Exhibit 3:

OPERATING REVENUE

Exhibit 3: Operating Revenue

Tab 1 (of 4): Load and Revenue Forecast

OVERVIEW OF OPERATING REVENUE

This Exhibit provides the details of Erie Thames Powerlines Inc.'s ("ETPL's") operating revenues for 2012 Board Approved, 2012 Actual, 2013 Actual, 2014 Actual, 2015 Actual, 2016 Actual, 2017 Bridge Year and the 2018 Test Year. This Exhibit also provides a detailed variance analysis by rate classification for the operating revenue components. Distribution revenue excludes revenue from commodity sales.

ETPL is proposing a total Service Revenue Requirement of $10,780,159 for the 2018 Test Year. This amount includes a Base Revenue Requirement of $10,285,712 plus Other Revenue of $494,447 as discussed in Section 3.3 below.

Other Revenue includes Specific Service Charges, Late Payment Charges, Other Operating Revenues and Other Income or Deductions. As summary of these operating revenues with a materiality analysis of variances is presented in Section 3.3.

This exhibit also describes ETPL's load and customer forecasts. The load forecast methodology and assumptions are described in detail at 3.1 Load Forecast Methodology.

The evidence provided here is organized per the following topics;

Revenue and Load Forecast

Accuracy of Forecast and Variance analysis

Other Revenues

HISTORICAL & FORECAST VOLUMES

Overview of Revenue Forecast

Distribution revenues are derived through a combination of fixed monthly charges and volumetric charges ETPL has provided the following table which applied to the utility's proposed Load Forecast and customer counts to its current approved rates. ETPL's 2018 forecasted load and customer counts applied to its currently approved rates produces Distribution Revenue of $10,119,835 exclusive of all rate riders and low voltage charges.

ETPL is not requesting any changes to its current class composition that would impact this breakdown of Distribution Revenue.

Proposed Load Forecast

Traditionally, kWh data is collected by month for 10 historic years for use in the regression analysis. This includes purchase data from the IESO and Hydro One Networks Inc. ("HONI"), as well as embedded generation data. Accordingly, ETPL has utilized kWh purchase data, by month, for its entire service from January 2007 to January of 2017 in order to ensure that all billed consumption is collected and applied to its appropriate consumed month.

Erie Thames engaged Elenchus to complete a 2018 CDM adjusted Load Forecast. A report detailing the approach and load forecast results is included as Appendix 1 to this schedule. The following table summarizes the historic and forecast loads by class from 2012 actuals to the 2018 forecast.

Table 3-1 kWh Forecast by Class

Normal Forecast

kWh	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2016 Normalized	2017 Forecast	2018 Forecast
Residential	136,951,769	139,174,379	137,614,288	135,712,848	136,671,067	134,543,557	133,927,949	133,312,341
GS < 50	47,672,679	48,218,851	48,123,471	50,019,956	48,503,240	48,633,327	48,915,619	49,204,000
GS > 50	125,014,555	122,356,889	126,877,352	122,207,045	126,567,691	117,205,515	114,652,868	113,115,019
Intermediate	69,565,629	69,417,979	70,641,461	66,642,313	56,877,241	51,789,364	62,080,889	54,466,922
Large User	96,186,938	98,312,961	103,336,247	107,405,736	115,608,242	108,025,611	98,980,671	99,199,237
Embedded Distributor	15,488,407	15,613,195	16,830,475	16,494,364	16,248,812	16,106,610	16,296,711	16,296,711
Street Light	3,484,987	2,710,402	2,115,842	2,025,403	1,938,875	1,938,875	1,962,132	1,985,669
Sentinel Light	280,910	272,742	266,366	246,528	231,256	231,256	226,333	221,514
USL	513,343	539,394	535,721	537,894	504,437	504,437	510,974	517,597
Total	495,159,218	496,616,791	506,341,223	501,292,088	503,150,861	478,978,552	477,554,147	468,319,010

The following table summarizes 2015-2020 CDM Adjusted Load Forecast kWh.

Table 3-1 CDM Adjusted kWh forecast

CDM Adjusted

kWh	2016 Weather Normal Forecast	CDM Adjustment	2016 CDM Adjusted Forecast
Residential	133,312,341	1,256,917	132,055,423
GS < 50	49,204,000	1,142,122	48,061,878
GS > 50	113,115,019	2,796,366	110,318,653
Intermediate	54,466,922	1,519,686	52,947,236
Large User	99,199,237	2,264,838	96,934,399
Embedded Distributor	16,296,711	0	16,296,711
Street Light	1,985,669	0	1,985,669
Sentinel Light	221,514	0	221,514
USL	517,597	0	517,597
Total	468,319,010	8,979,929	459,339,081

The historic and forecast kW for 2012-2018 is summarized in the following table.

Table 2-3 kW Forecast

Normal Forecast

kW	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2016 Normalized	2017 Forecast	2018 Forecast
GS > 50	368,507	345,792	350,962	252,230	329,499	331,653	324,430	320,078
Intermediate	139,939	140,015	128,435	158,509	141,887	114,710	137,505	119,149
Large User	160,412	163,430	178,918	169,422	177,134	187,446	171,751	172,130
Embedded Distributor	36,022	36,253	36,009	35,856	36,389	34,450	34,856	34,856
Street Light	9,969	7,518	5,900	5,564	5,229	5,321	5,384	5,449
Sentinel Light	643	647	657	653	615	599	587	574
Total	715,491	693,655	700,881	622,234	690,753	674,178	674,513	652,238

The following table summarizes 2015-2020 CDM Adjusted Load Forecast kW. Details for CDM adjustment calculations can be found in Schedule 6 of Attachment 3A.

Table 3-3 CDM Adjusted kW Forecast

CDM Adjusted

kW	2016 Weather Normal Forecast	CDM Adjustment	2016 CDM Adjusted Forecast
GS > 50	320,078	11,869	308,209
Intermediate	119,149	4,987	114,163
Large User	172,130	5,895	166,236
Embedded Distributor	34,856	0	34,856
Street Light	5,449	0	5,449
Sentinel Light	574	0	574
Total	652,238	22,751	629,487

The following table presents the actual and forecasted trends for customer counts, kWh's consumed and kW demand data that will underpin the resulting rates applied for as part of this application.

Table 3-4 Customer / Connection Forecast for 2012-2018

Customer Connections

kW	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Forecast	2018 Forecast
Residential	16,236	16,383	16,516	16,667	16,855	16,987	17,119
GS < 50	1,921	1,940	1,953	1,989	1,993	2,006	2,018
GS > 50	189	187	183	157	160	157	155
Intermediate	5	5	5	5	5	5	4
Large User	1	1	1	1	1	1	1
Embedded Distributor	3	4	4	4	4	4	4
Street Light	4,283	4,498	4,498	4,617	5,927	5,998	6,070
Sentinel Light	301	248	248	248	248	243	238
USL	120	124	121	128	126	128	130
Total	23,059	23,390	23,528	23,817	25,320	25,529	25,739

A completed copy of Appendix 2-IB is presented in Attachment 3B of this exhibit, included in Excel format and is also included in Tab 10 of RRWF submitted as part of this application. This provides comparisons of:

Historic Board-Approved vs. Historic Actual vs. Weather-Normalized Historic Actual

The Historic Actual trend

Weather-Normalized Historic Actual and Weather-Normalized Forecast

Customer-Specific Load Forecast Adjustments

Prior to any modeling, ETPL determined that a few facility closures and or changes had been announced to take place within its service territory and notified its consultant to ensure that load for any closing customers would be factored out of the analysis. Copies of the news articles that drove the decision to include these adjustments have been attached as Attachments 3C (Maple Leaf Foods) and 3D (CAMI-GM Assembly Ingersoll). With respect to Maple Leaf Foods closure ETPL has taken the approach that the account would be removed from all load forecast modeling since they plan to close in early 2018 prior to ETPL's new rates being implemented. In the case of GM Assembly Ingersoll (CAMI Automotive) ETPL determined to make no adjustment for the laying off of employees and the reduction of its operations. ETPL made this determination due to the fact that CAMI is billed distribution revenue on kW Demand and it is likely that Demand would not be materially impacted by the reductions.

Given that the forecast's main result is to drive distribution rates and the fact that demand would not be materially impacted ETPL feels that this is the best approach rather than trying to make an uninformed determination on how the layoffs would affect the plant's hydro usage. GM staff were canvased to see if an estimate could be placed upon the impending layoffs and unfortunately a response will not be provided. Lastly a grocery store in a small town within ETPL service territory announced its closure in August of 2017, due to the fact that it is a fair sized and growing community (Belmont Ontario) ETPL determined to not adjust for this closure and instead feels that, given the growth of the town, and the fact that there is no other grocer within the community, the store will eventually be replaced and ETPL will be kept whole on customer counts and usage data at that time.

Wholesale Market Participants

ETPL currently has no Wholesale Market Participants ("WMPs") operating within its service territory.

CDM ADJUSTMENT

ETPL has based its planned CDM on the assumption of equal program delivery in all years 2016-2020, and 100% persistence of these programs until 2020. For 2015 program delivery, ETPL has relied on the verified savings reported by the IESO. In that report, 5,180,177 kWh from its 2015 CDM program delivery is counted towards the 2015-2020 target, leaving 22,449,823 kWh to be achieved due to programs delivered 2016-2020, or 4,489,965 kWh per year.

The IESO report provided verified savings of 5,870,204 kWh from 2015 CDM program delivery in 2015, of which 5,180,177 kWh are persisting to 2020. The IESO only counts the savings which will be persisting into 2020 as counting towards the 2015-2020 target. Therefore, only 5,180,177 kWh is counted as completed towards the target. In order to be consistent with this methodology, ETPL is planning to deliver CDM programs that achieve a total savings of 27,630,000 kWh in 2020.

In order to arrive at CDM program delivery and CDM savings in the years leading up to 2020, ETPL has relied on the assumption that programs delivered in 2016-2020 will have 100% persistence until 2020. For programs delivered in 2015, the IESO has provided persistence values for 2015 into 2020. Attachment 3E provides the OEB Appendix 2-I Load Forecast CDM Adjustment Workform.

In preparing the 2017 CDM adjusted load forecast and LRAMVA target, Elenchus relied upon projected CDM program delivery and persistence into 2018. For the CDM adjustment, Elenchus included half of the savings in 2016, a full year of the savings from 2017 programs, and a half-year of savings from 2018 program delivery. The LRAMVA target is set using full years of program delivery 2016-2018, therefore 6,580,891 kWh is realized in – the amount of CDM program delivery 2016-2018 which persists into 2018.

PASS-THROUGH CHARGES

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 3-6 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 3-7 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 this exhibit as part of ETPL's load forecasting.

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 3-8 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 3-9 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 3-10 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

The following Table summarized 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.

1 **Table 3-11 Summary of Cost of Power**

	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**

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Exhibit 3: Operating Revenue

Tab 2 (of 4): Accuracy of Load Forecast and Variance Analysis

VARIANCE ANALYSIS OF LOAD FORECAST

OVERVIEW

Provided in the following section is ETPL's analysis of the accuracy of the historical load forecast covering 2012 Board Approved, historical actual results from 2012 to 2016, the 2017 Bridge Year and the 2018 Test Year. The analysis has been completed on the following basis:

Distribution Revenue,

Billing Determinants (customer/connection counts, billed kWh and billed kW), and

Distribution Revenue calculated on the basis of existing rates and proposed rates.

All historical amounts reflect actual weather conditions in the year. The 2017 Bridge Year and 2018 Test Year are weather normalized. It is the understanding of ETPL that there is not a Board approved method with which to weather normalize actual data. Consequently, ETPL relied upon Elenchus in order to obtain expertise in producing weather normalized results. An explanation of the process undertaken by Elenchus can be found in their report included in this exhibit as Attachment 3A.

2012 Board Approved Distribution Revenues

As described in Exhibit 1, ETPL's last COS was filed in 2012 (EB-2012-0121). The following tables detail the Distribution Revenues allocated to rate classes, as well as billing determinants and customer accounts approved in the derivation of rates.

Table 3-12 Distribution Revenues Allocated by Rate Class

	Distribution Revenue
Residential	$ 5,636,524.48
GS < 50 kW	$ 1,142,520.09
GS>50 to 999 kW	$ 862,570.92
GS>1000 to 4999 kW	$ 526,240.60
Large Use	$ 307,548.77
Sentinel Lighting	$ 30,336.57
Street Lights	$ 344,523.30
Embedded Distributor	$ 166,008.80
Unmetered	$ 70,761.89
Total	$ 9,087,035.41

Table 3-13 Customer Counts by Rate Classs

	Customers
Residential	16,461
GS < 50 kW	1,857
GS>50 to 999 kW	175
GS>1000 to 4999 kW	7
Large Use	1
Sentinel Lighting	301
Street Lights	4,283
Embedded Distributor	3
Unmetered	121
Total	23,209

Table 3-14 Consumption by Rate Class

	Consumption
Residential	147,767,075
GS < 50 kW	50,306,768
GS>50 to 999 kW	227,921
GS>1000 to 4999 kW	96,900
Large Use	160,146
Sentinel Lighting	772
Street Lights	6,754
Embedded Distributor	23,768
Unmetered	618,341
Total	199,208,445

3.2.1 DISTRIBUTION REVENUE VARIANCE ANALYSIS

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 $50,000 as its basis for variance analysis of Distribution Revenue. Table 3-15 below shows the variances by rate class for Distribution Revenue. Variances outside of the materiality threshold are discussed in detail below.

Total distribution revenue amounts tie to those filed in RRR 2.1.7 annually and to the audited financial statements, unless otherwise noted. ETPL accrues for unbilled revenue at the end of each period, which is later reversed and replaced with the actual results.

TABLE 3-315: DISTRIBUTION REVENUE VARIANCE ANALYSIS

Rate Class	2012 BAP	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual
Residential	$ 5,636,524	$ 4,372,821	$ 5,496,828	$ 5,308,101	$ 5,715,607	$ 5,896,553
General Service <50 kW	$ 1,149,106	$ 891,542	$ 1,080,052	$ 1,220,581	$ 1,197,844	$ 1,216,304
General Service >50 to 999 kW	$ 917,272	$ 900,883	$ 1,095,882	$ 1,198,976	$ 1,063,075	$ 1,080,844
General Service >1,000 to 4,999 kW	$ 584,381	$ 573,940	$ 698,170	$ 763,850	$ 677,270	$ 648,442
Large Use	$ 403,636	$ 340,205	$ 342,722	$ 336,501	$ 350,698	$ 349,721
Unmetered Scattered Load	$ 70,762	$ 10,771	$ 57,341	$ 68,665	$ 63,627	$ 60,766
Sentinel Lighting	$ 30,337	$ 21,689	$ 26,007	$ 29,633	$ 25,608	$ 25,194
Street Lighting	$ 344,523	$ 327,827	$ 425,418	$ 445,803	$ 402,098	$ 405,334
Embedded Distributor	$ 170,676	$ 42,884	$ 246,730	$ 248,709	$ 230,552	$ 349,721
Total	**$ 9,307,216**	**$ 7,482,563**	**$ 9,469,151**	**$ 9,620,818**	**$ 9,726,379**	**$ 10,032,880**
		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**
Residential		-$ 1,263,703	$ 1,124,007	-$ 188,727	$ 407,506	$ 180,946
General Service <50 kW		-$ 257,564	$ 188,511	$ 140,528	-$ 22,737	$ 18,460
General Service >50 to 999 kW		-$ 16,389	$ 194,999	$ 103,094	-$ 135,901	$ 17,769
General Service >1,000 to 4,999 kW		-$ 10,441	$ 124,231	$ 65,680	-$ 86,581	-$ 28,828
Large Use		-$ 63,431	$ 2,518	-$ 6,221	$ 14,197	-$ 977
Unmetered Scattered Load		-$ 59,990	$ 46,570	$ 11,323	-$ 5,038	-$ 2,860
Sentinel Lighting		-$ 8,647	$ 4,318	$ 3,625	-$ 4,025	-$ 414
Street Lighting		-$ 16,696	$ 97,591	$ 20,385	-$ 43,704	$ 3,236
Embedded Distributor		-$ 127,792	$ 203,846	$ 1,979	-$ 18,157	$ 119,169
Total	**$ -**	**-$ 1,824,654**	**$ 1,986,589**	**$ 151,666**	**$ 105,561**	**$ 306,501**
		2012 BAP vs. 2012 Actual	**2012 BAP vs. 2013 Actual**	**2012 BAP vs. 2014 Actual**	**2012 BAP vs. 2015 Actual**	**2012 BAP vs. 2016 Actual**
Residential		-$ 1,263,703	-$ 139,696	-$ 328,424	$ 79,083	$ 260,028
General Service <50 kW		-$ 257,564	-$ 69,054	$ 71,475	$ 48,738	$ 67,198
General Service >50 to 999 kW		-$ 16,389	$ 178,610	$ 281,704	$ 145,803	$ 163,572
General Service >1,000 to 4,999 kW		-$ 10,441	$ 113,790	$ 179,470	$ 92,889	$ 64,062
Large Use		-$ 63,431	-$ 60,913	-$ 67,135	-$ 52,938	-$ 53,915
Unmetered Scattered Load		-$ 59,990	-$ 13,421	-$ 2,097	-$ 7,135	-$ 9,995
Sentinel Lighting		-$ 8,647	-$ 4,329	-$ 704	-$ 4,729	-$ 5,142
Street Lighting		-$ 16,696	$ 80,894	$ 101,279	$ 57,575	$ 60,811
Embedded Distributor		-$ 127,792	$ 76,054	$ 78,033	$ 59,876	$ 179,045
Total	**$ -**	**-$ 1,824,654**	**$ 161,935**	**$ 313,601**	**$ 419,163**	**$ 725,664**

2012 BOARD APPROVED VS. 2012 ACTUAL RESULTS

ETPL experienced a decrease of 2012 actual distribution revenue of $1,824,654 from the 2012 Board-approved amounts. The decrease from the Board Approved amount is directly attributable to the fact that ETPL's rates for 2012 Test Year were not effective until January of 2013, due to delays in filing and the normal timelines of the process. Effectively the 2012 distribution revenue was still based upon 2008 Cost of Service process and therefore does not tie to the 2012 Board approved amounts.

2012 ACTUAL RESULTS VS. 2013 ACTUAL RESULTS

In 2013, ETPL finally had its 2012 Cost of Service rates approved and for the full year. Therefore, the increase in 2013 results vs. those detailed for 2012 are not based upon the same rate structure and therefore are not a relevant comparator. When looking at 2013 actual vs. 2012 Board approved the difference is $161,935 or a 1.7% increase. A portion of this increase can be attributed to ETPL's 2013 IRM increase in May of 2013 which increased rates a further 0.28% while the remaining increases can be attributed to changes in usage levels and customer counts and usage changes year over year.

Table 3-16 Distribution Revenues Variance Analysis 2013 Actuals vs 2012 Board Approved

Rate Class	Customers / Connections	kWh/kW	Customers / Connections	kWh/kW	Customers / Connections	kWh/kW
	2012 BAP		2013 Actual Results		Variance	
Residential	16,461	147,767,075	16,383	139,174,379	- 78	- 8,592,696
General Service <50 kW	1,857	50,306,768	1,940	48,218,851	83	- 2,087,917
General Service >50 to 999 kW	175	227,921	187	345,792	12	117,871
General Service >1,000 to 4,999 kW	7	96,900	5	140,015	- 2	43,115
Large Use	1	160,146	1	163,430	-	3,284
Unmetered Scattered Load	121	618,341	124	539,394	3	- 78,947
Sentinel Lighting	301	772	248	647	- 53	- 125
Street Lighting	4,283	6,754	4,498	7,518	215	764
Embedded Distributor	3	23,768	4	36,253	1	12,485
Total	**23,209**	**199,208,445**	**23,390**	**188,626,279**	**181**	**- 10,582,165**

2013 ACTUAL RESULTS VS. 2014 ACTUAL RESULTS

In 2014, ETPL experienced an increase in distribution revenue of $151,666 from 2013, or an increase of 1.6% year over year. During ETPL's 2014 IRM application ETPL was approved for a rate increase of 1.25% effective May 1st 2014 which is directly attributable almost all of the increase in distribution revenues. The remaining differences are attributed to changes in customer counts and billed volumes.

The following table shows 2014 Actual year end billing determinants versus the 2013 year end billing determinants. During 2014, ETPL experienced a small increase in Residential customers, while total kWh billed remained relatively flat.

Table 3-17 Distribution Revenues Variance Analysis 2014 Actuals vs 2013 Actuals

Rate Class	Customers / Connections	kWh/kW	Customers / Connections	kWh/kW	Customers / Connections	kWh/kW
	2013 Actual Results		2014 Actual Results		Variance	
Residential	16,383	139,174,379	16,516	137,614,288	133	- 1,560,091
General Service <50 kW	1,940	48,218,851	1,953	48,123,471	13	- 95,380
General Service >50 to 999 kW	187	345,792	183	350,962	- 5	5,170
General Service >1,000 to 4,999 k\	5	140,015	5	128,435	-	- 11,580
Large Use	1	163,430	1	178,918	-	15,488
Unmetered Scattered Load	124	539,394	121	535,721	- 3	- 3,673
Sentinel Lighting	248	647	248	657	-	10
Street Lighting	4,498	7,518	4,498	5,900	-	- 1,618
Embedded Distributor	4	36,253	4	36,009	-	- 245
Total	**23,390**	**188,626,279**	**23,528**	**186,974,361**	**138**	**- 1,651,918**

2014 ACTUAL RESULTS VS. 2015 ACTUAL RESULTS

In 2015, ETPL experienced increased distribution revenue of $105,561 from 2014, which represents an increase of 1.10%. This increase is less than the 2015 IRM increase of 1.30% that ETPL was approved for in May of 2015 and therefore fully explains the increase year over year. Notwithstanding ETPL is including a breakdown of change in billing determinants year over year to provide consistency in the data provided as part of this analysis.

Table 3-18 Distribution Revenues Variance Analysis 2015 Actuals vs 2014 Actuals

Rate Class	Customers / Connections	kWh/kW	Customers / Connections	kWh/kW	Customers / Connections	kWh/kW
	2014 Actual Results		2015 Actual Results		Variance	
Residential	16,516	137,614,288	16,667	135,712,848	152	- 1,901,440
General Service <50 kW	1,953	48,123,471	1,989	50,019,956	36	1,896,485
General Service >50 to 999 kW	183	350,962	157	252,230	- 25	- 98,732
General Service >1,000 to 4,999 k\	5	128,435	5	158,509	-	30,074
Large Use	1	178,918	1	169,422	-	- 9,496
Unmetered Scattered Load	121	535,721	128	537,894	7	2,173
Sentinel Lighting	248	657	248	653	-	- 4
Street Lighting	4,498	5,900	4,617	5,564	119	- 336
Embedded Distributor	4	36,009	4	35,856	-	- 153
Total	**23,528**	**186,974,361**	**23,817**	**186,892,933**	**288**	**- 81,428**

2015 ACTUAL RESULTS VS. 2016 ACTUAL RESULTS

In 2016, ETPL experienced an increase in distribution revenue of $306,501 from 2015 actual results, or a 3.15% increase. In 2016 ETPL received an IRM increase that effectively increased rates by 1.30% on May 1st 2016. The remaining difference can be attributed to the increase in customers and connections coupled by the increase in Residential and GS>50 usage year over year. The following table details these changes in actual customer counts and usage.

Table 3-19 Distribution Revenues Variance Analysis 2016 Actuals vs 2015 Actuals

Rate Class	Customers / Connections	kWh/kW	Customers / Connections	kWh/kW	Customers / Connections	kWh/kW
	2015 Actual Results		2016 Actual Results		Variance	
Residential	16,667	135,712,848	16,855	136,671,067	188	958,219
General Service <50 kW	1,989	50,019,956	1,993	48,503,240	4	- 1,516,716
General Service >50 to 999 kW	157	252,230	160	329,499	3	77,269
General Service >1,000 to 4,999 k	5	158,509	5	141,887	-	- 16,622
Large Use	1	169,422	1	177,134	-	7,711
Unmetered Scattered Load	128	537,894	126	504,437	- 1	- 33,457
Sentinel Lighting	248	653	248	615	-	- 38
Street Lighting	4,617	5,564	5,927	5,229	1,310	- 335
Embedded Distributor	4	35,856	4	36,389	-	533
Total	**23,817**	**186,892,933**	**25,320**	**186,369,497**	**1,503**	**- 523,435**

2016 ACTUAL RESULTS VS. 2017 FORECAST AT EXISTING RATES

Utilizing the 2017 forecasted customer counts and variable billing determinants ETPL has calculated the 2017 distribution revenues by class at existing rates and compared them to actual results. This analysis has demonstrated an increase of $425,453 increase year over year. The following table displays the breakdown by rate class.

Table 3-20 Distribution Revenues Variance Analysis 2017 BY vs 2016 Actuals

Rate Class	Distribution Revenue Total	Distribution Revenue Total	
	2016 Actual	2017 Bridge	Variance
Residential	$ 5,896,553	$ 6,009,528	$ 112,975
General Service <50 kW	$ 1,216,304	$ 1,249,666	$ 33,362
General Service >50 to 999 kW	$ 1,080,844	$ 1,250,577	$ 169,733
General Service >1,000 to 4,999 kW	$ 648,442	$ 733,407	$ 84,965
Large Use	$ 349,721	$ 452,357	$ 102,636
Unmetered Scattered Load	$ 60,766	$ 63,395	$ 2,629
Sentinel Lighting	$ 25,194	$ 25,519	$ 325
Street Lighting	$ 405,334	$ 418,435	$ 13,101
Embedded Distributor	$ 349,721	$ 255,450	-$ 94,271
Total	**$ 10,032,880**	**$ 10,458,333**	**$ 425,453**

1.8% of this increase can be explained due to the 2017 IRM application approved effective May 1st, 2017. The remaining differences are attributed to changes in customer and load forecasts employed by the models. The fact that Residential customer counts increased by 132 year over year and ETPL moved another step closer to fully fixed rates results in ETPL earning more distribution revenue from the Residential class year over year with less usage. The other differences are normal variances due to changes in customer counts and usages as detailed in the following table.

Table 3-21 Customers and Consumption Variance Analysis 2016 Forecast vs 2016 Actuals

Rate Class	Customers / Connections	kWh/kW	Customers / Connections	kWh/kW	Customers / Connections	kWh/kW
	2016 Actual Results		2017 Forecast		Variance	
Residential	16,855	136,671,067	16,987	133,927,949	132	- 2,743,118
General Service <50 kW	1,993	48,503,240	2,006	48,915,619	12	412,379
General Service >50 to 999 kW	160	329,499	157	324,430	- 2	- 5,070
General Service >1,000 to 4,999 kW	5	141,887	5	137,505	-	- 4,382
Large Use	1	177,134	1	171,751	-	- 5,382
Unmetered Scattered Load	126	504,437	128	510,974	2	6,537
Sentinel Lighting	248	615	243	587	- 5	- 28
Street Lighting	5,927	5,229	5,998	5,384	71	156
Embedded Distributor	4	36,389	4	34,856	-	- 1,533
Total	**25,320**	**186,369,497**	**25,529**	**184,029,056**	**209**	**- 2,340,442**

2017 FORECAST AT EXISTING RATES VS. 2018 FORECAST AT EXISTING RATES

ETPL would anticipate a decrease in distribution revenue from the 2017 Bridge Year to the 2018 Test Year of $183,118 or -1.75% as detailed in the following table. The biggest impact leading to this reduction is the reduction in load forecasting due to Conservation and Demand Management programs.

Table 3-22 Distribution Revenues Variance Analysis 2018 TY vs 2017 BY

Rate Class	Distribution Revenue Total	Distribution Revenue Total	
	2017 Bridge	2018 test	Variance
Residential	$ 6,009,528	$ 6,028,811	$ 19,283
General Service <50 kW	$ 1,249,666	$ 1,240,588	-$ 9,077
General Service >50 to 999 kW	$ 1,250,577	$ 1,196,612	-$ 53,965
General Service >1,000 to 4,999 kW	$ 733,407	$ 604,295	-$ 129,111
Large Use	$ 452,357	$ 441,831	-$ 10,526
Unmetered Scattered Load	$ 63,395	$ 64,217	$ 822
Sentinel Lighting	$ 25,519	$ 24,976	-$ 543
Street Lighting	$ 418,435	$ 423,454	
Embedded Distributor	$ 255,450	$ 255,450	$ -
Total	**$ 10,458,333**	**$ 10,280,235**	**-$ 183,118**

ETPL expects to continue to see a decrease in Residential usage but an increase in customer count, while General Service < kW demand sees growth in both customer counts and usage as business continues to stabilize in ETPL's communities. The remaining classes see very little change in other than the closure of two GS>50 to 999 kW customers due to the ongoing trend for this class within ETPL, and the loss of one GS>1,000 to 4,999 kW customer as detailed earlier in this exhibit.

Table 3-23 Customers and Consumption Variance Analysis 2018 Forecast vs 2017 Forecast

Rate Class	Customers / Connections	kWh/kW	Customers / Connections	kWh/kW	Customers / Connections	kWh/kW
	2017 Forecast		2018 Forecast		Variance	
Residential	16,987	133,927,949	17,119	132,055,423	133	- 1,872,526
General Service <50 kW	2,006	48,915,619	2,018	48,061,878	13	- 853,741
General Service >50 to 999 kW	157	324,430	155	308,209	- 2	- 16,221
General Service >1,000 to 4,999 kW	5	137,505	4	114,163	- 1	- 23,342
Large Use	1	171,751	1	166,236	-	- 5,516
Unmetered Scattered Load	128	510,974	130	517,597	2	6,622
Sentinel Lighting	243	587	238	574	- 5	- 12
Street Lighting	5,998	5,384	6,070	5,449	72	65
Embedded Distributor	4	34,856	4	34,856	-	-
Total	**25,529**	**184,029,056**	**25,739**	**181,264,385**	**210**	**- 2,764,671**

2017 & 2018 DISTRIBUTION REVENUE EXCLUDING SMIRR & SHARED TAX SAVINGS

Consistent with the Board Filing Requirements for the Revenue Requirement calculation and Cost Allocation Model, ETPL has calculated the 2015 and 2016 Distribution Revenue at existing 2015 distribution rates excluding the SMIRR rate riders ("RRs") and Shared Tax Savings RRs. The results are presented in Table 3-24 below.

TABLE 3-24: 2015 AND 2016 DISTRIBUTION REVENUE FOR RRWF & CA MODEL

Description	Distribution Revenue Total	Distribution Revenue Total
Residential	$ 10,677,393	$ 10,650,079
General Service <50 kW	$ 2,578,954	$ 2,525,658
General Service >50 kW	$ 4,220,450	$ 4,399,012
Large User	$ 179,659	$ 106,949
Unmetered Scattered Load Connections	$ 39,982	$ 45,830
Sentinel Lighting Connections	$ 46,394	$ 48,477
Street Lighting Connections	$ 255,280	$ 256,509
Embedded Distributor	$ 1,474	$ 1,474
Total	**$ 17,999,586**	**$ 18,033,987**

2018 DISTRIBUTION REVENUE AT PROPOSED RATES

The following is a comparison of 2016 Actual Distribution Revenue, 2017 Bridge Year Forecast with Existing Rates Revenue and 2018 Test Year Proposed Distribution Revenue. The proposed test year distribution revenue is a reflection of this 2018 COS Application and the Proposed Base Revenue Requirement of ETPL.

Table 3-25 Distribution Revenues Variance Analysis 2018 TY vs 2017 BY vs 2016 Actuals

Rate Class	Distribution Revenue Total 2016 Actual	Distribution Revenue Total 2017 Bridge	Distribution Revenue Total 2018 Test	Variance
Residential	$ 5,896,553	$ 6,009,528	$ 6,735,793	$ 726,265
General Service <50 kW	$ 1,216,304	$ 1,249,666	$ 1,497,130	$ 247,465
General Service >50 to 999 kW	$ 1,080,844	$ 1,250,577	$ 667,783	-$ 582,794
General Service >1,000 to 4,999 kW	$ 648,442	$ 733,407	$ 492,804	-$ 240,603
Large Use	$ 349,721	$ 452,357	$ 455,977	$ 3,620
Unmetered Scattered Load	$ 60,766	$ 63,395	$ 42,037	-$ 21,358
Sentinel Lighting	$ 25,194	$ 25,519	$ 54,872	$ 29,354
Street Lighting	$ 405,334	$ 418,435	$ 235,362	-$ 183,073
Embedded Distributor	$ 349,721	$ 255,450	$ 105,620	-$ 149,830
Total	**$ 10,032,880**	**$ 10,458,333**	**$ 10,287,379**	**-$ 170,955**

The preceding table illustrates that ETPL's distribution revenue is reducing by $171,000. This is primarily attributable to decreases in the depreciation and taxes consistent with MIFRS transition, as well as, an expected decrease in in working capital allowance of 7.5% from 13%.

Exhibit 3: Operating Revenue

Tab 3 (of 4): Other Revenue

OTHER REVENUE

3.3.1 Overview

Other Revenue is any revenue that is distribution in nature but that is sourced from means other than distribution rates. ETPL currently earns and forecasts to continue earn Other Revenue. Other Revenues comprises four major categories: Specific Service Charges, Late Payment Charges, Other Operating Revenues and Other Income or Deductions.

Table 3-26 below provides a high level summary and comparison of these four categories for the Board Approved Proxy, the Historic Years 2012 through 2016, the 2017 Bridge Year and 2018 Test Year.

Table 3-26 Other Revenue Summary

Description	2012 Board Approved	2012	2013	2014	2015	2016	2017	2018
Specific Service Charges	-$ 183,856	-$ 198,569	-$ 202,129	-$ 199,896	-$ 195,662	-$ 192,299	-$ 163,644	-$ 177,069
Late Payment Charges	-$ 143,440	-$ 108,661	-$ 117,342	-$ 109,435	-$ 112,834	-$ 134,656	-$ 138,978	-$ 145,947
Other Distribution Operating Revenues	-$ 464,953	-$ 166,321	-$ 113,030	-$ 104,205	-$ 124,600	-$ 164,827	-$ 134,847	-$ 151,972
Other Income and Deductions	-$ 93,743	-$ 122,362	-$ 22,904	-$ 40,750	-$ 36,628	-$ 64,800	-$ 17,267	-$ 19,460
Total	**-$ 885,992**	**-$ 595,913**	**-$ 455,405**	**-$ 454,285**	**-$ 469,723**	**-$ 556,582**	**-$ 454,735**	**-$ 494,448**

More details of Other Revenue amounts earned and expected to be earned in the Bridge and Test Years can be found in OEB Appendix 2-H, included as Attachment 3-F to this Exhibit. A detailed breakdown by USoA account shown in table 3-27 below shows the changes in other revenues year over year.

Table 3-27 Other Revenue Detail Listing

Account	Description	2012 Board Approved	2012	2013	2014	2015	2016	2017	2018
4235	Miscellaneous Service Revenues	-$146,652.00	-$101,873.90	-$113,884.98	-$113,765.00	-$103,720.00	-$105,040.00	-$ 87,100.00	-$ 98,161.70
4225	Late Payment Charges	-$143,440.00	-$108,661.09	-$117,341.67	-$109,434.71	-$112,833.85	-$134,656.29	-$138,977.92	-$145,947.00
4080	Distribution Services Revenue SSS		-$ 68,175.40	-$ 64,324.06	-$ 64,246.17	-$ 64,288.31	-$ 66,018.63	-$ 57,928.83	-$ 57,928.83
4082	Retail Services Revenues	-$ 37,204.00	-$ 19,214.50	-$ 16,279.50	-$ 14,815.00	-$ 18,983.00	-$ 14,779.00	-$ 13,067.00	-$ 14,726.51
4084	Service Transaction Requests		-$ 9,305.20	-$ 7,640.40	-$ 7,069.95	-$ 8,670.25	-$ 6,461.05	-$ 5,547.70	-$ 6,252.26
4210	Rent from Electric Property	-$156,609.00	-$105,306.50	-$103,070.55	-$104,876.83	-$ 92,903.82	-$103,987.32	-$117,381.94	-$132,289.45
4220	Other Electric Revenues	-$308,344.00	-$ 35,814.52	-$ 3,138.25	-$ 6,987.43	-$ 11,477.49	$ 4,862.55	-$ 8,676.00	-$ 9,777.85
4355	Gain on Distposition of Asset		-$ 25,200.00	-$ 6,821.40			-$ 65,702.36	-$ 8,788.70	-$ 9,904.86
4360	Loss on Disposition of Asset				$ 7,659.71	-$ 20,218.56			
4375	Revenues from Non-Utility Operations								
4380	Non Utility Rental Income	-$ 93,743.00	-$103,895.30	-$ 22,904.48	-$ 22,329.22	-$ 22,193.59	-$ 16,139.00	-$ 14,566.68	-$ 16,416.65
4385	Miscellaneous Non Operating Income		-$ 18,466.34		-$ 18,420.45	-$ 14,434.23	-$ 48,661.36	-$ 2,700.00	-$ 3,042.90
4390	Rate Payer Benefit Including Interest								
4398	Foreign Exchange Gains and Losses								
4405	Interest and Dividend Income		-$133,238.27	-$ 57,315.43	-$ 69,802.29	-$ 57,661.20	-$ 66,707.12		
	Specific Service Charges	-$ 183,856	-$ 198,569	-$ 202,129	-$ 199,896	-$ 195,662	-$ 192,299	-$ 163,644	-$ 177,069
	Late Payment Charges	-$ 143,440	-$ 108,661	-$ 117,342	-$ 109,435	-$ 112,834	-$ 134,656	-$ 138,978	-$ 145,947
	Other Distribution Operating Revenues	-$ 464,953	-$ 166,321	-$ 113,030	-$ 104,205	-$ 124,600	-$ 164,827	-$ 134,847	-$ 151,972
	Other Income and Deductions	-$ 93,743	-$ 122,362	-$ 22,904	-$ 40,750	-$ 36,628	-$ 64,800	-$ 17,267	-$ 19,460
	Total	**-$ 885,992**	**-$ 595,913**	**-$ 455,405**	**-$ 454,285**	**-$ 469,723**	**-$ 556,582**	**-$ 454,735**	**-$ 494,448**

3.3.2 Other Revenue Variance Analysis

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 $55,000 as its materiality threshold based upon the calculations required by the filing requirements.

Table 3-28 Other Revenue Variance Analysis 2012 Actuals vs 2012 BA

Account	Description	2012 Board Approved	2012	Variance $	Variance %
4235	Miscellaneous Service Revenues	-$146,652.00	-$101,873.90	$ 44,778.10	-30.5%
4225	Late Payment Charges	-$143,440.00	-$108,661.09	$ 34,778.91	-24.2%
4080	Distribution Services Revenue SSS		-$ 68,175.40	-$ 68,175.40	
4082	Retail Services Revenues	-$ 37,204.00	-$ 19,214.50	$ 17,989.50	-48.4%
4084	Service Transaction Requests		-$ 9,305.20	-$ 9,305.20	
4210	Rent from Electric Property	-$156,609.00	-$105,306.50	$ 51,302.50	-32.8%
4220	Other Electric Revenues	-$308,344.00	-$ 35,814.52	$272,529.48	-88.4%
4355	Gain on Distposition of Asset		-$ 25,200.00	-$ 25,200.00	
4360	Loss on Disposition of Asset			$ -	
4375	Revenues from Non-Utility Operations			$ -	
4380	Non Utility Rental Income	-$ 93,743.00	-$103,895.30	-$ 10,152.30	10.8%
4385	Miscellaneous Non Operating Income		-$ 18,466.34	-$ 18,466.34	
4390	Rate Payer Benefit Including Interest			$ -	
4398	Foreign Exchange Gains and Losses			$ -	
4405	Interest and Dividend Income		-$133,238.27	-$133,238.27	
	Specific Service Charges	-$ 183,856	-$ 198,569	-$ 14,713.00	8.0%
	Late Payment Charges	-$ 143,440	-$ 108,661	$ 34,778.91	-24.2%
	Other Distribution Operating Revenues	-$ 464,953	-$ 166,321	$298,631.98	-64.2%
	Other Income and Deductions	-$ 93,743	-$ 122,362	-$ 28,618.64	30.5%
	Total	**-$ 885,992**	**-$ 595,913**	$290,079.25	-32.7%

In ETPL's 2012 actual results there were several significant reductions in revenues that occurred when compared with 2012 Board Approved amounts. While there appear to be some large swings by GL account ETPL points out that there was no GL by GL forecast available in the 2012 COS filing and that some of the variances occur simply because values reported in 2012 actuals have no associated approved amount as the approved amounts appear to be lumped in elsewhere. I.E. SSS revenues look to be split between the other miscellaneous charges. If you look at the summary specific service charges are up 8% over Board approved and then remain consistent going forward. Late payment charges are lower than approved and can be attributed in large part to an economic upswing in the region that saw improved payment and collections for ETPL post the 2008 economic downturn. Rent from electric property reduced from 2012 Board Approved due to corrections in Pole attachment records and more accurate billings. These amounts are consistent and accurate going forward. Other electric revenues have reduced as ETPL implemented a change in account to move revenues received from its affiliate from revenue accounts to a cost account. ETPL bills third party customers on behalf of its affiliate and receives revenues to cover its cost to complete the work.

Table 3-29 Other Revenue Variance Analysis 2013 Actuals vs 2012 Actuals

Account	Description	2012	2013	Variance $	Variance %
4235	Miscellaneous Service Revenues	-$101,873.90	-$113,884.98	-$ 12,011.08	11.8%
4225	Late Payment Charges	-$108,661.09	-$117,341.67	-$ 8,680.58	8.0%
4080	Distribution Services Revenue SSS	-$ 68,175.40	-$ 64,324.06	$ 3,851.34	-5.6%
4082	Retail Services Revenues	-$ 19,214.50	-$ 16,279.50	$ 2,935.00	-15.3%
4084	Service Transaction Requests	-$ 9,305.20	-$ 7,640.40	$ 1,664.80	-17.9%
4210	Rent from Electric Property	-$105,306.50	-$103,070.55	$ 2,235.95	-2.1%
4220	Other Electric Revenues	-$ 35,814.52	-$ 3,138.25	$ 32,676.27	-91.2%
4355	Gain on Distposition of Asset	-$ 25,200.00	-$ 6,821.40	$ 18,378.60	-72.9%
4360	Loss on Disposition of Asset			$ -	
4375	Revenues from Non-Utility Operations			$ -	
4380	Non Utility Rental Income	-$103,895.30	-$ 22,904.48	$ 80,990.82	-78.0%
4385	Miscellaneous Non Operating Income	-$ 18,466.34		$ 18,466.34	-100.0%
4390	Rate Payer Benefit Including Interest			$ -	
4398	Foreign Exchange Gains and Losses			$ -	
4405	Interest and Dividend Income	-$133,238.27	-$ 57,315.43	$ 75,922.84	-57.0%
	Specific Service Charges	-$ 198,569	-$ 202,129	-$ 3,559.94	1.8%
	Late Payment Charges	-$ 108,661	-$ 117,342	-$ 8,680.58	8.0%
	Other Distribution Operating Revenues	-$ 166,321	-$ 113,030	$ 53,290.82	-32.0%
	Other Income and Deductions	-$ 122,362	-$ 22,904	$ 99,457.16	-81.3%
	Total	**-$ 595,913**	**-$ 455,405**	**$140,507.46**	**-23.6%**

In 2013 ETPL realized a 23% reduction in its other revenues due primarily to the exit from its water heater and sentinel lighting rental business in the town of Ingersoll. Some water heater rental business remains and has be forecasted out into the test year. However, ETPL does plan to exit fully from this business prior to its next cost of service.

Table 3-30 Other Revenue Variance Analysis 2014 Actuals vs 2013 Actuals

Account	Description	2013	2014	Variance $	Variance %
4235	Miscellaneous Service Revenues	-$ 113,884.98	-$ 113,765.00	$ 119.98	-0.1%
4225	Late Payment Charges	-$ 117,341.67	-$ 109,434.71	$ 7,906.96	-6.7%
4080	Distribution Services Revenue SSS	-$ 64,324.06	-$ 64,246.17	$ 77.89	-0.1%
4082	Retail Services Revenues	-$ 16,279.50	-$ 14,815.00	$ 1,464.50	-9.0%
4084	Service Transaction Requests	-$ 7,640.40	-$ 7,069.95	$ 570.45	-7.5%
4210	Rent from Electric Property	-$ 103,070.55	-$ 104,876.83	-$ 1,806.28	1.8%
4220	Other Electric Revenues	-$ 3,138.25	-$ 6,987.43	-$ 3,849.18	122.7%
4355	Gain on Distposition of Asset	-$ 6,821.40		$ 6,821.40	-100.0%
4360	Loss on Disposition of Asset		$ 7,659.71	$ 7,659.71	
4375	Revenues from Non-Utility Operations			$ -	
4380	Non Utility Rental Income	-$ 22,904.48	-$ 22,329.22	$ 575.26	-2.5%
4385	Miscellaneous Non Operating Income		-$ 18,420.45	-$ 18,420.45	
4390	Rate Payer Benefit Including Interest			$ -	
4398	Foreign Exchange Gains and Losses			$ -	
4405	Interest and Dividend Income	-$ 57,315.43	-$ 69,802.29	-$ 12,486.86	21.8%
	Specific Service Charges	-$ 202,129	-$ 199,896	$ 2,232.82	-1.1%
	Late Payment Charges	-$ 117,342	-$ 109,435	$ 7,906.96	-6.7%
	Other Distribution Operating Revenues	-$ 113,030	-$ 104,205	$ 8,825.65	-7.8%
	Other Income and Deductions	-$ 22,904	-$ 40,750	-$ 17,845.19	77.9%
	Total	**-$ 455,405**	**-$ 454,285**	**$ 1,120.24**	**-0.2%**

ETPL realized no significant variances in 2014 when compared to 2013 aside from a small decrease in late payment charges and a swing from a gain on sale of asset in 2013 to a loss in 2014.

Table 3-31 Other Revenue Variance Analysis 2015 Actuals vs 2014 Actuals

Account	Description	2014	2015	Variance $	Variance %
4235	Miscellaneous Service Revenues	-$113,765.00	-$103,720.00	$ 10,045.00	-8.8%
4225	Late Payment Charges	-$109,434.71	-$112,833.85	-$ 3,399.14	3.1%
4080	Distribution Services Revenue SSS	-$ 64,246.17	-$ 64,288.31	-$ 42.14	0.1%
4082	Retail Services Revenues	-$ 14,815.00	-$ 18,983.00	-$ 4,168.00	28.1%
4084	Service Transaction Requests	-$ 7,069.95	-$ 8,670.25	-$ 1,600.30	22.6%
4210	Rent from Electric Property	-$104,876.83	-$ 92,903.82	$ 11,973.01	-11.4%
4220	Other Electric Revenues	-$ 6,987.43	-$ 11,477.49	-$ 4,490.06	64.3%
4355	Gain on Distposition of Asset			$ -	
4360	Loss on Disposition of Asset	$ 7,659.71	-$ 20,218.56	-$ 27,878.27	-364.0%
4375	Revenues from Non-Utility Operations			$ -	
4380	Non Utility Rental Income	-$ 22,329.22	-$ 22,193.59	$ 135.63	-0.6%
4385	Miscellaneous Non Operating Income	-$ 18,420.45	-$ 14,434.23	$ 3,986.22	-21.6%
4390	Rate Payer Benefit Including Interest			$ -	
4398	Foreign Exchange Gains and Losses			$ -	
4405	Interest and Dividend Income	-$ 69,802.29	-$ 57,661.20	$ 12,141.09	-17.4%
	Specific Service Charges	-$ 199,896	-$ 195,662	$ 4,234.56	-2.1%
	Late Payment Charges	-$ 109,435	-$ 112,834	-$ 3,399.14	3.1%
	Other Distribution Operating Revenues	-$ 104,205	-$ 124,600	-$ 20,395.32	19.6%
	Other Income and Deductions	-$ 40,750	-$ 36,628	$ 4,121.85	-10.1%
	Total	**-$ 454,285**	**-$ 469,723**	**-$ 15,438.05**	**3.4%**

ETPL once again only experience small differences in 2015 when compared to 2014 revenues with the most significant change a gain on sale of asset replacing a lost in 2014 causing an increase in revenue by almost $30,000. The remaining differences were minor and all part of the normal course of business.

Table 3-32 Other Revenue Variance Analysis 2016 Actuals vs 2015 Actuals

Account	Description	2015	2016	Variance $	Variance %
4235	Miscellaneous Service Revenues	-$103,720.00	-$105,040.00	-$ 1,320.00	1.3%
4225	Late Payment Charges	-$112,833.85	-$134,656.29	-$ 21,822.44	19.3%
4080	Distribution Services Revenue SSS	-$ 64,288.31	-$ 66,018.63	-$ 1,730.32	2.7%
4082	Retail Services Revenues	-$ 18,983.00	-$ 14,779.00	$ 4,204.00	-22.1%
4084	Service Transaction Requests	-$ 8,670.25	-$ 6,461.05	$ 2,209.20	-25.5%
4210	Rent from Electric Property	-$ 92,903.82	-$103,987.32	-$ 11,083.50	11.9%
4220	Other Electric Revenues	-$ 11,477.49	$ 4,862.55	$ 16,340.04	-142.4%
4355	Gain on Distposition of Asset	-$ 20,218.56	-$ 65,702.36	-$ 45,483.80	225.0%
4360	Loss on Disposition of Asset			$ -	
4375	Revenues from Non-Utility Operations			$ -	
4380	Non Utility Rental Income	-$ 22,193.59	-$ 16,139.00	$ 6,054.59	-27.3%
4385	Miscellaneous Non Operating Income	-$ 14,434.23	-$ 48,661.36	-$ 34,227.13	237.1%
4390	Rate Payer Benefit Including Interest			$ -	
4398	Foreign Exchange Gains and Losses			$ -	
4405	Interest and Dividend Income	-$ 57,661.20	-$ 66,707.12	-$ 9,045.92	15.7%
	Specific Service Charges	-$ 195,662	-$ 192,299	$ 3,362.88	-1.7%
	Late Payment Charges	-$ 112,834	-$ 134,656	-$ 21,822.44	19.3%
	Other Distribution Operating Revenues	-$ 124,600	-$ 164,827	-$ 40,227.26	32.3%
	Other Income and Deductions	-$ 36,628	-$ 64,800	-$ 28,172.54	76.9%
	Total	**-$ 469,723**	**-$ 556,582**	**-$ 86,859.36**	**18.5%**

In 2016 ETPL sold a retired large bucket truck for a significant gain on sale of asset that explains almost half of the 2016 increase in other revenues. Also, the increased cost pressures of electricity bills couple with the pending layoffs and closures at a few regional large plants caused the late payment charges to escalate by $22,000 in 2016 also contributed to the increase in revenues for 2016. Lastly ETPL had one time miscellaneous operating income of about $40,000 in 2016 of which $20,000 were for inventory adjustments and another $20,000 was for revenue associated with CDM activities.

Table 3-33 Other Revenue Variance Analysis 2017 BY vs 2016 Actuals

Account	Description	2016	2017	Variance $	Variance %
4235	Miscellaneous Service Revenues	-$ 105,040.00	-$ 87,100.00	$ 17,940.00	-17.1%
4225	Late Payment Charges	-$ 134,656.29	-$ 138,977.92	-$ 4,321.63	3.2%
4080	Distribution Services Revenue SSS	-$ 66,018.63	-$ 57,503.46	$ 8,515.17	-12.9%
4082	Retail Services Revenues	-$ 14,779.00	-$ 13,067.00	$ 1,712.00	-11.6%
4084	Service Transaction Requests	-$ 6,461.05	-$ 5,547.70	$ 913.35	-14.1%
4210	Rent from Electric Property	-$ 103,987.32	-$ 117,381.94	-$ 13,394.62	12.9%
4220	Other Electric Revenues	$ 4,862.55	-$ 8,676.00	-$ 13,538.55	-278.4%
4355	Gain on Distposition of Asset	-$ 65,702.36	-$ 8,788.70	$ 56,913.66	-86.6%
4360	Loss on Disposition of Asset			$ -	
4375	Revenues from Non-Utility Operations			$ -	
4380	Non Utility Rental Income	-$ 16,139.00	-$ 14,566.68	$ 1,572.32	-9.7%
4385	Miscellaneous Non Operating Income	-$ 48,661.36	-$ 2,700.00	$ 45,961.36	-94.5%
4390	Rate Payer Benefit Including Interest			$ -	
4398	Foreign Exchange Gains and Losses			$ -	
4405	Interest and Dividend Income	-$ 66,707.12		$ 66,707.12	-100.0%
	Specific Service Charges	-$ 192,299	-$ 163,218	$ 29,080.52	-15.1%
	Late Payment Charges	-$ 134,656	-$ 138,978	-$ 4,321.63	3.2%
	Other Distribution Operating Revenues	-$ 164,827	-$ 134,847	$ 29,980.49	-18.2%
	Other Income and Deductions	-$ 64,800	-$ 17,692	$ 47,108.31	-72.7%
	Total	**-$ 556,582**	**-$ 454,735**	**$ 101,847.69**	**-18.3%**

For the 2017 Bridge Year ETPL forecast its standard rates and charges by utilizing half a year of its value through June and doubling it. The remaining not transaction based accounts were forecast based on actual values as at June 30th. The resulting variance is primarily driven by the two 2016 one time transactions of the sale of a large truck and the $40,000 split between the inventory adjustment and the CDM activity revenues. The remaining values are consistent with the forecast aside from SSS revenue which were forecast using customer counts multiplied the rate and 12 months. Should the 2017 actual values be materially different than half of 2017 results doubled ETPL would expect to revisit this 2017 as it underpins the 2018 Test Year projections.

Table 3-34 Other Revenue Variance Analysis 2018 TY vs 2017 BY

Account	Description	2017	2018	Variance $	Variance %
4235	Miscellaneous Service Revenues	-$ 87,100.00	-$ 98,161.70	-$ 11,061.70	12.7%
4225	Late Payment Charges	-$ 138,977.92	-$ 145,947.00	-$ 6,969.08	5.0%
4080	Distribution Services Revenue SSS	-$ 57,503.46	-$ 57,928.83	-$ 425.37	0.7%
4082	Retail Services Revenues	-$ 13,067.00	-$ 14,726.51	-$ 1,659.51	12.7%
4084	Service Transaction Requests	-$ 5,547.70	-$ 6,252.26	-$ 704.56	12.7%
4210	Rent from Electric Property	-$ 117,381.94	-$ 132,289.45	-$ 14,907.51	12.7%
4220	Other Electric Revenues	-$ 8,676.00	-$ 9,777.85	-$ 1,101.85	12.7%
4355	Gain on Distposition of Asset	-$ 8,788.70	-$ 9,904.86	-$ 1,116.16	12.7%
4360	Loss on Disposition of Asset			$ -	
4375	Revenues from Non-Utility Operations			$ -	
4380	Non Utility Rental Income	-$ 14,566.68	-$ 16,416.65	-$ 1,849.97	12.7%
4385	Miscellaneous Non Operating Income	-$ 2,700.00	-$ 3,042.90	-$ 342.90	12.7%
4390	Rate Payer Benefit Including Interest			$ -	
4398	Foreign Exchange Gains and Losses			$ -	
4405	Interest and Dividend Income			$ -	
	Specific Service Charges	-$ 163,218	-$ 177,069	-$ 13,851.14	8.5%
	Late Payment Charges	-$ 138,978	-$ 145,947	-$ 6,969.08	5.0%
	Other Distribution Operating Revenues	-$ 134,847	-$ 151,972	-$ 17,125.52	12.7%
	Other Income and Deductions	-$ 17,692	-$ 19,460	-$ 1,767.50	10.0%
	Total	**-$ 454,735**	**-$ 494,448**	**-$ 39,713.23**	**8.7%**

ETPL anticipates that other revenues for the 2018 Test Year will grow over the forecast 2017 Bridge year by approximately $40,000. This forecast of other revenue is consistent with the changes and trends since 2014 and when the one-time events are removed from the change analysis the results illustrate a consistent trend.

3.3.3 Specific Service Charges

ETPL proposes the following Specific Service Charges ("SSCs") as presented in Table 3-34. For more details regarding the currently approved and the proposed Specific Service Charges, please see Exhibit 8, Section 8.8.3.

1 **TABLE 3-35: ETPL 2016 PROPOSED SSCS**

Description	Unit	Rate
Customer Administration		
Arrears Certificate	$	$ 15.00
Statement of Account	$	$ 15.00
Easement Letter	$	$ 15.00
Credit Reference/Credit Check (plus credit agency costs)	$	$ 15.00
Returned Cheque Charge (plus bank charges)	$	$ 15.00
Account Set Up Charge/Change of Occupancy Charge	$	$ 30.00
Meter dispute Charge plus Measurement Canada fees (if meter found correct)	$	$ 30.00
Non-Payment of Account		
Late Payment-per month	%	1.50%
Late Payment-per annum	%	19.56%
Collection of account charge - no disconnection - during regular business hours	$	$ 30.00
Collection of account charge - no disconnection - after regular hours	$	$ 165.00
Disconnect/Reconnect at Meter - during regular hours	$	$ 65.00
Disconnect/Reconnect at Meter - after regular hours	$	$ 185.00
Disconnect/Reconnect at Pole - during regular hours	$	$ 185.00
Other Charges		
Temporary service - install & remove - overhead - no transformer	$	$ 500.00
Temporary service - install & remove - underground - no transformer	$	$ 300.00
Specific charge for access to the power poles - $/pole/year	$	$ 22.35

2

Exhibit 3: Operating Revenue

Tab 4 (of 4): Exhibit 3 Appendices

Attachment 1 (of 7):

3-A Load Forecast Report

Weather Normalized Distribution System Load Forecast: 2018 Cost of Service

Report prepared by
Andrew Frank
Elenchus Research Associates Inc.

Prepared for:
Erie Thames Powerlines

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1 INTRODUCTION

This report outlines the results and methodology used to derive the weather normal load forecast prepared for use in the Cost of Service application for 2018 rates for Erie Thames Powerlines ("Erie Thames").

The regression equations used to normalize and forecast Erie Thames' weather sensitive load use monthly heating degree days and cooling degree days as measured at Environment Canada's London Airport weather station to take into account temperature sensitivity. This location is central to the communities in Erie Thames's service territory, and has strong historical weather data. Erie Thames experiences peak loads in both the summer and winter seasons. Environment Canada defines heating degree days and cooling degree days as the difference between the average daily temperature and 18°C for each day (below for heating, above for cooling).

Overall economic activity also impacts energy consumption. There is no known agency that publishes monthly economic accounts on a regional basis for Ontario. However, regional employment levels are available. Given that income from employment and labour sources accounts for the largest portion of GDP on an income basis, and a study by Statistics Canada that has indicated that "turning points in the growth of output and employment appear to have been virtually the same over the past three decades"[1], employment has been chosen as the economic variable to incorporate into the analysis. Specifically, the monthly full-time employment level for London, Ontario, as reported in Statistics Canada's Monthly Labour Force Survey (CANSIM series Table 282-0135) was tested and used for the GS < 50 rate class. Employment was found to not have a statistically significant explanatory value for the Residential rate class, the only other class where linear regression was found to be appropriate.

In order to isolate demand determinants at the class specific level, equations to weather normalize and forecast kWh consumption for the Residential and GS<50 classes, have been estimated.

In addition to the weather and economic variables, a time trend variable, number of days and number of working days in each month, number of customers, and month of year variables, have been examined for all rate classes. More details on the individual class specifications are provided in the next section.

Finally, for classes with demand charges, an annual kW to kWh ratio is calculated using actual observations for each historical year and applied to the normalized kWh to derive a weather normal kW observation. For forecast values, the average kW to kWh ratio for

[1] Philip Cross, "Cyclical changes in output and employment," *Canadian Economic Observer*, May 2009.

2007-2016 is applied for all metered rate classes. For the Street Light and Sentinel rate classes, a more recent history of 2014-2016 is used as these classes should not be sensitive to weather, and aren't expected to benefit from the longer time horizon.

1.1 SUMMARIZED RESULTS

The following table summarizes the historic and forecast kWh for 2012-2018:

Normal Forecast

kWh	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2016 Normalized	2017 Forecast	2018 Forecast
Residential	136,951,769	139,174,379	137,614,288	135,712,848	136,671,067	134,543,558	133,927,949	133,764,095
GS < 50	47,672,679	48,218,851	48,123,471	50,019,956	48,503,240	48,633,330	48,915,623	49,394,965
GS > 50	102,465,298	99,138,275	103,487,654	97,248,975	101,805,845	94,283,345	91,704,465	90,474,936
Intermediate	92,117,889	92,636,597	94,031,167	91,600,392	81,639,097	74,711,534	84,528,325	76,967,386
Large User	96,186,937	98,312,959	103,336,243	107,405,730	115,608,236	108,025,611	98,980,673	99,199,239
Embedded Distributor	15,488,407	15,613,195	16,830,475	16,494,364	16,248,812	16,106,610	16,296,711	16,296,711
Street Light	3,484,987	2,710,402	2,115,842	2,025,403	1,938,875	1,938,875	1,962,132	1,985,669
Sentinel Light	280,910	272,742	266,366	246,528	231,256	231,256	226,333	221,514
USL	513,343	539,394	535,721	537,894	504,437	504,437	510,974	517,597
Total	495,162,219	496,616,793	506,341,226	501,292,091	503,150,865	478,978,556	477,053,186	468,822,112

Table 1 kWh forecast by class

The following table summarizes 2015-2020 CDM Adjusted Load Forecast kWh. Details for this calculation can be found in Schedule 6 of this report.

CDM Adjusted

kWh	2018 Weather Normal Forecast	CDM Adjustment	2018 CDM Adjusted Forecast
Residential	133,764,095	1,256,917	132,507,178
GS < 50	49,394,965	1,142,121	48,252,843
GS > 50	90,474,936	2,246,878	88,228,059
Intermediate	76,967,386	2,069,177	74,898,209
Large User	99,199,239	2,264,836	96,934,403
Embedded Distributor	16,296,711	0	16,296,711
Street Light	1,985,669	0	1,985,669
Sentinel Light	221,514	0	221,514
USL	517,597	0	517,597
Total	468,822,112	8,979,929	459,842,183

Table 2 CDM Adjusted kWh forecast

The following table summarizes the historic and forecast kW for 2012-2018. The calculations can be found as follows:

Normal Forecast

kW	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2016 Normalized	2017 Forecast	2018 Forecast
GS > 50	319,837	299,744	305,696	207,631	285,018	284,071	276,301	272,597
Intermediate	188,608	186,063	173,701	203,108	186,369	162,302	183,628	165,382
Large User	160,412	163,430	178,918	169,422	177,134	187,446	171,751	172,130
Embedded Distributor	36,022	36,253	36,009	35,856	36,389	34,450	34,856	34,856
Street Light	9,969	7,518	5,900	5,564	5,229	5,321	5,384	5,449
Sentinel Light	643	647	657	653	615	599	587	574
Total	715,491	693,655	700,881	622,234	690,753	674,189	672,508	650,988

Table 3 kW Forecast

The following table summarizes 2015-2020 CDM Adjusted Load Forecast kW. Details for this calculation can be found at the end of in Schedule 6 of this report.

CDM Adjusted

kW	2016 Weather Normal Forecast	CDM Adjustment	2016 CDM Adjusted Forecast
GS > 50	272,597	10,155	262,442
Intermediate	165,382	6,669	158,713
Large User	172,130	5,895	166,236
Embedded Distributor	34,856	0	34,856
Street Light	5,449	0	5,449
Sentinel Light	574	0	574
Total	650,988	22,719	628,270

Table 4 CDM Adjusted kW Forecast

The following table summarizes the historic and forecast customer/connections for 2012-2018:

Customer Connections

kW	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Forecast	2018 Forecast
Residential	16,236	16,383	16,516	16,667	16,855	16,987	17,119
GS < 50	1,921	1,940	1,953	1,989	1,993	2,006	2,018
GS > 50	187	185	181	155	158	155	153
Intermediate	7	7	7	7	7	7	6
Large User	1	1	1	1	1	1	1
Embedded Distributor	3	4	4	4	4	4	4
Street Light	4,283	4,498	4,498	4,617	5,927	5,998	6,070
Sentinel Light	301	248	248	248	248	243	238
USL	120	124	121	128	126	128	130
Total	23,059	23,390	23,528	23,817	25,320	25,529	25,739

Table 5 Customer / Connection Forecast for 2009-2020

2 CLASS SPECIFIC KWH REGRESSION

2.1 RESIDENTIAL

For the Residential Class kWh consumption the equation was estimated using 120 observations from 2007:01-2016:12.

Heating and Cooling Degree days were used, as measured at the London Airport weather station as described in the introduction. A Trend variable was used, indicating 1 in January 2007, and incrementing once each month, reaching 120 in the last month of the regression, December 2015. Finally, binary indicator variables for the Shoulder months of March, April, and May, September, October, and November, as well as for the months of February and July were used.

Several other variables were examined, and found to not show a statistically significant relationship to energy usage. Those included an economic indicator of full time employment, the number of days in the month, and a count of customer connections.

The following table outlines the resulting regression model:

Model 11: OLS, using observations 2007:01-2016:12 (T = 120)
Dependent variable: Residential_no_CDM

	Coefficient	*Std. Error*	*t-ratio*	*p-value*	
const	1.03976e+07	229284	45.3480	<0.0001	***
London_HDD	5573.62	326.222	17.0854	<0.0001	***
London_CDD	27524.7	2309.55	11.9178	<0.0001	***
Trend	−4275.06	1274.81	−3.3535	0.0011	***
Shoulder	−1.41996e+06	139198	−10.2010	<0.0001	***
Feb	−473349	184502	−2.5656	0.0116	**
June	−773165	189478	−4.0805	<0.0001	***
Sept	772942	175758	4.3978	<0.0001	***

Mean dependent var	11823416	S.D. dependent var	1558243
Sum squared resid	2.61e+13	S.E. of regression	482936.8
R-squared	0.909597	Adjusted R-squared	0.903947
F(7, 112)	160.9859	P-value(F)	2.13e-55
Log-likelihood	−1736.650	Akaike criterion	3489.300
Schwarz criterion	3511.600	Hannan-Quinn	3498.356
Rho	0.184466	Durbin-Watson	1.611728
Theil's U	0.30271		

Table 6 Residential Regression Model

Using the above model coefficients, we derive the following:

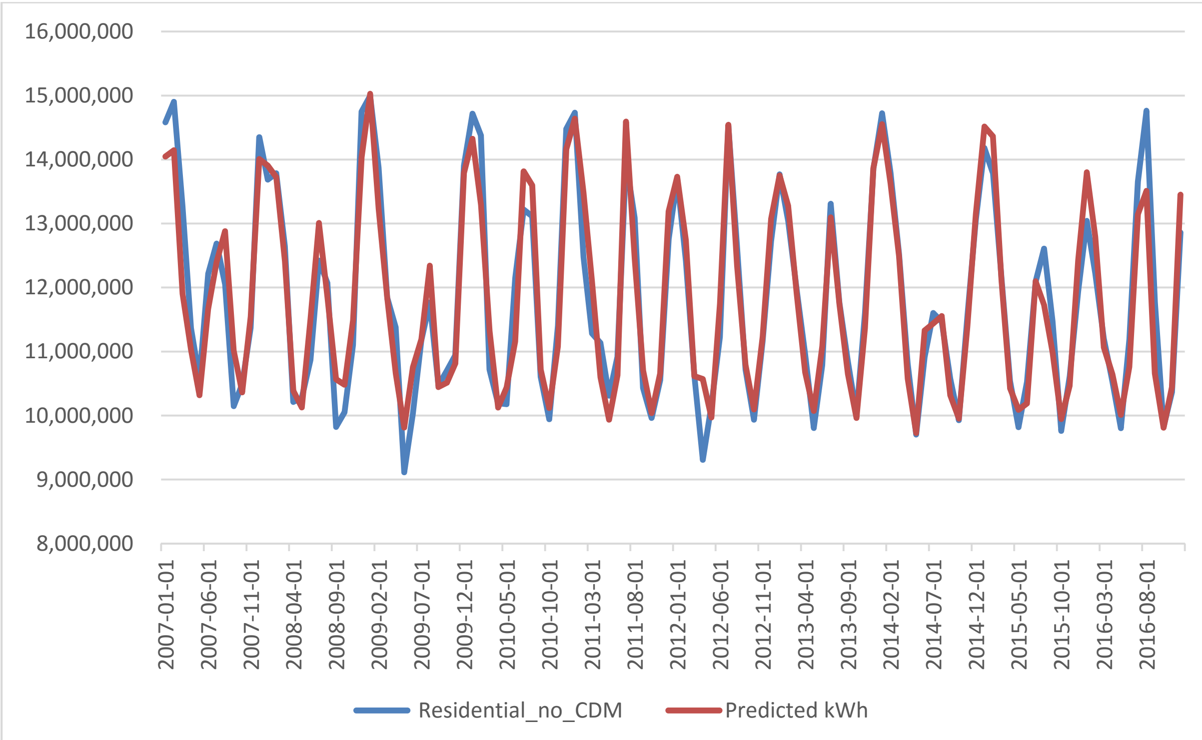

Figure 1 Residential Predicted vs Actual observations

Annual estimates using actual weather are compared to actual values in the table below. Mean absolute percentage error (MAPE) for annual estimates for the period is 1.0%. Annual errors are calculated as the model is used to derive annual forecasts. However, in proceedings Elenchus has been involved in, intervenors and Board Staff have requested MAPE calculated on a monthly basis and this has been provided as well. The MAPE calculated monthly over the period is 3.0%.

	Residential kWh		Absolute
Year	Actual	Predicted	Error (%)
2008	41,965,837	42,674,965	1.7%
2009	42,988,146	42,676,422	0.7%
2010	41,640,773	41,375,775	0.6%
2011	41,936,263	42,089,710	0.4%
2012	41,580,385	41,109,016	1.1%
2013	43,317,250	42,738,840	1.3%
2014	42,817,440	42,850,442	0.1%
2015	41,096,056	41,826,980	1.8%
Mean Absolute Percentage of Error (Annual)			1.0%
Mean Absolute Percentage of Error (Monthly)			3.0%

Table 7 Residential model error

2.2 GS < 50

For the GS < 50 class, the regression equation was estimated using 120 observations from 2007:01-2016:12.

Heating degree days and cooling degree days were used, as measured at the London Airport weather station as described in the introduction.

A count of customers, and a trend variable indicating 1 in January 2007, increasing to 120 in December 2016 were used. As a measure of economic activity, the number of full time employees, “London_FTE” was included. Binary variables representing the months of March, June, July, August, and September were used.

Other variables were examined, and found to not show a statistically significant relationship to energy usage. Those included an indicator of days in the month, and spring and fall dummy variables.

The following table outlines the resulting regression model:

Model 50: OLS, using observations 2007:01-2016:12 (T = 120)
Dependent variable: GS_lt_50_no_CDM

	coefficient	std. error	t-ratio	p-value
const	-11631489.55	3030819.386	-3.837737612	0.000208592
GS_lt_50_Cust	6551.127986	1741.140986	3.762548834	2.73E-04
London_HDD	2094.073158	109.077515	19.19802774	9.33E-37
London_CDD	5924.857551	1108.897466	5.343016584	5.06E-07
London_FTE	10421.48982	3094.139807	3.368137988	1.05E-03
Trend	-4822.694077	1876.272497	-2.570359095	1.15E-02
Mar	-156104.0665	68013.96157	-2.295176797	0.023637321
June	359272.7117	93117.03515	3.858291999	0.000193754
July	411098.3059	125921.8156	3.264710756	0.001464529
Aug	494220.9231	110691.9098	4.46E+00	1.96E-05
Sept	249265.1315	80695.8435	3.09E+00	0.002548735

Mean dependent var	4190028.628	S.D. dependent var	442281.5561
Sum squared resid	4.2434E+12	S.E. of regression	197307.5945
R-squared	0.817707214	Adjusted R-squared	0.800983105
F(10, 109)	48.89391855	P-value(F)	1.03E-35
Log-likelihood	-1627.606294	Akaike criterion	3277.212589
Schwarz criterion	3307.874998	Hannan-Quinn	3289.664735
rho	0.086702585	Durbin-Watson	1.819920886
Theil's U	0.44297		

Table 8 GS < 50 Regression Model

Using the above model coefficients we derive the following:

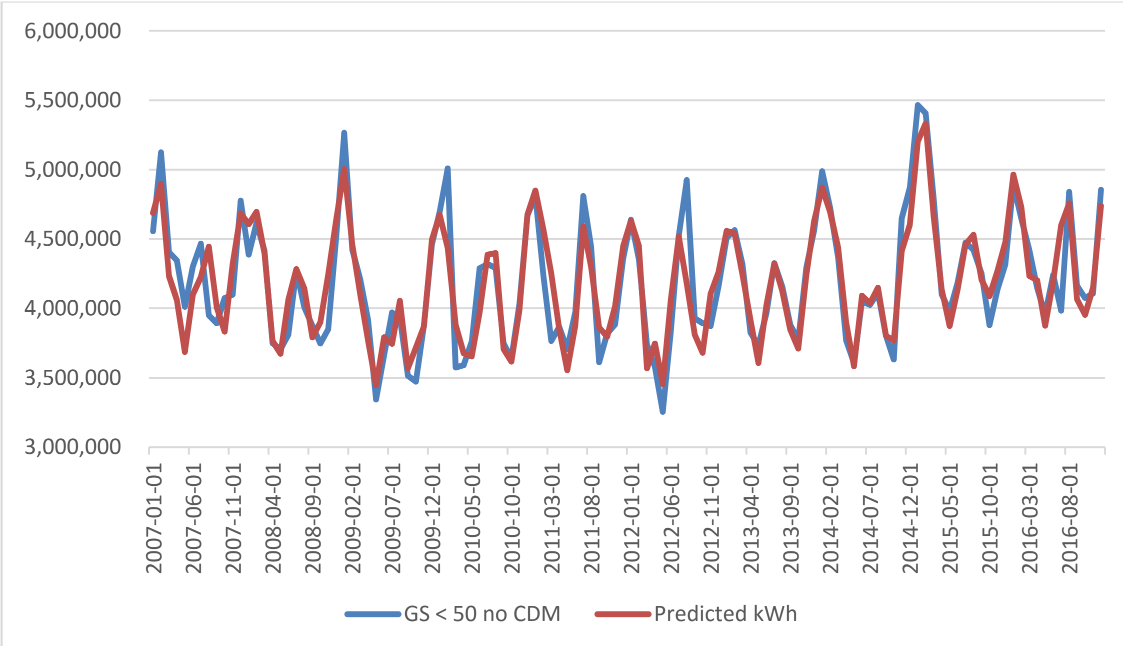

Figure 2 GS < 50 Predicted vs Actual observations

Annual estimates using actual weather are compared to actual values in the table below. Mean absolute percentage error (MAPE) for annual estimates for the period is 0.8%. Annual errors are calculated as the model is used to derive annual forecasts. However, in recent proceedings Elenchus has been involved in, intervenors and Board Staff have requested MAPE calculated on a monthly basis and this has been provided as well. The MAPE calculated monthly over the period is 3.3%.

	GS<50 kWh CDM Added Back	Predicted	Absolute Error (%)
2007	51,997,633	51,179,679	1.6%
2008	48,943,216	50,195,637	2.6%
2009	48,039,983	48,018,945	0.0%
2010	49,616,194	49,050,622	1.1%
2011	49,273,917	49,953,305	1.4%
2012	48,699,091	48,462,747	0.5%
2013	49,904,173	49,758,085	0.3%
2014	50,588,552	50,348,351	0.5%
2015	53,413,626	53,374,866	0.1%
2016	52,327,039	52,461,199	0.3%

Mean Absolute Percentage Error (Annual)	0.8%
Mean Absolute Percentage Error (Monthly)	3.3%

Table 9 GS < 50 model error

3 WEATHER NORMALIZATION AND ECONOMIC FORECAST

It is not possible to accurately forecast weather for months or years in advance. Therefore, one can only base future weather expectations on what has happened in the past. Individual years may experience unusual spells of weather (unusually cold winter, unusually warm summer, etc.). However, over time, these unusual spells "average" out. While there may be trends over several years (e.g., warmer winters for example), using several years of data rather than one particular year filters out the extremes of any particular year. While there are several different approaches to determining an appropriate weather normal, Erie Thames has adopted the most recent 10 year monthly degree day average as the definition of weather normal, which to our knowledge, is consistent with many LDCs load forecast filings for cost-of-service rebasing applications.

The table below displays the most recent 10 year average of heating degree days and cooling degree days as reported by Environment Canada for London Airport, which is used as the weather station for Erie Thames

10 Year Average

		HDD	CDD
London Airport	January	1035.18	0
London Airport	February	937.08	0
London Airport	March	773.14	0.14
London Airport	April	490.04	0.16
London Airport	May	249.86	7.95
London Airport	June	100.25	18.03
London Airport	July	49.4	38.42
London Airport	August	76.26	24.46
London Airport	September	191.69	6.89
London Airport	October	404.82	0.68
London Airport	November	606.4	0
London Airport	December	897.86	0

Table 10 10 Year Average HDD and CDD

As part of the minimum filing requirements the OEB has requested monthly degree days calculated using a trend based on 20 years. This is shown in the table below.

20 Year Trend (2017)

		HDD	CDD
London Airport	January	1049.06	0.00
London Airport	February	966.99	0.00
London Airport	March	777.60	0.23
London Airport	April	503.87	0.20
London Airport	May	241.87	8.09
London Airport	June	106.30	12.43
London Airport	July	49.08	40.85
London Airport	August	67.62	25.50
London Airport	September	184.45	8.59
London Airport	October	400.71	0.89
London Airport	November	600.10	0.00
London Airport	December	901.92	0.00

Table 11 20 Year Trend HDD and CDD

4 CLASS SPECIFIC NORMALIZED FORECASTS

4.1 RESIDENTIAL

Incorporating the forecast economic variables, 10-yr weather normal heating and cooling degree days, and calendar variables, the following weather corrected consumption and forecast values are calculated:

			Res kWh				
Year	Actual	Cumulative Persisting CDM	Actual No CDM	alized No CDM	Cumulative Persisting CDM	End of LTLT	Normalized
	A	B	C = A + B	D	E = B		F = D - E
2007	147,855,081	139,228	147,994,308	144,651,232	139,228		144,512,004
2008	141,293,621	406,078	141,699,699	144,035,624	406,078		143,629,545
2009	139,285,895	885,458	140,171,354	143,420,015	885,458		142,534,557
2010	143,730,192	1,348,377	145,078,569	142,804,407	1,348,377		141,456,030
2011	139,849,072	1,775,465	141,624,537	142,188,799	1,775,465		140,413,334
2012	136,951,769	2,183,609	139,135,378	141,573,191	2,183,609		139,389,582
2013	139,174,379	2,547,102	141,721,481	140,957,582	2,547,102		138,410,481
2014	137,614,288	3,029,863	140,644,151	140,341,974	3,029,863		137,312,111
2015	135,712,848	3,789,350	139,502,198	139,726,366	3,789,350		135,937,016
2016	136,671,067	4,567,200	141,238,267	139,110,758	4,567,200		134,543,558
2017				138,495,150	4,567,200		133,927,949
2018				137,879,541	4,567,200	451,754	133,764,095

Table 12 Actual vs Normalized Residential kWh

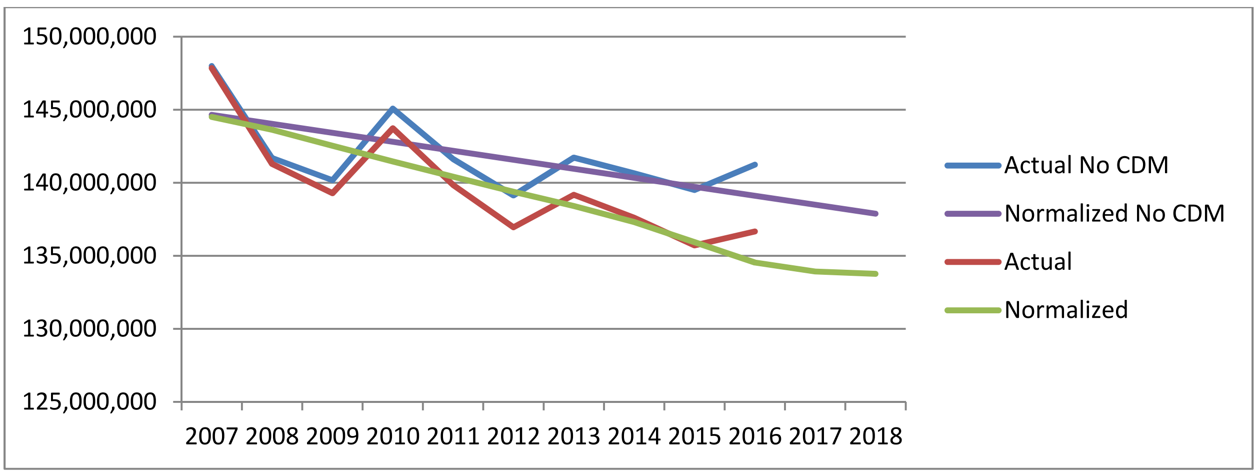

Figure 3 Actual vs Normalized Residential kWh

While Residential customer counts are not a component of the regression model, they are forecasted for the purpose of rate setting. The Geometric mean of the annual growth from 2007 to 2016 was used to forecast the growth rate from 2017 to 2018.

Year	Residential Customers	Percent of Prior Year
2007	15,716	
2008	15,819	100.66%
2009	15,888	100.44%
2010	15,992	100.65%
2011	16,123	100.82%
2012	16,236	100.70%
2013	16,383	100.90%
2014	16,516	100.81%
2015	16,667	100.92%
2016	16,855	101.13%
2017	16,987	100.78%
2018	17,119	100.78%

Table 13 Forecasted Residential Customer Count

4.2 GS < 50

GS<50 kWh

Year	Actual	Cumulative Persisting CDM	Actual No CDM	Normalized No CDM	Cumulative Persisting CDM	End of LTLT	Normalized
	A	B	C = A + B	D	E = B		F = D - E
2007	51,948,960	48,673	51,997,633	51,021,168	48,673		50,972,495
2008	48,801,254	141,963	48,943,216	50,181,731	141,963		50,039,769
2009	47,730,433	309,551	48,039,983	48,573,915	309,551		48,264,364
2010	49,127,425	488,768	49,616,194	48,890,988	488,768		48,402,220
2011	48,634,112	639,805	49,273,917	49,809,163	639,805		49,169,358
2012	47,672,679	1,026,412	48,699,091	48,911,868	1,026,412		47,885,456
2013	48,218,851	1,685,321	49,904,173	49,530,766	1,685,321		47,845,444
2014	48,123,471	2,465,081	50,588,552	50,059,110	2,465,081		47,594,029
2015	50,019,956	3,393,670	53,413,626	53,367,596	3,393,670		49,973,926
2016	48,503,240	3,823,799	52,327,039	52,457,129	3,823,799		48,633,330
2017				52,739,421	3,823,799		48,915,623
2018				53,027,803	3,823,799	190,961	49,394,965

Table 14 Actual vs Normalized GS < 50 kWh

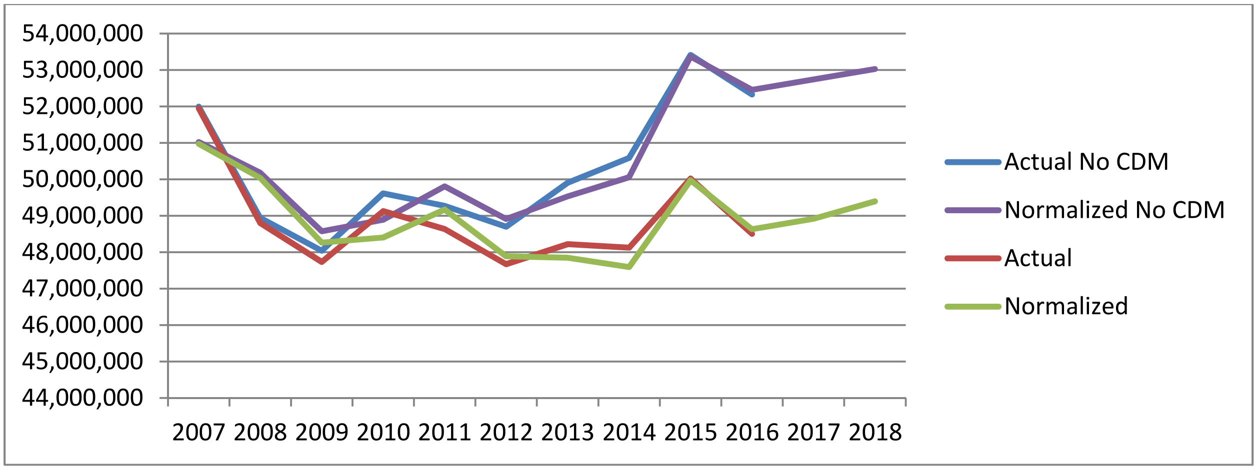

Figure 4 Actual vs Normalized GS < 50 kWh

GS < 50 customer counts forecasted both for the purpose of the regression model, and for direct use in rate setting. The Geometric mean of the annual growth from 2007 to 2016 was used to forecast the growth rate from 2017 to 2018.

The following table includes the customer Actual / Forecast customer count on this basis:

Year	GS < 50 Customers	Percent of Prior Year
2007	1,885	
2008	1,892	100.35%
2009	1,895	100.19%
2010	1,906	100.56%
2011	1,931	101.29%
2012	1,921	99.51%
2013	1,940	100.99%
2014	1,953	100.67%
2015	1,989	101.86%
2016	1,993	100.20%
2017	2,006	100.62%
2018	2,018	100.62%

Table 15 Forecasted GS < 50 Customer Count*

4.3 GS > 50

The GS > 50 rate class is not weather sensitive. The historical consumption of the rate class has been adjusted to reflect the reclassification of two larger customers into the intermediate rate class. Due to changes in the composition of the rate class, usage prior to 2015 is not reflective of the expected load going forward. The GS > 50 forecast was calculated as an average of the 2015-2016 Actual usage.

Year	GS>50 kWh Actual No CDM	Customers	Average per Customer	Forecasted no CDM	Persisting CDM	Normal Forecast	End of LTLT	Final Forecast
2007	100,933,973	182	553,316		95,754			
2008	94,039,899	187	501,992		279,281			
2009	94,089,721	189	497,610		608,974			
2010	95,612,119	187	512,437		961,546			
2011	100,335,644	188	533,937		1,258,678			
2012	102,465,298	189	541,190		2,019,245			
2013	99,138,275	187	528,973		3,315,507			
2014	103,487,654	183	566,538		4,849,516			
2015	97,248,975	157	618,435		6,676,314			
2016	101,805,845	160	637,282	101,805,845	7,522,500	94,283,345		
2017		155	627,859	97,578,203	7,128,147	90,450,056		
2018		153	627,859	96,133,383	6,911,314	89,222,069	232,530	89,454,599

Table 16 Actual vs Forecast GS > 50 kWh

GS > 50 customer counts are forecasted for the purpose of rate setting. The Geometric mean of the annual growth from 2007 to 2016 was used to forecast the growth rate from 2017 to 2018.

Year	GS > 50 Customers	Percent of Prior Year
2007	180	
2008	185	102.73%
2009	187	100.94%
2010	185	98.66%
2011	186	100.72%
2012	187	100.76%
2013	185	98.98%
2014	181	97.44%
2015	155	85.93%
2016	158	101.61%
2017	155	98.52%
2018	153	98.52%

Table 17 Forecasted GS > 50 Customer Count*

In order to normalize and forecast class kW for those classes that bill based on kW (demand) billing determinants, the relationship between billed kW and kWh is used. The average ratio from 2007-2016 is used to forecast kW for all future years. An adjustment is made to reflect the upcoming end of the Load Transfer arrangement with Hydro One.

		GS>50	
Year	kWh Actual	Ratio	kW Actual
	A	**C = B / A**	**B**
2007	100,838,219	0.002977035	300,199
2008	93,760,619	0.003045233	285,523
2009	93,480,747	0.003077357	287,674
2010	94,650,573	0.003158418	298,946
2011	99,076,966	0.003144611	311,559
2012	100,446,053	0.003184167	319,837
2013	95,822,768	0.003128104	299,744
2014	98,638,138	0.003099165	305,696
2015	90,572,661	0.002292426	207,631
2016	94,283,345	0.003022989	285,018

	kWh Normalized		kW Normalized	End of LTLT	Forecast
	D	**E**	**F = D * E**	**G**	**H=F+G**
2016	94,283,345	0.003012951	284,071		
2017	90,450,056	0.003012951	272,522		
2018	89,222,069	0.003012951	268,822	931	269,752

Table 18 Forecasted GS > 50 kW

4.4 INTERMEDIATE

The Intermediate rate class is not weather sensitive. The historical consumption of the rate class has been adjusted to reflect the reclassification of two larger GS > 50 customers into this class. The Intermediate forecast was calculated as an average of the 2007-2016 Actual usage. One customer is discontinuing operations. The historic energy and demand of that customer have been removed from the resulting totals.

			Intermediate					
Year	Actual No CDM	Customers	Average per Customer	recasted no CDM	Persisting CDM	Normal Forecast	Lost Customer	Net Forecast
2007	108,148,350	7	15,449,764		88,181			
2008	87,266,948	7	12,466,707		257,193			
2009	74,672,290	7	10,667,470		560,812			
2010	96,466,560	7	13,780,937		885,500			
2011	92,347,944	7	13,192,563		1,159,132			
2012	92,117,889	7	13,159,698		1,859,548			
2013	92,636,597	7	13,233,800		3,053,291			
2014	94,031,167	7	13,433,024		4,465,979			
2015	91,600,392	7	13,085,770		6,148,300			
2016	81,639,097	7	11,662,728	81,639,097	6,927,563	74,711,534		74,711,534
2017		7	13,013,246	91,092,723	6,564,398	84,528,325		84,528,325
2018		6		91,092,723	6,364,714	84,728,009	-7,760,623	76,967,386

Table 19 Actual vs Forecast Intermediate kWh

Intermediate customer counts are forecasted for the purpose of rate setting. Erie Thames expects that the remaining 6 customers will persist into 2018

Year	Intermediate Customers	Percent of Prior Year
2007	7	
2008	7	100.00%
2009	7	100.00%
2010	7	100.00%
2011	7	100.00%
2012	7	100.00%
2013	7	100.00%
2014	7	100.00%
2015	7	100.00%
2016	7	100.00%
2017	7	100.00%
2018	6	85.71%

Table 20 Forecasted Intermediate Customer Count*

To normalize and forecast class kW for those classes that bill based on kW (demand) billing determinants, the relationship between billed kW and kWh is used. The average ratio from 2007-2016 is used to forecast kW for all future years.

	Intermediate		
Year	kWh Actual	Ratio	kW Actual
	A	**C = B / A**	**B**
2007	108,060,169	0.002161745	233,599
2008	87,009,755	0.002226491	193,726
2009	74,111,478	0.002258834	167,406
2010	95,581,060	0.002070326	197,884
2011	91,188,812	0.002029048	185,026
2012	90,258,341	0.002089651	188,608
2013	89,583,306	0.002076987	186,063
2014	89,565,188	0.001939384	173,701
2015	85,452,092	0.002376859	203,108
2016	74,711,534	0.00249451	186,369

	kWh Normalized		kW Normalized	Lost Customer	Net Forecast
	D	**E**	**F = D * E**		
2016	74,711,534	0.002172383	162,302		162,302
2017	84,528,325	0.002172383	183,628		183,628
2018	84,728,009	0.002172383	184,062	-18,680	165,382

Table 21 Forecasted Intermediate kW

4.5 LARGE USE

The Large Use rate class is not weather sensitive. Due to changes in the composition of the rate class, usage prior to 2015 is not reflective of the expected load going forward. The GS > 50 forecast was calculated as an average of the 2013-2016 Actual usage.

Year	Actual No CDM	Large Use Forecasted no CDM	Persisting CDM	Normal Forecast
2007	87,365,937	87,365,937	96,519	
2008	84,846,627	84,846,627	281,513	
2009	108,083,961	108,083,961	613,842	
2010	96,739,998	96,739,998	969,231	
2011	99,176,657	99,176,657	1,268,738	
2012	96,186,937	96,186,937	2,035,384	
2013	98,312,959	98,312,959	3,342,006	
2014	103,336,243	103,336,243	4,888,276	
2015	107,405,730	107,405,730	6,729,675	
2016	115,608,236	115,608,236	7,582,624	108,025,611
2017		106,165,792	7,185,119	98,980,673
2018		106,165,792	6,966,553	99,199,239

Table 22 Actual vs Forecast Large Use kWh

The Large Use rate class has had 1 customer for at least the past 10 years, and is expected to have 1 customer going forward.

In order to normalize and forecast class kW for those classes that bill based on kW (demand) billing determinants, the relationship between billed kW and kWh is used. The average ratio from 2017-2016 is used to forecast kW for all future years.

	Large Use		
Year	kWh Actual	Ratio	kW Actual
	A	**C = B / A**	**B**
2007	87,269,418	0.001858888	162,224
2008	84,565,114	0.001904589	161,062
2009	107,470,119	0.001645558	176,848
2010	95,770,767	0.001748532	167,458
2011	97,907,919	0.001629855	159,576
2012	94,151,553	0.001703762	160,412
2013	94,970,953	0.001720841	163,430
2014	98,447,967	0.00181739	178,918
2015	100,676,055	0.001682845	169,422
2016	108,025,611	0.001639737	177,134
	kWh Normalized		kW Normalized
	D	**E**	**F = D * E**
2016	108,025,611	0.0017352	187,446
2017	98,980,673	0.0017352	171,751
2018	99,199,239	0.0017352	172,130

Table 23 Forecasted Large Use kW

4.6 EMBEDDED DISTRIBUTOR

The Embedded Distributor rate class is not sufficiently weather sensitive for meaningful regression analysis. The GS > 50 forecast was calculated as an average of the 2013-2016 Actual usage.

Year	Embedded Actual	Connections	Normal Forecast
2007	17,391,305	2	
2008	15,895,270	3	
2009	17,281,081	3	
2010	17,355,209	3	
2011	17,333,527	3	
2012	15,488,407	3	
2013	15,613,195	4	
2014	16,830,475	4	
2015	16,494,364	4	
2016	16,248,812	4	16,296,711
2017		4	16,296,711
2018		4	16,296,711

Table 24 Actual vs Forecast Embedded kWh

The Embedded Class is served by 4 connections, and this configuration is expected to remain in 2018.

In order to normalize and forecast class kW for those classes that bill based on kW (demand) billing determinants, the relationship between billed kW and kWh is used. The average ratio from 2007-2016 is used to forecast kW for all future years.

Embedded Distributor			
Year	kWh Actual	Ratio	kW Actual
	A	**C = B / A**	**B**
2007	17,391,305	0.001642597	28,567
2008	15,895,270	0.002199981	34,969
2009	17,281,081	0.00224659	38,824
2010	17,355,209	0.001991137	34,557
2011	17,333,527	0.002107823	36,536
2012	15,488,407	0.002325707	36,022
2013	15,613,195	0.002321959	36,253
2014	16,830,475	0.002139482	36,009
2015	16,494,364	0.002173833	35,856
2016	16,248,812	0.002239499	36,389

	kWh Normalized		kW Normalized
	D	**E**	**F = D * E**
2016	16,296,711	0.002138861	34,856
2017	16,296,711	0.002138861	34,856
2018	16,296,711	0.002138861	34,856

Table 25 Forecasted GS > 50 kW

5 STREET LIGHT, SENTINEL AND USL FORECAST

The Street Lighting, Sentinel, and Unmetered Scattered Load Classes are non-weather sensitive classes. The tables below summarize the historic annual energy consumption for both classes and the anticipated consumption in the forecast period.

The Street Light class has a significant increase in connection count in December 2015. The growth rate from 2007-2015 is expected to reflect the norm from 2017-2018.

Street Light Year	Lamps / Devices	Percent of Prior Year
2007	4,197	
2008	4,283	102.05%
2009	4,283	100.00%
2010	4,283	100.00%
2011	4,283	100.00%
2012	4,283	100.00%
2013	4,498	105.02%
2014	4,498	100.00%
2015	4,617	102.65%
2016	5,927	128.37%
2017	5,998	101.20%
2018	6,070	101.20%

Table 26 Forecasted Street Light lamps (devices)

Street Light Year	Lamps / Devices	Percent of Prior Year
2007	4,197	
2008	4,283	102.05%
2009	4,283	100.00%
2010	4,283	100.00%
2011	4,283	100.00%
2012	4,283	100.00%
2013	4,498	105.02%
2014	4,498	100.00%
2015	4,617	102.65%
2016	5,927	128.37%
2017	5,998	101.20%
2018	6,070	101.20%

Table 27 Forecasted Sentinel connections

Year	USL Connections	Percent of Prior Year
2007	113	
2008	123	108.81%
2009	128	104.49%
2010	127	99.35%
2011	124	97.71%
2012	120	96.31%
2013	124	103.34%
2014	121	97.78%
2015	128	105.58%
2016	126	99.02%
2017	128	101.30%
2018	130	101.30%

Table 28 Forecasted USL connections

Year	Street Light Actual	Lamps / Devices	Average per Customer	Normal Forecast
2007	4,143,939	4,197	987	
2008	3,636,366	4,283	849	
2009	3,489,623	4,283	815	
2010	4,583,498	4,283	1,070	
2011	3,899,368	4,283	910	
2012	3,484,987	4,283	814	
2013	2,710,402	4,498	603	
2014	2,115,842	4,498	470	
2015	2,025,403	4,617	439	
2016	1,938,875	5,927	327	1,938,875
2017		5,998	327	1,962,132
2018		6,070	327	1,985,669

Table 29 Forecasted Street Light kWh

	Sentinel			
Year	Actual	Connections	Average per Customer	Normal Forecast
2012	280,910	301	933	
2013	272,742	248	1,100	
2014	266,366	248	1,074	
2015	246,528	248	994	
2016	231,256	248	932	231,256
2017		243	932	226,333
2018		238	932	221,514

Table 30 Forecasted Sentinel kWh

	USL			
Year	Actual	Connections	Average per Customer	Normal Forecast
2007	539,336	113	4,791	
2008	539,138	123	4,401	
2009	605,366	128	4,729	
2010	565,196	127	4,445	
2011	556,906	124	4,482	
2012	513,343	120	4,290	
2013	539,394	124	4,362	
2014	535,721	121	4,430	
2015	537,894	128	4,213	
2016	504,437	126	3,990	504,437
2017		128	3,990	510,974
2018		130	3,990	517,597

Table 31 Forecasted USL kWh

		Street Light	
Year	kWh Actual	Ratio	kW Actual
	A	**C = B / A**	**B**
2007	4,143,939	0.002722248	11,281
2008	3,636,366	0.002895418	10,529
2009	3,489,623	0.002699011	9,419
2010	4,583,498	0.002608577	11,956
2011	3,899,368	0.002765679	10,784
2012	3,484,987	0.002860599	9,969
2013	2,710,402	0.002773733	7,518
2014	2,115,842	0.002788507	5,900

2015	2,025,403	0.002747221	5,564
2016	1,938,875	0.002696838	5,229

	kWh Normalized		kW Normalized
	D	**E**	**F = D * E**
2016	1,938,875	0.002744188	5,321
2017	1,962,132	0.002744188	5,384
2018	1,985,669	0.002744188	5,449

Table 32 Forecasted Street Light kW

Sentinel

Year	kWh Actual	Ratio	kW Actual
	A	**C = B / A**	**B**
2012	280,910	0.002288993	643
2013	272,742	0.002372208	647
2014	266,366	0.002466529	657
2015	246,528	0.002648789	653
2016	231,256	0.002659389	615

	kWh Normalized		kW Normalized
	D	**E**	**F = D * E**
2016	231,256	0.002591569	599
2017	226,333	0.002591569	587
2018	221,514	0.002591569	574

Table 33 Forecasted Sentinel kW

6 CDM ADJUSTMENT TO LOAD FORECAST

The current Chapter 2 OEB Minimum Filing requirements, consistent with the Board's CDM Guideline EB-2012-0003, expects the distributor to integrate an adjustment into its load forecast that takes into account the six-year (2015-2020) targets for kWh and kW reductions.

The filing requirements note that the distributors license condition targets and the LRAMVA balances are based on the IESO targets, which are annualized. It is recognized that the CDM programs in a year are not in effect for the full year, although persistence of previous year's programs will be. Therefore, the actual impact on the load forecast for the first year of the program should not be the full annualized amount. For this reason, the amount that will be used for the LRAMVA will be related to, but not necessarily equal to, the CDM adjustment for the load forecast.

The following is the proposed allocation of the CDM kWh load forecast adjustment and final proposed load forecast, based on a half-year of savings from 2016, a full year of savings from 2017, and a half year of savings from 2018. The IESO verified savings persisting to 2020, as well as the 2015-2020 Draft Historic Target and Budget Analysis dated July, 2014 informed the Residential and General Service apportionment of the target. The class volumes were used for the GS < 50 and GS > 50 apportionment of the General Service portion of the target.

For 2018 LRAMVA Elenchus reasons that the effects of 2015-2017 IESO CDM programs should be included in the LRAMVA calculation. In particular, full years of 2016-2018 are included.

	2015 Verified CDM	Share	CDM Adjustment	LRAMVA Target
Residential	743,199	14.0%	1,256,917	1,885,376
GS < 50	675,321	12.7%	1,142,121	1,713,182
GS > 50	1,328,549	25.0%	2,246,878	3,370,316
Intermediate	1,223,477	23.0%	2,069,177	3,103,766
Large Use	1,339,168	25.2%	2,264,836	3,397,254
Total	5,309,714	100.0%	8,979,929	13,469,894

Table 34 Proposed CDM Adjustment

In order to calculate the kW Elenchus proposes using a proportional ratio utilizing the base load forecast kW and kWh.

	Weather Normalized 2018 Forecast (kWh)	CDM Adjustment (kWh)	% Savings	Weather Normalized 2018 Forecast (kW)	CDM Adjustment (kW)
GS > 50	89,222,069	2,246,878	2.5%	268,822	6,770
Intermediate	76,967,386	2,069,177	2.7%	165,382	4,446
Large Use	99,199,239	2,264,836	2.3%	172,130	3,930
Total	265,388,694	6,580,891	0	606,334	15,146

Table 35 Proposed kW CDM adjustment

	Weather Normalized 2018 Forecast (kWh)	LRAMVA Adjustment (kWh)	% Savings	Weather Normalized 2018 Forecast (kW)	LRAMVA Adjustment (kW)
GS > 50	89,222,069	3,370,316	3.8%	268,822	10,155
Intermediate	76,967,386	3,103,766	4.0%	165,382	6,669
Large Use	99,199,239	3,397,254	3.4%	172,130	5,895
Total	265,388,694	9,871,336	0	606,334	22,719

* Note that LRRAMVA kW is the proportional LF kW over LF kWh times kWh LRAMVA

Table 36 LRAMVA kW threshold by class

Attachment 2 (of 7):

3-B OEB Appendix 2-IB

Appendix 2-IB
Customer, Connections, Load Forecast and Revenues Data and Analysis

This sheet is to be filled in accordance with the instructions documented in section 2.3.2 of Chapter 2 of the Filing Requirements for Distribution Rate Applications, in terms of one set of tables per customer class.

Color coding for Cells:	Data input		Drop-down List
	No data entry required		Blank or calculated value

Distribution System (Total)

	Calendar Year (for 2018 Cost of Service			Consumption (kWh) (3)			
				Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	*2012*		Actual	489,248,042	491,617,723		
Historical	*2013*		Actual	486,905,989	485,495,942	Board-approved	462,657,415
Historical	*2014*		Actual	492,137,456	491,039,471		
Historical	*2015*		Actual	481,737,801	481,669,412		
Historical	*2016*		Actual	481,118,177	478,889,501		
Bridge Year	*2017*		Forecast		482,700,591		
Test Year	*2018*		Forecast		482,019,668		

Variance Analysis	Year	Year-over-year		Versus Board-approved
	2012			
	2013	-0.5%	-1.2%	
	2014	1.1%	1.1%	
	2015	-2.1%	-1.9%	
	2016	-0.1%	-0.6%	
	2017		0.8%	
	2018		-0.1%	4.2%
	Geometric Mean	-0.6%	-0.4%	1.0%

Customer Class Analysis (one for each Customer Class, excluding MicroFIT and Standby)

1 Customer Class: Residential   Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2018 Cost of Service)	Customers			
Historical	*2012*	Actual	16,236		
Historical	*2013*	Actual	16,383	Board-approved	16,461
Historical	*2014*	Actual	16,516		
Historical	*2015*	Actual	16,667		
Historical	*2016*	Actual	16,855		
Bridge Year	*2017*	Forecast	16,987		
Test Year	*2018*	Forecast	17,119		

	Calendar Year (for 2018 Cost of Service)	Consumption (kWh) [3]	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	*2012*	Actual	136,951,769	139,389,582		
Historical	*2013*	Actual	139,174,379	138,410,481	Board-approved	147,767,075
Historical	*2014*	Actual	137,614,288	137,312,111		
Historical	*2015*	Actual	135,712,848	135,937,016		
Historical	*2016*	Actual	136,671,067	134,543,558		
Bridge Year	*2017*	Forecast		133,927,949		
Test Year	*2018*	Forecast		133,764,095		

	Calendar Year (for 2018 Cost of Service)	Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	*2012*	Actual	8434.9384	8585.08473		
Historical	*2013*	Actual	8495.0485	8448.42097	Board-approved	8976.79819
Historical	*2014*	Actual	8332.2222	8313.92613		
Historical	*2015*	Actual	8142.4045	8155.85397		
Historical	*2016*	Actual	8108.5964	7982.37273		
Bridge Year	*2017*	Forecast	0	7884.30682		
Test Year	*2018*	Forecast	0	7813.6698		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2012		
	2013	0.9%	
	2014	0.8%	
	2015	0.9%	
	2016	1.1%	
	2017	0.8%	
	2018	0.8%	4.0%
	Geometric Mean	1.1%	1.0%

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	1.6%	-0.7%	
2014	-1.1%	-0.8%	
2015	-1.4%	-1.0%	
2016	0.7%	-1.0%	
2017		-0.5%	
2018		-0.1%	-9.5%
Geometric Mean	-0.1%	-0.8%	-2.5%

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	0.7%	-1.6%	
2014	-1.9%	-1.6%	
2015	-2.3%	-1.9%	
2016	-0.4%	-2.1%	
2017		-1.2%	
2018		-0.9%	-13.0%
Geometric Mean	-1.3%	-1.9%	-3.4%

	Calendar Year (for 2018 Cost of Service)	Revenues			
Historical	*2012*				
Historical	*2013*		Board-approved	5636524.48	
Historical	*2014*				
Historical	*2015*				
Historical	*2016*				
Bridge Year (Foreca	*2017*				
Test Year (Forecast)	*2018*	6986214.4			

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2012		
	2013		
	2014		
	2015		
	2016		
	2017		
	2018		23.9%
	Geometric Mean		5.5%

2 **Customer Class:** GS < 50 kW

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2018 Cost of Service	Customers				Consumption (kWh) [3]					Consumption (kWh) per Customer				
							Actual (Weather actual)	Weather-normalized		Weather-normalized		Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	*2012*	Actual	1,921			Actual	47,672,679	47,885,456			Actual	24816.595	24927.3587		
Historical	*2013*	Actual	1,940	Board-approved	1,857	Actual	48,218,851	47,845,444	Board-approved	50,306,768	Actual	24855.078	24662.6002	Board-approved	27090.34356
Historical	*2014*	Actual	1,953			Actual	48,123,471	47,594,029			Actual	24641.846	24370.7426		
Historical	*2015*	Actual	1,989			Actual	50,019,956	49,973,926			Actual	25144.08	25120.9416		
Historical	*2016*	Actual	1,993			Actual	48,503,240	48,633,330			Actual	24332.729	24397.9916		
Bridge Year	*2017*	Forecast	2,006			Forecast		48,915,623			Forecast	0	24387.5973		
Test Year	*2018*	Forecast	2,018			Forecast		49,394,965			Forecast	0	24474.0288		

Variance Analysis

Year	Customers Year-over-year	Customers Test Year Versus Board-approved	Year	Consumption Year-over-year (Actual)	Consumption Year-over-year (Weather-normalized)	Consumption Test Year Versus Board-approved	Year	Per Customer Year-over-year (Actual)	Per Customer Year-over-year (Weather-normalized)	Per Customer Test Year Versus Board-approved
2012			*2012*				*2012*			
2013	1.0%		*2013*	1.1%	-0.1%		*2013*	0.2%	-1.1%	
2014	0.7%		*2014*	-0.2%	-0.5%		*2014*	-0.9%	-1.2%	
2015	1.9%		*2015*	3.9%	5.0%		*2015*	2.0%	3.1%	
2016	0.2%		*2016*	-3.0%	-2.7%		*2016*	-3.2%	-2.9%	
2017	0.6%		*2017*		0.6%		*2017*		0.0%	
2018	0.6%	8.7%	*2018*		1.0%	-1.8%	*2018*		0.4%	-9.7%
Geometric Mean	1.0%	2.1%	Geometric Mean	0.6%	0.6%	-0.5%	Geometric Mean	-0.7%	-0.4%	-2.5%

	Calendar Year (for 2018 Cost of Service	Revenues			
Historical	*2012*	Actual			
Historical	*2013*	Actual		Board-approved	1,149,106
Historical	*2014*	Actual			
Historical	*2015*	Actual			
Historical	*2016*	Actual			
Bridge Year (Foreca	*2017*	Forecast			
Test Year (Forecast	*2018*	Forecast	$ 1,275,038		

Variance Analysis

Year	Year-over-year	Test Year Versus Board-approved
2012		
2013		
2014		
2015		
2016		
2017		
2018		11.0%
Geometric Mean		2.6%

3 Customer Class: GS > 50 kW

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kW

	Calendar Year (for 2018 Cost of Service)	Customers			
Historical	*2012*	Actual	187		
Historical	*2013*	Actual	185	Board-approved	175
Historical	*2014*	Actual	181		
Historical	*2015*	Actual	155		
Historical	*2016*	Actual	158		
Bridge Year	*2017*	Forecast	155		
Test Year	*2018*	Forecast	153		

	Calendar Year (for 2018 Cost of Service)	Consumption (kWh) [3]	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	*2012*	Actual	102,465,298	102,465,298		
Historical	*2013*	Actual	99,138,275	99,138,275	Board-approved	77,849,023
Historical	*2014*	Actual	103,487,654	103,487,654		
Historical	*2015*	Actual	97,248,975	97,248,975		
Historical	*2016*	Actual	101,805,845	101,805,845		
Bridge Year	*2017*	Forecast		90,450,056		
Test Year	*2018*	Forecast		89,222,069		

	Calendar Year (for 2018 Cost of Service)	Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	*2012*	Actual	546967.79	546967.785		
Historical	*2013*	Actual	534678.34	534678.335	Board-approved	84.87016919
Historical	*2014*	Actual	572809.89	572809.891		
Historical	*2015*	Actual	626402.42	626402.416		
Historical	*2016*	Actual	645361.93	645361.932		
Bridge Year	*2017*	Forecast	0	581993.397		
Test Year	*2018*	Forecast	0	582720.232		

Variance Analysis

Year	Customers Year-over-year	Test Year Versus Board-approved
2012		
2013	-1.0%	
2014	-2.6%	
2015	-14.1%	
2016	1.6%	
2017	-1.5%	
2018	-1.5%	-12.5%
Geometric Mean	-4.0%	-3.3%

Year	Consumption Year-over-year (Actual)	Year-over-year (Weather-normalized)	Test Year Versus Board-approved
2012			
2013	-3.2%	-3.2%	
2014	4.4%	4.4%	
2015	-6.0%	-6.0%	
2016	4.7%	4.7%	
2017		-11.2%	
2018		-1.4%	14.6%
Geometric Mean	-0.2%	-2.7%	3.5%

Year	Consumption per Customer Year-over-year (Actual)	Year-over-year (Weather-normalized)	Test Year Versus Board-approved
2012			
2013	-2.2%	-2.2%	
2014	7.1%	7.1%	
2015	9.4%	9.4%	
2016	3.0%	3.0%	
2017		-9.8%	
2018		0.1%	686501.9%
Geometric Mean	5.7%	1.3%	810.3%

	Calendar Year (for 2018 Cost of Service)	Revenues			
Historical	*2012*	Actual			
Historical	*2013*	Actual		Board-approved	917,272
Historical	*2014*	Actual			
Historical	*2015*	Actual			
Historical	*2016*	Actual			
Bridge Year (Foreca	*2017*	Forecast			
Test Year (Forecast)	*2018*	Forecast	$ 812,155		

	Calendar Year (for 2018 Cost of Service)	Demand (kW)	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	*2012*	Actual	319,837	319,837		
Historical	*2013*	Actual	299,744	299,744	Board-approved	227,921
Historical	*2014*	Actual	305,696	305,696		
Historical	*2015*	Actual	207,631	207,631		
Historical	*2016*	Actual	285,018	285,018		
Bridge Year (Foreca	*2017*	Forecast		272,522		
Test Year (Forecast)	*2018*	Forecast		269,752		

	Calendar Year (for 2018 Cost of Service)	Demand (kW) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	*2012*	Actual				
Historical	*2013*	Actual			Board-approved	
Historical	*2014*	Actual				
Historical	*2015*	Actual				
Historical	*2016*	Actual				
Bridge Year (Foreca	*2017*	Forecast				
Test Year (Forecast)	*2018*	Forecast	0	0.33214411		

Variance Analysis

Year	Revenues Year-over-year	Test Year Versus Board-approved
2012		
2013		
2014		
2015		
2016		
2017		
2018		-11.5%
Geometric Mean		-3.0%

Year	Demand Year-over-year (Actual)	Year-over-year (Weather-normalized)	Test Year Versus Board-approved
2012			
2013	-6.3%	-6.3%	
2014	2.0%	2.0%	
2015	-32.1%	-32.1%	
2016	37.3%	37.3%	
2017		-4.4%	
2018		-1.0%	18.4%
Geometric Mean	-3.8%	-3.3%	4.3%

Year	Demand per Customer Year-over-year	Test Year Versus Board-approved
2012		
2013		
2014		
2015		
2016		
2017		
2018		
Geometric Mean		

4 Customer Class: Intermediate

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kW

	Calendar Year (for 2018 Cost of Service)	Customers			
Historical	2012	Actual	7		
Historical	2013	Actual	7	Board-approved	7
Historical	2014	Actual	7		
Historical	2015	Actual	7		
Historical	2016	Actual	7		
Bridge Year	2017	Forecast	7		
Test Year	2018	Forecast	6		

	Consumption (kWh) [3]			
	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	90258341.32	90258341.32		
Actual	89583306.36	89583306.36	Board-approved	69200000
Actual	89565187.66	89565187.66		
Actual	85452092.27	85452092.27		
Actual	74711534.26	74711534.26		
Forecast		84528325.19		
Forecast		76967386.17		

	Consumption (kWh) per Customer			
	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	12894049	12894048.8		
Actual	12797615	12797615.2	Board-approved	9885714.286
Actual	12795027	12795026.8		
Actual	12207442	12207441.8		
Actual	10673076	10673076.3		
Forecast	0	12075475		
Forecast	0	12827897.7		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2012		
	2013	0.0%	
	2014	0.0%	
	2015	0.0%	
	2016	0.0%	
	2017	0.0%	
	2018	-14.3%	-14.3%
	Geometric Mean	-3.0%	-3.8%

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	-0.7%	-0.7%	
2014	0.0%	0.0%	
2015	-4.6%	-4.6%	
2016	-12.6%	-12.6%	
2017		13.1%	
2018		-8.9%	11.2%
Geometric Mean	-6.1%	-3.1%	2.7%

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	-0.7%	-0.7%	
2014	0.0%	0.0%	
2015	-4.6%	-4.6%	
2016	-12.6%	-12.6%	
2017		13.1%	
2018		6.2%	29.8%
Geometric Mean	-6.1%	-0.1%	6.7%

	Calendar Year (for 2018 Cost of Service)	Revenues			
Historical	2012	Actual			
Historical	2013	Actual		Board-approved	584380.5991
Historical	2014	Actual			
Historical	2015	Actual			
Historical	2016	Actual			
Bridge Year (Foreca	2017	Forecast			
Test Year (Forecast)	2018	Forecast	$ 501,055		

	Demand (kW)			
	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	188608.4	188608.4		
Actual	186063.39	186063.39	Board-approved	123604
Actual	173701.3	173701.3		
Actual	203107.54	203107.54		
Actual	186368.7	186368.7		
Forecast		183627.9386		
Forecast		165381.7288		

	Demand (kW) per Customer			
	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual				
Actual			Board-approved	0.21151284
Actual				
Actual				
Actual				
Forecast				
Forecast	0	0.33006676		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2012		
	2013		
	2014		
	2015		
	2016		
	2017		
	2018		-14.3%
	Geometric Mean		-3.8%

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	-1.3%	-1.3%	
2014	-6.6%	-6.6%	
2015	16.9%	16.9%	
2016	-8.2%	-8.2%	
2017		-1.5%	
2018		-9.9%	33.8%
Geometric Mean	-0.4%	-2.6%	7.6%

Year	Year-over-year	Test Year Versus Board-approved
2012	Large User	
2013		
2014		
2015		
2016		
2017		
2018		56.1%
Geometric Mean		11.8%

5 **Customer Class:** Large User

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2018 Cost of Service)	Customers			
Historical	2012	Actual	1		
Historical	2013	Actual	1	Board-approved	1
Historical	2014	Actual	1		
Historical	2015	Actual	1		
Historical	2016	Actual	1		
Bridge Year	2017	Forecast	1		
Test Year	2018	Forecast	1		

Calendar Year	Consumption (kWh) [3]	Actual (Weather actual)	Weather-normalized		Weather-normalized
2012	Actual	94151552.84	94151552.84		
2013	Actual	94970952.53	94970952.53	Board-approved	97146783
2014	Actual	98447966.93	98447966.93		
2015	Actual	100676054.7	100676054.7		
2016	Actual	108025611.4	108025611.4		
2017	Forecast		98980672.79		
2018	Forecast		99199238.61		

Calendar Year	Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
2012	Actual	94151553	94151552.8		
2013	Actual	94970953	94970952.5	Board-approved	97146783
2014	Actual	98447967	98447966.9		
2015	Actual	100676055	100676055		
2016	Actual	108025611	108025611		
2017	Forecast	0	98980672.8		
2018	Forecast	0	99199238.6		

Variance Analysis

Year	Customers Year-over-year	Test Year Versus Board-approved
2012		
2013	0.0%	
2014	0.0%	
2015	0.0%	
2016	0.0%	
2017	0.0%	
2018	0.0%	0.0%
Geometric Mean	0.0%	0.0%

Year	Consumption Year-over-year (Actual)	Year-over-year (Weather-normalized)	Test Year Versus Board-approved
2012			
2013	0.9%	0.9%	
2014	3.7%	3.7%	
2015	2.3%	2.3%	
2016	7.3%	7.3%	
2017		-8.4%	
2018		0.2%	2.1%
Geometric Mean	4.7%	1.0%	0.5%

Year	Consumption per Customer Year-over-year (Actual)	Year-over-year (Weather-normalized)	Test Year Versus Board-approved
2012			
2013	0.9%	0.9%	
2014	3.7%	3.7%	
2015	2.3%	2.3%	
2016	7.3%	7.3%	
2017		-8.4%	
2018		0.2%	2.1%
Geometric Mean	4.7%	1.0%	0.4%

	Calendar Year (for 2018 Cost of Service)	Revenues			
Historical	2012	Actual			
Historical	2013	Actual		Board-approved	403635.7699
Historical	2014	Actual			
Historical	2015	Actual			
Historical	2016	Actual			
Bridge Year (Foreca	2017	Forecast			
Test Year (Forecast	2018	Forecast	$ 249,626		
					403635.7699

Calendar Year	Demand (kW)	Actual (Weather actual)	Weather-normalized		Weather-normalized
2012	Actual	160,412	160,412		
2013	Actual	163,430	163,430	Board-approved	160,146
2014	Actual	178,918	178,918		
2015	Actual	169,422	169,422		
2016	Actual	177,134	177,134		
2017	Forecast		171,751		
2018	Forecast		172,130		

Calendar Year	Demand (kW) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
2012	Actual				
2013	Actual			Board-approved	0.396758692
2014	Actual				
2015	Actual				
2016	Actual				
2017	Forecast				
2018	Forecast	0	0.68955453		

Variance Analysis

Year	Revenues Year-over-year	Test Year Versus Board-approved
2012		
2013		
2014		
2015		
2016		
2017		
2018		-38.2%
Geometric Mean		-9.2%

Year	Demand Year-over-year (Actual)	Year-over-year (Weather-normalized)	Test Year Versus Board-approved
2012			
2013	1.9%	1.9%	
2014	9.5%	9.5%	
2015	-5.3%	-5.3%	
2016	4.6%	4.6%	
2017		-3.0%	
2018		0.2%	7.5%
Geometric Mean	3.4%	1.4%	1.8%

Year	Demand per Customer Year-over-year	Test Year Versus Board-approved
2012		
2013		
2014		
2015		
2016		
2017		
2018		73.8%
Geometric Mean		14.8%

6 **Customer Class:** Unmetered Scattered Load

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2018 Cost of Service)	Customers			
Historical	2012	Actual	120		
Historical	2013	Actual	124	Board-approved	121
Historical	2014	Actual	121		
Historical	2015	Actual	128		
Historical	2016	Actual	126		
Bridge Year	2017	Forecast	128		
Test Year	2018	Forecast	130		
					121

	Calendar Year (for 2018 Cost of Service)	Consumption (kWh) [3]	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2012	Actual	513343	513343		
Historical	2013	Actual	539394	539394	Board-approved	618341
Historical	2014	Actual	535721	535721		
Historical	2015	Actual	537894	537894		
Historical	2016	Actual	504437	504437		
Bridge Year	2017	Forecast		510974.4468		
Test Year	2018	Forecast		517596.6182		
						618341

	Calendar Year (for 2018 Cost of Service)	Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2012	Actual	4289.7744	4289.77437		
Historical	2013	Actual	4361.6765	4361.67655	Board-approved	5110.256198
Historical	2014	Actual	4430.4976	4430.49759		
Historical	2015	Actual	4213.2689	4213.26893		
Historical	2016	Actual	3990.2729	3990.27291		
Bridge Year	2017	Forecast	0	3990.27291		
Test Year	2018	Forecast	0	3990.27291		
						5110.256198

Variance Analysis	Year	Customers Year-over-year	Customers Test Year Versus Board-approved	Consumption Year-over-year (Actual)	Consumption Year-over-year (Weather-normalized)	Consumption Test Year Versus Board-approved	Per Customer Year-over-year (Actual)	Per Customer Year-over-year (Weather-normalized)	Per Customer Test Year Versus Board-approved
	2012								
	2013	3.3%		5.1%	5.1%		1.7%	1.7%	
	2014	-2.2%		-0.7%	-0.7%		1.6%	1.6%	
	2015	5.6%		0.4%	0.4%		-4.9%	-4.9%	
	2016	-1.0%		-6.2%	-6.2%		-5.3%	-5.3%	
	2017	1.3%			1.3%			0.0%	
	2018	1.3%	7.2%		1.3%	-16.3%		0.0%	-21.9%
	Geometric Mean	1.6%	1.8%	-0.6%	0.2%	-4.3%	-2.4%	-1.4%	-6.0%

	Calendar Year (for 2018 Cost of Service)	Revenues			
Historical	2012	Actual			
Historical	2013	Actual		Board-approved	70,762
Historical	2014	Actual			
Historical	2015	Actual			
Historical	2016	Actual			
Bridge Year (Foreca	2017	Forecast			
Test Year (Forecast)	2018	Forecast	$ 45,133		
					70761.88856

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2012		
	2013		
	2014		
	2015		
	2016		
	2017		
	2018		-36.2%
	Geometric Mean		-10.6%

7 Customer Class: Sentinel Lighting

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kW

	Calendar Year (for 2018 Cost of Service)	Customers			
Historical	2012	Actual	301		
Historical	2013	Actual	248	Board-approved	301
Historical	2014	Actual	248		
Historical	2015	Actual	248		
Historical	2016	Actual	248		
Bridge Year	2017	Forecast	243		
Test Year	2018	Forecast	238		
					301

	Calendar Year	Consumption (kWh) [3]	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2012	Actual	280909.51	280909.51		
Historical	2013	Actual	272741.7	272741.7	Board-approved	274492
Historical	2014	Actual	266366.21	266366.21		
Historical	2015	Actual	246527.76	246527.76		
Historical	2016	Actual	231256.11	231256.11		
Bridge Year	2017	Forecast		226332.6068		
Test Year	2018	Forecast		221513.9263		
						274492

	Calendar Year	Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2012	Actual	933.25419	933.254186		
Historical	2013	Actual	1099.7649	1099.76492	Board-approved	911.9335548
Historical	2014	Actual	1074.0573	1074.0573		
Historical	2015	Actual	994.06355	994.063548		
Historical	2016	Actual	932.48431	932.484315		
Bridge Year	2017	Forecast	0	932.484315		
Test Year	2018	Forecast	0	932.484315		
						911.9335548

Variance Analysis	Year	Customers Year-over-year	Test Year Versus Board-approved
	2012		
	2013	-17.6%	
	2014	0.0%	
	2015	0.0%	
	2016	0.0%	
	2017	-2.1%	
	2018	-2.1%	-21.1%
	Geometric Mean	-4.6%	-5.7%

Year	Consumption Year-over-year (Actual)	Year-over-year (Weather-normalized)	Test Year Versus Board-approved
2012			
2013	-2.9%	-2.9%	
2014	-2.3%	-2.3%	
2015	-7.4%	-7.4%	
2016	-6.2%	-6.2%	
2017		-2.1%	
2018		-2.1%	-19.3%
Geometric Mean	-6.3%	-4.6%	-5.2%

Year	Consumption per Customer Year-over-year (Actual)	Year-over-year (Weather-normalized)	Test Year Versus Board-approved
2012			
2013	17.8%	17.8%	
2014	-2.3%	-2.3%	
2015	-7.4%	-7.4%	
2016	-6.2%	-6.2%	
2017		0.0%	
2018		0.0%	2.3%
Geometric Mean	0.0%	0.0%	0.6%

	Calendar Year (for 2018 Cost of Service)	Revenues			
Historical	2012	Actual			
Historical	2013	Actual		Board-approved	30336.56808
Historical	2014	Actual			
Historical	2015	Actual			
Historical	2016	Actual			
Bridge Year (Foreca	2017	Forecast			
Test Year (Forecast)	2018	Forecast	$ 46,128		
					30336.56808

	Calendar Year	Demand (kW)	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2012	Actual	643	643		
Historical	2013	Actual	647	647	Board-approved	772
Historical	2014	Actual	657	657		
Historical	2015	Actual	653	653		
Historical	2016	Actual	615	615		
Bridge Year (Foreca	2017	Forecast		586.5565816		
Test Year (Forecast)	2018	Forecast		574.0686383		
						772

	Calendar Year	Demand (kW) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2012	Actual				
Historical	2013	Actual			Board-approved	0.025447836
Historical	2014	Actual				
Historical	2015	Actual				
Historical	2016	Actual				
Bridge Year (Foreca	2017	Forecast				
Test Year (Forecast)	2018	Forecast	0	0.01244501		
						0.025447836

Variance Analysis	Year	Revenues Year-over-year	Test Year Versus Board-approved
	2012		
	2013		
	2014		
	2015		
	2016		
	2017		
	2018		52.1%
	Geometric Mean		11.0%

Year	Demand Year-over-year (Actual)	Year-over-year (Weather-normalized)	Test Year Versus Board-approved
2012			
2013	0.6%	0.6%	
2014	1.5%	1.5%	
2015	-0.6%	-0.6%	
2016	-5.8%	-5.8%	
2017		-4.6%	
2018		-2.1%	-25.6%
Geometric Mean	-1.5%	-2.2%	-7.1%

Year	Demand per Customer Year-over-year (Actual)	Year-over-year (Weather-normalized)	Test Year Versus Board-approved
2012			
2013			
2014			
2015			
2016			
2017			
2018			-51.1%
Geometric Mean			-16.4%

8 Customer Class: Street Lighting

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kW

	Calendar Year (for 2018 Cost of Service)	Customers			
Historical	*2012*	Actual	4,283		
Historical	*2013*	Actual	4,498	Board-approved	4283
Historical	*2014*	Actual	4,498		
Historical	*2015*	Actual	4,617		
Historical	*2016*	Actual	5,927		
Bridge Year	*2017*	Forecast	5,998		
Test Year	*2018*	Forecast	6,070		
					4283

Calendar Year	Consumption (kWh) [(3)]	Actual (Weather actual)	Weather-normalized		Weather-normalized
2012	Actual	3484987.18	3484987.18		
2013	Actual	2710401.72	2710401.72	Board-approved	2144934
2014	Actual	2115841.93	2115841.93		
2015	Actual	2025403.37	2025403.37		
2016	Actual	1938874.62	1938874.62		
2017	Forecast		1962132.443		
2018	Forecast		1985669.256		
					2144934

Calendar Year	Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
2012	Actual	813.67901	813.679005		
2013	Actual	602.57931	602.579306	Board-approved	500.8017745
2014	Actual	470.39616	470.396161		
2015	Actual	438.67594	438.67594		
2016	Actual	327.1258	327.125801		
2017	Forecast	0	327.125801		
2018	Forecast	0	327.125801		
					500.8017745

Variance Analysis

Year	Customers Year-over-year	Customers Test Year Versus Board-approved	Consumption Year-over-year (Actual)	Consumption Year-over-year (Weather-normalized)	Consumption Test Year Versus Board-approved	Per Customer Year-over-year (Actual)	Per Customer Year-over-year (Weather-normalized)	Per Customer Test Year Versus Board-approved
2012								
2013	5.0%		-22.2%	-22.2%		-25.9%	-25.9%	
2014	0.0%		-21.9%	-21.9%		-21.9%	-21.9%	
2015	2.6%		-4.3%	-4.3%		-6.7%	-6.7%	
2016	28.4%		-4.3%	-4.3%		-25.4%	-25.4%	
2017	1.2%			1.2%			0.0%	
2018	1.2%	41.7%		1.2%	-7.4%		0.0%	-34.7%
Geometric Mean	7.2%	9.1%	-17.8%	-10.6%	-1.9%	-26.2%	-16.7%	-10.1%

	Calendar Year (for 2018 Cost of Service)	Revenues			
Historical	*2012*	Actual			
Historical	*2013*	Actual		Board-approved	344,523
Historical	*2014*	Actual			
Historical	*2015*	Actual			
Historical	*2016*	Actual			
Bridge Year (Foreca	*2017*	Forecast			
Test Year (Forecast)	*2018*	Forecast	$ 287,342		
					344523.3009

Calendar Year	Demand (kW)	Actual (Weather actual)	Weather-normalized		Weather-normalized
2012	Actual	9969.15	9969.15		
2013	Actual	7517.93	7517.93	Board-approved	6753.5
2014	Actual	5900.04	5900.04		
2015	Actual	5564.23	5564.23		
2016	Actual	5228.83	5228.83		
2017	Forecast		5384.461132		
2018	Forecast		5449.050582		
					6753.5

Calendar Year	Demand (kW) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
2012	Actual				
2013	Actual			Board-approved	0.019602448
2014	Actual				
2015	Actual				
2016	Actual				
2017	Forecast				
2018	Forecast	0	0.01896367		
					0.019602448

Variance Analysis

Year	Revenues Year-over-year	Revenues Test Year Versus Board-approved	Demand Year-over-year (Actual)	Demand Year-over-year (Weather-normalized)	Demand Test Year Versus Board-approved	Per Customer Year-over-year	Per Customer Test Year Versus Board-approved
2012							
2013			-24.6%	-24.6%			
2014			-21.5%	-21.5%			
2015			-5.7%	-5.7%			
2016			-6.0%	-6.0%			
2017				3.0%			
2018		-16.6%		1.2%	-19.3%		-3.3%
Geometric Mean		-4.4%	-19.4%	-11.4%	-5.2%		-0.8%

9 Customer Class: Embedded Distributor

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kW

	Calendar Year (for 2018 Cost of Service)	Customers			
Historical	*2012*	Actual	3		
Historical	*2013*	Actual	4	Board-approved	3
Historical	*2014*	Actual	4		
Historical	*2015*	Actual	4		
Historical	*2016*	Actual	4		
Bridge Year	*2017*	Forecast	4		
Test Year	*2018*	Forecast	4		
					3

	Consumption (kWh) [3] Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	15488406.9	15488406.9		
Actual	15613194.55	15613194.55	Board-approved	17350000
Actual	16830475.1	16830475.1		
Actual	16494364	16494364		
Actual	16248812.1	16248812.1		
Forecast		16296711.44		
Forecast		16296711.44		
				17350000

	Consumption (kWh) per Customer Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	5162802.3	5162802.3		
Actual	3903298.6	3903298.64	Board-approved	5783333.333
Actual	4207618.8	4207618.78		
Actual	4123591	4123591		
Actual	4062203	4062203.03		
Forecast	0	4074177.86		
Forecast	0	4074177.86		
				5783333.333

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2012		
	2013	33.3%	
	2014	0.0%	
	2015	0.0%	
	2016	0.0%	
	2017	0.0%	
	2018	0.0%	33.3%
	Geometric Mean	5.9%	7.5%

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	0.8%	0.8%	
2014	7.8%	7.8%	
2015	-2.0%	-2.0%	
2016	-1.5%	-1.5%	
2017		0.3%	
2018		0.0%	-6.1%
Geometric Mean	1.6%	1.0%	-1.6%

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	-24.4%	-24.4%	
2014	7.8%	7.8%	
2015	-2.0%	-2.0%	
2016	-1.5%	-1.5%	
2017		0.3%	
2018		0.0%	-29.6%
Geometric Mean	-7.7%	-4.6%	-8.4%

	Calendar Year (for 2018 Cost of Service)	Revenues			
Historical	*2012*	Actual			
Historical	*2013*	Actual		Board-approved	170,676
Historical	*2014*	Actual			
Historical	*2015*	Actual			
Historical	*2016*	Actual			
Bridge Year (Foreca	*2017*	Forecast			
Test Year (Forecast)	*2018*	Forecast	$ 131,369		
					170675.7985

	Demand (kW) Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	36021.5	36021.5		
Actual	36253.2	36253.2	Board-approved	39284
Actual	36008.5	36008.5		
Actual	35856	35856		
Actual	36389.2	36389.2		
Forecast		34856.3983		
Forecast		34856.3983		
				39284

	Demand (kW) per Customer Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual				
Actual			Board-approved	0.230167372
Actual				
Actual				
Actual				
Forecast				
Forecast	0	0.26533149		
				0.230167372

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2012		
	2013		
	2014		
	2015		
	2016		
	2017		
	2018		-23.0%
	Geometric Mean		-6.3%

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	0.6%	0.6%	
2014	-0.7%	-0.7%	
2015	-0.4%	-0.4%	
2016	1.5%	1.5%	
2017		-4.2%	
2018		0.0%	-11.3%
Geometric Mean	0.3%	-0.7%	-2.9%

Year	Year-over-year	Test Year Versus Board-approved
2012		
2013		
2014		
2015		
2016		
2017		
2018		15.3%
Geometric Mean		3.6%

10 Customer Class:

Is the customer class billed on consumption (kWh) or demand (kW or kVA)?

	Calendar Year (for 2018 Cost of Service)	Customers			
Historical	*2012*	Actual		Board-approved	
Historical	*2013*	Actual			
Historical	*2014*	Actual			
Historical	*2015*	Actual			
Historical	*2016*	Actual			
Bridge Year	*2017*	Forecast			
Test Year	*2018*	Forecast			
					0

Consumption (kWh) [3]				
	Actual (Weather actual)	**Weather-normalized**		**Weather-normalized**
Actual			Board-approved	
Actual				
Actual				
Actual				
Actual				
Forecast				
Forecast				
				0

Consumption (kWh) per Customer				
	Actual (Weather actual)	**Weather-normalized**		**Weather-normalized**
Actual			Board-approved	
Actual				
Actual				
Actual				
Actual				
Forecast				
Forecast				
				0

Variance Analysis	**Year**	**Year-over-year**	**Test Year Versus Board-approved**
	2012		
	2013		
	2014		
	2015		
	2016		
	2017		
	2018		
	Geometric Mean		

Year	**Year-over-year**	**Test Year Versus Board-approved**
2012		
2013		
2014		
2015		
2016		
2017		
2018		
Geometric Mean		

Year	**Year-over-year**	**Test Year Versus Board-approved**
2012		
2013		
2014		
2015		
2016		
2017		
2018		
Geometric Mean		

	Calendar Year (for 2018 Cost of Service)	Revenues			
Historical	*2012*	Actual		Board-approved	
Historical	*2013*	Actual			
Historical	*2014*	Actual			
Historical	*2015*	Actual			
Historical	*2016*	Actual			
Bridge Year (Foreca	*2017*	Forecast			
Test Year (Forecast	*2018*	Forecast			
					0

	Actual (Weather actual)	**Weather-normalized**		**Weather-normalized**
Actual			Board-approved	
Actual				
Actual				
Actual				
Actual				
Forecast				
Forecast				
				0

Demand () per Customer				
	Actual (Weather actual)	**Weather-normalized**		**Weather-normalized**
Actual			Board-approved	
Actual				
Actual				
Actual				
Actual				
Forecast				
Forecast				
				0

Variance Analysis	**Year**	**Year-over-year**	**Test Year Versus Board-approved**
	2012		
	2013		
	2014		
	2015		
	2016		
	2017		
	2018		
	Geometric Mean		

Year	**Year-over-year**	**Test Year Versus Board-approved**
2012		
2013		
2014		
2015		
2016		
2017		
2018		
Geometric Mean		

Year	**Year-over-year**	**Test Year Versus Board-approved**
2012		
2013		
2014		
2015		
2016		
2017		
2018		
Geometric Mean		

Note: If there are more than ten (10) customer classes, please contact OEB Staff to add tables for additional customer classes.

Attachment 3 (of 7):

3-C Maple Leafs Foods Closing

NEWS WOODSTOCK & REGION

Agreement reached in Thamesford Maple Leaf turkey plant closure

By Bruce Chessell, Woodstock Sentinel-Review
Wednesday, February 1, 2017 9:51:40 EST AM

More Coverage

- **Maple Leaf announces closure of Thamesford plant**

A closure agreement for 350 employees at the Thamesford turkey processing plant was reached Monday.

LiUNA Local 3000 ratified a closure agreement with Maple Leaf Foods Moday, following a lengthy negotiation process. Maple Leaf Foods announced last November that it would be closing its Thamesford turkey processing plant as the work would move to a new Sofina facility in Mitchell, Ont.

Business representative of LiUNA 3000 Ken Sharpe said the agreement was reached after several days of negotiations.

“After several days of negotiations we managed to hammer out a closer agreement that was ratified by about 85 per cent,” Sharpe said. “The majority of the membership was in attendance yesterday and it was ratified by 85 to 88 per cent yes and 13 per cent no.”

Sharpe said he couldn’t talk about the particulars of the agreement, adding that he was only able to say they reached a deal that was better than the Employment Standards Act.

The closure agreement will provide enhanced severance payments for active and inactive employees, a production bonus recognizing employees’ years of service and commitment to the operation of the plant, a continuation of benefits, the ability to convert benefits to private coverage and substantial contributions to career transition services for the purpose of assisting employees displaced by the closure of the plant.

Business manager of LiUNA 3000 Ann Waller said in a release that, “While we are still absorbing the full impact of the projected closure of the Thamesford turkey processing plant, we have worked hard to achieve a closure agreement that will ensure our members are secure in the knowledge that they will receive enhanced severance provisions and continued benefit coverage, as well as support, training and education through career transition services when the plant ultimately closes in 2018.

“Of course,” she added, “it continues to be our hope that these union jobs will not disappear and that our members will follow the work to another facility.”

The plant is expected to start phase one of its layoffs in spring, laying 30 to 60 workers. The plant is expected to stay open until the early part of 2018.

Attachment 4 (of 7):

3-D Cami Ingersoll Slashing 600 Jobs

NEWS LOCAL

Cami Ingersoll slashing 600 jobs, moving Terrain production to Mexico

By Norman De Bono, The London Free Press
Friday, January 27, 2017 10:34:18 EST AM

(MIKE HENSEN, The London Free Press)

After eight years of pushing workers for six days a week, Cami Assembly is slashing 600 jobs.

The Ingersoll assembly plant is shipping production of its GMC Terrain crossover utility vehicle to Mexico in July, forcing jobs

losses here. "I don't know why they are doing this. We are the No. 1 plant in North America according to the Harbord Report,

we are the most efficient a
they are making record profits," said Mike Van Boekel, chairperson of Unifor Local 88.

Unifor, the union which represents Cami workers, will meet with the company Monday to begin talks on mitigating the cuts. GM Canada, which operates Cami, will offer buyouts and retirement packages, he added.

The move will also end overflow production of its Chevy Equinox vehicle at GM Canada's Oshawa assembly plant.

"Our members are furious, they are pissed off. We have been working six days a week for eight years and now this. We have done everything they have asked of us. It is terrible," said Van Boekel.

Cami, began production of its new, revamped Equinox Jan. 9.

Unifor has 2,800 workers now at the plant, and another 300 are non-union salaried positions.

The company and union will begin talks later this year on a new collective agreement.

The Harbord Report measures plant production and efficiency.

Attachment 5 (of 7):

3-E OEB Appendix 2-I

File Number:	2017-0038
Exhibit:	3
Tab:	1
Schedule:	3
Page:	
Date:	06-Sep-17

Appendix 2-I
Load Forecast CDM Adjustment Work Form (2018)

Appendix 2-I was initially developed to help determine what would be the amount of CDM savings needed in each year to cumulatively achieve the four year 2011-2014 CDM target. This then

2018 is the fourth year of the six-year (2015-2020) Conservation First program. Final results for the 2011-14 program were issued in the fall of 2015, and the programis completed, although in

The new six year (2015-2020) CDM program works in a slightly different manner to the previous 2011-2014 CDM program. Distributors will offer programs each year that, over the six years (from

2015-2020 CDM Program - 2018 fourth year of the current CDM plan

For the first year of the new 2015-2020 CDM plan, it is assumed that each year's program will achieve an equal amount of new CDM savings. This results in each year's program being about 1/6

6 Year (2015-2020) kWh Target:							
27,630,000							
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**Total**
%							
2015 CDM Programs						18.75%	18.75%
2016 CDM Programs						16.25%	16.25%
2017 CDM Programs						16.25%	16.25%
2018 CDM Programs						16.25%	16.25%
2019 CDM Programs						16.25%	16.25%
2020 CDM Programs						16.25%	16.25%
Total in Year						**100.00%**	**100.00%**
kWh							
2015 CDM Programs	5,180,177.00	5,180,177.00	5,180,177.00	5,180,177.00	5,180,177.00	5,180,177.00	5,180,177.00
2016 CDM Programs		4,489,964.60	4,489,964.60	4,489,964.60	4,489,964.60	4,489,964.60	4,489,964.60
2017 CDM Programs			4,489,964.60	4,489,964.60	4,489,964.60	4,489,964.60	4,489,964.60
2018 CDM Programs				4,489,964.60	4,489,964.60	4,489,964.60	4,489,964.60
2019 CDM Programs					4,489,964.60	4,489,964.60	4,489,964.60
2020 CDM Programs						4,489,964.60	4,489,964.60
Total in Year	**5,180,177.00**	**9,670,141.60**	**14,160,106.20**	**18,650,070.80**	**23,140,035.40**	**27,630,000.00**	**27,630,000.00**

Note: The default formulae in the above table assume that the 2015-2020 kWh CDM target is achieved through persistence of CDM savings to the end of 2020. The distributor should enter

Determination of 2018 Load Forecast Adjustment

The Board determined that the "net" number should be used in its Decision and Order with respect to Centre Wellington Hydro Ltd.'s 2013 Cost of Service rates (EB-2012-0113). This approach

From each of the 2006-2010 CDM Final Report, and the 2011 to 2016 CDM Final Reports, issued by the OPA/IESO for the distributor, the distributor should input the "gross" and "net" results of

Net-to-Gross Conversion				
Is CDM adjustment being done on a "net" or "gross" basis?				**net**
Persistence of Historical CDM programs to 2015	**"Gross" kWh**	**"Net" kWh**	**Difference kWh**	**"Net-to-Gross" Conversion Factor ('g')**
2006-2010 CDM programs				
2011 CDM program				
2012 CDM program				
2013 CDM program				
2014 CDM program				
2015 CDM program				
2016 CDM program				
2006 to 2016 OPA CDM programs: Persistence to 2018.	0	0	0	0.00%

The default values below represent the factor used for how each year's CDM program is factored into the manual CDM adjustment. Distributors can choose alternative weights of "0", "0.5" or

These factors do not mean that CDM programs are excluded, but the assumption that impacts of previous year CDM programs are already implicitly reflected in the actual data for historical

Weight Factor for Inclusion in CDM Adjustment to 2018 Load Forecast

	2015	2016	2017	2018	2019	2020	
Weight Factor for each year's CDM program impact on 2018 load forecast	**0**	**0.5**	**1**	**0.5**	**0**	**0**	Distributor can select "0", "0.5", or "1" from drop-down list
Default Value selection rationale.	*Full year impact of 2015 CDM is assumed to be reflected in the base forecast, as the full year persistence of 2015 CDM programs is in the 2016 historical actual data. No further impact is necessary for the manual adjustment to the load forecast.*	*Default is 0.5, but one option is for full year impact of persistence of 2016 CDM programs on 2018 load forecast, but 50% impact in base forecast (first year impact of 2016 CDM programs on 2016 actuals, which is part of the data underlying the base load forecast).*	*Full year impact of persistence of 2017 programs on 2018 load forecast. 2017 CDM program impacts are not in the base forecast.*	*Only 50% of 2017 CDM programs are assumed to impact the 2018 load forecast based on the "half-year" rule.*	*2019 and 2020 are future years beyond the 2018 test year. No impacts of CDM programs beyond the 2018 test year are factored into the test year load forecast.*		

2015-2020 LRAMVA and 2018 CDM adjustment to Load Forecast

One manual adjustment for CDM impacts to the 2018 load forecast is made. There is a different but related threshold amount that is used for the 2018 LRAMVA amount for Account 1568.

The amount used for the CDM threshold of the LRAMVA is the kWh that will be used to determine the base amount for the LRAMVA balance for 2018, for assessing performance against the six-year target.

If used to determine the manual CDM adjustment for the system purchased kWh, the proposed loss factor should correspond with the proposed total loss factor calculated in Appendix 2-R .

The Manual Adjustment for the 2018 Load Forecast is the amount manually subtracted from the system-wide load forecast (either based on a purchased or billed basis) derived from the base forecast from historical data. If the distributor has developed their load forecast on a system purchased basis, then the manual adjustment should be on a system purchased basis, including the adjustment for losses. If the load forecast has been developed on a billed basis, either on a system basis or on a class-specific basis, the manual adjustment should be on a billed basis, excluding losses.

The distributor should determine the allocation of the savings to all customer classes in a reasonable manner (e.g. taking into account what programs and what IESO-measured impacts were directed at specific customer classes), for both the LRAMVA and for the load forecast adjustment.

	2015	2016	2017	2018	2019	2020	Total for 2018
Amount used for CDM threshold for LRAMVA (2018)	5,180,177.00	4,489,964.60	4,489,964.60	4,489,964.60			**18,650,070.80**
Manual Adjustment for 2018 Load Forecast (billed basis)	-	2,244,982.30	4,489,964.60	2,244,982.30			8,979,929.20
Manual Adjustment for 2018 LDC-only CDM programs (billed basis)							
Total Manual Forecast to Load Forecast	-	2,244,982.30	4,489,964.60	2,244,982.30			**8,979,929.20**
Proposed Loss Factor (TLF)	3.25%	Format: X.XX%					
Manual Adjustment for 2018 Load Forecast (system purchased basis)	-	2,317,944.22	4,635,888.45	2,317,944.22			**9,271,776.90**

Manual adjustment uses "gross" versus "net" (i.e. numbers multiplied by (1 + g). The Weight factor is also used to calculate the impact of each year's program on the CDM adjustment to the

Attachment 6 (of 7):

3-F Appendix 2-H Other Operating Revenue

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Appendix 2-H
Other Operating Revenue

USoA #	USoA Description	2013 Actual²	2014 Actuals		2015 Actual²	Actual Year	Bridge Year	Test Year
		2013	2014 CGAAP	2014 MIFRS	2015	2016	2017	2018
	Reporting Basis							
4235	**Specific Service Charges**	$ 113,885	$ 113,765	$ 113,765	$ 103,720	$ 105,040	$ 87,100	$ 98,162
4225	**Late Payment Charges**	$ 117,342	$ 109,435	$ 109,435	$ 112,834	$ 134,656	$ 138,978	$ 145,947
4082	**Retail Services Revenues**	$ 16,280	$ 14,815	$ 14,815	$ 18,983	$ 14,779	$ 13,067	$ 14,727
etc.								
Specific Service Charges		$ 113,885	$ 113,765	$ 113,765	$ 103,720	$ 105,040	$ 87,100	$ 98,162
Late Payment Charges		$ 117,342	$ 109,435	$ 109,435	$ 112,834	$ 134,656	$ 138,978	$ 145,947
Other Operating Revenues		$ 201,274	$ 190,335	$ 190,335	$ 216,541	$ 252,086	$ 210,965	$ 230,879
Other Income or Deductions		$ 22,904	$ 40,750	$ 40,750	$ 36,628	$ 64,800	$ 17,692	$ 19,460
Total		$ 455,405	$ 454,285	$ 454,285	$ 469,723	$ 556,582	$ 454,735	$ 494,448

Description	Account(s)
Specific Service Charges:	4235
Late Payment Charges:	4225
Other Distribution Revenues:	4080, 4082, 4084, 4090, 4205, 4210, 4215, 4220, 4240, 4245
Other Income and Expenses:	4305, 4310, 4315, 4320, 4325, 4330, 4335, 4340, 4345, 4350, 4355, 4360, 4365, 4370, 4375, 4380, 4385, 4390, 4395, 4398, 4405, 4415

Note: Add all applicable accounts listed above to the table and include all relevant information.

Account Breakdown Details

For each "Other Operating Revenue" and "Other Income or Deductions" Account, a detailed breakdown of the account components is required. See the example below for Account 4405, Interest and Dividend Income.

	2013 Actual²	2014 Actuals		2015 Actual²	Actual Year	Bridge Year	Test Year
	2013	2014 CGAAP	2014 MIFRS	2015	2016	2017	2018
Reporting Basis							
SSS ADMIN CHG RESIDENTL	$ 64,324	$ 6,426	$ 64,246	$ 64,288	$ 66,019	$ 57,503	$ 57,929
Total	$ 64,324	$ 6,426	$ 64,246	$ 64,288	$ 66,019	$ 57,503	$ 57,929

Notes:

1 List and specify any other interest revenue.

2 In the transition year to IFRS, the applicant is to present information in both MIFRS and CGAAP. For the typical applicant that adopted IFRS on January 1, 2015, 2014 must be presented in both a CGAAP and MIFRS basis.

	2013 Actual²	2014 Actuals		2015 Actual²	Actual Year	Bridge Year	Test Year
	2013	2014 CGAAP	2014 MIFRS	2015	2016	2017	2018
Reporting Basis							
RETAIL SERVCE REV-RETAIL	$ 16,280	$ 14,815	$ 14,815	$ 18,983	$ 14,779	$ 13,067	$ 14,727
Total	$ 16,280	$ 14,815	$ 14,815	$ 18,983	$ 14,779	$ 13,067	$ 14,727

Notes:
1 List and specify any other interest revenue.
2 In the transition year to IFRS, the applicant is to present information in both MIFRS and CGAAP. For the typical applicant that adopted IFRS on January 1,

	2013 Actual²	2014 Actuals		2015 Actual²	Actual Year	Bridge Year	Test Year
	2013	2014 CGAAP	2014 MIFRS	2015	2016	2017	2018
Reporting Basis							
SERVC STR REQUEST FEE	$ 7,640	$ 7,070	$ 7,070	$ 8,670	$ 6,461	$ 5,548	$ 6,252
Total	$ 7,640	$ 7,070	$ 7,070	$ 8,670	$ 6,461	$ 5,548	$ 6,252

Notes:
1 List and specify any other interest revenue.
2 In the transition year to IFRS, the applicant is to present information in both MIFRS and CGAAP. For the typical applicant that adopted IFRS on January 1,

	2013 Actual²	2014 Actuals		2015 Actual²	Actual Year	Bridge Year	Test Year
	2013	2014 CGAAP	2014 MIFRS	2015	2016	2017	2018
Reporting Basis							
RENT FR EL PROP-POLE RENT	$ 103,071	$ 104,877	$ 104,877	$ 92,904	$ 103,987	$ 117,382	$ 132,289
Total	$ 103,071	$ 104,877	$ 104,877	$ 92,904	$ 103,987	$ 117,382	$ 132,289

Notes:
1 List and specify any other interest revenue.
2 In the transition year to IFRS, the applicant is to present information in both MIFRS and CGAAP. For the typical applicant that adopted IFRS on January 1,

	2013 Actual²	2014 Actuals		2015 Actual²	Actual Year	Bridge Year	Test Year
	2013	2014 CGAAP	2014 MIFRS	2015	2016	2017	2018
Reporting Basis							
SALE OF STOCK	$ 3,138	$ 6,987	$ 6,987	$ 11,477	$ 4,863	$ 8,676	$ 9,778
Total	$ 3,138	$ 6,987	$ 6,987	$ 11,477	$ 4,863	$ 8,676	$ 9,778

Notes:
1 List and specify any other interest revenue.
2 In the transition year to IFRS, the applicant is to present information in both MIFRS and CGAAP. For the typical applicant that adopted IFRS on January 1,

	2013 Actual²	2014 Actuals		2015 Actual²	Actual Year	Bridge Year	Test Year
	2013	2014 CGAAP	2014 MIFRS	2015	2016	2017	2018
Reporting Basis							
GAIN ON DISPOSAL	$ 6,821	$ -	$ -	$ 20,219	$ 65,702	$ 8,789	$ 9,905
Total	$ 6,821	$ -	$ -	$ 20,219	$ 65,702	$ 8,789	$ 9,905

Notes:
1 List and specify any other interest revenue.
2 In the transition year to IFRS, the applicant is to present information in both MIFRS and CGAAP. For the typical applicant that adopted IFRS on January 1,

	2013 Actual²	2014 Actuals		2015 Actual²	Actual Year	Bridge Year	Test Year
	2013	2014 CGAAP	2014 MIFRS	2015	2016	2017	2018
Reporting Basis							
NON UTILITY INCOME & EXPENSE	$ 22,904	$ 22,329	$ 22,329	$ 22,194	$ 16,139	$ 14,567	$ 16,417
Total	$ 22,904	$ 22,329	$ 22,329	$ 22,194	$ 16,139	$ 14,567	$ 16,417

Notes:

1 List and specify any other interest revenue.

2 In the transition year to IFRS, the applicant is to present information in both MIFRS and CGAAP. For the typical applicant that adopted IFRS on January 1,

Attachment 7 (of 7):

3-G CDM Plan

OVERVIEW OF CDM PLAN
This CDM Plan must be used by the LDC in submitting a CDM Plan to the IESO under the Energy Conservation Agreement between the LDC and the IESO The CDM Plan will consist of the information provided in this document and any additional information and supporting documents provided by the LDC to the IESO in support of this CDM Plan. Capitalized terms not otherwise defined herein have the meaning ascribed to them in the Energy Conservation Agreement as may be applicable.
Complete all fields within the CDM Plan that are applicable. Where additional space is required to complete a section of the CDM Plan, please append additional pages as required. The LDC should indicate that additional information has been attached in the related question field on the CDM Plan. Please refer to the CDM Plan Submission and Review Criteria Rules for further information.

A. General Information

1.

CDM Plan Submission Date: ***(DD-Mon-YYYY)***	28-Jun-2017
CDM Plan Version	Initial Submission

2.

LDC INFORMATION	LDC 1	LDC 2	LDC 3	LDC 4	LDC 5	LDC 6	LCD 7	LCD 8	LCD 9	LCD 10
LDC Name:	Alectra Utilities	COLLUS PowerStream Corp.	Erie Thames Powerlines Corporation							
Company Representative:										
Name:	Raegan Bond	Cindy Shuttleworth	Tim Collins							
Title:	Vice President									
Email Address:	raegan.bond@alectrautilities.com	Cindy Shuttleworth;	timcollins@eriethamespower.com							
Phone Number (XXX-XXX-XXXX):	905-532-4540									

3.

Primary Contact for CDM Plan	
Name:	Raegan Bond
LDC Name:	Alectra Utilities Corporation
Title:	Vice President, CDM
Email Address:	raegan.bond@alectrautilities.com
Phone Number (XXX-XXX-XXXX):	905-532-4540

Estimated Start Date of CDM Plan: ***(DD-Mon-YYYY)***	1-Jul-2015

LDC CONFIRMATION FOR CDM PLAN	
Each LDC to this CDM Plan has executed the Energy Conservation Agreement.	Yes
A completed Cost-Effectiveness Tool is attached and forms part of the CDM Plan.	Yes
A completed Achievable Potential Tool is attached and forms part of the CDM Plan.	Yes
All customer segments in each LDC's service area are served by the Programs set out in this CDM Plan.	Yes
The CDM Plan includes all electricity savings attributable to all Programs and pilot programs that have in-service dates between Jan 1, 2015 and December 31, 2020.	Yes
The CDM Plan Budget for each LDC includes all eligible funding under the full cost recovery and pay-for-performance mechanisms for Programs under its CDM Plan.	Yes
Frequency of LDC Invoicing to IESO (subsequent changes to the frequency should be notified to us by email).	Monthly

COMPLETE FOR CDM PLAN AMENDMENTS ONLY		
Select the reason(s) for CDM Plan amendment, as per ECA.		
One time each calendar year of the term		Yes
LDC wishes to request an adjustment to the CDM Plan Budget		
The amendments to a provision of the ECA or any Rules will have a material effect on the CDM Plan		
LDC's actual spending under CDM Plan has exceeded (or is reasonably expected to exceed) the portion of the CDM Plan Budget allocated to the current year of the term		
Under a joint CDM Plan, LDCs that are parties to a joint CDM Plan reallocate any portion of their respective CDM Plan Targets and CDM Plan Budgets [*Reallocation not subject to IESO approval*]		
IESO has triggered remedies under Article 5 of the ECA		
LDC seeking to change its selection of the type of funding that it wishes to receive for each Program in the CDM Plan [ECA, section 4.1]		Yes
Other (Please specify reason)	Resubmission of the Joint CDM Plan due to the Merger and formation of Alectra Utilities	Yes

B. LDC Authorization

LDC DECLARATION
Please complete the declaration for each LDC that is listed in this CDM Plan. A separate page with each LDC's signed declaration should be included as part of the CDM Plan submission.

LDC	
I represent that the information contained in this CDM Plan as it relates to the LDC is complete, true, and accurate in all respects. I acknowledge and agree to the following terms and conditions: (1) if this CDM Plan is approved by the IESO and accepted by each LDC to this CDM Plan, the CDM Plan together with any conditions to that approval is incorporated by reference into the Energy Conservation Agreement between the LDC and the IESO (2) the LDC will offer the Programs set out in Table 2 of this CDM Plan to customers in its service area; and (3) the LDC of will implement this CDM Plan in accordance with the CDM Plan Budget.	
LDC's Legal Name:	Alectra Utilities Corporation
Company Representative:	Raegan Bond
Signature	
	I/We have the authority to bind the Corporation.
Date (DD-Mon-YYYY)	

B. LDC Authorization

LDC DECLARATION
Please complete the declaration for each LDC that is listed in this CDM Plan. A separate page with each LDC's signed declaration should be included as part of the CDM Plan submission.

LDC	
I represent that the information contained in this CDM Plan as it relates to the LDC is complete, true, and accurate in all respects. I acknowledge and agree to the following terms and conditions: (1) if this CDM Plan is approved by the IESO and accepted by each LDC to this CDM Plan, the CDM Plan together with any conditions to that approval is incorporated by reference into the Energy Conservation Agreement between the LDC and the IESO (2) the LDC will offer the Programs set out in Table 2 of this CDM Plan to customers in its service area; and (3) the LDC of will implement this CDM Plan in accordance with the CDM Plan Budget.	
LDC's Legal Name:	Collus PowerStream
Company Representative:	
Signature	
	I/We have the authority to bind the Corporation.
Date (DD-Mon-YYYY)	

B. LDC Authorization

LDC DECLARATION
Please complete the declaration for each LDC that is listed in this CDM Plan. A separate page with each LDC's signed declaration should be included as part of the CDM Plan submission.

LDC	
I represent that the information contained in this CDM Plan as it relates to the LDC is complete, true, and accurate in all respects. I acknowledge and agree to the following terms and conditions: (1) if this CDM Plan is approved by the IESO and accepted by each LDC to this CDM Plan, the CDM Plan together with any conditions to that approval is incorporated by reference into the Energy Conservation Agreement between the LDC and the IESO (2) the LDC will offer the Programs set out in Table 2 of this CDM Plan to customers in its service area; and (3) the LDC of will implement this CDM Plan in accordance with the CDM Plan Budget.	
LDC's Legal Name:	Erie Thames Powerlines Corporation
Company Representative:	Chris White - President
Signature	
	I/We have the authority to bind the Corporation.
Date (DD-Mon-YYYY)	23-06-2017

C. CDM Plan Summary

TABLE 1: SUMMARY OF CDM PORTFOLIO SAVINGS AND BUDGET

		CDM PLAN TOTAL	LDC 1	LDC 2	LDC 3	LDC 4	LDC 5	LCD 6	LCD 7	LCD 8	LCD 9	LCD 10
a.	**Allocated LDC CDM Plan Target (MWh)** *Indicate total CDM Plan Target allocated to LDC(s)*	**1,649,040**	1,604,550.0	16,860.0	27,630.0							
b.	**CDM Plan MWh Savings** *Calculated as part of CDM Plan*	**1,854,844**	1,786,676	17,179	50,989	0	0	0	0	0	0	0
c.	**Allocated LDC CDM Plan Budget ($)** *Indicate total budget allocated to LDC*	**$426,376,273**	$414,824,478.00	$4,446,841.00	$7,104,954.00							
d.	**Total CDM Plan Budget ($)** *Calculated as part of CDM Plan*	**$424,304,018**	$411,937,861	4,446,841	7,919,315	0	0	0	0	0	0	0

f.	**CDM Plan Cost Effectiveness** *Indicate annual portfolio-level Cost Effectiveness for CDM Plan as determined by LDC(s) using output from Cost-Effectiveness Tool*		Total Resource Cost (TRC)			Program Administrator Cost (PAC)			Levelized Cost
		Program Year	**Benefits ($)**	**Costs ($)**	**Ratio**	**Benefits ($)**	**Costs ($)**	**Ratio**	**($/kWh)**
		2015	$61,938,472.52	$17,396,808.79	3.6	$51,307,597.06	$7,655,212.28	6.7	$0.010
		2016	$59,388,637.28	$31,997,750.52	1.9	$51,617,652.37	$26,981,895.98	1.9	$0.030
		2017	$72,926,075.88	$38,050,257.82	1.9	$63,389,338.11	$29,433,733.08	2.2	$0.027
		2018	$67,020,778.20	$46,469,072.34	1.4	$58,254,296.65	$25,116,892.94	2.3	$0.024
		2019	$69,819,655.78	$43,962,617.78	1.6	$60,688,103.24	$24,327,499.68	2.5	$0.023
		2020	$67,586,998.73	$42,918,790.15	1.6	$58,746,662.32	$23,871,770.16	2.5	$0.025
		CDM Plan Total	**$398,680,618**	**$220,795,297**	1.8	**$344,003,650**	**$137,387,004**	2.5	**$0.023**

g	**Plan Cost Effectiveness-Exceptions Rationale** *Complete this section if proposed plan <u>does not</u> meet minimum Cost-Effectiveness Thresholds set out in CDM Plan Submission and Review Criteria Rules.*	

D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the IESO could only be achieved with funding in addition to the CDM Plan Budget.

LDC 1:	Alectra Utilities

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Customer Segments Targeted by Program							Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)													
												2015		2016		2017		2018		2019		2020		Total 2015 - 2020	
					Residential	Low-income	Small business	Commercial (inc. Multi-F	Agricultural	Institutional	Industrial	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Total CDM Plan Budget ($)	Total Persisting Energy Savings in 2020 (MWh)
Full Cost Recovery Programs	Save on Energy Audit			1-Jul-2015			Yes	Yes	Yes	Yes	Yes	$107,967	660.4	$956,701	1,353.7	$559,083	1,682.3	$633,532	1,932.0	$640,155	1,932.0	$321,319	972.6	$3,218,757	8,532.9
	Save on Energy Coupon			1-Jul-2015	Yes	Yes						$1,947,536	11,596.3	$7,692,721	80,341.8	$4,858,797	10,729.9	$0	0.0	$0	0.0	$0	0.0	$14,499,054	102,563.9
	Save on Energy Energy Manager Program			1-Jan-2016				Yes	Yes	Yes	Yes	$200,582	0.0	$476,252	4,976.2	$1,866,468	2,005.9	$3,000,700	3,302.5	$3,593,046	3,807.7	$4,641,949	4,312.8	$13,778,997	17,604.1
	Save on Energy Existing Building Commissioning Program			1-Jul-2015				Yes		Yes	Yes	$0	0.0	$2,073	0.0	$55,719	86.2	$55,535	86.2	$75,522	172.3	$77,761	172.3	$266,611	517.0
	Save on Energy Heating and Cooling Program			1-Jul-2015	Yes							$3,045,644	5,485.0	$9,942,532	17,519.6	$8,769,784	21,595.4	$4,643,916	13,557.7	$3,196,353	8,492.8	$3,083,570	7,391.9	$32,681,799	74,042.3
	Save on Energy High Performance New Construction Program			1-Jan-2016			Yes	Yes	Yes	Yes	Yes	$389,213	2,273.8	$1,873,031	7,788.9	$2,623,753	14,631.4	$612,531	1,596.6	$1,089,203	3,772.9	$1,383,957	4,509.1	$7,971,688	34,572.8
	Save on Energy Home Assistance Program			1-Jan-2016		Yes						$21,398	0.0	$630,270	928.9	$1,361,555	1,327.6	$2,662,226	2,655.3	$2,671,330	2,655.3	$2,705,820	2,655.3	$10,052,598	10,222.4
	Save on Energy Instant Discount Program			1-Oct-2017	Yes							$0	0.0	$0	0.0	$2,263,403	10,561.3	$3,994,844	19,297.3	$1,214,716	3,049.1	$1,214,195	2,738.0	$8,687,158	35,645.6
	Save on Energy Monitoring & Targeting Program			1-Jan-2016							Yes	$0	0.0	$10,120	0.0	$168,272	92.8	$242,936	463.9	$218,086	742.2	$215,524	371.1	$854,938	1,669.9
	Save on Energy New Construction Program			1-Jan-2016	Yes							$41,514	0.0	$692,651	847.4	$904,068	4,845.9	$891,813	4,804.8	$891,484	4,763.8	$911,193	4,722.7	$4,332,723	19,984.6
	Save on Energy Process & Systems Upgrades Program FCR			1-Jan-2016							Yes	$793,210	2,759.2	$1,566,259	798.2	$1,778,223	2,820.3	$9,841,254	37,318.5	$20,003,849	78,029.2	$13,542,008	57,274.4	$47,524,803	178,999.8
	Business Refrigeration Incentive Program			1-Jan-2016			Yes					$10,556	0.0	$905,385	1,013.5	$3,214,655	5,040.2	$2,211,308	3,450.6	$1,111,808	1,725.3	$565,992	860.7	$8,019,703	9,884.6
	Save on Energy Retrofit Program Enabled Savings			1-Jan-2016			Yes	Yes	Yes	Yes	Yes	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0		0.0
	Save on Energy Retrofit Program FCR			1-Jul-2015			Yes	Yes	Yes	Yes	Yes	$6,846,545	25,153.4	$22,166,863	121,732.1	$9,404,170	43,372.2	$1,710,328	8,570.8	$1,394,715	7,285.2	$946,591	4,371.1	$42,469,212	207,811.3
	Save on Energy Small Business Lighting Program			1-Jan-2016			Yes					$63,818	0.0	$1,363,779	241.4	$1,703,504	4,135.8	$1,691,183	4,135.8	$998,592	2,412.6	$521,299	1,206.3	$6,342,173	12,102.3
		Social Benchmarking Conservation Fund Pilot Program		1-Jul-2015	Yes							$0	2,978.7	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0		0.0
		Social Benchmarking Program		1-Jan-2016	Yes							$0	0.0	$3,164,196	15,112.4	$3,283,404	12,814.6	$2,794,988	35,147.5	$3,602,516	41,731.3	$3,724,680	43,391.5	$16,569,784	57,993.9
		Solar-Powered Attic Vent Pilot		1-Jan-2016	Yes							$0	0.0	$0	199.4	$0	0.0	$0	0.0	$0	0.0	$0	0.0		199.4
		Strategic Energy Group Conservation Fund Pilot Program		1-Jul-2015								$0	9,195.8	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0		0.0
		Truckload Event Pilot Program		1-Jan-2016								$0	0.0	$325,005	2,236.2	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$325,005	2,236.2
		Whole Home Pilot Program		1-Aug-2017								$0	0.0	$0	0.0	$0	1,399.8	$0	0.0	$0	0.0	$0	0.0		1,399.8
		Loblaw P4P Conservation Fund Pilot Program		1-Jul-2015			Yes	Yes				$0	1,085.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0		1,085.0
		EnerNOC Conservation Fund Pilot Program		1-Jul-2015			Yes	Yes				$0	130.1	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0		0.0
		Conservation Investment Capital Fund Pilot CFF		1-Aug-2017							Yes	$0	0.0	$0	0.0	$0	0.0	$0	1,781.9	$0	0.0	$0	0.0		1,781.9
			Development Unrecovered Expenses - Appliance Rebate Program	1-Aug-2017	Yes							$0	0.0	$0	0.0	$27,298	0.0	$0	0.0	$0	0.0	$0	0.0	$27,298	0.0
			Development Unrecovered Expenses - C&I Midstream Lighting Program	1-Aug-2017				Yes		Yes	Yes	$0	0.0	$0	0.0	$25,000	0.0	$0	0.0	$0	0.0	$0	0.0	$25,000	0.0
			Development Unrecovered Expenses - IT Program	1-Aug-2017				Yes		Yes		$0	0.0	$0	0.0	$17,178	0.0	$0	0.0	$0	0.0	$0	0.0	$17,178	0.0
			Development Unrecovered Expenses - Residential Home Kit Program	1-Aug-2017	Yes							$0	0.0	$0	0.0	$25,000	0.0	$0	0.0	$0	0.0	$0	0.0	$25,000	0.0
			Development Unrecovered Expenses - Retro Commissioning Program	1-Aug-2017			Yes	Yes	Yes	Yes	Yes	$0	0.0	$0	0.0	$25,000	0.0	$0	0.0	$0	0.0	$0	0.0	$25,000	0.0
			Development Unrecovered Expenses - Whole Home Program	1-Aug-2017	Yes							$0	0.0	$0	0.0	$46,308	0.0	$0	0.0	$0	0.0	$0	0.0	$46,308	0.0
FCR TOTAL												$13,467,983	61,317.7	$51,767,838	255,089.7	$42,980,641	137,141.5	$34,987,093	138,101.3	$40,701,374	160,571.4	$33,855,857	134,949.8	$217,760,786	778,849.7
Pay for Performance Programs	Process and Systems Upgrades Program			1-Nov-2015							Yes	$0	0.0	$6,496,645	25,420.4	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$6,496,645	25,420.4
	Retrofit Initiative			1-Nov-2015			Yes	Yes	Yes	Yes	Yes	$1,129,112	4,516.4	$23,562,935	94,251.7	$43,536,886	174,147.5	$50,571,597	202,286.4	$41,368,563	165,474.3	$27,511,338	110,045.4	$187,680,430	750,629.6
P4P TOTAL												$1,129,112	4,516.4	$30,059,581	119,672.2	$43,536,886	174,147.5	$50,571,597	202,286.4	$41,368,563	165,474.3	$27,511,338	110,045.4	$194,177,075	776,050.0

2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement) ***(Not funded through 2015-2020 CDM Framework)***	Appliance Retirement Initiative		336.8												**0.0**
	Bi-Annual Retailer Event Initiative		10,082.2												**9,844.0**
	Coupon Initiative		6,131.7												**6,074.9**
	Direct Install Lighting and Water Heating Initiative		11,783.6												**7,332.8**
	Efficiency: Equipment Replacement Incentive Initiative		150,220.2												**149,382.4**
	Energy Audit Initiative		2,470.8												**2,470.8**
	Existing Building Commissioning Incentive Initiative		596.7												**0.0**
	HVAC Incentives Initiative		10,084.0												**10,084.0**
	Low Income Initiative		962.4												**695.6**
	New Construction and Major Renovation Initiative		6,017.6												**6,017.6**
	Process and Systems Upgrades Initiatives - Energy Manager Initiative		6,775.9												**5,227.9**
	Process and Systems Upgrades Initiatives - Project Incentive Initiative		31,477.1												**29,551.0**
	Program Enabled Savings		653.2												**417.9**
	Residential New Construction and Major Renovation Initiative		4,677.5												**4,677.5**
			4,677.5												
2011-2014 CDM Framework (and 2015 extension) TOTAL		**$0**	**246,947.4**											**0.0**	**231,776.4**
TARGET GAP TOTAL														**0.0**	
CDM PLAN TOTAL		**$14,597,094**	**312,781.5**	**$81,827,419**	**374,761.8**	**$86,517,527**	**311,289.1**	**$85,558,690**	**340,387.7**	**$82,069,937**	**326,045.7**	**$61,367,195**	**244,995.2**	**$411,937,861**	**1,786,676.1**
MINIMUM ANNUAL SAVINGS CHECK			**True**		**True**		**True**		**True**		**True**		**True**		

D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the IESO, could only be achieved with funding in addition to the CDM Plan Budget.

LDC 2:	COLLUS PowerStream Corp.

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Customer Segments Targeted by Program: Residential	Low-income	Small business	Commercial (inc. Multi-F	Agricultural	Institutional	Industrial
Full Cost Recovery Programs	Save on Energy Audit			1-Jul-2015			Yes	Yes	Yes	Yes	Yes
	Save on Energy Coupon			1-Jul-2015	Yes	Yes					
	Save on Energy Energy Manager Program			1-Jan-2016				Yes	Yes	Yes	Yes
	Save on Energy Heating and Cooling Program			1-Jul-2015	Yes	Yes					
	Save on Energy High Performance New Construction Program			1-Jul-2015			Yes	Yes	Yes	Yes	Yes
	Save on Energy Home Assistance Program			1-Jan-2016		Yes					
	Save on Energy Instant Discount Program			1-Oct-2017	Yes						
	Save on Energy Process & Systems Upgrades Program			1-Jul-2015							Yes
	Save on Energy Retrofit Program			1-Jul-2015			Yes	Yes	Yes	Yes	Yes
	Save on Energy Small Business Lighting Program			1-Jan-2016			Yes				
		Social Benchmarking Program		1-Jan-2016	Yes	Yes					
	Business Refrigeration Incentive Program			1-Jan-2016			Yes				

Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)

Program	2015 Anticipated Annual Budget ($)	2015 Energy Savings (MWh)	2016 Anticipated Annual Budget ($)	2016 Energy Savings (MWh)	2017 Anticipated Annual Budget ($)	2017 Energy Savings (MWh)	2018 Anticipated Annual Budget ($)	2018 Energy Savings (MWh)	2019 Anticipated Annual Budget ($)	2019 Energy Savings (MWh)	2020 Anticipated Annual Budget ($)	2020 Energy Savings (MWh)	Total 2015 - 2020 Total CDM Plan Budget ($)	Total Persisting Energy Savings in 2020 (MWh)
Save on Energy Audit	$4,766	13.1	$6,750	13.1	$1,000	0.0	$5,582	13.1	$8,797	13.1	$0	0.0	$26,895	52.6
Save on Energy Coupon	$48,142	298.9	$121,495	1,328.8	$73,509	150.6	$0	0.0	$0	0.0	$0	0.0	$243,146	1,775.5
Save on Energy Energy Manager Program	$4,068	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$4,068	0.0
Save on Energy Heating and Cooling Program	$48,230	78.6	$75,028	162.0	$110,696	226.1	$58,356	110.7	$56,571	74.1	$36,064	77.4	$384,945	728.9
Save on Energy High Performance New Construction Program	$947	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$947	0.0
Save on Energy Home Assistance Program	$1,050	0.0	$0	0.0	$14,617	13.3	$25,007	26.6	$27,574	26.6	$24,083	26.6	$92,330	92.9
Save on Energy Instant Discount Program	$0	0.0	$0	0.0	$42,500	163.1	$75,300	297.6	$43,547	63.9	$24,995	63.9	$186,342	588.4
Save on Energy Process & Systems Upgrades Program	$0	0.0	$0	0.0	$98,659	346.2	$0	0.0	$0	0.0	$867,089	3,181.5	$965,747	3,527.7
Save on Energy Retrofit Program	$106,285	715.5	$561,032	2,920.3	$487,604	1,859.9	$489,043	1,859.9	$232,518	532.7	$79,694	324.4	$1,956,176	8,205.9
Save on Energy Small Business Lighting Program	$0	0.0	$43,526	0.0	$34,560	86.2	$34,896	86.2	$1,971	3.4	$1,270	3.4	$116,223	179.2
Social Benchmarking Program	$0	0.0	$127,417	123.2	$79,614	334.3	$18,059	136.7	$21,377	125.1	$22,647	205.5	$269,114	627.3
Business Refrigeration Incentive Program	$0	0.0	$97,814	160.4	$58,657	89.2	$38,972	58.2	$3,228	3.9	$2,236	3.9	$200,907	243.4
FCR TOTAL	**$213,488**	**1,106.0**	**$1,033,062**	**4,707.9**	**$1,001,415**	**3,268.8**	**$745,216**	**2,588.9**	**$395,582**	**842.8**	**$1,058,078**	**3,886.6**	**$4,446,841**	**16,022.0**
Pay for Performance Programs														
P4P TOTAL	**$0**	**0.0**	**$0**	**0.0**	**$0**	**0.0**	**$0**	**0.0**	**$0**	**0.0**	**$0**	**0.0**	**$0**	**0.0**

Funding Mechanism	Program	2015 Anticipated Annual Budget ($)	2015 Energy Savings (MWh)	Total CDM Plan Budget ($)	Total Persisting Energy Savings in 2020 (MWh)
2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement) *(Not funded through 2015-2020 CDM Framework)*	Appliance Retirement Initiative		11.6		0.0
	Bi-Annual Retailer Event Initiative		96.2		92.9
	Coupon Initiative		40.7		40.4
	Direct Install Lighting and Water Heating Initiative		200.3		145.1
	Efficiency: Equipment Replacement Incentive Initiative		801.8		799.7
	HVAC Incentives Initiative		52.2		52.2
	Low Income Initiative		10.3		10.3
	Process and Systems Upgrades Initiatives - Energy Manager Initiative		16.4		16.4
2011-2014 CDM Framework (and 2015 extension) TOTAL		**$0**	**1,229.6**	**0.0**	**1,156.9**

ieso Independent Electricity System Operator

TARGET GAP TOTAL													0.0	
CDM PLAN TOTAL	$213,488	2,335.6	$1,033,062	4,707.9	$1,001,415	3,268.8	$745,216	2,588.9	$395,582	842.8	$1,058,078	3,886.6	$4,446,841	17,178.8
MINIMUM ANNUAL SAVINGS CHECK		True		True		True		True		False		True		

D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the IESO, could only be achieved with funding in addition to the CDM Plan Budget.

LDC 3:	Erie Thames Powerlines Corporation

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Customer Segments Targeted by Program: Residential	Low-income	Small business	Commercial (inc. Multi-F	Agricultural	Institutional	Industrial	2015 Anticipated Annual Budget ($)	2015 Energy Savings (MWh)	2016 Anticipated Annual Budget ($)	2016 Energy Savings (MWh)	2017 Anticipated Annual Budget ($)	2017 Energy Savings (MWh)	2018 Anticipated Annual Budget ($)	2018 Energy Savings (MWh)	2019 Anticipated Annual Budget ($)	2019 Energy Savings (MWh)	2020 Anticipated Annual Budget ($)	2020 Energy Savings (MWh)	Total 2015 - 2020: Total CDM Plan Budget ($)	Total 2015 - 2020: Total Persisting Energy Savings in 2020 (MWh)
Full Cost Recovery Programs	Save on Energy Audit			1-Jan-2016			Yes	Yes	Yes	Yes	Yes	$271	0.0	$5,830	0.0	$13,178	75.9	$13,884	75.9	$14,947	75.9	$15,341	75.9	**$63,450**	**303.4**
	Business Refrigeration			1-Aug-2017			Yes					$0	0.0	$0	0.0	$2,119	3.1	$124,198	156.0	$124,940	156.0	$2,119	3.1	**$253,375**	**318.2**
	Save on Energy Coupon Program			1-Jan-2016	Yes	Yes						$5,740	29.0	$173,634	1,483.1	$179,048	867.9	$0	0.0	$0	0.0	$0	0.0	**$358,422**	**2,380.0**
	Save on Energy Energy Manager Program			1-Jan-2016				Yes	Yes	Yes	Yes	$2,207	0.0	$3,951	0.0	$150,000	500.0	$150,000	500.0	$150,000	500.0	$150,000	500.0	**$606,158**	**2,000.0**
		Save on Energy Energy Perfromance Program						Yes	Yes	Yes	Yes	$0	0.0	$0	0.0	$1	1.0	$1	1.0	$1	1.0	$1	1.0	**$4**	**4.0**
	Save on Energy Existing Building Commissioning Program			1-Jan-2016				Yes		Yes	Yes	$0	0.0	$0	0.0	$1	1.0	$1	1.0	$1	1.0	$1	1.0	**$4**	**3.0**
	Save on Energy Heating and Cooling Program			1-Jan-2016	Yes	Yes						$8,852	18.5	$129,098	234.8	$85,441	232.5	$69,249	176.0	$69,820	181.0	$71,760	186.0	**$434,221**	**1,028.8**
	Save on Energy High Performance New Construction Program			1-Jan-2016			Yes	Yes	Yes	Yes	Yes	$0	0.0	$0	0.0	$1	1.0	$1	1.0	$1	1.0	$1	1.0	**$4**	**4.0**
	Save on Energy Home Assistance Program			1-Jan-2016		Yes						$175	0.0	$6,516	0.0	$1	1.0	$1	1.0	$1	1.0	$1	1.0	**$6,695**	**4.0**
	Save on Energy Instant Discount Program			1-Oct-2017	Yes	Yes						$0	0.0	$0	0.0	$185,015	867.9	$350,349	1,718.4	$254,159	852.9	$255,755	852.9	**$1,045,278**	**4,292.1**
	Save on Energy Monitoring & Targeting Program			1-Jan-2016							Yes	$0	0.0	$0	0.0	$1	1.0	$1	1.0	$1	1.0	$1	1.0	**$4**	**1.0**
	Save on Energy New Construction Program			1-Jan-2016	Yes							$38	0.0	$1,585	0.0	$1	1.0	$1	1.0	$1	1.0	$1	1.0	**$1,627**	**4.0**
	Save on Energy Process & Systems Upgrades Program			1-Jan-2016							Yes	$2,714	0.0	$650	0.0	$60,000	0.0	$50,000	0.0	$1,560,000	7,120.8	$50,000	0.0	**$1,723,364**	**7,120.8**
	Save on Energy Retrofit Program			1-Jan-2016			Yes	Yes	Yes	Yes	Yes	$43,124	251.0	$303,085	962.4	$972,809	4,251.8	$437,407	1,502.0	$436,951	1,502.0	$443,858	1,502.0	**$2,637,234**	**9,971.1**
	Save on Energy Small Business Lighting Program			1-Jan-2016			Yes					$1,260	0.0	$18,657	0.0	$306,384	1,266.2	$176,018	666.7	$179,551	666.7	$107,606	335.7	**$789,476**	**2,935.3**
		Strategic Energy Group Conservation Fund Pilot Program		1-Jan-2016								$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0		**0.0**
		Whole Home Pilot Program		1-Aug-2017								$0	0.0	$0	0.0	$0	10.1	$0	0.0	$0	0.0	$0	0.0		**10.1**
		EnerNOC Conservation Fund Pilot Program		1-Jan-2016								$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0		**0.0**
FCR TOTAL												**$64,381**	**298.5**	**$643,006**	**2,680.3**	**$1,953,999**	**8,081.4**	**$1,371,111**	**4,800.9**	**$2,790,373**	**11,061.1**	**$1,096,445**	**3,461.6**	**$7,919,315**	**30,379.6**
Pay for Performance Programs																									
P4P TOTAL												**$0**	**0.0**	**$0**	**0.0**	**$0**	**0.0**	**$0**	**0.0**	**$0**	**0.0**	**$0**	**0.0**	**$0**	**0.0**
2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement)	Appliance Retirement Initiative												38.5												**0.0**
	Coupon Initiative												112.4												**112.4**
	Direct Install Lighting and Water Heating Initiative												137.3												**67.1**
	Efficiency: Equipment Replacement Incentive Initiative												2,515.7												**2,467.3**
	Energy Audit Initiative												532.4												**0.0**
	Existing Building Commissioning Incentive Initiative												0.0												**0.0**
	HVAC Incentives Initiative												169.0												**169.0**
	Low Income Initiative												69.0												**47.9**
	New Construction and Major Renovation Initiative												0.0												**0.0**

Master CDM Agreement) ***(Not funded through 2015-2020 CDM Framework)***	Process and Systems Upgrades Initiatives - Energy Manager Initiative		1,976.3												**1,976.3**
	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative		0.0												**0.0**
	Process and Systems Upgrades Initiatives - Project Incentive Initiative		0.0												**0.0**
	Program Enabled Savings		15,717.6												**15,717.6**
	Residential New Construction and Major Renovation Initiative		51.6												**51.6**
2011-2014 CDM Framework (and 2015 extension) TOTAL		**$0**	**21,319.9**											**0.0**	**20,609.4**
TARGET GAP TOTAL														**0.0**	
CDM PLAN TOTAL		**$64,381**	**21,618.4**	**$643,006**	**2,680.3**	**$1,953,999**	**8,081.4**	**$1,371,111**	**4,800.9**	**$2,790,373**	**11,061.1**	**$1,096,445**	**3,461.6**	**$7,919,315**	**50,989.0**
MINIMUM ANNUAL SAVINGS CHECK			**True**		**False**		**True**		**True**		**True**		**False**		

D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the IESO, could only be achieved with funding in addition to the CDM Plan Budget.

LDC 4:	

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Customer Segments Targeted by Program: Residential	Low-income	Small business	Commercial (inc. Multi-F	Agricultural	Institutional	Industrial
Full Cost Recovery Programs											
FCR TOTAL											
Pay for Performance Programs											
P4P TOTAL											
2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement) *(Not funded through 2015-2020 CDM Framework)*											
2011-2014 CDM Framework (and 2015 extension) TOTAL											
TARGET GAP TOTAL											
CDM PLAN TOTAL											
MINIMUM ANNUAL SAVINGS CHECK											

Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)

Funding Mechanism	2015 Anticipated Annual Budget ($)	2015 Energy Savings (MWh)	2016 Anticipated Annual Budget ($)	2016 Energy Savings (MWh)	2017 Anticipated Annual Budget ($)	2017 Energy Savings (MWh)	2018 Anticipated Annual Budget ($)	2018 Energy Savings (MWh)	2019 Anticipated Annual Budget ($)	2019 Energy Savings (MWh)	2020 Anticipated Annual Budget ($)	2020 Energy Savings (MWh)	Total 2015 - 2020 Total CDM Plan Budget ($)	Total 2015 - 2020 Total Persisting Energy Savings in 2020 (MWh)
Full Cost Recovery Programs														
FCR TOTAL	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
Pay for Performance Programs														
P4P TOTAL	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement) *(Not funded through 2015-2020 CDM Framework)*														
2011-2014 CDM Framework (and 2015 extension) TOTAL	$0	0.0											0.0	0.0
TARGET GAP TOTAL													0.0	
CDM PLAN TOTAL	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
MINIMUM ANNUAL SAVINGS CHECK														

D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the IESO, could only be achieved with funding in addition to the CDM Plan Budget.

LDC 5:	

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Customer Segments Targeted by Program							Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)													
												2015		2016		2017		2018		2019		2020		Total 2015 - 2020	
					Residential	Low-income	Small business	Commercial (inc. Multi-F	Agricultural	Institutional	Industrial	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Total CDM Plan Budget ($)	Total Persisting Energy Savings in 2020 (MWh)
Full Cost Recovery Programs																									
FCR TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
Pay for Performance Programs																									
P4P TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement) *(Not funded through 2015-2020 CDM Framework)*																									
2011-2014 CDM Framework (and 2015 extension) TOTAL												$0	0.0											0.0	0.0
TARGET GAP TOTAL																								0.0	
CDM PLAN TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
MINIMUM ANNUAL SAVINGS CHECK																									

D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the IESO, could only be achieved with funding in addition to the CDM Plan Budget.

LDC 6:	

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Customer Segments Targeted by Program							Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program) 2015		2016		2017		2018		2019		2020		Total 2015 - 2020	
					Residential	Low-income	Small business	Commercial (inc. Multi-F	Agricultural	Institutional	Industrial	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Total CDM Plan Budget ($)	Total Persisting Energy Savings in 2020 (MWh)
Full Cost Recovery Programs																									
FCR TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
Pay for Performance Programs																									
P4P TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement) *(Not funded through 2015-2020 CDM Framework)*																									
2011-2014 CDM Framework (and 2015 extension) TOTAL												$0	0.0											0.0	0.0
TARGET GAP TOTAL																								0.0	
CDM PLAN TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
MINIMUM ANNUAL SAVINGS CHECK																									

D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the IESO, could only be achieved with funding in addition to the CDM Plan Budget.

LDC 7:	

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Customer Segments Targeted by Program							Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)													
												2015		2016		2017		2018		2019		2020		Total 2015 - 2020	
					Residential	Low-income	Small business	Commercial (inc. Multi-F	Agricultural	Institutional	Industrial	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Total CDM Plan Budget ($)	Total Persisting Energy Savings in 2020 (MWh)
Full Cost Recovery Programs																									
FCR TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
Pay for Performance Programs																									
P4P TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement) *(Not funded through 2015-2020 CDM Framework)*																									
2011-2014 CDM Framework (and 2015 extension) TOTAL												$0	0.0											0.0	0.0
TARGET GAP TOTAL																								0.0	
CDM PLAN TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
MINIMUM ANNUAL SAVINGS CHECK																									

D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the IESO, could only be achieved with funding in addition to the CDM Plan Budget.

LDC 8:	

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Customer Segments Targeted by Program							Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)													
												2015		2016		2017		2018		2019		2020		Total 2015 - 2020	
					Residential	Low-income	Small business	Commercial (inc. Multi-F	Agricultural	Institutional	Industrial	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Total CDM Plan Budget ($)	Total Persisting Energy Savings in 2020 (MWh)
Full Cost Recovery Programs																									
FCR TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
Pay for Performance Programs																									
P4P TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement) *(Not funded through 2015-2020 CDM Framework)*																									
2011-2014 CDM Framework (and 2015 extension) TOTAL												$0	0.0											0.0	0.0
TARGET GAP TOTAL																								0.0	
CDM PLAN TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
MINIMUM ANNUAL SAVINGS CHECK																									

D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the IESO, could only be achieved with funding in addition to the CDM Plan Budget.

LDC 9:	

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Customer Segments Targeted by Program							Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)													
												2015		2016		2017		2018		2019		2020		Total 2015 - 2020	
					Residential	Low-income	Small business	Commercial (inc. Multi-F	Agricultural	Institutional	Industrial	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Total CDM Plan Budget ($)	Total Persisting Energy Savings in 2020 (MWh)
Full Cost Recovery Programs																									
FCR TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
Pay for Performance Programs																									
P4P TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement) *(Not funded through 2015-2020 CDM Framework)*																									
2011-2014 CDM Framework (and 2015 extension) TOTAL												$0	0.0											0.0	0.0
TARGET GAP TOTAL																								0.0	
CDM PLAN TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
MINIMUM ANNUAL SAVINGS CHECK																									

D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the IESO, could only be achieved with funding in addition to the CDM Plan Budget.

LDC 10:	

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Customer Segments Targeted by Program							Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)													
												2015		2016		2017		2018		2019		2020		Total 2015 - 2020	
					Residential	Low-income	Small business	Commercial (inc. Multi-F	Agricultural	Institutional	Industrial	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Total CDM Plan Budget ($)	Total Persisting Energy Savings in 2020 (MWh)
Full Cost Recovery Programs																									
FCR TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
Pay for Performance Programs																									
P4P TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement) *(Not funded through 2015-2020 CDM Framework)*																									
2011-2014 CDM Framework (and 2015 extension) TOTAL												$0	0.0											0.0	0.0
TARGET GAP TOTAL																								0.0	
CDM PLAN TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
MINIMUM ANNUAL SAVINGS CHECK																									

E. Proposed Local and Regional Pilot CDM Programs

Notes
Complete the following Table(s) for each proposed local and regional Program or Pilot Program in the CDM Plan for which a business case has NOT previously been approved by the IESO. Please refer to the Program Development and Rule Revision Guideline and the Business Case Template for full details on requirements and submission of a business case for approval of a local or regional Program. For the process for receiving funding for a Pilot Program, refer to the LDC Program Innovation Guideline.

TABLE 3a. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS				
a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3b. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS				
a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3c. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS				
a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3d. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS				
a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3e. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS				
a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3f. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS				
a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

E. Proposed Local and Regional Pilot CDM Programs

Notes
Complete the following Table(s) for each proposed local and regional Program or Pilot Program in the CDM Plan for which a business case has NOT previously been approved by the IESO. Please refer to the Program Development and Rule Revision Guideline and the Business Case Template for full details on requirements and submission of a business case for approval of a local or regional Program. For the process for receiving funding for a Pilot Program, refer to the LDC Program Innovation Guideline.

TABLE 3g. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3h. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3i. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3j. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

F. Detailed Information on Collaboration and Regional Planning

ADDITIONAL DETAILED INFORMATION	
Regional LDC(s) Collaboration *Description of how the LDC(s) will collaborate with other LDCs. If collaboration will not occur, description of why it will not occur.*	In addition to the inherent collaboration through a joint CDM Plan among Alectra Utilities, Collus PowerStream, and Erie Thames Powerlines, all three LDCs regularly seek out opportunities for further CDM program collaboration through their existing regional networks (e.g., GTHA, CHEC) and industry committees/working groups. All facets of collaboration are considered, including potential joint design/piloting of new programs as well as enhanced collaboration in the delivery of existing programs. Select collaboration examples include: signing a CDM collaboration MOU with 12 LDCs in the Greater Toronto Hamilton Area (GTHA CDM Group), the Energy Into Action event in October, 2016 (supported by the IESO's collaboration fund) and again in the fall of 2017; the joint procurement of delivery services for the Small Business Lighting Program in 2016, and cross-training of LDC and gas utility staff on CDM and DSM program offerings. CDM staff from GTHA LDCs are in regular contact to discuss, compare and improve our respective practices and approaches on a wide spectrum of issues, from results reporting to program design to customer experience. Alectra Utilities is also a key member and active participant on the CFIC, the Municipal Electricity Profile steering committee, all current IESO Working Groups and a number of their sub-groups, demonstrating its ongoing willingness to collaborate with other LDCs and contribute significant amount of resources to ensure the success of the Conservation First Framework.
Gas Collaboration *Description of how the LDC(s) will collaborate with other gas utility programs delivered in service area (if applicable). If collaboration will not occur, description of why it will not occur.*	Both Enbridge Gas and Union Gas have been invited to participate in the GTHA CDM group referenced above. Alectra continues to meet directly with Enbridge and Union to share information and identify opportunities for collaboration. One example was the cross-promotion with Enbridge of demand control kitchen ventilation, including the use of a video and direct mail piece as part of the campaign. Other cross-promotional activities are being explored. Cross training of in-field CDM/DSM staff on program offerings is a continuing priority.
CDM Contribution to Regional Planning *Description of how the CDM Plan considers the electricity needs and investments identified in other plans or planned initiatives, completed or underway within the LDC(s)' service area or region. This may included Integrated Regional Resource Plans or Municipal Community Energy Plans.*	Alectra's 2015-2020 Conservation Targets have been built into the development of the IRRP and RIP for GTA North, and will be built into Alectra's consolidated Distribution System Plan that is to be filed with the Ontario Energy Board in 2019. Alectra is also actively supporting municipalities including Mississauga, Vaughan, Markham, Hamilton and Aurora with their Community Energy Plans, by providing data and by participating on advisory committees. Further, Alectra provides support to other stakeholders such as the Toronto Regional Conservation Authority where opportunities may exist to effectively promote CDM programs.

G. Additional Documentation for CDM Plan (If applicable)

ADDITIONAL INFORMATION AND DOCUMENTATION	
Programs *Opportunity to provide any additional information on assumptions used for budgets and/or savings for approved 2015-2020 province-wide programs*	
Approved Local and/or Regional Programs and Pilot Programs *Opportunity to provide any additional information on assumptions used for budgets and/or savings for approved 2015-2020 local or regional programs or pilot programs*	
Proposed Local and/or Regional Programs and Pilot Programs *Opportunity to provide additional information on assumptions used for forecast budgets and/or savings for proposed programs or pilot programs*	
Programs from 2011-2014/2015 CDM Framework *Opportunity to provide any additional information on assumptions used for budgets and/or savings from existing 2011-2014/2015 CDM Programs*	
Programs funded through Pay-for-Performance *Opportunity to provide any additional information on assumptions used for budgets and/or savings for Pay for Performance Programs*	
Other *Additional assumptions used in the CDM Plan*	

Summary of Changes to CDM Template

Version No.	Date	Tab	Change Summary
2	20-Jan-15	A. General Information	Inclusion of "Company Name" for Primary Contact
			Inclusion of frequency of invoicing (monthly vs. quarterly)
			Update date format to eliminate confusion
			Change reference to OPA
			Additional LDCs for joint plan
		B. LDC Authorization	Update date format to eliminate confusion
		D. CDM Plan Milestone LDC 1-10	Additional line items for FRC program names
			Additional LDCs for joint plan
			Update on the program names
			Update date format to eliminate confusion
			Update column headers: - "Province Wide Program Name" - "Proposed Regional or Local CDM Program or Pilot Program Name"
			Change reference to OPA
			Update Header and Footer
		E.. Proposed Program&Pilots	Additional boxes for proposed programs
			Update date format to eliminate confusion
		Q. Detailed Information	Clarity if it is primary LDC or all LDCs in a joint CDM Plan.