred solution(s) that have been identified through this Local Planning Report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Local Planning 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 Local Planning 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 Local Planning Report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the Local Planning 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 Local Planning Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

LOCAL PLANNING EXECUTIVE SUMMARY

REGION	London Region (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	June 17, 2016	**END DATE**	September 12, 2016

1. INTRODUCTION

In 2015, a Needs Assessment study was conducted to assess the transmission system supplying the London Region and a number of issues were identified. Subsequently, the IESO carried out its Scoping Assessment to determine the degree of regional coordination required to address each need. It was concluded that Strathroy TS transformer capacity need is local in nature and is best addressed by wires options through local planning led by Hydro One with participation of the impacted LDCs. The purpose of this Local Planning report is to develop wires-only options and recommend a preferred solution that will address the Strathroy TS transformation capacity need referenced in both Needs Assessment and the Scoping Assessment reports for London Area.

The development of the LP 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".

2. LOCAL NEEDS ADDRESSED IN THIS REPORT

During Needs Assessment, it was forecasted that Strathroy TS transformer will exceed its capacity and this report is developed to address this transformer capacity need.

3. FINDINGS

Based on the updated load forecast information, while load at Strathroy TS is expected to experience a mild growth over the next ten years, there is sufficient transformer capacity at Strathroy TS over the study period.

4. CONCLUSION

The local planning study team agreed that no action is required at this time.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1 Introduction

As part of the OEB-mandated regional planning process, a Needs Assessment study for London area was conducted in 2015 by Hydro One Transmission, Independent Electricity System Operator ("IESO"), Erie Thames Power, Entegrus, Hydro One Distribution, London Hydro, St. Thomas Energy, Tillsonburg Hydro and Woodstock Hydro. The study assessed the electricity infrastructure supplying the London Region for the ten – year period starting from 2014 and it identified a number of constraints in the area. The IESO subsequently carried out its Scoping Assessment and concluded that, among other things, need in the Strathroy sub-region should be addressed through Local Planning between Hydro One Transmission and impacted local distribution companies ("LDCs").

This Local Planning report was prepared for the purposes of addressing the Strathroy TS transformation capacity need referenced in both Needs Assessment and the Scoping Assessment reports for London Area.

1.1 Geographical Area and Existing Supply Network

Strathroy Transformer Station ("TS") is a transmission substation that is located in Middlesex County in Southwestern Ontario and supplies the surrounding mainly-rural area, including the Middlesex county and townships of Adelaide-Metcalfe, Warwick, Strathroy-Caradoc. Presently, Strathroy TS is supplied radially from Buchanan TS, 45 km to the east, via 115 kV circuit W2S. Alternately, it can be supplied from the west from Scott TS via 115 kV circuit S2N. Strathroy TS houses two 25/33/42 MVA 110/28 kV step-down transformers and currently supplies Entegrus and Hydro One Distribution at 27.6 kV level.

Following the replacement of transformer T2 at Strathroy TS in August 2012, there is plan in place to replace T1 like-for-like by 2017.

The physical location of Strathroy TS and the existing substation assets are shown in Figure 1 and Figure 2 respectively.

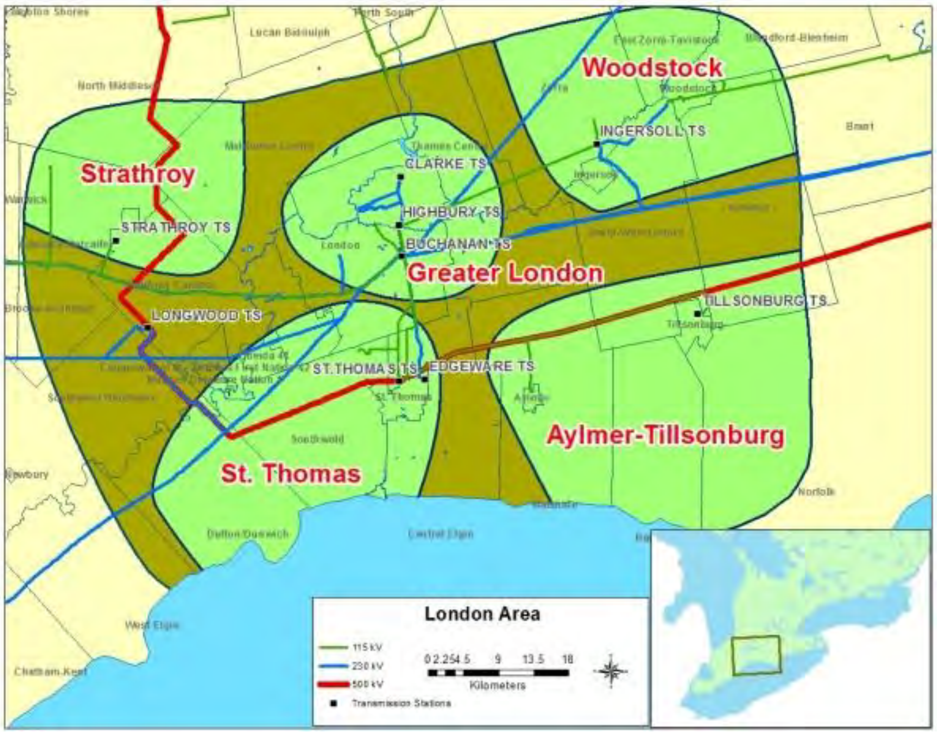

Figure 1 – Map of Strathroy Sub-region and London Region

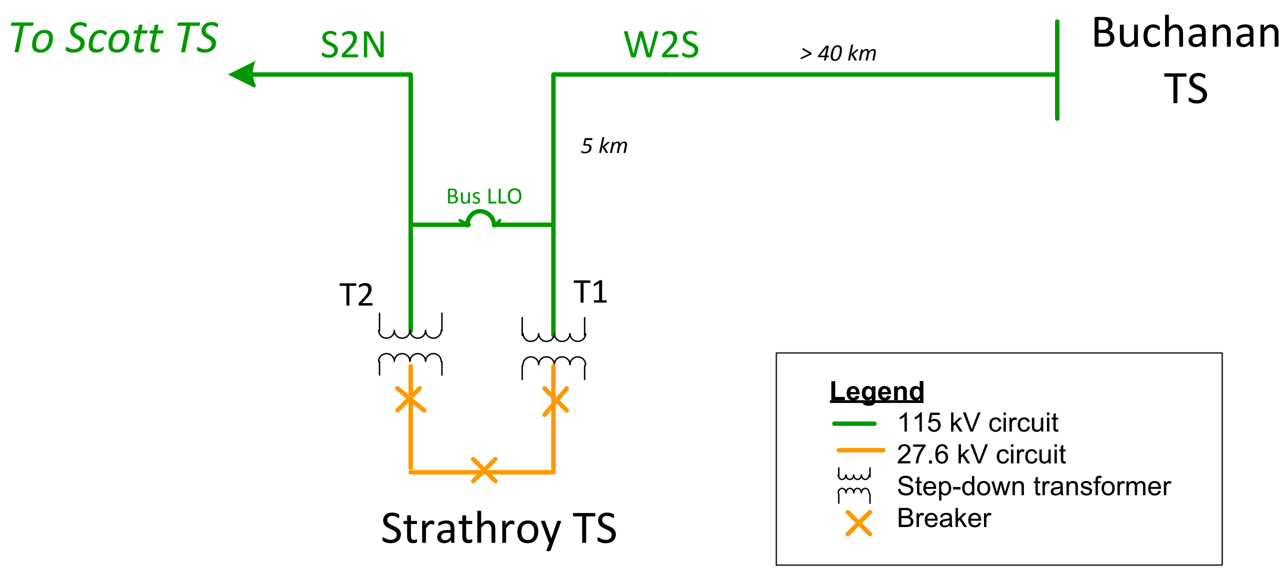

Figure 2 – Simplified schematic of Strathroy TS

2 Load Forecast

Ten – year electricity load forecast was prepared with inputs from downstream LDCs and the IESO. Entegrus and Hydro One Distribution provided gross load forecasts for 2016 – 2025. The station gross load forecast was then extrapolated by applying the corresponding annual growth rates to 2015 historical demand. The net load forecast takes account of conservation demand management ("CDM") programs and distributed generation ("DG") in the distribution network that are either presently in place or foreseen by the IESO, each of which may have the effect of reducing the forecast demand to be supplied. The forecasted CDM achievement in Strathroy TS is represented by percentages reduction applied to gross peak demand and DG information represents the annual incremental, effective capacity of all generation contracts with the IESO. The 2015 observed station peak for Strathroy TS is 38.9 MW and for planning purpose, the reference point of the forecast was adjusted upward by 6% to account for extreme weather correction. The resultant net load forecast is tabulated in Table 1.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Station Gross Load		41.8	42.2	42.7	43.1	43.6	44.1	44.6	45.1	45.6	46.1
Incremental DG		0.15	0	0	0	0	0	0	0	0	0
CDM		1%	2%	3%	4%	5%	5%	6%	6%	7%	7%
Station Net Load	41.3	41.1	41.5	41.4	41.5	41.6	41.8	42.0	42.2	42.5	42.8

Table 1 – Ten-year load forecast for Strathroy TS (MW)

3 Assessment and Findings

The Ontario Resource and Transmission Assessment Criteria ("ORTAC") outlines the supply reliability planning requirements to ensure loading on transmission network does not exceed equipment ratings under both normal and contingency operating conditions. For transformer, in the event where one of the two transformers in a substation suffers an outage, namely a (N – 1) event, loading of the remaining transformer should not exceed its 10 – day limited time rating ("LTR").

At the time of this assessment, the 10 – Day Summer LTR rating for Strathroy TS is 53 MVA (or 50.4 MW at 0.95 power factor)[1]. During Needs Assessment, the combined station load was forecasted to exceed 50 MW in the near term, which means the remaining transformer could be overloaded for the loss its companion transformer. However, in examining the revised and updated load forecast, the 2015 historical actual is tracking 23% lower than the forecasted level in the Needs Assessment and in fact, the revised ten – year net forecast is 17% less than what was previously assumed in Needs Assessment. The downward adjustment

[1] 10 – Day LTR of 53 MVA is rated at 30 °C ambient temperature.

in station load forecast has meant that for the loss of one of the two transformers, the remaining transformer is capable of supplying all of Strathroy TS load while remaining under its 10 – Day LTR rating for the entire study period.

4 Conclusion

Based on the information provided in this report, there is sufficient transformer capacity at Strathroy TS to meet expected load growth over the ten – year study period between 2016 and 2025. Therefore, Entegrus, Hydro One Distribution and Hydro One Transmission agreed that no action is required at this time. Further, the study team will continue to monitor and track the development in the Strathroy sub-region and reconvene should unforeseen needs emerge prior to the next planning cycle starting in 2018.

5 References

[1] Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013

[2] IESO Ontario Resource and Transmission Assessment Criteria (ORTAC)

[3] London Region Needs Assessment Report

[4] London Region Scoping Assessment Report

Appendix A: Acronyms

CDM	Conservation and Demand Management
DG	Distributed Generation
DSC	Distribution System Code
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Planning
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
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
TSC	Transmission System Code

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LOCAL PLANNING REPORT

Woodstock Sub-region Restoration
Region: London Area

Date: May 19, 2017
Revision: Final

Prepared by: Woodstock Sub-region Local Planning Study Team

This report is prepared on behalf of the Woodstock Sub-region Local Planning study team with the participation of representatives from the following organizations:

Organizations
Hydro One Networks Inc. (Lead Transmitter)
Erie Thames Powerlines Corporation
Hydro One Networks Inc. (Distribution)

Disclaimer

This Local Planning Report was prepared for the purpose of developing wires-only options and recommending a preferred solution(s) to address the local needs identified in the Needs Assessment (NA) report for the London Region that do not require further coordinated regional planning. The preferred solution(s) that have been identified through this Local Planning Report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Local Planning Report are based on the information and assumptions provided by study team participants.

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LOCAL PLANNING EXECUTIVE SUMMARY

REGION	London Region (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	September 16, 2016	**END DATE**	May 19, 2017

1. INTRODUCTION

In 2015, a Needs Assessment study was conducted to assess the transmission system supplying the London Region and a number of issues were identified. Subsequently, the IESO carried out its Scoping Assessment to determine the degree of regional coordination required to address each need. It was concluded that Woodstock sub-region restoration need is local in nature and is best addressed by wires options through local planning led by Hydro One with participation of the impacted LDCs. The purpose of this Local Planning report is to develop wires-only options and recommend a preferred solution that will address the Woodstock sub-region restoration need referenced in both Needs Assessment and the Scoping Assessment reports for London Area.

The development of the LP 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".

2. LOCAL NEED ADDRESSED IN THIS REPORT

During Needs Assessment, it was identified that more than 180 MW of load will be interrupted by configuration following the simultaneous loss of the 230 kV supply circuits M31W/M32W and this report is developed to address the restoration need.

3. FINDINGS

Based on the updated load forecast and transfer capability information, there is sufficient transfer capability in the existing system to restore interrupted loads from neighbouring regions within prescribed time frames and therefore, satisfying the restoration criteria.

4. CONCLUSION

The local planning study team agreed that no action is required at this time.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1 Introduction

As part of the OEB-mandated regional planning process, a Needs Assessment study for London area was conducted in 2015 by Hydro One Transmission, Independent Electricity System Operator ("IESO"), Erie Thames Powerlines, Entegrus, Hydro One Distribution, London Hydro, St. Thomas Energy, Tillsonburg Hydro and Woodstock Hydro. The study assessed the electricity infrastructure supplying the London Region for the ten – year period starting from 2014 and it identified a number of constraints in the area. The IESO subsequently carried out its Scoping Assessment and concluded that, among other things, need in the Woodstock sub-region should be addressed through Local Planning between Hydro One Transmission and impacted local distribution companies ("LDCs").

This Local Planning report was prepared for the purposes of addressing the Woodstock sub-region M31W/M32W restoration need referenced in both Needs Assessment and the Scoping Assessment reports for London Area. Following the acquisition of Woodstock Hydro, the Woodstock sub-region Local Planning study team is consist of Erie Thames Powerlines, Hydro One Distribution and Hydro One Transmission.

1.1 Geographical Area and Existing Supply Network

The Woodstock sub-region is located in southwestern Ontario and includes town of Ingersoll, City of Woodstock and rest of northern part of Oxford County.

Woodstock sub-region's electricity demand is a mix of residential, commercial and industrial loads. There is no major generation facility in the Woodstock sub-region and power is delivered by the 230 kV and 115 kV transmission lines in the vicinity. The 230 kV double circuit line, M31W and M32W connecting Buchanan TS and Middleport TS, is tapped off at Salford Junction and supplies Karn TS and step-down transformer station Ingersoll TS. Karn TS currently houses two autotransformers which were placed in-service in 2011 as part of the "Woodstock Area Transmission Reinforcement" project and they provide necessary transformation from 230 kV level to 115 kV level. The 115 kV double circuit lines K7/K12 supplied out of Karn TS are approximately 22 km in length and the three transformer stations connected – namely Woodstock TS, Commerce Way TS, and Toyota Woodstock TS – step 115 kV transmission voltage level down to lower distribution voltages for serving customers in the area. Electricity distribution services to customers in the Woodstock sub-region are provided by Erie Thames Powerlines and Hydro One Distribution.

A map of the Woodstock sub-region and schematic of the existing transmission system of the area are shown in Figure 1 and Figure 2 respectively.

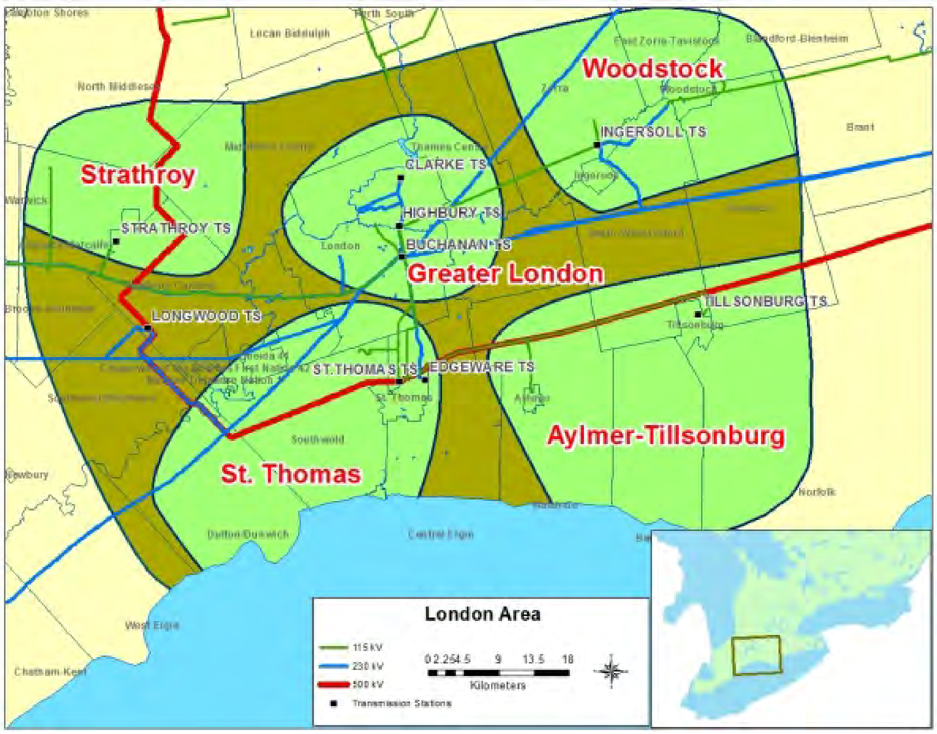


Figure 1 – Map of Woodstock Sub-region and London Region

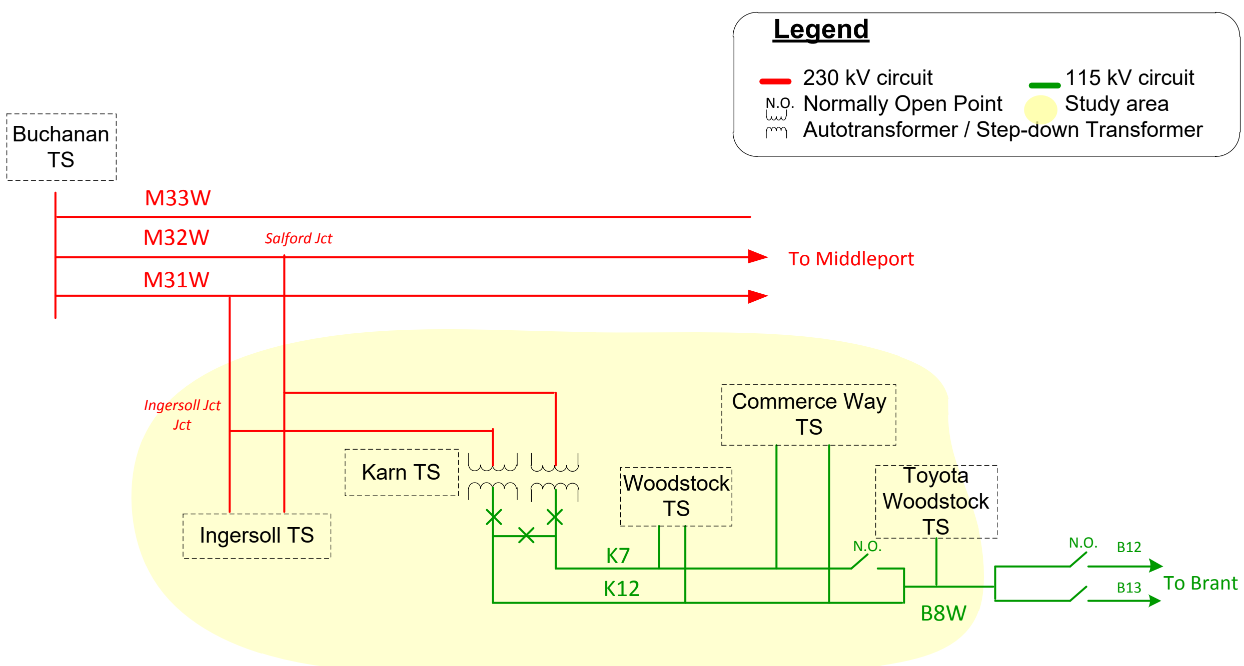


Figure 2 – Simplified schematic of Woodstock sub-region transmission system

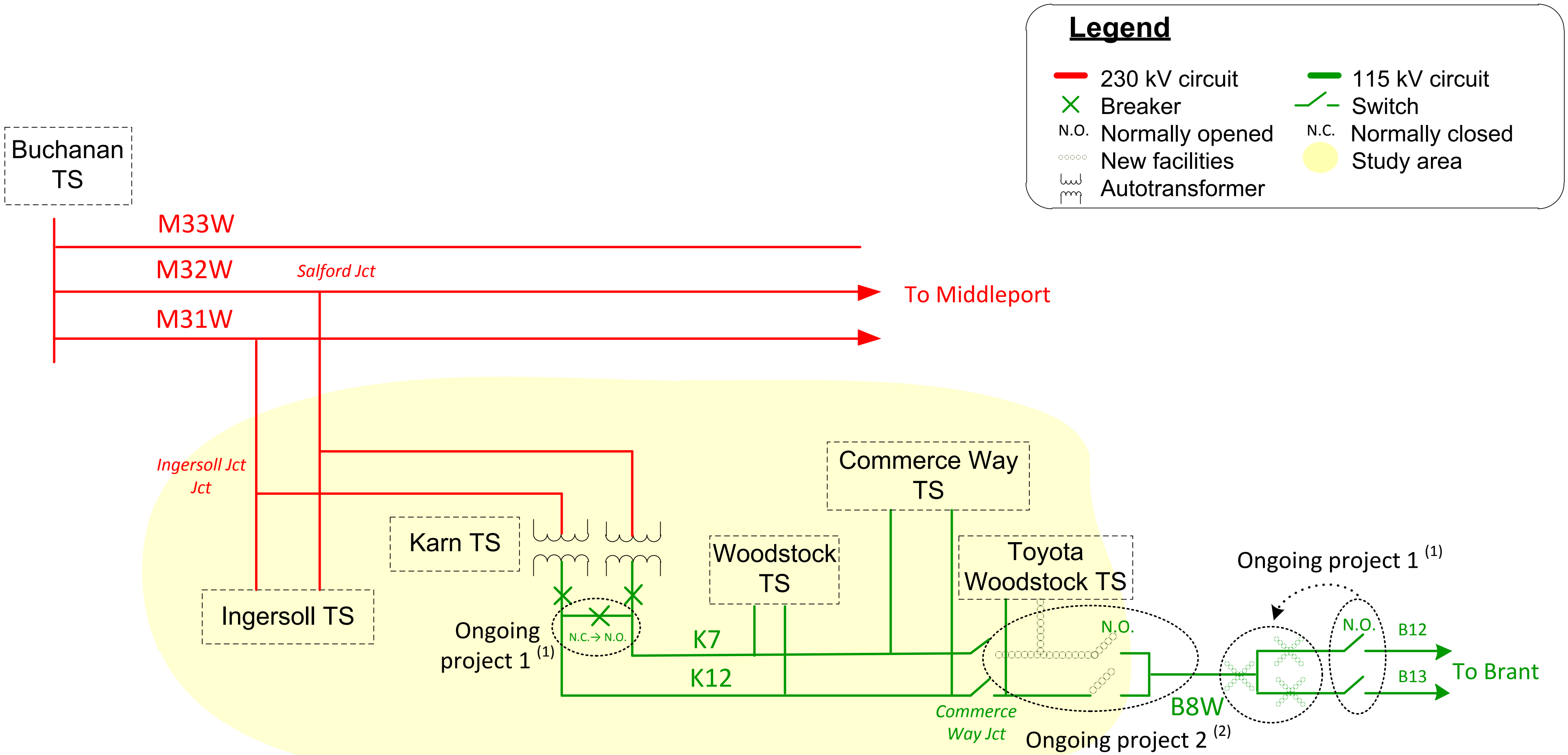
1.2 Planned and Committed Facilities

There are several projects currently under development or being planned to address immediate and near term customer needs and reliability issues within the Woodstock sub-region and neighbouring region.

As shown in Figure 2, Woodstock subsystem and Brant subsystem are electrically isolated at the normally-opened points on B12/B13 circuits. In 2015, the Brant Integrated Regional Resource Plan ("IRRP") study team comprising of Brant County Power Inc., Brantford Power Inc. Hydro One Distribution, Hydro One Transmission and the IESO recommended new switching facilities to be built at Brant TS to address the near term capacity needs in the Brant-Powerline 115 kV sub-system. By replacing the existing normally-opened points on B12/B13 and B8W with three 115 kV breakers and operating the Karn TS 115 kV tie breaker normally open, this project will provide additional supply capacity to the Brant-Powerline 115 kV sub-system. Further, measures will be in place for B8W in-line breaker to be automatically opened for loss of both Karn TS autotransformers. As a result of this project, the Woodstock sub-region will be connected to its neighbouring Brant sub-region electrically in normal operating conditions. The proposed in-service date for this project is Q1 2019. Hydro One brought forward this proposal in its transmission rates application (EB-2016-0160).

Development for a new overhead extension of 115 kV circuit K7/B8W 3 km in length from Commerce Way Junction to Toyota Woodstock TS and a new step-down transformer at Toyota Woodstock TS is currently underway at customer's request to improve supply reliability. The project will be subject to OEB's Leave-to-Construct Section 92 Approval process and the target in-service date is Q1 2019.

These reinforcements are summarized pictorially in Figure 3.



(1) Brant TS – Add 115kV Switching Facilities
(2) Toyota Woodstock TS – Conversion to DESN Configuration

Figure 3 – Planned and committed transmission projects in the Woodstock sub-region

2 Load Forecast

Ten – year electricity load forecast was prepared with inputs from downstream LDCs and the IESO. Erie Thames Powerlines and Hydro One Distribution provided gross load forecasts for 2016 – 2025 inclusive. The station gross load forecast was then extrapolated by applying the corresponding annual growth rates to 2015 historical demand. The Woodstock sub-regional actual coincident peak load in 2015 was approximately 182 MW and for planning purpose, the reference points of step-down transformer stations were adjusted upward by 2 – 4% to account for extreme weather correction[1]. The net load forecast takes account of conservation and demand management ("CDM") programs and distributed generation ("DG") in the distribution network that are either presently in place or foreseen by the IESO, each of which may have the effect of reducing the forecast demand to be supplied. The DG information included represents the annual incremental, effective capacity of all generation contracts with the IESO and in combination with forecasted CDM, they reflect reduction applied to gross peak demand.

Assuming that large industrial customer load will maintain at its current 20 MW level, the total load in the Woodstock sub-region will remain above 180 MW throughout the study period.

The resultant net load forecast on a station basis is tabulated in Table 1.

(MW)		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Commerce Way TS	Station Gross Load		34.9	35.0	35.1	35.3	35.4	35.5	35.6	35.8	35.9	36.0
	Incremental DG		0.03	0	0	0	0	0	0	0	0	0
	CDM		0.4	0.6	1.0	1.4	1.7	1.9	2.1	2.2	2.4	2.6
	Station Net Load	33.4	34.5	34.4	34.1	33.9	33.7	33.6	33.5	33.5	33.5	33.4
Ingersoll TS	Station Gross Load		76.4	76.5	76.6	76.6	76.7	76.8	76.9	77.0	77.1	77.2
	Incremental DG		0.00	0.20	0.49	0	0	0	0	0	0	0
	CDM		0.8	1.4	2.2	3.0	3.6	4.1	4.5	4.8	5.2	5.6
	Station Net Load	75.1	75.6	74.9	73.9	73.7	73.1	72.8	72.4	72.2	71.9	71.6
Woodstock TS	Station Gross Load		58.3	58.5	58.7	58.9	59.1	59.3	59.5	59.7	60.0	60.2
	Incremental DG		0.02	0.24	0	0	0	0	0	0	0	0
	CDM		0.6	1.0	1.7	2.3	2.8	3.1	3.5	3.7	4.1	4.3
	Station Net Load	56.5	57.6	57.2	57.0	56.6	56.3	56.2	56.0	56.0	55.9	55.8
Toyota Woodstock TS	Station Load*		20	20	20	20	20	20	20	20	20	20
Woodstock Sub-region Total Net Load			188	186	185	184	183	182	182	182	181	181

* Assumed load, based on Hydro One Transmission's information

Table 1 – Ten-year load forecast for Woodstock sub-region (MW)

3 Assessment and Findings

The Ontario Resource and Transmission Assessment Criteria ("ORTAC") outlines the supply reliability planning requirements to ensure loading on transmission network does not exceed equipment ratings under both normal and contingency operating conditions. Among other things,

[1] Weather correction factors for Commerce Way TS, Ingersoll TS and Woodstock TS are 4%, 2% and 3% respectively

the supply restoration criteria in ORTAC requires that in the planning of electrical services to an area, the delivery system needs to have sufficient ability to restore interrupted load in a reasonable time following the critical double-element of [N – 2] contingency. Specifically, for interrupted load of over 250 MW, the portion above 250 MW must be restored within 30 minutes. For interrupted load level between 150 and 250 MW, the portion above 150 MW must be restored within 4 hours with the reminder restored in 8 hours. Additionally, the maximum amount of load that can be interrupted under the security criterion for a [N – 2] contingency is 600 MW. The application of the security criterion identifies when an area would require an alternative source of supply or a greater diversity of supply to maintain an adequate level of security.

For Woodstock sub-region, the critical line section for [N – 2] contingency is M31W/M32W tap between Salford Junction and Ingersoll Junction, which is approximately 11 km in length. Should this contingency occur, all of the sub-region load, which amounts to 188 MW in 2016 (Table 1), would be interrupted by configuration. In accordance with ORTAC, the system is required to restore 38 MW within 4 hours and the remaining 150 MW within 8 hours.

Under such emergency conditions, depending on system performance and availability of switching facilities, all or a portion of a load station could be restored by transferring load to neighbouring unaffected supply. Hydro One Distribution estimated 10 MW of load at Ingersoll TS can be transferred to Highbury TS. Another 8 MW could be transferred from Commerce Way TS to Tillsonburg TS on the feeder level. On the transmission side, the supply from Brant will be able to restore about 20 MW of load in the Woodstock sub-region before minimum allowable post-contingency voltage limit of 108 kV is reached[2]. These measures can be deployed remotely to manage and mitigate the impact of the [N – 2] contingency within the 4 hours timeframe. To restore the remaining 150 MW of interrupted load within 8 hours, field crew from the nearest staffed centre in London area will be dispatched and install temporary fixes on the transmission system such as building emergency by-pass.

4 Conclusion

Based on the information provided in this report, there is sufficient transfer capability on existing system to meet restoration criteria over the ten – year study period between 2016 and 2025. Therefore, Erie Thames Powerlines, Hydro One Distribution and Hydro One Transmission agreed that no further action is required at this time. The study team will continue to monitor and track the development in the Woodstock sub-region and reconvene should unforeseen needs emerge prior to the next regional planning cycle starting in 2018.

[2] Based on the load forecast for stations connected to B12/B13 as documented in Brant IRRP and Burlington to Nanticoke Local Planning report: combined loading of 158 MW was assumed for Powerline MTS and Brant TS; 54 MW for Dundas TS #2.

5 References

[1] Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013

[2] IESO Ontario Resource and Transmission Assessment Criteria (ORTAC)

[3] London Region Needs Assessment Report

[4] London Region Scoping Assessment Report

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MW	Megawatt
MVA	Mega Volt-Ampere
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
TSC	Transmission System Code

Appendix D

1) Needs Assessment Report – Greater Bruce / Huron
2) Local Planning Report – Bruce HWB TS Power Factor Assessment
3) Local Planning Report – L7S Thermal Overload
4) Local Planning Report – Wingham TS Power Factor Assessment

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NEEDS ASSESSMENT REPORT

Region: Greater Bruce – Huron

Revision: Final

Date: May 6, 2016

Prepared by: Greater Bruce-Huron Study Team

Distribution

Transmission

Greater Bruce-Huron Region Study Team
Organization
Entegrus
Erie Thames Power
Festival Hydro Inc.
Goderich Hydro - West Coast Huron Energy Inc.
Hydro One Networks Inc. (Distribution)
Hydro One Networks Inc. (Lead Transmitter)
Independent Electricity System Operator
Wellington North Power Inc.
Westario Power Inc.

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Greater Bruce-Huron 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.

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NEEDS ASSESSMENT EXECUTIVE SUMMARY

REGION	Greater Bruce-Huron Region (the Region)		
LEAD	Hydro One Networks Inc. (Hydro One)		
START DATE	February 29, 2016	**END DATE**	April 28, 2016

1. INTRODUCTION

The purpose of this Needs Assessment report is to undertake an assessment of the Greater Bruce-Huron 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, the Independent Electricity System Operator (IESO) will initiate the Scoping Assessment process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or whether both are required.

2. REGIONAL ISSUE/ TRIGGER

The Needs Assessment for the Greater Bruce-Huron 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 - Group 1 Regions are being reviewed first. The Greater Bruce-Huron Region belongs to Group 3. The Needs Assessment for this Region was triggered on February 29, 2016 and was completed on April 28, 2016.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this Needs Assessment was limited to the next 10 years as per the recommendations of the Planning Process Working Group Report to the OEB.

The scope of the Needs Assessment includes a review of transmission system capability which covers transformer station capacity, transmission circuit thermal capacity, and voltage performance. System reliability, operational issues and asset replacement plans were also briefly reviewed as part of this Needs Assessment.

Needs emerging over the next 10 years and requiring coordinated regional planning may be further assessed as part of the IESO-led Scoping Assessment and/or IRRP, or in the next planning cycle. If required, an IRRP will develop a 20-year strategic direction for the Region.

4. INPUTS/DATA

Study team participants, including representatives from LDCs, the IESO, and Hydro One transmission provided information for the Greater Bruce-Huron Region. The information included: planning activities already underway, historical load and power factor, load forecast, conservation and demand management (CDM) and distributed generation (DG) information, system reliability performance, operational issues and major equipment approaching end-of-life.

5. ASSESSMENT METHODOLOGY

The assessment's primary objective was to identify the electrical infrastructure needs in the Region over the study period (2016 to 2025). The assessment reviewed available information and load forecasts and included single contingency analysis to identify needs.

6. RESULTS

Transmission System Capacity Needs

A. 230/115 kV Autotransformer Capacity

- Based on the gross regional-coincident load forecast, the 230/115 kV autotransformer capacity (Seaforth TS, Hanover TS) supplying the Region is adequate over the study period for the loss of a single 230/115 kV autotransformer in the Region.

B. 230 kV Transmission Lines

- Based on the gross regional-coincident load forecast, 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.

C. 115 kV Transmission Lines

- Based on the gross regional-coincident load forecast, thermal limits for 115 kV circuit L7S between Seaforth Junction and Kirkton Junction will be exceeded in the near term (summer 2019) for the loss of 115 kV circuit D8S.
- Based on the net regional-coincident load forecast, the need date is expected to be deferred to the end of the study period.
- Due to the limited recorded effectiveness of CDM uptake in this Region, further study is required to identify an action plan.
  - The Need will be managed via Local Planning with the Region's study team.

D. 230 kV and 115 kV Connection Facilities

- Based on the gross non-coincident load forecast, the capacity of the 230 kV and 115 kV connection facilities in the Region are adequate over the study period.

System Reliability, Operation and Restoration Needs

A. Load Security

- Based on the gross regional-coincident load forecast and the existing transmission configuration, load security criteria can be met over the study period.

B. Load Restoration

- Based on the gross regional-coincident load forecasts with the use of existing transmission infrastructure, restoration criteria can be met over the study period.

C. Power Factor at Connection Facilities

- Historically, power factor at Wingham TS and Bruce HWP B TS do not meet Market Rule requirements.
  - The Need at Wingham TS will be managed via Local Planning between the transmitter and the affected LDCs.
  - The Need at Bruce HWP B TS will be managed via Local Planning between the transmitter

and the affected customer.

D. Voltage Performance

- Under gross regional-coincident peak load conditions, post-contingency voltage at the Wingham TS 44 kV bus is below 6% of nominal voltage and may result in poor end-of-feeder voltages (winter 2020/2021).
- Based on the net regional-coincident peak load forecast at Wingham TS, the need date may be deferred by 2 years.
- Due to the synergy between voltage performance and power factor, this voltage deficiency Need will be further studied in coordination with Wingham TS's power factor.
    - The Need will be managed via Local Planning between the transmitters and the affected LDCs

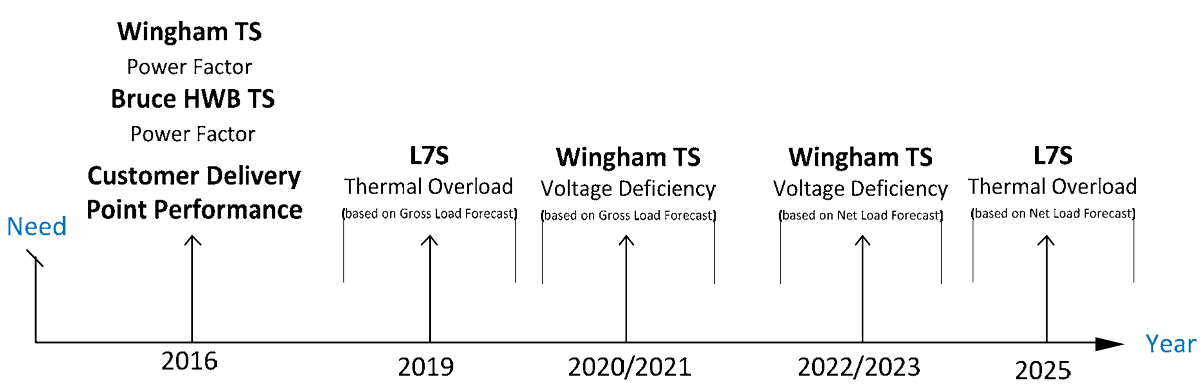
E. Customer Delivery Point Performance

- Based on a review of delivery point performance, several customer delivery points in the Region are below their historical measures.
    - Mitigation measures that align with Hydro One's OEB-approved process for addressing poor performance will be discussed between the transmitter and the affected LDCs and transmission customers.

F. Bulk Power System Performance in the Region

- Based on a limited analysis of the bulk power system in the Region, 230 kV transmission circuit D7V between Detweiler TS and Waterloo North Junction is over its thermal limit near the end of the study period. This result is consistent with the KWCG Regional Infrastructure Plan (RIP) findings.
    - As recommended in the KWCG RIP, this Needs Assessment also recommends further investigation via bulk system planning study.

Needs Timeline Summary



Aging Infrastructure / Replacement Plan

During the study period, plans to replace aged equipment at ten stations and several transmission circuits will take place. The replacement of aged equipment may improve customer delivery point performance. Investigation into customer delivery point performance will take into consideration this replacement work.

Further details of these investments can be found in Section 6.3 of this report.

7. RECOMMENDATIONS

Based on the findings of this Needs Assessment, the study team recommendations:

1. Poor power factor and voltage deficiency at Wingham TS to be managed by Local Planning between Hydro One transmission and Hydro One distribution and may include additional LDC's embedded within Hydro One distribution fed out of Wingham TS

2. Poor power factor at Bruce HWP B TS to be managed by Local Planning between Hydro One transmission and the transmission connected customer.

3. Mitigation of poor delivery point performance to several 115 kV connected customers to be managed according to Hydro One's OEB-approved process between Hydro One transmission, Hydro One distribution, Goderich Hydro and transmission connected customers.

4. Thermal overload on circuit L7S to be managed by Local Planning between Hydro One transmission and the Region's study team.

TABLE OF CONTENTS

LIST OF FIGURES AND TABLES

1 INTRODUCTION

This Needs Assessment report provides a description of the analysis to identify needs that may be emerging in the Greater Bruce-Huron Region (the Region) over the next ten years. The development of the Needs Assessment report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the Planning Process Working Group (PPWG) Report to the OEB.

The purpose of this Needs Assessment report is to: consider the information from planning activities already underway; undertake an assessment of the Greater Bruce-Huron Region to identify 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 LDCs or other connecting customer(s) will further undertake planning assessments to develop options and recommend solution(s). For needs that require further regional planning and coordination, the Independent Electricity System Operator (the IESO) will initiate the Scoping Assessment 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.

This report was prepared by Hydro One (Lead Transmitter) with input from the Greater Bruce-Huron Region Needs Assessment study team listed in Table 1. The report captures the results of the assessment based on information provided by LDCs and the IESO.

Table 1: Study Team Participants for Greater Bruce-Huron Region

No.	Company
1	Hydro One Networks Inc. (Lead Transmitter)
2	Entegrus
3	Erie Thames Power
4	Festival Hydro Inc.
5	Goderich Hydro - West Coast Huron Energy Inc.
6	Hydro One Networks Inc. (Distribution)
7	Independent Electricity System Operator
8	Wellington North Power Inc.
9	Westario Power Inc.

2 TRIGGER OF NEEDS SCREEN

The Needs Assessment for the Greater Bruce-Huron 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, where Group 1 Regions are being reviewed first. The Region falls into Group 3. The Needs Assessment for this Region was triggered on February 29, 2016 and was completed on April 28, 2016.

3 SCOPE OF NEEDS ASSESSMENT

This Needs Assessment covers the Greater Bruce-Huron Region over an assessment period of 2016 to 2025. The scope of the Needs Assessment includes a review of transmission system connection facility capability which covers transformer station capacity, transmission circuit thermal capacity, and voltage performance. System reliability, operational issues such as load restoration, and asset replacement plans were also briefly reviewed as part of this Needs Assessment.

3.1 Greater Bruce-Huron Region Description and Connection Configuration

The Greater Bruce-Huron Region includes the counties of Bruce, Huron and Perth, as well as portions of Grey, Wellington, Waterloo, Oxford and Middlesex counties. The boundary of the Greater Bruce-Huron Region is shown in Figure 1.

Figure 1: Greater Bruce-Huron Region Map

Electricity supply for the Region is provided through a network of 230 kV and 115 kV transmission lines supplied mainly by generation from the Bruce Nuclear Generating Station and local renewable generation facilities in the Region. The bulk of the electrical supply is transmitted through 230 kV circuits (B4V, B5V, B22D, B23D, B27S and B28S) radiating out from Bruce A TS. These circuits connect the Region to the adjacent South Georgian Bay/Muskoka Region and the adjacent Kitchener-Waterloo-Cambridge-Guelph (KWCG) Region.

Listed in Table 2 and shown in Figure 2, are the transmission and transmission connected assets in the Greater Bruce-Huron Region.

Table 2: Hydro One and Customer Assets Bounded by the Greater Bruce-Huron Region

115 kV Circuits	230 kV Circuits	Hydro One Transformer Stations	Customer Transformer Stations
61M18, D8S, D10H, L7S, S1H	B4V, B5V, B22D, B23D, B20P, B24P, B27S, B28S, B81HW, B82HW	Bruce HWP B TS, Centralia TS, Douglas Point TS, Goderich TS, Hanover TS, Owen Sound TS, Palmerston TS, Seaforth TS, St. Marys TS, Stratford TS, Wingham TS	Constance DS, Festival MTS, Grand Bend East DS, Customer CTS #1, Customer CTS #2, Customer CTS #3, Customer CTS #4

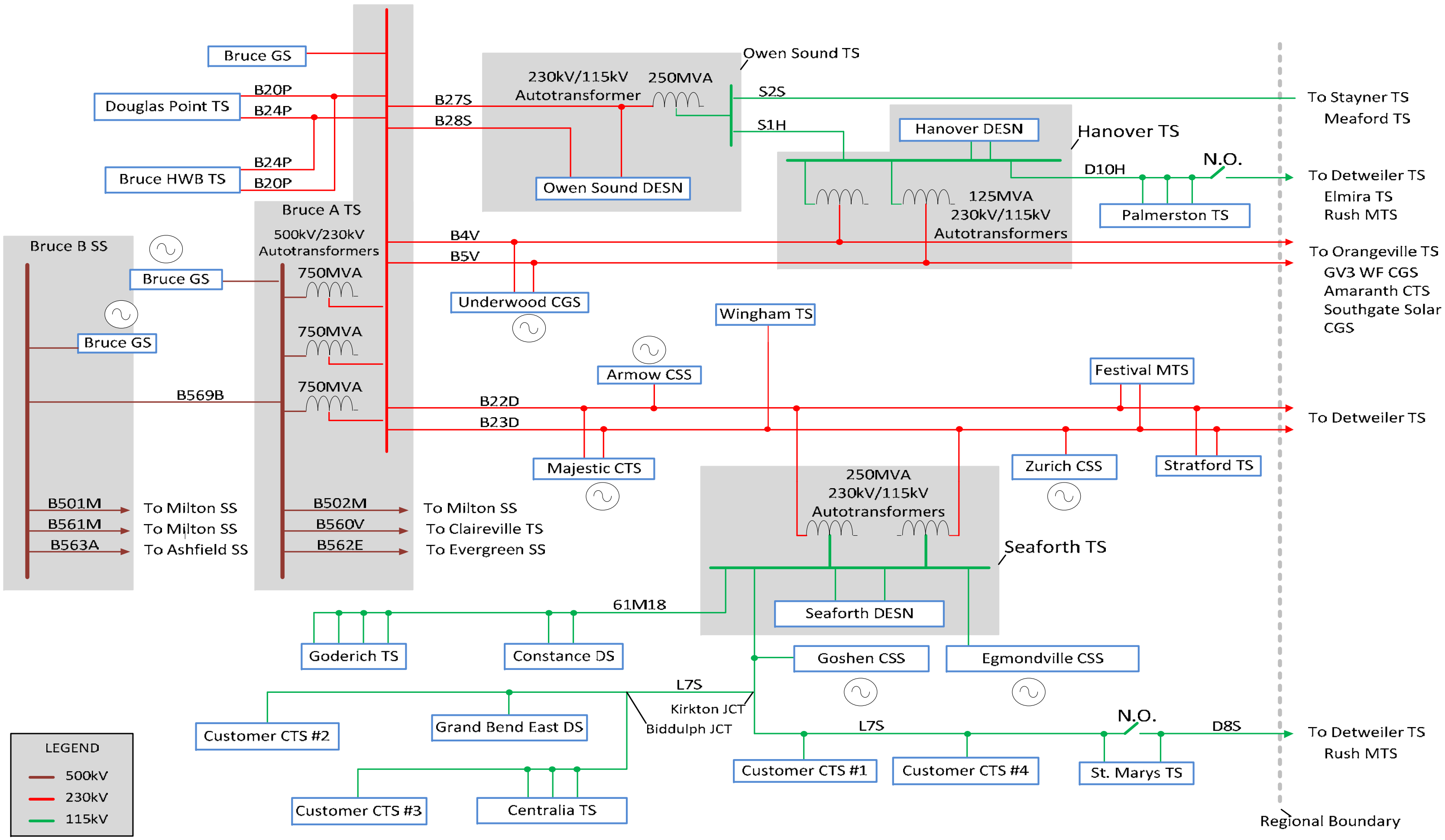


Figure 2: Single Line Diagram – Greater Bruce-Huron Region

4 INPUTS AND DATA

In order to conduct this Needs Assessment, study team participants provided the following information to Hydro One:

- IESO provided:
    i. Historical regional coincident peak load and station non-coincident peak load
    ii. List of existing reliability and operational issues
    iii. Conservation and Demand Management (CDM) and Distributed Generation (DG) data
    iv. Historical power factor data, MW and MVar for each station in the Region
- LDCs provided historical summer and winter net load (2013-2015) as well as summer and winter gross load forecast (2016-2025)
- Hydro One (Transmission) provided transformer, station and circuit ratings
- Hydro One (Transmission) provided existing reliability and operation issues
- Any relevant planning information, including planned transmission and distribution investments are provided by Hydro One (Transmission) and LDCs

4.1 Load Forecast

As per the data provided by the study team, the winter *gross* coincident load in the Region is expected to grow at an average rate of approximately 1.1% annually from 2016-2025 and the summer *gross* coincident load in the Region is expected to grow at an average rate of approximately 1.0% from 2016-2025.

As per the data provided by the study team, the winter *net* coincident load in the Region is expected to grow at an average rate of approximately 0.5% annually from 2016-2025 and the summer *net* coincident load in the Region is expected to grow at an average rate of approximately 0.3% from 2016-2025.

Based on historical load and on the load forecast, the Regions' winter coincident peak load is larger than its summer coincident peak load. As well, the majority of stations within the Region are winter peaking. The load forecasts utilized for this Needs Assessment are found in Appendix A: Load Forecasts.

5 NEEDS ASSESSMENT METHODOLOGY

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

1. The Region contains some stations that are summer peaking and others that are winter peaking. Equipment ratings are normally lower in the summer than winter due to ambient temperature. Based on these factors this assessment is conducted for both summer and winter peak load.
2. Forecast loads are provided by the Region's LDCs using historical 2015 summer and historical 2014/2015 winter peak loads as reference points.
3. Forecast loads are provided by industrial customers in the Region. Where data was not provided, the load is assumed to be consistent with historical loads.
4. The historical peak loads are adjusted for extreme weather conditions according to Hydro One methodology.
5. The LDC's load forecast is translated into load growth rates and is applied onto the historical, extreme weather adjusted, reference points.
6. Accounting for (2), (3), (4), (5) above, a gross load forecast and a net load forecast are developed. The gross load forecast is used to develop a worst case scenario to identify needs. Where there are issues, the net forecast, which accounts for CDM and DG, is analyzed to determine if the needs can be deferred.
    a. A gross and net non-coincident peak load forecast was used to perform the analysis for sections 6.1.4 and 6.2.3
    b. A gross and net regional-coincident peak load forecast was used to perform the analysis for sections 6.1.1 to 6.1.3 and 6.2.1 and 6.2.2 and 6.2.4
7. Review impact of any on-going and planned development projects in the Region during the study period.
8. Review and assess impact of any critical/major elements planned/identified to be replaced at the end of their useful life such as transformers, cables, and stations.
9. Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity by assuming a 90% lagging power factor for stations without low-voltage capacitor banks 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 and winter 10-Day Limited Time Rating (LTR), as appropriate.
10. Transmission adequacy assessment is primarily based on the following criteria:
    - Regional load is set to the forecasted regional-coincident peak load
    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range.

- With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their long-term emergency (LTE) ratings and transformers within their 10-Day LTR.
- All voltages must be within pre and post contingency ranges as per the Ontario Resource and Transmission Assessment Criteria (ORTAC).
- The system to meet load security criteria as per the ORTAC, specifically, 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.
- The system is capable of meeting the load restoration timeframes as per the ORTAC.

6 RESULTS

This section summarizes the results of the Needs Assessment in the Greater Bruce-Huron Region. The results are based on all 8 Bruce nuclear generating units in-service and no local/renewable generating units in-service in order to verify whether the transmission system has adequate capacity to supply the forecasted regional load.

6.1 Transmission System Capacity Needs

6.1.1 230 kV and 115 kV Autotransformers

The 230/115 kV autotransformers (Seaforth TS, Hanover TS, Detweiler TS, Owen Sound TS) supplying the Region are adequate over the study period for the loss of a single 230/115 kV autotransformer in the Region.

6.1.2 230 kV Transmission Lines

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

6.1.3 115 kV Transmission Lines

The 115 kV lines supplying the Region are radial single circuit lines. These 115 kV circuits have adequate capacity over the study period.

115 kV circuit L7S that runs between Seaforth TS and St. Mary’s TS is connected to 115 kV circuit D8S that runs between St. Marys TS and Detweiler TS, through the St. Marys TS low voltage bus-tie breaker. For the loss of D8S, L7S will exceed its short-term emergency (STE) and LTE ratings in the near term (summer 2019), under summer *gross*

peak load conditions. Under summer *net* peak load conditions, the flow on L7S decreases to ~97% of its emergency ratings at the end of the study period (summer 2025).

The sections of circuit explicitly over their ratings are: Seaforth Jct. x Goshen Jct., and Goshen Jct. x Kirkton Jct. The emergency ratings of these sections are limited by substandard clearances due to ground topology and a rural distribution line. Due to the limited recorded effectiveness of CDM uptake in this Region, this thermal overload Need will require further study and will therefore be managed by Local Planning with the Region's study team.

6.1.4 230 kV and 115 kV Connection Facilities

A station capacity assessment was performed over the study period for the 230 kV and 115 kV transformer stations in the Region using the winter and summer station non-coincident peak load forecasts. All stations in the Region have adequate supply capacity for the study period (2016-2025).

6.2 System Reliability, Operation and Restoration Review

6.2.1 Load Security

Based on the gross regional-coincident peak load forecast, with all transmission facilities in-service and coincident with an outage of the largest local generation units, all facilities are within applicable ratings. The largest local generation unit is a 230 kV-connected Bruce nuclear unit on the 230 kV system while on the 115 kV system Goshen wind farm is assumed out of service.

Based on the gross regional-coincident load forecast, the loss of one element will not result in load interruption greater than 150 MW by configuration, by planned load curtailment or by load rejection. In addition, under these conditions, all facilities are within their applicable ratings.

Based on the gross regional-coincident load forecast, the loss of two elements will not results in load interruption greater than 600 MW by configuration, by planned load curtailment or by load rejection. In addition, under these conditions, all facilities are within their applicable ratings.

Therefore, load security criteria for the Region are met.

6.2.2 Load Restoration

Based on the gross regional-coincident peak load forecasts, with the use of existing transmission infrastructure, all load can be restored within approximately 8 hours depending on the severity of the contingency, the prevailing system conditions and the relative distance from the nearest field maintenance centre. Existing transmission infrastructure includes switches that can be operated from the Ontario Grid Control Centre (OGCC), Mid-Span Openers (MSOs) and other isolating devices that require a bucket truck and line crew to open and close.

The largest loss of load in the Region is 325 MW in winter 2024/2025 for the loss of the double circuit line B22D/B23D. By use of existing 61B22D-21 and 61B23D-26 switches at Seaforth TS, the OGCC can quickly resupply, within 30 minutes, approximately 218 MW from Bruce A TS or approximately 268 MW from Detwiler TS. The remaining load can be resupplied in 4-8 hours by opening existing bolted openers along the circuits.

Therefore, load restoration criteria for the Region are met.

6.2.3 Power Factor at Connection Facilities

Based on the analysis of historical power factors at connection facilities under peak load conditions, the power factor at Wingham TS does not meet Market Rule requirements. Based on May 2014 to May 2015 historical data the power factor at Wingham TS does not meet Market Rule requirement of 0.9 lead-lag power factor at the defined meter point at least 60% of the time. This is a Need that will be managed by Local Planning between the transmitter and the affected LDCs.

Based on the analysis of historical power factors at connection facilities under peak load conditions, the power factor at Bruce HWP B TS does not meet Market Rule requirements. Based on January 2014 to December 2015 historical data the power factor at Bruce HWP B TS does not meet Market Rule requirement of 0.9 lead-lag power factor at the defined meter point approximately 80% of the time. This is a Need that will be managed by Local Planning between the transmitter and the affected customer.

6.2.4 Voltage Performance

Under winter 2020/2021 gross regional-coincident peak load conditions, post-contingency voltage at the Wingham TS 44 kV bus is below 6% of nominal voltage and may result is poor end-of-feeder voltages. Under winter *net* regional-coincident peak load conditions, the need is deferred by two years to winter 2022/2023. This is a Need that requires mitigation via Local Planning between the transmitter and the affected LDCs.

6.2.5 Customer Delivery Point Performance

Based on a review of Hydro One's historical delivery point performance statistics, several customer delivery points in the Region are below their historical measures. The delivery points are those fed from the Region's 115 kV system. These statistics are consistent with those provided by IESO. Mitigation measures that align with Hydro One's OEB approved process for addressing poor performance will be discussed between the transmitter and the affected LDCs and transmission customers.

6.2.6 Bulk Power System Performance in the Region

To bridge regional system planning with bulk system planning, a select number of bulk system planning contingencies within the Region are undertaken. With respect to the 230 kV circuits that supply regional load, breaker failure contingencies of these circuit's terminal breakers at BES and BPS station are analyzed to determine their impact. Gross regional-coincident peak load for the Greater Bruce-Huron region was used while a net regional-coincident peak load forecast for the KWCG region was used.

The results showed that 230 kV transmission circuit D7V between Detweiler TS and Waterloo North Junction is at its thermal rating at the end of the study period. This result is consistent with KWCG Regional Infrastructure Plan findings.

As recommended in the KWCG RIP, this Needs Assessment also recommends further investigation via bulk system planning study.

6.3 Aging Infrastructure and Replacement Plan of Major Equipment

Table 3 lists Hydro One transmission sustainment initiatives that are currently planned for aging and End-Of-Life (EOL) infrastructure.

Table 3: Hydro One Transmission Sustainment Initiatives

Station/Circuit	Description of Work	Planning In-Service Date
Bruce A TS	230 kV breaker replacement	2019
	500 kV breaker replacement	2024
Bruce B SS	500 kV breaker replacement	2020
Goderich TS	Station refurbishment: replace existing 3 transformers (T1/T2/T3) with a typical 50/83 MVA 2 transformer DESN arrangement (T4/T5)	2017
Detweiler TS	Replace AC station service	2017
	Replace T2 and T4 autotransformers	2021
Centralia TS	Station refurbishment: replace existing 3 transformers with a typical 25/42 MVA 2	2018

	transformer DESN arrangement	
Palmerston TS	Station refurbishment: replace existing 3 transformers with a typical 50/83 MVA 2 transformer DESN arrangement	2018
Wingham TS	Station refurbishment	2022
Seaforth TS	Station refurbishment: to include autotransformers and DESN	2023
Hanover TS	Station refurbishment: to include DESN	2023
Stratford TS	Station refurbishment	2023
Circuit L7S	Replacement of 4 wood poles	2016
	Insulator replacements	As required
Circuit S1H	Replacement of shield wire	2016
	Replacement of 9 wood poles	2017
Circuits B4V & B5V	Insulator and U-bolt replacement	As required
Circuits B22D & B23D	Insulator replacements	As required
Circuits B27S & B28S	Insulator replacements	As required
Circuits B20P & B24P	Insulator replacements	As required

The replacement and/or refurbishment of equipment may improve the overall reliability performance at customer delivery points. Further investigation is required to verify.

6.4 Planned Transmission and Distribution Investments

Listed in Table 4 are planned transmission and distribution investments in the Region. Note that other than the currently planned refurbishment work in table 3, Hydro One transmission does not have additional planned investments within the Region other than connecting generation upon request.

Table 4: Planned Local Distribution Company Investments

LDC	**Investment Description**	**Planning In-Service Date**
Wellington North Power	Transfer ~50% of LDC's Mount Forest load fed from Hanover TS to Palmerston TS in 2016. A feeder extension (M2) from Palmerston TS will be used for this load transfer. This transfer has been incorporated into the Region's station load forecast.	2016

7 RECOMMENDATIONS

Based on the findings of the Needs Assessment, the study team's recommendations are as follows:

1. To mitigate poor power factor and to prevent against voltage deficiency at Wingham TS, Local Planning between Hydro One transmission and Hydro One distribution (this may include additional LDC's embedded within Hydro One distribution fed out of Wingham TS) is recommended.

2. To mitigate poor power factor at Bruce HWP B TS, Local Planning between Hydro One transmission and the transmission connected customer is recommended.

3. To mitigate poor delivery point performance to several 115 kV connected customers, planning in accordance with Hydro One's OEB-approved process between Hydro One transmission, Hydro One distribution, Goderich Hydro and transmission connected customers is recommended.

4. To prevent against thermal overload on circuit L7S, Local Planning between Hydro One transmission and the Region's study team is recommended.

8 REFERENCES

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013

ii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0

9 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
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
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

APPENDIX A: LOAD FORECASTS

Table A1: Gross – Winter Regional-Coincident Peak Load Forecast

Station	Historical (MW)	Forecast (MW)									
	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Centralia TS	32.42	32.87	33.40	33.77	34.25	34.87	35.48	35.93	36.36	36.77	37.19
Constance DS	17.58	17.68	17.76	17.79	17.87	18.01	18.16	18.26	18.35	18.46	18.57
Douglas Point TS	70.95	71.97	72.93	73.75	74.76	75.95	77.17	78.29	79.41	80.58	81.80
Customer CTS #1	0.89*	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Festival MTS #1	19.26	19.41	19.55	19.70	19.85	20.00	20.15	20.30	20.45	20.60	20.76
Goderich TS	36.21	36.35	36.50	36.59	36.73	36.92	37.11	37.25	37.37	37.49	37.61
Grand Bend East DS	14.11	14.22	14.36	14.43	14.55	14.72	14.89	15.00	15.09	15.19	15.28
Hanover TS	101.59	102.37	103.16	103.93	104.95	105.99	107.05	107.73	108.39	109.06	109.72
Customer CTS #2	4.27**	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30
Customer CTS #3	1.93**	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Owen Sound TS	133.69	135.53	137.73	139.21	141.20	143.81	146.38	148.20	149.90	151.56	153.19
Palmerston TS	60.95	61.92	62.92	63.88	65.12	66.22	67.44	68.42	69.41	70.41	71.40
Seaforth TS	33.27	33.44	33.65	33.78	33.97	34.22	34.47	34.64	34.80	34.95	35.10
Customer CTS #4	9.37	9.49	10.07	10.07	10.64	10.64	10.64	10.64	10.64	10.64	10.64
St. Marys TS	23.48	23.74	25.04	25.17	25.31	25.50	25.69	25.84	25.98	26.12	26.25
Stratford TS	79.16	79.78	80.45	81.03	81.67	82.41	83.14	83.76	84.37	84.98	85.59
Wingham TS	48.21	48.99	49.80	50.44	51.23	52.24	53.24	54.07	54.89	55.74	56.62
Bruce HWB TS	10.95	10.96	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10

* Winter 2013/14

** Winter 2012/13

Table A2: Gross – Summer Regional-Coincident Peak Load Forecast

Station	Historical (MW)	Forecast (MW)									
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Centralia TS	32.00	32.42	32.73	33.15	33.78	34.40	34.83	35.24	35.65	36.05	36.45
Constance DS	15.47	15.56	15.57	15.63	15.76	15.90	15.98	16.07	16.16	16.26	16.36
Douglas Point TS	45.48	45.81	45.81	46.11	46.56	47.04	47.41	47.78	48.16	48.51	48.90
Customer CTS #1	1.29*	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30
Festival MTS #1	24.84	25.03	25.22	25.41	25.60	25.79	25.98	26.18	26.37	26.57	26.77
Goderich TS	38.95	39.08	39.15	39.27	39.48	39.68	39.81	39.93	40.06	40.18	40.31
Grand Bend East DS	16.32	16.44	16.50	16.62	16.84	17.05	17.17	17.29	17.39	17.50	17.61
Hanover TS	76.22	76.71	76.94	77.62	78.60	79.25	79.71	80.12	80.53	80.93	81.32
Customer CTS #2	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58
Customer CTS #3	4.17**	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20
Owen Sound TS	96.32	97.58	98.48	99.75	101.70	103.59	104.89	106.11	107.31	108.48	109.63
Palmerston TS	52.00	53.07	53.79	54.90	56.36	57.68	58.81	59.97	61.19	62.43	63.75
Seaforth TS	30.53	30.68	30.77	30.91	31.14	31.35	31.50	31.63	31.14	31.90	32.03
Customer CTS #4	14.42	14.62	15.54	15.54	16.47	16.47	16.47	16.47	16.47	16.47	16.47
St. Marys TS	25.16	25.31	25.42	25.57	25.75	25.94	26.09	26.24	26.38	26.52	26.66
Stratford TS	77.16	77.76	78.26	78.86	79.62	80.38	80.98	81.57	82.16	82.74	83.32
Wingham TS	37.69	37.99	38.11	38.36	38.87	39.37	39.67	39.97	40.26	40.54	40.83
Bruce HWB TS	5.05	5.14	5.24	5.34	5.44	5.54	5.64	5.74	5.84	5.93	6.03

* Summer 2014

** Summer 2013

Table A3: Gross – Winter Non-Coincident Peak Load Forecast

Station	Historical (MW)	Forecast (MW)									
	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Centralia TS	33.69	34.15	34.70	35.08	35.59	36.23	36.87	37.33	37.77	38.21	38.63
Constance DS	18.63	19.42	19.51	19.54	19.63	19.79	19.95	20.06	20.17	20.28	20.40
Douglas Point TS	70.95	71.97	72.93	73.75	74.76	75.95	77.17	78.29	79.41	80.58	81.80
Customer CTS #1	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79
Festival MTS #1	23.79	25.47	25.66	25.85	26.05	26.24	26.44	26.64	26.84	27.04	27.24
Goderich TS	40.95	41.61	41.78	41.88	42.04	42.26	42.48	42.63	42.77	42.91	43.05
Grand Bend East DS	14.63	14.75	14.89	14.97	15.09	15.27	15.45	15.56	15.66	15.75	15.85
Hanover TS	102.64	96.65*	97.40	98.12	99.09	100.07	101.06	101.71	102.33	102.97	103.58
Customer CTS #2	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90
Customer CTS #3	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63
Owen Sound TS	133.69	135.53	137.73	139.21	141.20	143.81	146.38	148.20	149.90	151.56	153.19
Palmerston TS	61.48	68.03*	69.12	70.18	71.54	72.76	74.10	75.17	76.26	77.36	78.45
Seaforth TS	33.69	34.75	34.96	35.10	35.29	35.55	35.81	35.99	36.15	36.31	36.47
Customer CTS #4	16.84	17.06	18.10	18.10	19.14	19.14	19.14	19.14	19.14	19.14	19.14
St. Marys TS	24.84	25.13	26.50	26.64	26.79	26.99	27.19	27.35	27.50	27.64	27.78
Stratford TS	83.48	84.52	85.23	85.84	86.52	87.30	88.08	88.74	89.39	90.03	90.68
Wingham TS	57.06	57.98	58.94	59.70	60.63	61.82	63.01	63.98	64.96	65.96	67.00
Bruce HWB TS	11.05	11.07	11.20	11.20	11.20	11.20	11.20	11.20	11.20	11.20	11.20

*Load Transfer from Hanover TS to Palmerston TS

Table A4: Gross – Summer Non-Coincident Peak Load Forecast

Station	Historical (MW)	Forecast (MW)									
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Centralia TS	33.79	34.23	34.56	35.01	35.67	36.32	36.78	37.22	37.64	38.07	38.49
Constance DS	17.69	17.78	17.79	17.86	18.01	18.17	18.27	18.36	18.47	18.58	18.70
Douglas Point TS	46.11	46.44	46.45	46.75	47.21	47.69	48.07	48.45	48.83	49.19	49.58
Customer CTS #1	2.53	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Festival MTS #1	27.90	28.11	28.32	28.53	28.74	28.96	29.18	29.39	29.61	29.84	30.06
Goderich TS	39.27	40.71	40.78	40.91	41.12	41.33	41.46	41.59	41.72	41.85	41.98
Grand Bend East DS	18.74	18.88	18.95	19.09	19.34	19.58	19.72	19.85	19.98	20.10	20.22
Hanover TS	76.22	75.61*	75.84	76.50	77.47	78.12	78.57	78.97	79.37	79.77	80.15
Customer CTS #2	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79
Customer CTS #3	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53
Owen Sound TS	100.01	101.31	102.25	103.57	105.59	107.55	108.90	110.17	111.41	112.63	113.82
Palmerston TS	52.32	54.71*	55.45	56.60	58.10	59.46	60.63	61.82	63.07	64.36	65.72
Seaforth TS	30.53	31.00	31.09	31.24	31.46	31.68	31.83	31.96	31.47	32.24	32.37
Customer CTS #4	16.00	16.22	17.24	17.24	18.27	18.27	18.27	18.27	18.27	18.27	18.27
St. Marys TS	25.90	26.05	26.17	26.31	26.51	26.70	26.86	27.01	27.16	27.30	27.44
Stratford TS	86.43	88.42	88.99	89.68	90.54	91.40	92.09	92.76	93.43	94.09	94.75
Wingham TS	50.74	54.05	54.21	54.58	55.29	56.00	56.43	56.86	57.27	57.67	58.08
Bruce HWB TS	6.42	6.54	6.66	6.79	6.91	7.04	7.16	7.29	7.42	7.54	7.67

*Load Transfer from Hanover TS to Palmerston TS

Table A5: Net – Winter Regional-Coincident Peak Load Forecast

Station	Historical (MW)	Forecast (MW)									
	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Centralia TS	32.42	32.65	32.92	32.96	33.16	33.52	33.90	34.16	34.45	34.69	34.94
Constance DS	17.58	17.57	17.55	17.41	17.35	17.36	17.40	17.41	17.44	17.46	17.50
Douglas Point TS	70.95	71.54	72.09	72.19	72.59	73.20	73.94	74.64	75.45	76.23	77.08
Customer CTS #1	0.89*	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Festival MTS #1	19.26	19.29	19.33	19.29	19.27	19.28	19.31	19.36	19.43	19.49	19.56
Goderich TS	36.21	36.12	36.07	35.81	35.65	35.58	35.55	35.50	35.49	35.45	35.43
Grand Bend East DS	14.11	14.13	14.19	14.13	14.13	14.19	14.27	14.30	14.34	14.37	14.39
Hanover TS	101.59	101.72	101.94	101.69	101.76	102.01	102.42	102.56	102.84	103.02	103.23
Customer CTS #2	4.27**	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30
Customer CTS #3	1.93**	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Owen Sound TS	133.69	134.70	136.07	136.18	137.02	138.53	140.18	141.21	142.35	143.29	144.25
Palmerston TS	60.95	61.53	62.17	62.50	63.20	63.80	64.60	65.20	65.92	66.58	67.25
Seaforth TS	33.27	33.24	33.26	33.06	32.98	32.98	33.02	33.02	33.06	33.06	33.07
Customer CTS #4	9.37	9.49	10.07	10.07	10.64	10.64	10.64	10.64	10.64	10.64	10.65
St. Marys TS	23.48	23.59	24.75	24.63	24.57	24.58	24.61	24.63	24.68	24.70	24.73
Stratford TS	79.16	79.30	79.52	79.30	79.29	79.42	79.65	79.86	80.16	80.39	80.64
Wingham TS	48.21	48.70	49.23	49.38	49.75	50.36	51.02	51.55	52.16	52.73	53.35
Bruce HWB TS	10.95	10.96	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10

* Winter 2013/14

** Winter 2012/13

Table A6: Net – Summer Regional-Coincident Peak Load Forecast

Station	Historical (MW)	Forecast (MW)									
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Centralia TS	32.00	32.04	31.57	31.62	31.89	32.20	32.42	32.61	32.85	33.05	33.25
Constance DS	15.47	15.45	15.35	15.23	15.20	15.20	15.19	15.18	15.20	15.22	15.24
Douglas Point TS	45.48	45.43	45.11	44.89	44.87	44.93	45.02	45.10	45.26	45.35	45.49
Customer CTS #1	1.29*	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30
Festival MTS #1	24.84	24.85	24.86	24.77	24.69	24.66	24.70	24.74	24.82	24.87	24.93
Goderich TS	38.95	38.70	38.50	38.18	37.98	37.84	37.74	37.63	37.59	37.50	37.43
Grand Bend East DS	16.32	16.32	16.27	16.20	16.24	16.31	16.33	16.33	16.37	16.38	16.40
Hanover TS	76.22	75.82	75.51	75.32	75.37	75.34	75.33	75.25	75.32	75.30	75.29
Customer CTS #2	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58
Customer CTS #3	4.17**	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20
Owen Sound TS	96.32	96.71	96.49	96.54	97.40	98.36	99.01	99.56	100.27	100.83	101.40
Palmerston TS	52.00	52.48	52.81	53.30	54.15	54.94	55.69	56.45	57.35	58.21	59.16
Seaforth TS	30.53	30.39	30.27	30.06	29.96	29.91	29.87	29.82	29.23	29.79	29.76
Customer CTS #4	14.42	14.62	15.54	15.54	16.47	16.47	16.47	16.47	16.47	16.47	16.47
St. Marys TS	25.16	25.07	25.01	24.87	24.79	24.76	24.75	24.74	24.77	24.77	24.78
Stratford TS	77.16	77.10	77.05	76.77	76.70	76.76	76.87	76.97	77.20	77.33	77.49
Wingham TS	37.69	37.72	37.57	37.40	37.49	37.65	37.71	37.76	37.88	37.94	38.03
Bruce HWB TS	5.05	5.06	5.12	5.12	5.12	5.12	5.12	5.12	5.12	5.12	5.12

* Summer 2014

** Summer 2013

Table A7: Net – Winter Non-Coincident Peak Load Forecast

Station	Historical (MW)	Forecast (MW)									
	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Centralia TS	33.69	33.93	34.20	34.24	34.46	34.82	35.23	35.50	35.79	36.05	36.31
Constance DS	18.63	18.62	18.61	18.45	18.39	18.40	18.44	18.45	18.48	18.51	18.55
Douglas Point TS	70.95	71.54	72.09	72.19	72.59	73.20	73.94	74.64	75.45	76.23	77.08
Customer CTS #1	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79
Festival MTS #1	23.79	23.83	23.87	23.82	23.80	23.81	23.84	23.90	24.00	24.07	24.16
Goderich TS	40.95	40.85	40.79	40.49	40.32	40.23	40.20	40.15	40.14	40.09	40.06
Grand Bend East DS	14.63	14.66	14.72	14.65	14.65	14.72	14.81	14.84	14.88	14.90	14.93
Hanover TS	102.64	102.77*	102.99	102.75	102.81	103.07	103.48	103.63	103.90	104.09	104.30
Customer CTS #2	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90
Customer CTS #3	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63
Owen Sound TS	133.69	134.70	136.07	136.18	137.02	138.53	140.18	141.21	142.35	143.29	144.25
Palmerston TS	61.48	62.06*	62.70	63.04	63.75	64.36	65.15	65.77	66.49	67.16	67.83
Seaforth TS	33.69	33.66	33.68	33.48	33.39	33.40	33.44	33.44	33.47	33.47	33.49
Customer CTS #4	16.84	17.06	18.10	18.10	19.14	19.14	19.14	19.14	19.14	19.14	19.14
St. Marys TS	24.84	24.97	26.19	26.07	26.01	26.01	26.04	26.07	26.12	26.14	26.17
Stratford TS	83.48	83.62	83.86	83.63	83.62	83.75	84.00	84.21	84.53	84.77	85.04
Wingham TS	57.06	57.64	58.26	58.44	58.87	59.59	60.38	61.01	61.73	62.41	63.14
Bruce HWB TS	11.05	11.07	11.20	11.20	11.20	11.20	11.20	11.20	11.20	11.20	11.20

*Load Transfer from Hanover TS to Palmerston TS

Table A8: Net – Summer Non-Coincident Peak Load Forecast

Station	Historical (MW)	Forecast (MW)									
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Centralia TS	33.79	33.84	33.38	33.43	33.72	34.04	34.27	34.47	34.72	34.93	35.15
Constance DS	17.69	17.66	17.54	17.41	17.37	17.38	17.36	17.35	17.38	17.39	17.42
Douglas Point TS	46.11	46.06	45.74	45.52	45.49	45.56	45.65	45.72	45.89	45.98	46.13
Customer CTS #1	2.53	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Festival MTS #1	27.90	27.91	27.92	27.81	27.73	27.69	27.74	27.77	27.87	27.93	28.00
Goderich TS	39.27	39.02	38.81	38.49	38.29	38.15	38.05	37.93	37.89	37.81	37.74
Grand Bend East DS	18.74	18.75	18.68	18.61	18.65	18.73	18.75	18.76	18.80	18.81	18.83
Hanover TS	76.22	75.82*	75.51	75.32	75.37	75.34	75.33	75.25	75.32	75.30	75.29
Customer CTS #2	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79
Customer CTS #3	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53
Owen Sound TS	100.01	100.41*	100.21	100.26	101.16	102.15	102.82	103.40	104.13	104.72	105.31
Palmerston TS	52.32	52.80	53.13	53.63	54.48	55.27	56.03	56.79	57.70	58.57	59.52
Seaforth TS	30.53	30.39	30.27	30.06	29.96	29.91	29.87	29.82	29.23	29.79	29.76
Customer CTS #4	16.00	16.22	17.24	17.24	18.27	18.27	18.27	18.27	18.27	18.27	18.27
St. Marys TS	25.90	25.81	25.74	25.60	25.52	25.49	25.48	25.47	25.50	25.50	25.50
Stratford TS	86.43	86.36	86.31	86.00	85.92	85.99	86.12	86.22	86.48	86.63	86.81
Wingham TS	50.74	50.79	50.58	50.35	50.48	50.69	50.77	50.84	51.00	51.08	51.20
Bruce HWB TS	6.42	9.83	9.95	9.95	9.95	9.95	9.95	9.95	9.95	9.95	9.95

*Load Transfer from Hanover TS to Palmerston TS

ASSESSMENT OF LOW POWER FACTOR AT BRUCE HEAVY WATER B TS

Date: May 12th, 2017

Prepared and Reviewed by:

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Disclaimer

This Local Planning Report was prepared for the purpose of developing wires options and recommending a preferred solution(s) to address the local needs identified in the Needs Assessment (NA) report for the Greater Bruce/Huron Region that do not require further coordinated regional planning. The preferred solution(s) that have been identified through this Local Planning Report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Local Planning Report are based on the information and assumptions provided by study team participants.

Background

As part of the Ontario Energy Board's (OEB) Regional Planning process, a Needs Assessment was performed for the Greater Bruce / Huron Region. There were four (4) needs identified in the 2016 Needs Assessment for this Region, one of them being the poor power factor at Bruce Heavy Water B (Bruce HWB) TS.

This assessment addresses the low power factor issues at the Bruce HWB TS identified in the Needs Assessment report.

Introduction

Bruce HWB TS is a 230/13.8kV transformer station supplying one transmission-connected customer, Bruce Power's loads. The station is supplied via 230kV circuits B20P and B24P and has an approximate loading of 10MW. There is no distributed generation (DG) connected at Bruce HWB TS.

As per IESO Market Rules, customers are required to maintain a power factor of 0.9 or better at the point of connection. From the data gathered for the Needs Assessment phase it was observed, from January 2014 to December 2015, that the power factor fell below the 0.9 requirement 80% of the time.

Findings

Upon further assessment, Hydro One reached out to Bruce Power (the Customer) to determine if the Customer had similar issues or concerns with the power factor at the point of connection. The Customer's metering data showed an average power factor of 0.91 from August 2014 to November 2016, varying from as low as 0.724 on occasion, up to a very healthy 0.975.

The Customer's metered data differed significantly from the IESO's telemetered data that was used for the Needs Assessment. To verify the discrepancy, historical data was requested from Hydro One's settlements department. Upon analyzing the Hydro One settlements data, Hydro One found that the power factor performance at Bruce HWB was very good, with a similar average and range to the power factor calculated from the Customer's data. From January 2015 to August 2016 the power factor was above 0.9 for almost 60% of the time, and above 0.85 more than 95% of the time. Graphs representing the power factor data and the power factor performance are shown in Figures 1 and 2, respectively, in Appendix A.

Even with the occasional dip to the mid-0.7 range, the Customer indicated that it believes that power factor at the point of connection is good, and that it is satisfied with the power quality that is being supplied to its loads. The station load at Bruce HWB TS is well below the station's capacity, and there are no concerns about equipment overloading or being damaged. It was also confirmed that both the 230kV and the 13.8kV bus voltage stayed within criteria during periods of low power factor.

Conclusion

The power factor at Bruce HWB TS is generally above 0.85. Since there are no voltage issues at Bruce HWB TS and there is no lack of reactive power support in the local area, Hydro One Transmission, IESO and Bruce Power propose that no action is required at this time and the occasional low power factor observed at Bruce HWB TS is not a need that requires mitigation. Hydro One will continue to monitor the situation and act accordingly if the low power factor becomes an issue in the future.

APPENDIX A

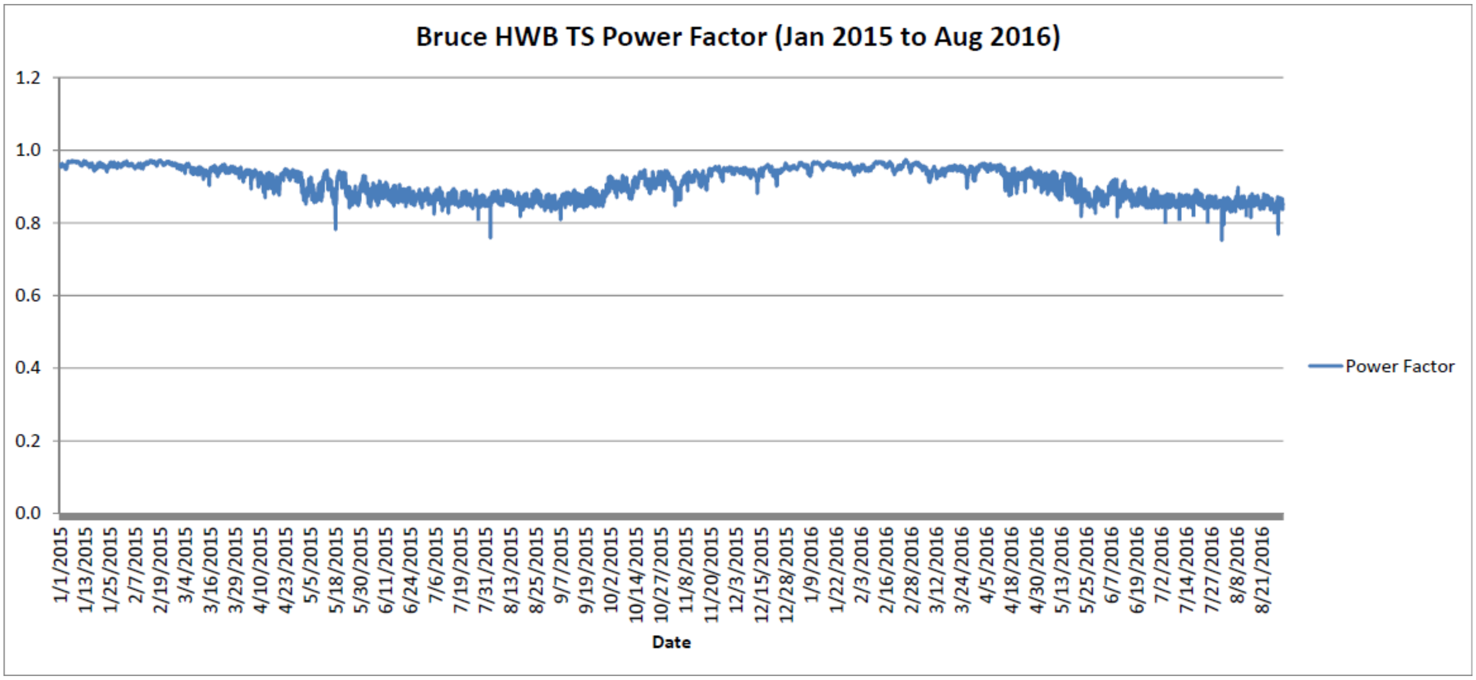

Figure 1: Graph showing the power factor at Bruce HWB TS between January 2015 and August 2016.

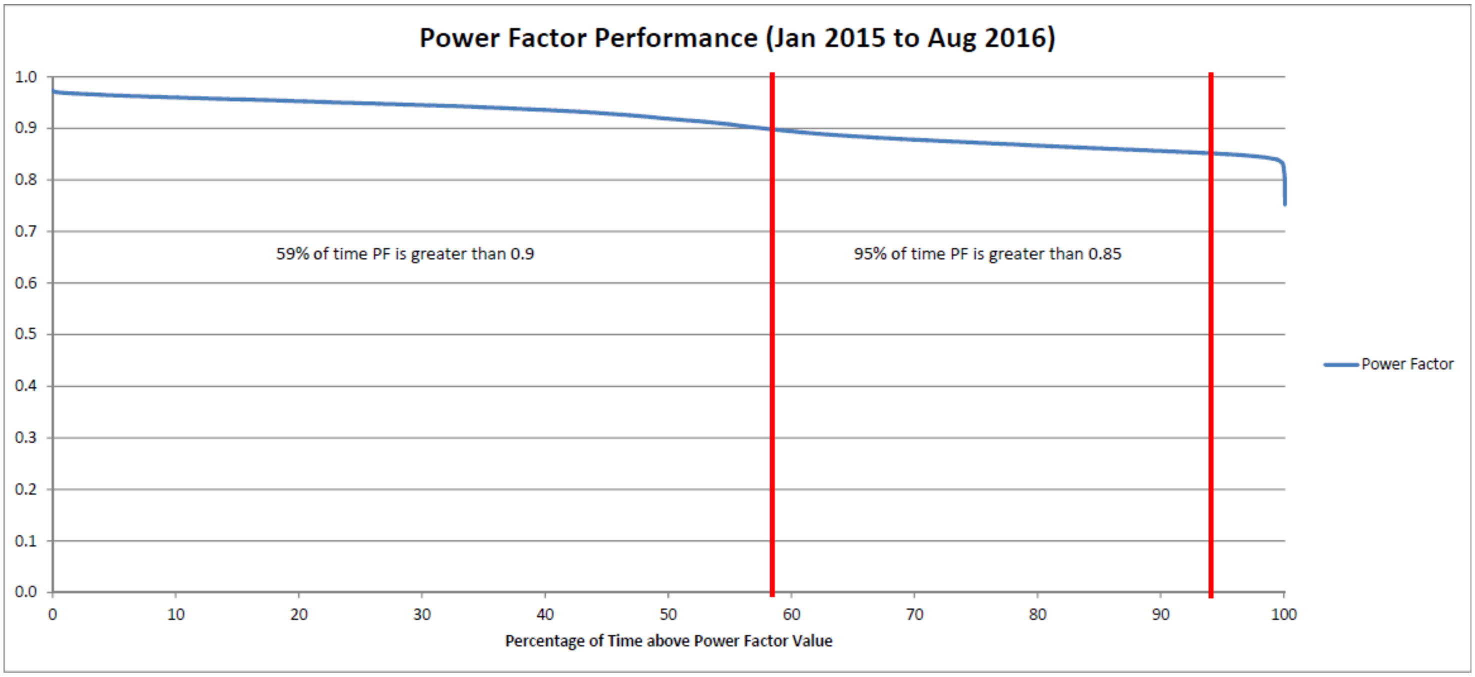

Figure 2: Graph showing power factor performance at Bruce HWB TS between January 2015 and August 2016.

Hydro One Networks Inc.
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LOCAL PLANNING REPORT

L7S Thermal Overload
Region: Greater Bruce - Huron

Date: November 14, 2016
Revision: Final

This report is prepared on behalf of the study team with the participation of representatives from the following organizations:

Disclaimer

This Local Planning Report was prepared for the purpose of developing transmission and distribution options and recommending a preferred solution(s) to address the local needs identified in the Needs Assessment for the Greater Bruce/Huron Region that do not require further coordinated regional planning. The preferred solution(s) that have been identified through this Local Planning Report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Local Planning Report are based on the information and assumptions provided by study team participants.

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EXECUTIVE SUMMARY

REGION	Greater Bruce-Huron Region (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	May 18, 2016	**END DATE**	November 14, 2016

1. INTRODUCTION

The purpose of this Local Planning ("LP") report is to evaluate options and develop a Plan to mitigate the thermal overload on circuit L7S as identified in the Greater Bruce-Huron Regional Planning Needs Assessment report (Needs Assessment).

2. THE NEED

Based on the Region's gross load forecast, circuit L7S will become loaded beyond both its Short-Term Emergency (STE) and Long-Term Emergency (LTE) ratings in year 2019. Utilizing the Region's net load forecast, the Need is deferred to year 2025. Due to the limited recorded effectiveness of Conservation and Demand Management (CDM) uptake in this Region, identification of a mitigation Plan was deemed prudent.

3. OPTIONS EVALUATED

The following options were evaluated:

- Option 1: Status Quo and Monitor Load Growth
- Option 2: Increase L7S Circuit Ratings
- Option 3: Load Transfer –> Pre-contingency control action
- Option 4: Load Rejection + Load Transfer –> Post-contingency control actions

4. PREFERRED SOLUTION

Option 1 is the preferred option. As the summer 2016 historical load was substantially lower that the forecasted 2016 load the status quo and monitor load growth option is deemed the most prudent in order to defer costs. The Region will continue to monitor load growth and when required, the preferred option to mitigate the thermal overload on circuit L7S is Option 2: Increase L7S Circuit Ratings.

5. RECOMMENDATIONS

The recommended Plan to mitigate the thermal overload on circuit L7S is:

Step 1 Review historical load and flow on circuit L7S after each summer and winter season

Step 2 When historical station load supplied by L7S reaches 99 MW or historical flow on L7S reaches 94% of the circuit's ampacity rating, refresh gross load forecast

Step 3 When refreshed gross load forecast indicates 105 MW of station load supplied by L7S OR simulated flow on L7S will reach 100% of the circuit's ampacity rating within the next 3 years proceed to increase circuit ratings. Capacity cost allocation will be as per the Transmission System Code.

Provided the station load and/or circuit flow meets the predetermined MW or % thresholds within the specified timeframe, the Plan can be implemented prior to subsequent cycles of Regional Planning. If the Plan is not already under implementation, it is to be reviewed and reaffirmed in subsequent cycles of Regional Planning.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1.0 Introduction

As part of the Ontario Energy Board's (OEB) Regional Planning requirements, a Needs Assessment was performed for the Greater Bruce / Huron Region. There were four (4) needs identified in the 2016 Needs Assessment for this Region (Needs Assessment), one of them being the thermal overload on circuit L7S.

The purpose of this Local Planning assessment is to evaluate options and develop a Plan to mitigate the thermal overload on circuit L7S.

1.1 Description of Need

Figure 1 illustrates 115 kV circuit L7S runs between Seaforth Transformer Station (TS) and St. Marys TS and is connected to 115 kV circuit D8S that runs between St. Marys TS and Detweiler TS, through the St. Marys TS low voltage bus-tie breaker. For the loss of D8S, L7S will exceed its short-term emergency (STE) and long-term emergency (LTE) ratings in the near term (summer 2019), under summer *gross* peak load conditions. Under summer *net* peak load conditions, the flow on L7S decreases to ~97% of its emergency ratings at the end of the study period (summer 2025). Table 1 is the amount of forecasted load supplied from circuit L7S when circuit D8S is unavailable. The forecast is as per the 2016 Needs Assessment for the Region.

The segments of circuit explicitly over their ratings are a few spans within the Seaforth Junction x Goshen Junction x Kirkton Junction sections. The emergency ratings of these spans are limited by substandard clearances due to ground topology and a rural distribution line. Due to the limited recorded effectiveness of Conservation and Demand Management (CDM) uptake in this Region, identification of a mitigation plan for the thermal overload is deemed prudent.

2.0 Options to Address the Need

Several options were considered in order to address the L7S thermal overload need. Table 2 lists and describes each option. There are several measures that can be utilized to compare and evaluate options. Measures utilized in this analysis were estimated cost, required approvals, long-term benefits and impact to customers. These measures were deemed most important in order to select the preferred option(s).

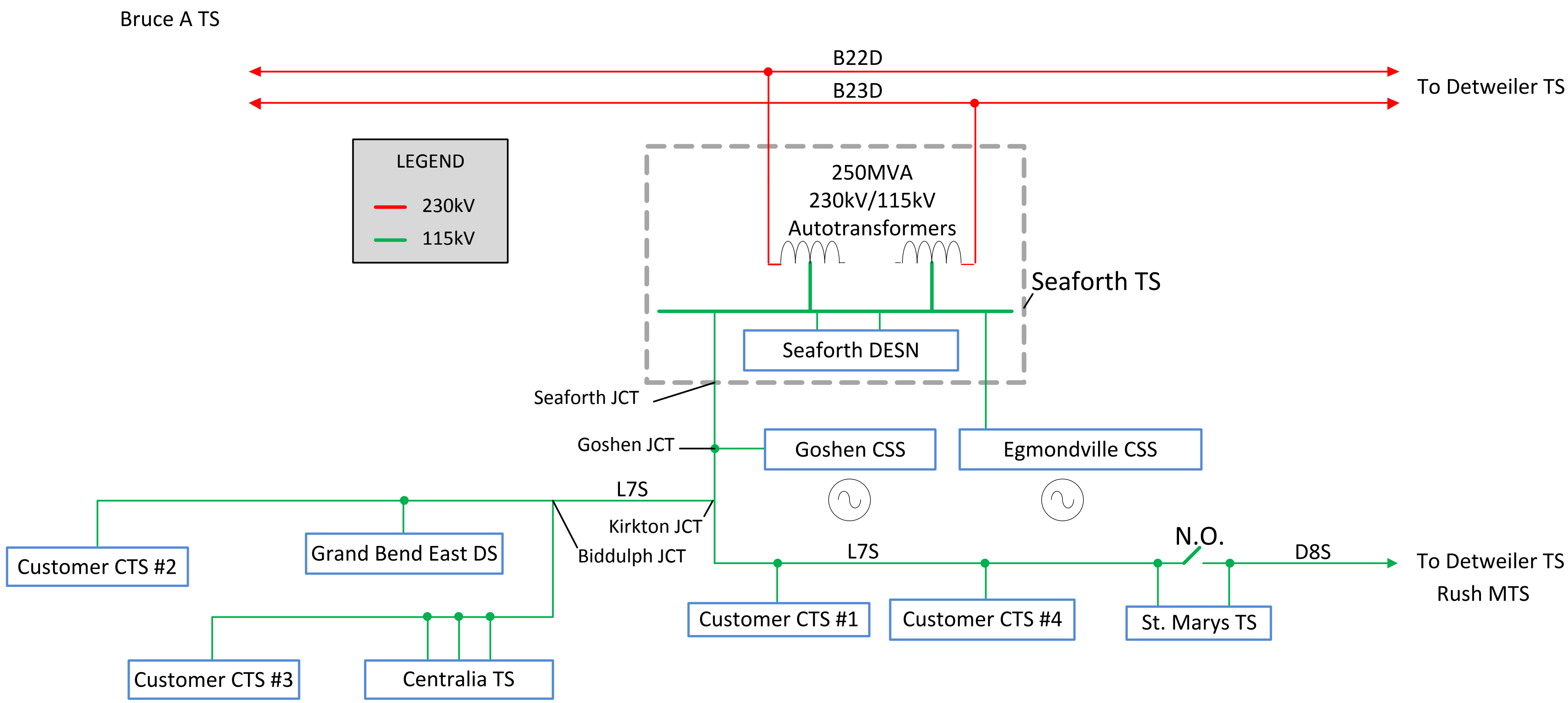

Figure 1 – Single Line Diagram of circuit L7S

Table 1 – Regional-Coincident Summer Peak Load Forecast supplied by circuit L7S[1]

Type of Forecast	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Gross Load on L7S [MW]	100	101	102	104	105	106	106	107	108	108
Total Net Load on L7S [MW]	99	99	99	100	101	101	101	102	102	102

[1] For the loss of circuit D8S, the following stations are supplied from circuit L7S: Centralia TS, Grand Bend East DS, St. Marys TS, Customer CTS #1, Customer CTS #2, Customer CTS #3 and Customer CTS #4. The forecast is a summation of the forecasted station loading. Actual flow on circuit L7S would be the summation of station load with it respective power factor plus line losses.

Table 2 – Options to Address the L7S Thermal Overload

Options		Description	Cost[2]	Required Approvals	Long-Term Benefits	Impact to Customers
1	Status Quo & Monitor Load Growth	Monitor load growth and CDM targets; when historical load approaches the forecasted load proceed with mitigation; see Figure 2: Load Growth at Stations Supplied by Circuit L7S	0	None	Defers costs until forecasted load begins to materialize.	None provided load growth is closely monitored to ensure mitigation is in place before the Need arise.
2	Increase L7S Circuit Ratings	Uprate limiting sections of the circuit to have emergency ratings that can accommodate the forecasted load; Increase the maximum sag temperature from 83°C to 110°C. Initial assessment indicates 3 spans require tower replacements and/or modifications.	$550 k	Environmental Approval Screen-out	Uprating will improve continuous and emergency ratings to accommodate the 10 year load forecast; no voltage issues with 10 year load forecast	A temporary outage during the construction of the project may be required; otherwise there is no negative impact to customers.
3	Load Transfer: Pre-contingency control action	During peak L7S loading conditions, ~8.5 MW is required to be transferred off circuit L7S from Centralia TS to Seaforth TS over the distribution system via remote switching from Hydro One Distribution's "Modernized" Grid. However, the distribution system is capable of transferring only *4.4 MW* due to end-of-line voltage limitations.	$300 k	None	A 4.4 MW load transfer would only defer the Need for additional mitigation as the load grows. However depending on the pace of load growth, the 4.4 MW of load transfer may be enough to satisfy the 10 year study period.	There is reduced reliability to load that is transferred due to the increase in distribution line distance creating additional exposure to interruptions.
4	Load Rejection + Load Transfer: Post-contingency control actions	Implement a Load Rejection (L/R) scheme for the loss of circuit D8S. During peak L7S loading conditions, OGCC will arm the scheme. Upon loss of D8S, the armed load will be rejected / unsupplied. The L/R scheme will mitigate against the immediate overload of circuit L7S until such time as the load can be transferred from Centralia TS to Seaforth TS. At that time, the rejected load can be resupplied.	$500 k[3] - $700 k[4]	Load Rejection scheme may be classified as a Special Protection Scheme and require approval from NPCC	A 4.4 MW load transfer would only defer the Need for additional mitigation as the load grows. However depending on the pace of load growth, the 4.4 MW of load transfer may be enough to satisfy the 10 year study period.	There is risk to being unsupplied for load that is armed for rejection. There is also reduced reliability to load that is transferred due to the increase in distribution line distance creating additional exposure to interruptions.

[2] Costs are budgetary and of +/- 50% accuracy and do not include interest and overhead. Detailed estimate would be required prior to project execution.
[3] $400 k* for L/R scheme + $100 k for manual switching (2 hr.) = $500 k, *If load is to be rejected at stations other than St. Marys TS, additional telecom circuits are required (at a minimum) and this will increase the cost
[4] $400 k* for L/R scheme + $300 k for remote switching (15 min.) = $700 k, *If load is to be rejected at stations other than St. Marys TS, additional telecom circuits are required (at a minimum) and this will increase the cost

3.0 Discussion of the Preferred Options

Based on the forecasted load supplied by circuit L7S, the circuit will become overloaded for the loss of circuit D8S within the 10-year study period.

Of the four options, option #1 "Status Quo and Monitor Load Growth" is the preferred option to satisfy the Need as it will defer costs until the forecasted load begins to materialize. The 2016 summer coincident peak for stations supplied by circuit L7S occurred on August 10, 2016 and totaled 91.4 MW as shown in Figure 2. This loading translates to about 460 Amperes flow on circuit L7S between Seaforth TS and Kirkton Junction when circuit D8S is out of service which is approximately 87% of the circuit's rating (530 Amperes). In Figure 2, L7S's circuit rating is illustrated as 105 MW of total station load supplied by L7S.

Once the historical load begins to approach the thermal limit of the circuit, option #2 "Increase L7S Circuit Ratings", is the preferred option to mitigate against the overload. Option #2 is a permanent capacity improvement as opposed to ongoing control actions required with options #3 and #4. As well, option #2 does not place customer load at an increased risk to being unsupplied when armed for L/R (option #4) nor does it reduce customer reliability due to long distribution lines (options #3 & #4) and therefore it is the preferred option.

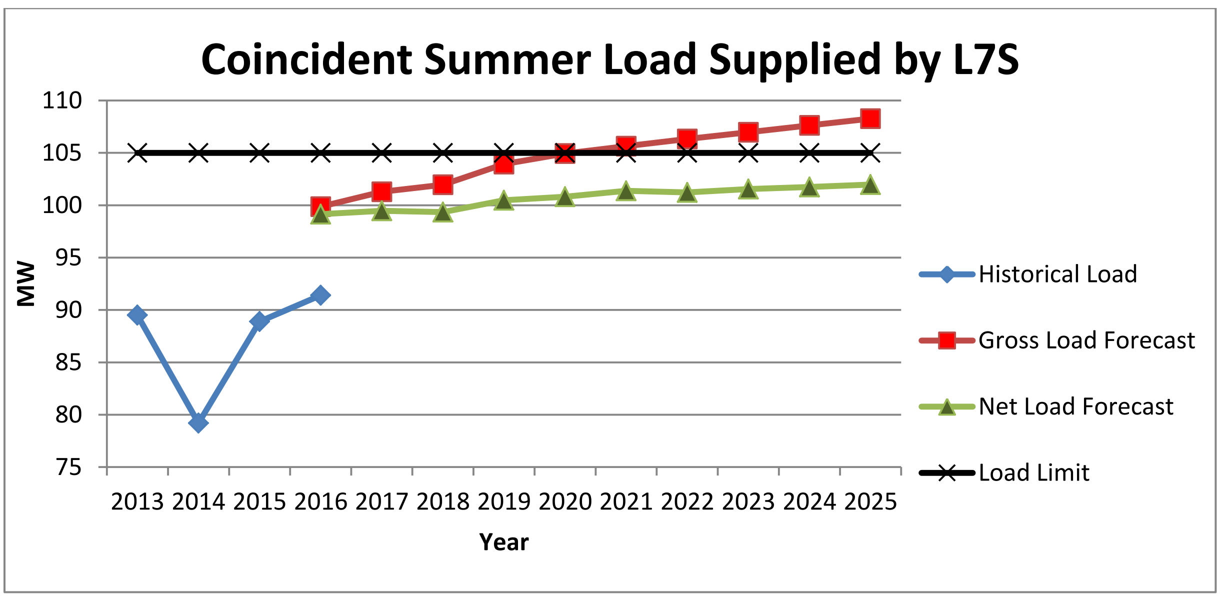

Figure 2 – Load Growth at Stations Supplied by Circuit L7S[5]

[5] The historical values and forecasts are a summation of station loading.

4.0 Development Plan

The transmission infrastructure development plan for the L7S thermal overload need is:

Step 1 Review coincident peak load on circuit L7S after each winter and summer season

- Action: IESO to provide historical data to Hydro One Transmission for review.

Step 2 Historical Load Analysis to determine if Trigger #1 met.

Trigger #1: when the historical load indicates that, for the loss of D8S, coincident peak station load supplied by circuit L7S reaches 99 MW OR historical flow on L7S out of Seaforth TS reaches 94% of the circuits' ampacity rating, a refreshed load forecast is to be provided by the LDC's and other connected customers.

- Action: Hydro One Transmission to review historical station load and flow; and when Trigger #1 is met, request a refreshed gross load forecast from LDC's and other connected customers.

- Action: LDC's and other connected customers to provide a refreshed gross load forecast within 45 days of the request to Hydro One Transmission.

Step 3 Load Forecast Analysis to determine if Trigger #2 met.

Trigger #2: when the refreshed gross load forecast indicates that, for the loss of D8S, coincident peak station loading of 105 MW is supplied by circuit L7S OR flow on L7S out of Seaforth TS reaches 100% of the circuits' ampacity rating within the next 3 years, Hydro One Transmission to proceed with mitigation.

- Action: Hydro One Transmission to review refreshed gross load forecast and flow; and if Trigger #2 is met, increase the thermal ratings of the limiting sections of circuit L7S. Capacity cost allocation will be as per the Transmission System Code.

The plan can be reviewed and reaffirmed in subsequent cycles of Regional Planning if not already under execution.

5.0 Recommendations

The following recommendations are to address the L7S thermal overload Need:

1. Continue to monitor load growth and refresh gross load forecasts according to the Development Plan outlined in Section 4.0.

2. When the loading on circuit L7S is expected to exceed its limits within the next 3 years, Hydro One Transmission to increase the thermal ratings of the limiting spans of circuit L7S. Capacity cost allocation will be as per the Transmission System Code.

LOW POWER FACTOR AT WINGHAM TS ASSESSMENT

Date: October 18th, 2016

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Disclaimer

This Local Planning Report was prepared for the purpose of developing wires options and recommending a preferred solution(s) to address the local needs identified in the Needs Assessment (NA) report for the Greater Bruce/Huron Region that do not require further coordinated regional planning. The preferred solution(s) that have been identified through this Local Planning Report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Local Planning Report are based on the information and assumptions provided by study team participants.

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Background

As part of the Ontario Energy Board's (OEB) Regional Planning process, a Needs Assessment was performed for the Greater Bruce / Huron Region. There were four (4) needs identified in the 2016 Needs Assessment for this Region, one of them being the poor power factor and voltage deficiency at Wingham TS.

This assessment addresses the low power factor and voltage deficiency issues at the Wingham TS identified in the Needs Assessment report.

Introduction

Wingham TS is a 230/44kV transformer station supplying Hydro One Distribution and Westario Power loads. The station is supplied via 230kV circuits B22D and B23D and has four (4) 44kV distribution feeders with an approximate loading of 60MW. There is also a significant amount of distributed generation (DG) connected at Wingham TS.

As per IESO Market Rules, customers are required to maintain a power factor of 0.9 or better at the point of connection. The power factor at Wingham TS has fallen below 0.5 on some occasions. A graph of the power factor performance at Wingham TS from June 2015 to June 2016 is shown in Figure 1 of Appendix A.

Findings

Upon further assessment, Hydro One Transmission, Hydro One Distribution and Westario Power determined that the low power factor was directly related to DGs connected on Hydro One's M4 feeder. The generation operates at a fixed power factor and is set to an appropriate value to help maintain the desired feeder voltage. DGs typically impact the load characteristic as seen from the transformer station. The DG will typically displace the loads real power (MW) absorbed from the transmission system while the reactive power (MVAr) of the load will typically remain unchanged.

To determine the root cause for low power factor, Hydro One Distribution and Westario Power investigated whether there were any loads that had undergone any facility modifications that could have caused this concern, however this was not the case. It was observed that, prior to the connection of an 18MW wind farm to a Wingham TS feeder, the power factor at the transformer station was consistently above 0.9, however the power factor started oscillating sporadically once the wind farm was placed in service. A graph showing the power factor performance before and after the incorporation of the wind farm is shown in Figure 2 of Appendix A.

To further confirm that it is the wind farm that is causing the poor power factor performance, the Wingham TS load power factor was isolated to determine if it would be acceptable without the effect of the 18MW wind farm. The wind farm's power output (MW and MVAr) was added to the Wingham TS load, and, the resulting load power factor was around 0.9. A graph showing the Wingham TS load power factor is shown in Figure 3 of Appendix A.

To ensure that the power factor performance was not negatively impacting the Wingham TS load customers, Hydro One Distribution and Westario Power looked into 1) customers' complaints about power quality (specifically voltage) and service, and 2) summer loading at Distribution Stations to confirm load power factors are acceptable. Neither Hydro One Distribution nor Westario Power received any customer complaints, and load power factors were found to be acceptable.

At this time, the Wingham TS load is well below the station's capacity, and therefore the higher MVA flow (caused by the absorption of VAR by the wind farm) will not result in equipment overload or cause equipment damage. It was also confirmed that both the 230kV and the 44kV bus voltage stayed within criteria during periods of low power factor. A graph of the Wingham TS MVA loading from May 2013 to May 2016 is shown in Figure 4 of Appendix A.

Conclusion

The power factor of loads at Wingham TS is within planning criteria, and the DGs connected at Wingham TS are the cause of the power factor deviating from Market Rules. Since there are no voltage issues at Wingham TS, and there is no lack of reactive power support in the local area, Hydro One Transmission, Hydro One Distribution and Westario Power propose that no action is required at this time and the occasional low power factor observed at Wingham TS is not a need that requires mitigation. Hydro One proposes to discuss, with the IESO, possible changes to the Market Rules that would take into account the effects DGs have on station power factor, and will continue to monitor the situation and act accordingly if the low power factor becomes an issue in the future.

APPENDIX A

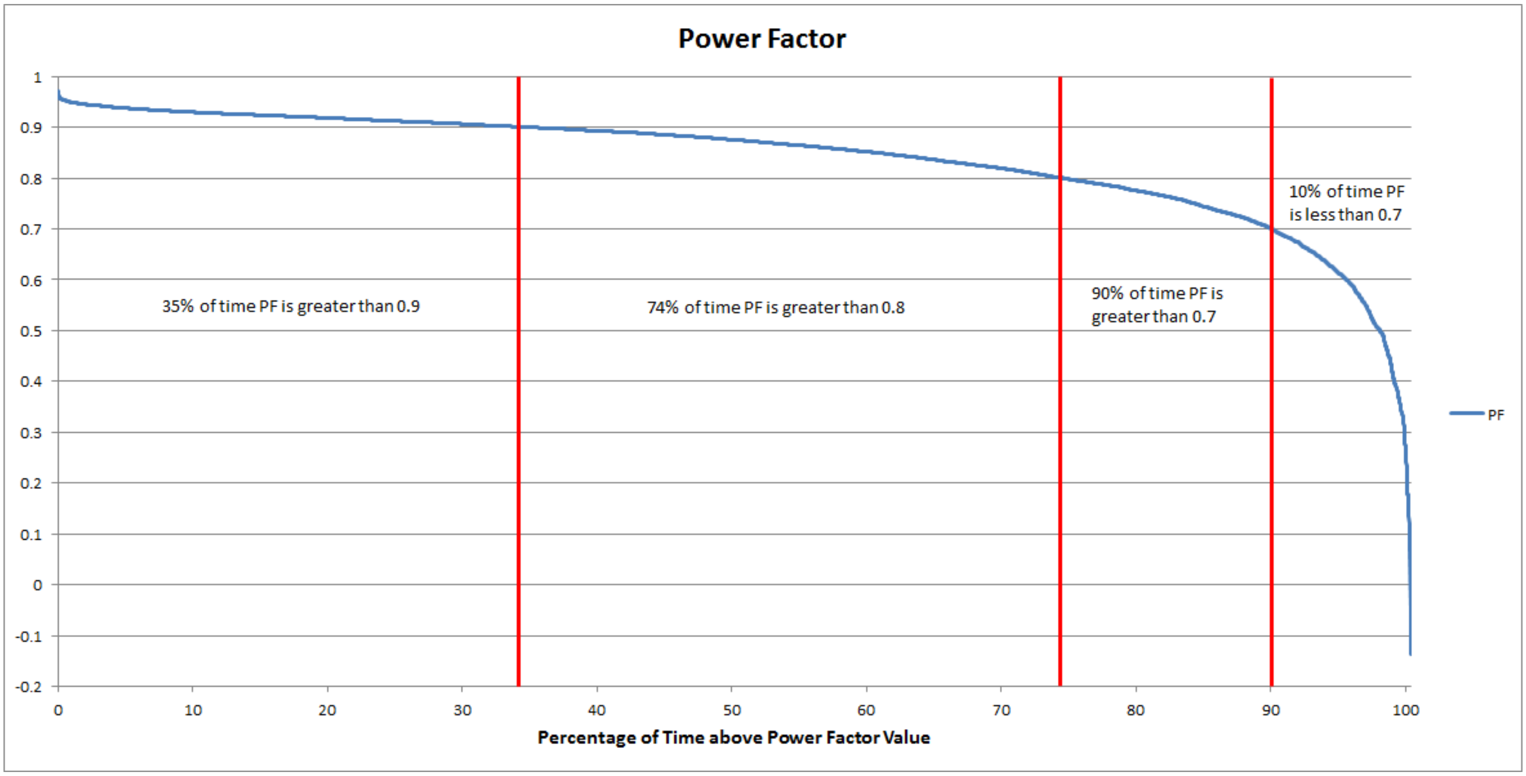

Figure 1: Graph showing the power factor performance ot Wingham TS between June 2015 and June 2016

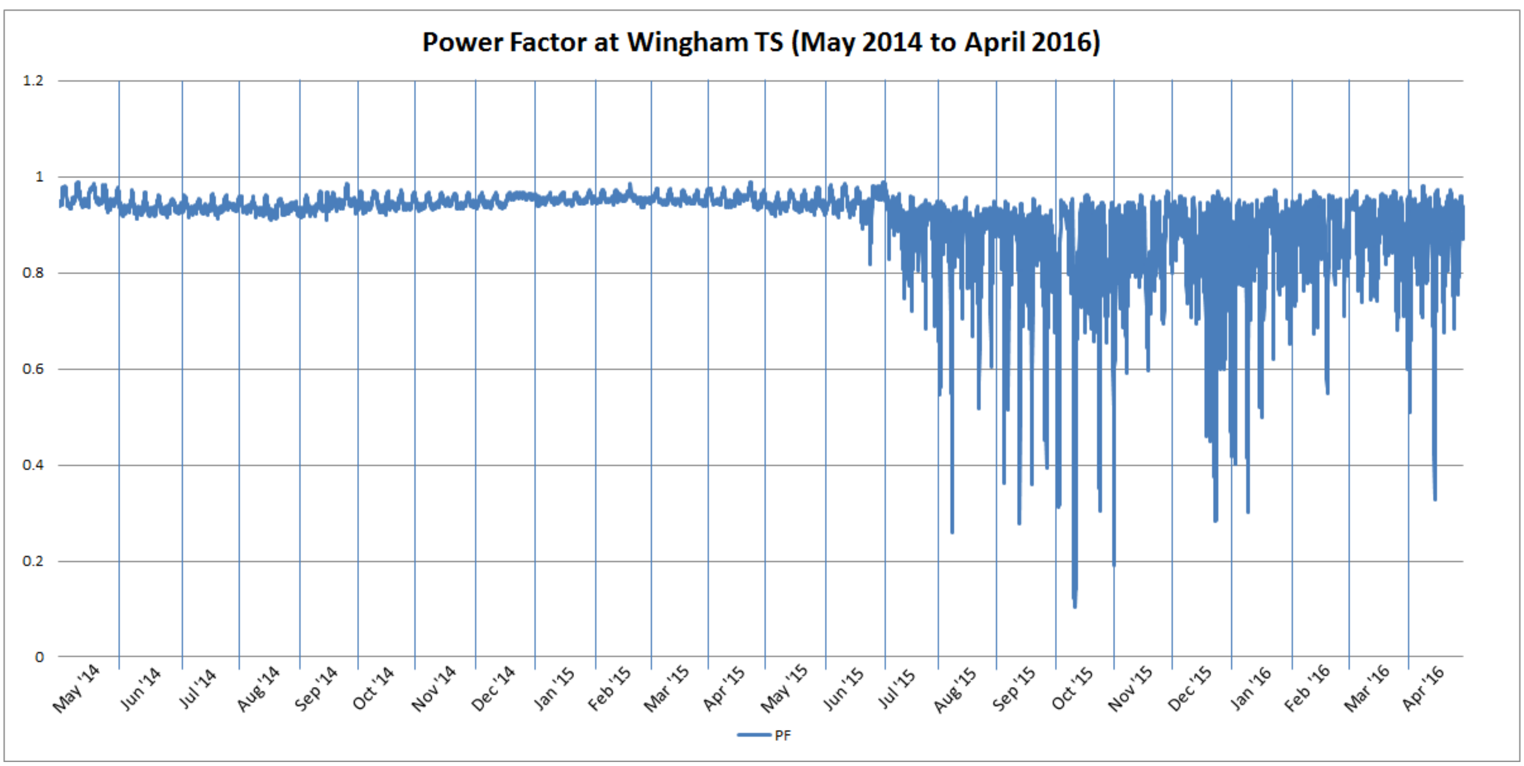

Figure 2: Graph showing Wingham TS power factor before and after wind farm was place in service.

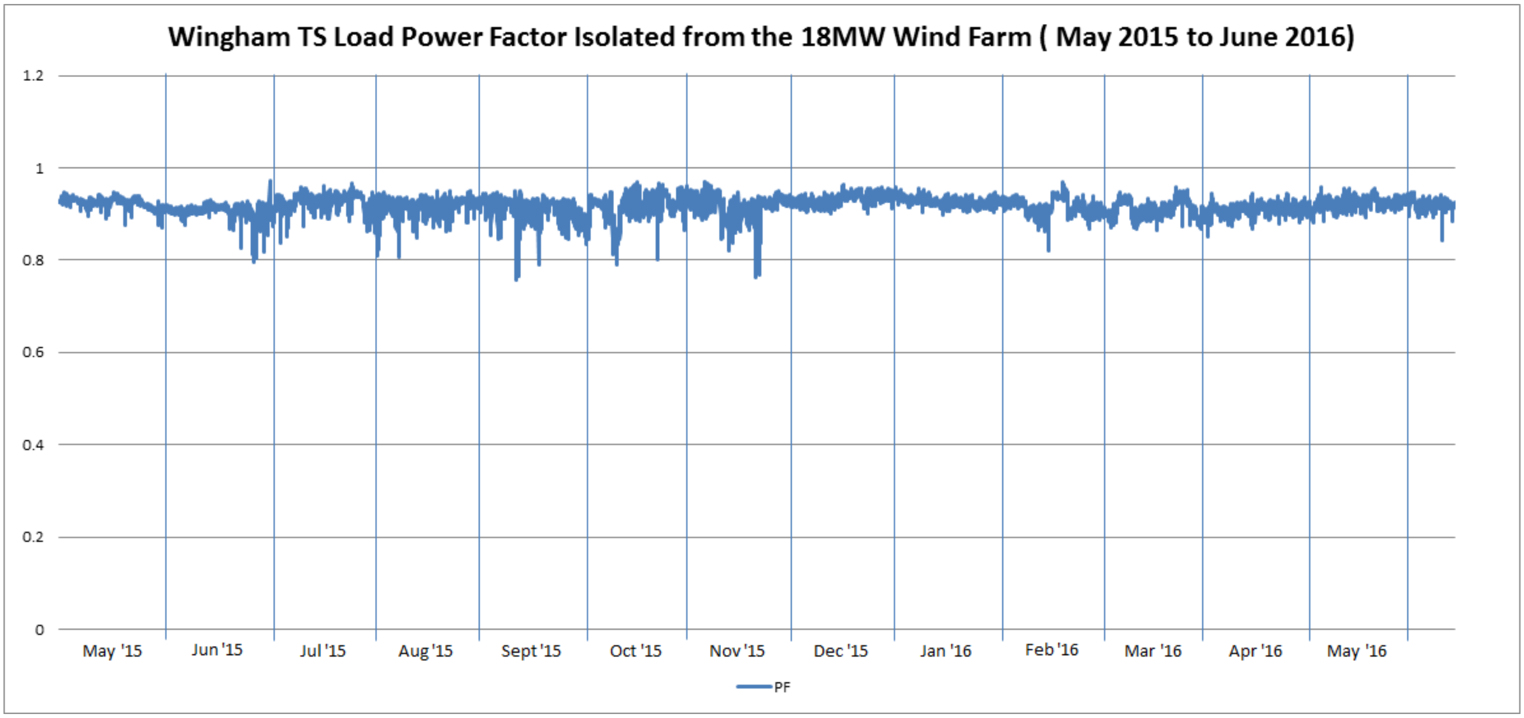

Figure 3: Graph showing Wingham TS load power factor since the connection of wind farm.

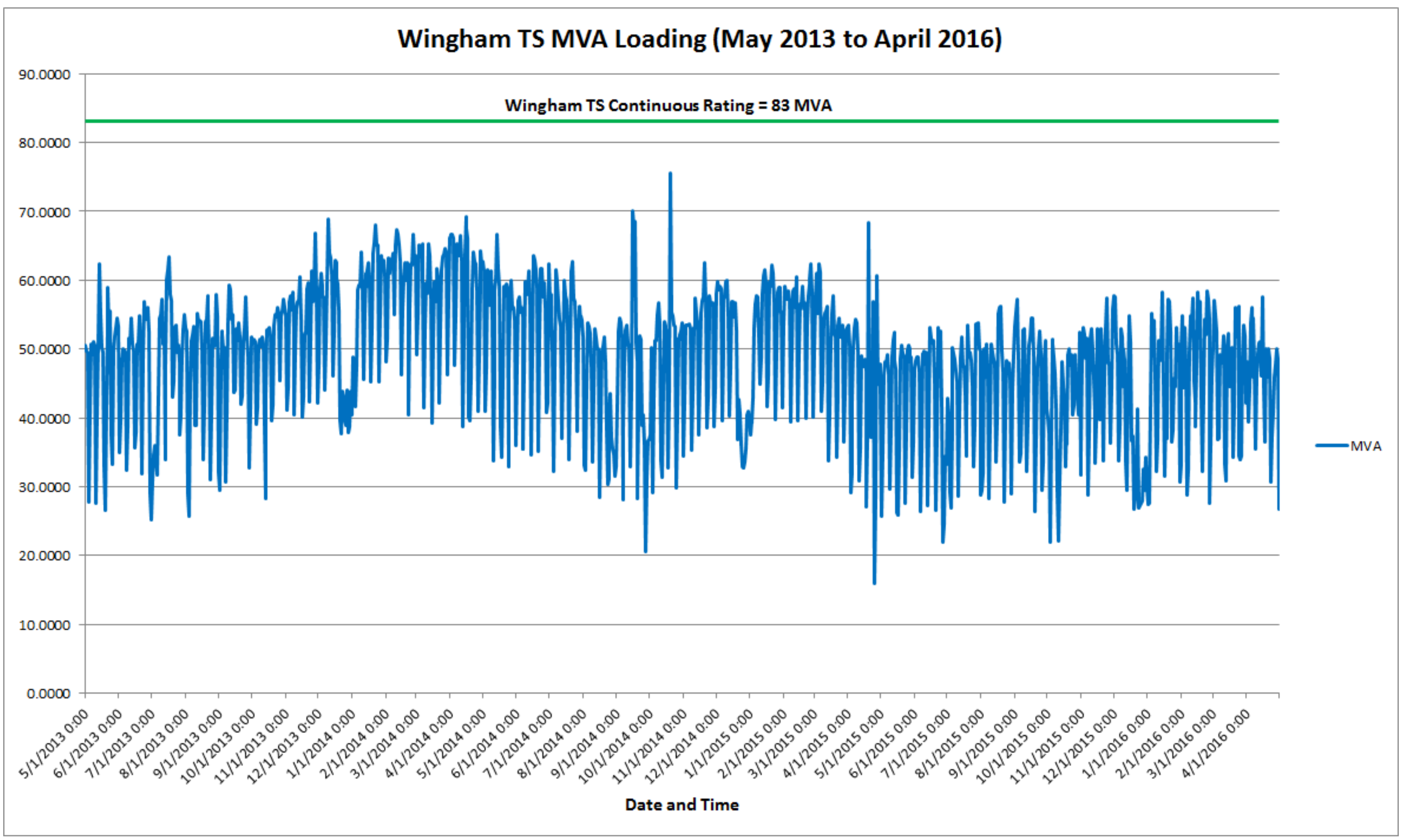

Figure 4: Graph showing MVA loading at Wingham TS over the last 3 years

APPENDIX F - IESO - REG LETTER OF COMMENT

IESO Letter of Comment

Erie Thames Powerlines

Renewable Energy Generation Investments Plan

August 3, 2017

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.

Erie Thames Powerlines Corporation – Distribution System Plan

On July 13, 2017, Erie Thames Powerlines Corporation ("ETPL") provided its Renewable Energy Generation ("Plan") to the IESO as part of its 5-year Distribution System Plan. The IESO has reviewed ETPL's Plan and has provided its comments below.

IESO FIT/microFIT Applications Received

ETPL's Plan indicates that the following FIT and microFIT projects are connected or pending connection to its distribution system:

- 7 FIT projects totaling 1.863 MW of capacity (and 4 projects totaling 1.050 MW pending connection), and
- 81 microFIT projects totaling 751.475 kW of capacity (and 2 projects totaling 15.92 kW pending connection)

According to the IESO's information as of June 30, 2017, the IESO has offered contracts to 80 microFIT projects totalling 0.744 MW of capacity, 11 FIT projects totaling 2.913 MW. The REG connections information in ETPL's Plan is therefore substantially 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
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Consultation / Participation in Planning Meetings; Coordination with Distributors / Transmitters / Others; Consistency with Regional Plans

For regional planning purposes, ETPL belongs to both the London Area and Greater Bruce/Huron regions.

A Needs Assessment ("NA") was carried out by Hydro One Networks Inc. ("Hydro One") for the London Area region in April 2015.[2] The NA identified electricity needs that may require regional coordination, recommending that a further review should be done through the Scoping Assessment ("SA") process led by the IESO. The SA was completed in August 2015. Representatives from Entegrus Power Lines, ETPL, London Hydro Inc., St. Thomas Energy Inc., Tillsonburg Hydro Inc., Woodstock Hydro Services Inc., Hydro One (Distribution and Transmission) and the IESO participated in these processes.

An outcome of the SA divided the London Area region into five sub-regions: **Greater London** sub-region, **Alymer-Tillsonburg** sub-region, **Strathroy** sub-region, **Woodstock** sub-region, and the **St. Thomas** sub-region.[3] The IESO notes that ETPL's distribution system is fully embedded and supplied from Hydro One distribution circuit(s) with one transmission connected supply point for the Town of Aylmer. ETPL supplies customers in the **Aylmer-Tillsonburg** sub-region.

An Integrated Regional Resource Plan ("IRRP") for the Greater London sub-region was published in January 2017 and addresses the capacity and load restoration needs identified in the Greater London sub-region.[4] In its Plan ETPL indicates that it actively participates in the regional planning processes through which concerns have been identified regarding the constraints at both Aylmer TS and Tillsonburg TS. Supply capability limitations identified through the NA and SA processes for the Alymer-Tillsonburg sub-region will be addressed through Regional Infrastructure Planning ("RIP"), recently commenced and led by Hydro One. ETPL's indicates that as a result, it does not expect any capital expenditure for this planning period.

Local planning between affected local distribution companies and Hydro One Transmission will address needs in the **Strathroy** and **Woodstock** sub-regions; and, the **St. Thomas** sub-region requires no further planning at this time.

Hydro One completed the NA for the Greater Bruce/Huron region and found that there were no needs requiring regional coordination.[5] Therefore the regional planning process for this planning cycle is

[2] Hydro One Needs Assessment Report, London Area, April 2015, http://www.hydroone.com/RegionalPlanning/LondonArea/Documents/Needs%20Assessment%20Report%20-%20London%20Region%20-%20April%202,%202015.pdf

[3] IESO Scoping Assessment Outcome Report, London Area, May 2015, http://www.ieso.ca/-/media/files/ieso/document-library/regional-planning/london-area/london-area-scoping-assessment-report-tor-for-irrp-and-rip.pdf

[4] IESO Greater London, IRRP, January 2017, http://www.ieso.ca/-/media/files/ieso/document-library/regional-planning/london-area/final-greater-london-irrp-20170120.pdf?la=en

[5] Hydro One Needs Assessment Report, Greater Bruce/Huron, May 6, 2016, http://www.hydroone.com/RegionalPlanning/GreaterBruce-Huron/Pages/default.aspx

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complete, commencing again within the 5-year regional planning time frame, or earlier if sufficient load growth materializes or an event triggers the need to initiate the planning process earlier.

The IESO looks forward to working with Erie Thames Powerlines on future regional planning activities, and appreciates the opportunity to comment on its REG investment plan at this time.

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APPENDIX G - 2011 ASSET MANAGEMENT PLAN (METSCO)