EXHIBIT 3 - REVENUES

2015 Cost of Service

Cooperative Hydro Embrun Inc.
EB-2017-0035

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3.1 LOAD AND REVENUE FORECAST

3.1.1 INTRODUCTION

The evidence presented in this exhibit provides information supporting the revenues derived from activities regulated by the Ontario Energy Board. Actual operating revenues from regulated operations are derived mainly from fixed and variable tariff charges as well as pass through charges and specific service charges. Revenues are collected from five (5) customer classes: Residential, General Service less than 50 kW, General Service greater than 50 kW, Unmetered Scattered Load (USL) and Street Lighting. CHEI does not anticipate any significant changes in its customer classes.

This exhibit also describes CHEI's load and customer forecasts. The load forecast methodology and assumptions are described in detail at 3.1.4 Load Forecast Methodology.

The evidence herein is organized per the following topics:

1) Revenue and Load Forecast
2) Impact and Persistence from Historical CDM Programs
3) Accuracy of Load Forecast and Variance Analysis, and
4) Other Revenues

3.1.2 OVERVIEW OF CURRENT REVENUES

Table 1 below shows revenues from current distribution charges for 2017. Distribution Revenues are derived from a combination of fixed monthly charges and volumetric charges applied to the utility's proposed Load Forecast. Fixed rate revenues are determined by applying the current fixed monthly charge to the number of customers or connections in each of the customer classes in each month. Variable rate revenue is based on a volumetric rate applied to meter readings for consumption or demand volume.

CHEI's 2018 forecasted revenues recovered through its currently approved distribution rates are projected at $830,391 (exclusive of all rate riders). The revenues at proposed distribution rates are presented in Exhibit 6 and Exhibit 8.

Table 1 - Revenues at Current Rates

2017 Rates at 2018 Load

	Test Year Projected Revenue from Existing Variable Charges							
Customer Class Name	Variable Distribution Rate	per	Test Year Volume	Gross Variable Revenue	Transform. Allowance Rate	Transform. Allowance kW's	Transform. Allowance $'s	Net Variable Revenue
Residential	$0.0072	kWh	21,616,344	$155,637.67			$0.00	$155,637.67
General Service < 50 kW	$0.0148	kWh	5,043,563	$74,644.73			$0.00	$74,644.73
General Service > 50 to 4999 kW	$3.6957	kW	12,736	$47,068.45	0.00		$0.00	$47,068.45
Unmetered Scattered Load	$0.0055	kWh	82,127	$451.70			$0.00	$451.70
Street Lighting	$8.0867	kW	603	$4,878.84			$0.00	$4,878.84
Total Variable Revenue			26,755,373	$282,681.40	0	0	$0.00	$282,681.40

2017 Rates at 2018 Load

	Test Year Projected Revenue from Existing Fixed Charges							
Customer Class Name	Fixed Rate	Customers (Connections)	Fixed Charge Revenue	Variable Revenue	TOTAL	% Fixed Revenue	% Variable Revenue	% Total Revenue
Residential	$21.8700	2,100	$551,124.00	$155,637.67	$706,761.67	77.98%	22.02%	77.72%
General Service < 50 kW	$17.9000	172	$36,969.84	$74,644.73	$111,614.58	33.12%	66.88%	12.27%
General Service > 50 to 4999 kW	$199.4500	9	$21,540.60	$47,068.45	$68,609.05	31.40%	68.60%	7.54%
Unmetered Scattered Load	$21.1600	17	$4,415.87	$451.70	$4,867.57	90.72%	9.28%	0.54%
Street Lighting	$1.9900	530	$12,646.72	$4,878.84	$17,525.56	72.16%	27.84%	1.93%
Total Fixed Revenue		2,828	$626,697.03	$282,681.40	$909,378.43			

A completed Appendix 2-IB Load Forecast Analysis is presented at Appendix A of this Exhibit and also in Tab 10 of the RRWF.[1]

CHEI does not foresee or plan for any changes in its customer classes.

3.1.3 PROPOSED LOAD FORECAST

The following section of the application covers the approach taken to determine the Load Forecast. This section also covers economic assumptions and data sources for customer and load forecasts. It explains wholesale purchases and subsequent adjustments to the wholesale purchases. It also provides the rationale behind each variable used in the regression analysis. Lastly, it presents the regression results and explains how they were used to determine the forecast for the bridge and test year.

[1] MFR - Completed Appendix 2-IB; the customer and load forecast for the test year must be entered on RRWF, Tab 10

Table 2 below presents the actual and forecast trends for customer/connection counts, kWh consumption and billed kW demand. The forecast trend is what CHEI has based its proposed rates on.

Table 2 - Customer and Volume Trend Table

	Year	2014	2015	2016	2017	2018	2018 CDM Adjusted
Residential	Cust/Conn	1,800	1,847	1,927	2,040	2,100	2,100
	kWh	19,479,913	19,377,540	19,268,403	21,046,900	21,676,646	21,616,344
	kW						
GS < 50 kW	Cust/Conn	159	165	163	168	172	172
	kWh	4,701,954	4,594,197	4,538,610	4,941,575	5,057,633	5,043,563
	kW						
GS > 50 to 4999 kW	Cust/Conn	11	11	11	9	9	9
	kWh	4,346,251	4,316,369	4,274,953	3,657,936	2,835,388	2,827,501
	kW	12,214	12,238	12,169	12,701	12,772	12,736
USL	Cust/Conn	19	19	18	17	17	17
	kWh	89,075	94,284	94,284	82,356	82,356	82,127
	kW	-	-	-	-	-	-
Street Lighting	Cust/Conn	409	430	505	517	530	530
	kWh	359,464	373,173	376,348	385,594	395,068	393,969
	kW	1,003	1,050	576	590	605	603
Total	Cust/Conn	2,398	2,471	2,623	2,751	2,828	2,828
	kWh	28,976,657	28,755,563	28,552,598	30,114,361	30,047,092	29,963,504
	kW	13,217	13,288	12,745	13,291	13,377	13,339

3.1.4 LOAD FORECAST METHODOLOGY AND DETAIL[2]

CHEI's load forecast methodology has not changed since its last Cost of Service in 2014. The forecast is prepared in two phases. The first phase, a billed energy forecast by customer class for 2018, is developed using a total purchase (**Wholesale**) basis regression analysis. Then, in the second phase, usage associated with the known change in customers for 2018 is determined and added (if applicable) (**Adjusted Wholesale**). The methodology proposed in this application predicts wholesale consumption (**Predicted**) using a multiple regression analysis that relates historical monthly wholesale kWh usage to carefully selected variables. The one-way analysis of variance (**ANOVA**) is used to determine whether there are any statistically significant differences between the means of three or more independent (unrelated) groups. The ANOVA compares the means between the groups you are interested in and determines whether any of those means are statistically significantly different from each other. The utility did not test the NAC method due to the fact that NAC is generally seen as an alternative when sound historical data is not available. [3]

The most significant variables used in weather related regressions are monthly historical heating degree days and cooling degree days. Heating degree-days provide a measure of how much (in degrees), and for how long (in days), the outside temperature was below that base temperature. The most readily available heating degree days come with a base temperature of 18°C. Cooling degree-day figures also come with a base temperature, and provide a measure of how much, and for how long, the outside temperature was above that base temperature.

For degree days, daily observations as reported in Ottawa are used. The regression model also uses other variables which are tested to see their relationship and contribution to the fluctuating wholesale purchases. Each variable is discussed in detail later in this section.

[2] MFR - Explanation of weather normalization methodology
[3] MFR - NAC Model - rationale for choice, data supporting NAC variables, description of accounting for CDM including licence conditions, discussion of weather normalization considerations

Explanation of Multiple Regression Analysis

Multiple regression can be utilized for forecasting purposes by analyzing how a number of variables have affected a depended variable historically. From this, the relationship between these variables and the depended variable can be expressed as:

$$Y=A+B1X1+B2X2\ldots+bNxN + E$$

Where:

Y = Predicted depended variable value

A = the value of Y when all Xs are zero

X = the independent variable

B = the coefficients corresponding to the independent variables

n = the number of independent variables

E = an error term

By forecasting the independent variables, the dependent variable can be predicted. However, to ascertain that the relationship is not coincidental, the utility must first assess the correlation between the dependent and individual independent variables. This can be accomplished by the Person Correlation Coefficient (otherwise known as "R") to each independent variable. This depicts how much of the change in depended variable can be explained by the change in independent variables. Those variables with a high R-squared should then be used for multiple regression. The same correlation coefficient can be applied to multiple independent variables to ascertain how much of the change in a dependent variable can be explained by changes in all independent variables.

$$R\ Squared=(B'X'Y - nAVG(Y)^2)/Y'Y-nAVG(Y)^2)$$

Where:

B',X',Y' = Matrixes of all combinations of B,X&Y respectively

^2 = Squared

The adjusted R-squared is calculated by "correcting" for the number of independent variables in a multiple regression analysis. The formula: Adj RSq=(1-(1-RSq)*((n-1)/(n-k)). It is often used to compare models involving a different number of coefficients. The statistical significance of the multiple regression can be tested with the F-test which is derived from a normal probability distribution. A critical point along the distribution can be found given a degree of confidence required, the number of variables and the number of observations. If the F-statistic is at this point, then the analysis can be deemed statistically significant at the level of confidence.

F-statistic = (R Squared/k-1)/(1-R Squared)/(n-k)

Where:

K = number of independent variable

n = number of observations

Independent variables that are highly correlated themselves can lead to high variances in slope estimation (B). This is known as "Multicollinearity." For this reason, independent variables with a high level of multicollinearity to the other independent variables should consider being omitted from the analysis.

3.1.5 ECONOMIC OVERVIEW

Embrun is a community in the Eastern Ontario region. The community is located approximately a twenty-five-minute drive from Ottawa, an hour and a half from Montreal, and a five-hour drive from Toronto. Embrun is located near Trans-Canada Highway 417, between Russell, Ontario and Limoges, Ontario.

Embrun is also part of the National Capital Region. Embrun is part of the larger Russell Township in Prescott and Russell United Counties. In 2011 (the year of the most recent census), the urban area of Embrun had a total population of 6,380, but if surrounding agricultural areas closely tied to the community are included, the population figure rises to 8,669. This makes Embrun the largest community in the Township of Russell.

Embrun has grown rapidly in recent years. Between 2001 and 2006, the population of Embrun's urban area increased by 26.6%, a higher growth rate than any other community in the 613 area code and the 8th highest growth rate in Ontario. Between 2006 and 2011 its growth was slower, but still more than double the provincial average, growing at a rate of 12.8%, which was the 6th fastest in the 613 area code and the 25th fastest in Ontario.

The town has a French-speaking majority, with a significant English-speaking minority. According to the 2006 Census, 57% of Embrun's population speaks French at home, while 41% speak English at home. The remaining 2% speak either both languages equally, or speak a non-official language.

Embrun is considered a bedroom community. The majority of the population works in nearby Ottawa and commutes into the city on a daily basis. A large proportion of these people are people with post-secondary education who work in the Canadian civil service or Ottawa's large high-tech sector. This has been the case since the mid-20th century. Prior to then, agriculture employed the majority of the community's population.

Agriculture still has a significant presence in the area. It is one of the major distributors of dairy products and bovine in the region.

57% of Embrun's population speaks French at home, while 41% speak English at home. The remaining 2% speak either both languages equally, or speak a non-official language. 63% of Embrun residents list French as their mother tongue, while 33% list English as their mother tongue. 66% of Embrun residents are bilingual in both English and French, 24% speak only English, and 9% speak only French. For the language of work, the English language is disproportionately common; while only 41% of Embrun residents speak English at home, 57% of Embrun residents speak primarily or exclusively English at work.

The median income for Embrun residents is $40,567 a year, higher than the Ontario average of $29,335 a year. Note that those values include all residents over the age of 15 with any reported income, meaning that (for example) teenagers working minimum wage on their days off school would be included. If only full-time workers are included, the median income for Embrun residents rises to $50,096 a year, still above the Ontario average, which for this category is $44,748 a year.

With respect to climate, Embrun has a continental climate with cool winters, humid summers, and short autumns and springs.

Summers and winters last approximately 4–4½ months long while autumn and spring are shorter. The first snowfalls of the year usually occur in mid-to-late November, but snow doesn't actually cover the ground until December. Before that, snow usually melts as soon as it hits the ground.

In the spring, the snow usually starts melting in March, although occasional "warm breaks" with temperatures as high as 10 °C (50 °F) usually occur once or twice in January and February.

In recent years, winters have gotten much warmer, so often in the winter; freezing rain will occur.

In the summer, humidity is often common, especially in July. Although temperatures are usually just under 30 °C (86 °F), with the humidity, it can feel as hot as 35 °C or higher.

While there are no definite plans for growth in the area, there are a few plans for subdivision development which may spur some residential growth in the area. Considered a bedroom community for Ottawa, families wishing to get out of the city but still work in the city are moving to urban service areas such as Embrun and buying townhomes or garden homes. It is expected this trend will continue for the next few years. [4]

[4] MFR - Explanation of causes, assumptions and adjustments for volume forecast. Economic assumptions and data sources for customer and load forecasts

3.1.6 OVERVIEW OF WHOLESALE PURCHASES

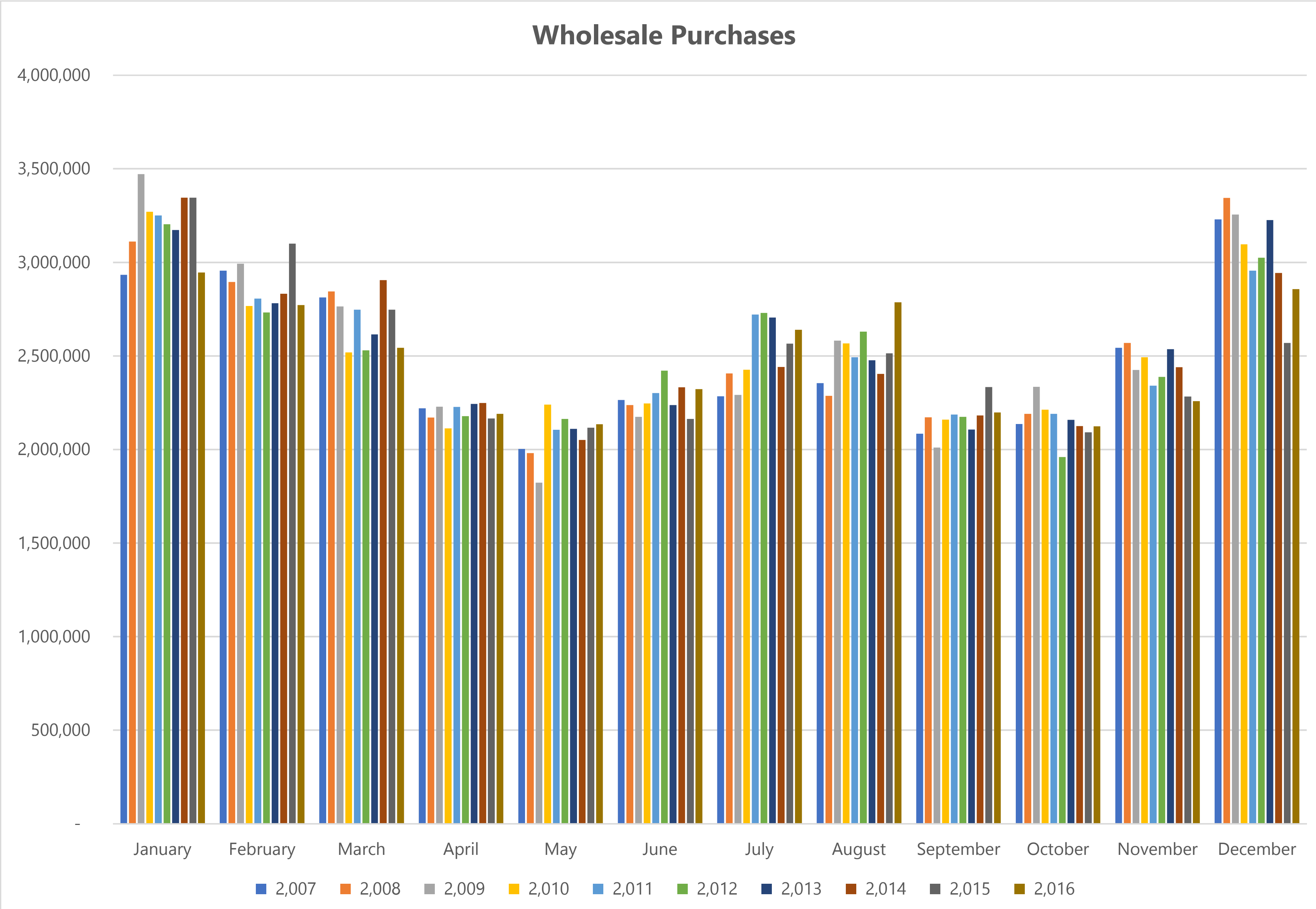
CHEI purchases electricity from Hydro One and embedded generation.

The following table outlines the unadjusted monthly wholesale purchases:

Table 3 - Wholesale Purchases 2007-2016 (net of Microfit)

	2,007	2,008	2,009	2,010	2,011	2,012	2,013	2,014	2,015	2,016
January	2,933,130	3,110,288	3,471,299	3,269,071	3,249,782	3,203,563	3,171,982	3,344,478	3,345,142	2,945,144
February	2,955,421	2,894,816	2,991,627	2,766,734	2,805,743	2,732,020	2,780,449	2,831,008	3,099,920	2,771,659
March	2,812,000	2,843,479	2,763,632	2,517,663	2,746,623	2,528,737	2,614,250	2,904,055	2,746,124	2,542,833
April	2,219,382	2,170,408	2,227,608	2,112,148	2,227,301	2,177,764	2,243,117	2,248,235	2,164,850	2,189,884
May	2,001,942	1,979,923	1,822,056	2,239,398	2,105,199	2,163,211	2,109,195	2,050,728	2,115,678	2,134,408
June	2,263,414	2,237,254	2,173,982	2,245,628	2,300,335	2,420,539	2,237,264	2,331,473	2,163,044	2,321,533
July	2,283,942	2,405,222	2,290,661	2,426,109	2,720,678	2,729,646	2,703,899	2,439,754	2,565,589	2,638,538
August	2,353,395	2,285,530	2,581,599	2,565,832	2,492,714	2,628,584	2,476,640	2,403,864	2,513,602	2,785,733
September	2,083,981	2,171,190	2,009,315	2,159,173	2,186,451	2,173,687	2,105,313	2,180,826	2,332,522	2,197,232
October	2,135,946	2,189,674	2,334,419	2,211,746	2,190,058	1,959,194	2,158,039	2,124,494	2,091,398	2,123,746
November	2,542,576	2,569,206	2,424,252	2,492,157	2,340,743	2,387,199	2,535,841	2,439,672	2,282,068	2,257,978
December	3,229,565	3,343,542	3,255,138	3,095,819	2,955,433	3,024,052	3,225,003	2,943,196	2,568,199	2,856,296
Total	29,814,696	30,200,534	30,345,587	30,101,478	30,321,059	30,128,196	30,360,992	30,241,782	29,988,135	29,764,983

CHEI's load has seen a modest decline over the past 10 years with the largest total wholesale being back in 2013. Wholesale purchases, on the whole, have decreased by 0.2% from 2007 to 2016. Since the number of customers has only moderately increased over the past 5 years, the assumption is that the effects of energy efficiency changes have contributed to the modest decline.


Wholesale Purchases
4,000,000
3,500,000
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
-
January
February
March
April
May
June
July
August
September
October
November
December
2,007
2,008
2,009
2,010
2,011
2,012
2,013
2,014
2,015
2,016

3.1.7 OVERVIEW OF VARIABLES USED[5]

In CHEI's case, variation in monthly electricity consumption is influenced by three main factors – weather (e.g. heating and cooling), which is by far the most dominant effect on most systems; employment factors (increases or decreases in economic activity leads to changes in employment); and lastly the number of days per month. Specifics relating to each variable used in the regression analysis are presented in the next section.

Heating and Cooling:

In order to determine the relationship between observed weather and energy consumption, monthly weather observations describing the extent of heating or cooling required within the month are necessary. Environment Canada publishes monthly observations on heating degree days (HDD) and cooling degree days (CDD) for selected weather stations across Canada. Heating degree-days for a given day are the number of Celsius degrees that the mean temperature is below 18°C. Cooling degree-days for a given day are the number of Celsius degrees that the mean temperature is above 18°C. For CHEI, the monthly HDD and CDD as reported at Ottawa International Airport were used.

CHEI has adopted the 10 year average from 2007 to 2016 as the definition of weather normal. Our view is that a ten-year average based on the most recent ten calendar years available is a reasonable compromise that likely reflects the "average" weather experienced in recent years. Many other LDCs have also adopted this definition for the purposes of cost-of-service rebasing. The following table outlines the monthly weather data used in the regression analysis.

[5] MFR - Multivariate Regression Model - rationale for choice, regression statistics, explanation of weather normalization methodology, sources of data for endogenous and exogenous variables, any binary variables used to either account for individual data points or to account for seasonal or cyclical trends or for discontinuities in the historical data, explanation of any specific adjustments made; data used in load forecast must be provided in Excel format, including derivation of constructed variables

Table 4 - HDD and CDD as reported at Utility Location

HDD	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
January	797.10	754.20	979.50	789.20	893.20	831.00	839.90	918.30	894.30	711.00
February	820.00	774.30	711.50	655.80	729.00	671.40	728.50	793.20	957.40	673.00
March	643.00	721.10	598.30	460.70	636.00	460.30	579.60	783.60	726.40	504.00
April	361.10	299.60	334.30	258.10	347.40	363.30	285.50	384.20	345.20	351.00
May	157.30	185.40	181.60	112.30	142.80	96.00	105.70	127.30	90.90	107.00
June	34.20	22.40	50.40	37.60	18.50	0.00	54.10	20.30	40.30	31.00
July	11.80	0.30	13.10	4.50	0.00	0.00	7.70	7.70	7.70	6.00
August	20.10	14.40	26.10	14.70	2.30	8.40	13.40	21.40	7.20	4.00
September	76.00	95.40	106.50	112.00	55.40	127.30	133.20	110.30	46.30	48.00
October	227.50	321.80	355.50	311.00	259.10	243.10	235.80	257.90	311.40	217.00
November	517.00	502.80	417.40	491.60	392.90	541.70	560.80	510.60	417.50	371.00
December	787.70	796.70	759.40	731.40	415.00	680.60	858.20	696.40	490.10	638.00
Total	797.10	6497.40	6543.60	5989.90	5903.60	6036.10	6416.40	6646.20	6350.70	5677.00

CDD		2008	2009	2010	2011	2012	2013	2014	2015	2016
January	0	0	0	0	0	0	0	0	0	0
February	0	0	0	0	0	0	0	0	0	0
March	0	0	0	0	0	0	0	0	0	0
April	0	0	0	0	0	3.2	0	0	0	4
May	17.30	0	2.5	1.6	16.7	21	15.3	8.8	23.5	84
June	66.90	0	3.2	38.2	59.1	70.4	39.4	54.9	22.5	135
July	65.10	60.5	44.9	33.4	137.5	142.2	111.1	62.8	103.8	198
August	79.30	78.9	42.9	150.8	82.3	97.6	57.2	55.8	71.2	213
September	25.70	49.5	82.1	93	32.9	20.6	10.1	21.6	51.7	88
October	1.90	25	5	26.2	1.4	0	0.7	3.1	0	14
November	0	0	0	0	0	0	0	0	0	0
December	0	0	0	0	0	0	0	0	0	0
Total		213.9	180.6	343.2	329.9	355	233.8	207	272.7	736

Employment Factor:

In order to measure the change in economic activity, a data series must be chosen which represents, as much as possible, regional economic activity. CHEI used the monthly full-time employment levels for the CHEI economic region, as reported in Statistics Canada's Monthly Labour Force Survey (CANSIM).

The following table outlines the full-time employment levels for the CHEI economic region which were tested and ultimately included in the regression analysis.

Table 5 - Full-Time Employment Levels for the CHEI Economic Region

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
January	620.00	671.20	677.30	671.80	666.30	684.20	691.20	690.20	691.90	681.70
February	623.20	669.90	668.00	669.80	663.40	685.10	686.60	683.80	685.10	681.30
March	628.70	667.80	657.00	668.50	666.00	686.90	679.30	685.10	680.30	680.80
April	638.60	668.20	652.40	669.60	668.90	695.10	676.60	686.20	683.70	681.40
May	647.50	669.80	647.10	677.10	674.90	702.50	678.60	695.20	686.30	687.70
June	657.40	676.10	655.10	688.40	684.40	709.40	682.90	700.10	692.20	692.20
July	669.30	684.20	666.00	693.80	689.90	705.40	689.00	708.20	695.40	701.10
August	673.40	688.40	678.90	687.90	694.60	699.20	691.50	708.40	694.70	699.80
September	670.90	685.70	679.50	677.70	687.80	691.60	688.20	704.70	690.10	693.50
October	669.70	681.70	677.60	673.50	681.10	687.90	684.20	701.70	690.20	695.30
November	670.60	681.70	675.20	673.80	676.80	689.30	685.20	700.60	687.80	697.60
December	673.90	683.20	673.30	671.00	679.30	692.10	687.90	701.40	690.30	703.00

Daylight hours:

The utility tested the regression analysis using Average Daylight Hours & Minutes/ Day. The premise behind this variable is that shorter days bring higher electricity consumption. During fall and winter months, the days are shorter, and as such, consumers spend more time indoors, lights and appliances are turned on earlier and used for longer periods of time. In 2008, Energy Department experts studied the impact of the extended Daylight Saving Time on energy consumption in the U.S. and found that Daylight Savings Time saved about 0.5 percent in total electricity per day. While this might not sound like a lot, it adds up to electricity savings of 1.3 billion kilowatt-hours -- or the amount of electricity used by more than 100,000 households for an entire year. These electricity savings generally occur during a 3-5 hour period in the evening. The utility tested but ultimately determined that its use did not improve the results. Therefore, the variable was dropped from the study.

Days per month:

Lastly, CHEI also tested a "Days per month" variable. Although the variables did not yield particularly significant results, it did slightly improve the R-Square, and therefore CHEI opted to keep it as a variable. All relevant scenarios tested by the utility can be found in the regression model at tab 6.1 entitled Regression Scenarios.

Using a combination of wholesale purchases and variables listed above, a multiple regression analysis was used to develop an equation describing the relationship between monthly actual wholesale kWh and the explanatory variables. CHEI also used a correlation function to examine the relationship between the variables included in the analysis. The results of the correlation analysis for each scenario can also be found at tab 6.1 entitled Regression Scenarios.

To project the adjusted wholesale purchases for the bridge and test year, the model uses, for the most part, a simple average of the last 10 years of historical data. CHEI has applied this method of prediction to all variables.

Origin of variables

- HDD: Stats Canada
- CDD : Stats Canada
- Employment: Stats Canada
- Days per month Computed by the utility
- Daylight hours http://www.ottawa.climatemps.com/index.php (not used)

Rational for including and excluding variables

During the process of testing the regression analysis, many different variables and times periods are tested to arrive to the best R-Squared. The utility's rational behind selecting or dropping certain variables involves a "no-worst" rational. In other words, if a variable is justified and does not worsen the results, it is generally kept as one of the regression variables. In this case, the Days per Month only slightly improved the R-Square however, the utility still opted to keep them as part of the regression analysis.

3.1.8 REGRESSION RESULTS

Table 6 below presents the regression results used to determine the load forecast

Table 6 - Correlation/Regression Results

R Squared	**0.7774**					**1.368**	**Durbin-Watson Statistic**			
Adjusted R Squared	**0.7697**					**1.65 - 1.75**	**Positive autocorrelation detected**			
Standard Error	**183266.2031**					**2.448**	**Critical F-Statistic - 95% Confidence**			
F - Statistic	**100.4219**					**86.12%**	**Confidence to which analysis holds**			
Multiple Regression Equation					**Independent Analysis**			**Auto Correlation**	**Multicollinearity**	
	Coefficients	**Standard Error**	**t Stat**	**p Value**	**R Squared**	**Coefficient**	**Intercept**	**Dl=1.69 Du=1.72**	**Adjusted R-Squared against other Indep**	**Variables With RSQ at > 90%**
Intercept	-989,930.411	957,231.488	-1.034	30.32%				**DW-Stat**		
HDD	1,410.520	71.241	19.799	0.00%	57.06%	946.76	2177336.75	**0.35**	38.54%	
CDD	4,569.272	510.271	8.955	0.00%	1.78%	-1173.39	2541151.25	**0.63**	41.00%	
NoD in Month	63,592.798	20,910.562	3.041	0.29%	0.00%	682.01	2489806.25	**2.96**	3.27%	
Employment	1,394.500	1,127.293	1.237	21.86%	0.36%	-1416.27	3474968.00	**0.23**	12.44%	

The resulting regression equation yields an adjusted R-squared of 0.769. When actual annual wholesale values are compared to annual values predicted by the regression equation, the mean absolute percentage error (MAPE) is 1.157 per cent. More detailed model statistics can be found in the next section.

Once CHEI calculated its preferred Regression Results, the Load Forecast model then uses the coefficients from the regression results to adjust the wholesale purchases. Table 7 as seen below, demonstrates the results of this adjustment. The table shows a comparison of the actual and predicted wholesale purchases.

Table 7 - Wholesale vs. Adjusted using the coefficients from the regression results

Year	Wholesale	year over year	Predicted	year over year	Wholesale VS Predicted
2007	29,814,696		29,720,954		-0.31%
2009	30,200,534	1.29%	29,974,902	0.85%	-0.75%
2009	30,345,587	0.48%	29,782,057	-0.64%	-1.86%
2010	30,098,957	-0.81%	29,840,077	0.19%	-0.86%
2011	30,311,723	0.71%	29,442,446	-1.33%	-2.87%
2012	30,091,478	-0.73%	30,243,327	2.72%	0.50%
2013	30,301,350	0.70%	30,138,226	-0.35%	-0.54%
2014	30,157,452	-0.47%	30,476,269	1.12%	1.06%
2015	29,896,472	-0.87%	30,222,148	-0.83%	1.09%
2016	29,672,839	-0.75%	31,427,034	3.99%	5.91%

Table **8** as seen below, shows the results of the mean absolute deviation (MAD), the mean square error (MSE), the root mean square (RMSE) and the mean absolute Percentage error (MAPE).

Table 8 - MAP-MSE-MAPE

Period	Actual	Forecast	Error	Absolute Value of Error	Square of Error	Absolute Values of Errors Divided by Actual Values.
t	A_t	F_t	$A_t - F_t$	$\lvert A_t - F_t \rvert$	$(A_t - F_t)^2$	$\lvert (A_t - F_t)/A_t \rvert$
1	29,814,696	29,720,954	93,741	93,741	8,787,439,547	0.0031
2	30,200,534	29,974,902	225,631	225,631	50,909,533,864	0.0075
3	30,345,587	29,782,057	563,530	563,530	317,566,008,846	0.0186
4	30,098,957	29,840,077	258,880	258,880	67,018,865,809	0.0086
5	30,311,723	29,442,446	869,276	869,276	755,641,626,654	0.0287
6	30,091,478	30,243,327	-151,849	151,849	23,058,138,100	0.0050
7	30,301,350	30,138,226	163,125	163,125	26,609,637,654	0.0054
8	30,157,452	30,476,269	-318,817	318,817	101,644,230,017	0.0106
9	29,896,472	30,222,148	-325,676	325,676	106,065,016,045	0.0109
10	29,672,839	31,427,034	-1,754,195	1,754,195	3,077,201,374,710	0.0591
	Totals		-376,353	4,724,721	4,534,501,871,247	**0.1570**

The mean absolute deviation (MAD) is the sum of absolute differences between the actual value and the forecast divided by the number of observations.

Mean square error (MSE) is probably the most commonly used error metric. It penalizes larger errors because squaring larger numbers has a greater impact than squaring smaller numbers. The MSE is the sum of the squared errors divided by the number of observations.

Mean Absolute Percentage Error (MAPE) is the average of absolute errors divided by actual observation values.

In accordance with the Filing Requirements, CHEI has also provided a 2018 forecast assuming twenty-year normal weather conditions. Table 9 below displays 20 years of historical Heating Degree Days and Cooling Degree Days. The impact of using both a 10 year average as well as a 20 year average to weather normalize wholesale purchases is presented in Table 10.

Table 9 - Forecast using a twenty-year weather normalization

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	10 year avg	20 year avg
HDD																						
Jan	923	802	875	875	848	709	977	1045	921	734	797	754	980	789	893	831	840	918.3	894	711	841	855
Feb	736	610	671	728	747	669	842	750	701	721	820	774	712	656	729	671	729	793.2	957	673	751	735
Mar	678	576	646	502	652	652	675	559	669	600	643	721	598	461	636	460	580	783.6	726	504	611	616
Apr	379	286	337	391	338	359	425	378	325	322	361	300	334	258	347	363	286	384.2	34	351	302	327
May	241	44	83	152	110	228	154	166	205	128	157	185	182	112	143	96	106	127.3	90	107	131	140
Jun	12	43	20	63	26	62	39	54	16	28	34	22	50	38	19	0	54	20.3	40	31	31	33
Jul	11	3	4	12	22	5	2	2	3	0	12	0	13	5	0	0	8	7.7	7	6	6	6
Aug	14	8	15	18	5	7	13	30	8	18	20	14	26	15	2	8	13	21.4	7	4	13	13
Sep	121	82	66	138	90	57	60	67	59	121	76	95	107	112	55	127	133	110.3	46	48	91	89
Oct	334	271	322	291	266	370	337	287	270	336	228	322	356	311	259	243	236	257.9	311	217	274	290
Nov	553	453	407	489	410	535	469	484	484	417	517	503	417	492	393	542	561	510.6	417	371	472	471
Dec	755	648	692	883	602	728	722	815	762	610	788	797	759	731	415	681	858	696.4	490	638	685	703
	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	10 year avg	20 year avg
CDD																						
Jan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Feb	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Apr	0	0	0	0	0	10	0	2	0	0	0	0	3	2	0	3	0	0	0	4	1	1
May	0	29	31	3	14	7	0	4	2	17	17.3	0	3	38	17	21	15	9	23.5	84	23	17
Jun	79	78	100	31	76	40	55	27	112	48	66.9	61	45	33	59	70	39	55	22.5	135	59	61
Jul	96	89	142	59	78	121	90	87	129	131	65.1	79	43	151	138	142	111	63	103.8	198	109	106
Aug	41	86	58	60	128	107	106	48	115	68	79.3	50	82	93	82	98	57	56	71.2	213	88	85
Sep	4	12	50	14	26	51	24	11	33	5	25.7	25	5	26	33	21	10	22	51.7	88	31	27
Oct	0	0	0	0	0	4	0	0	6	0	1.9	0	0	0	1	0	1	3	0	14	2	2
Nov	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 10 - Forecast using a 10 year vs. 20 year weather normalization

Date	Weather Normalized 10Year	Yearly Total 10Year	Weather Normalized 20Year	Yearly Total 210Year
2017-January	3142979.43		3142979.43	
2017-February	2840325.17		2840325.17	
2017-March	2820641.02		2820641.02	
2017-April	2368393.81		2368393.81	
2017-May	2222971.52		2222971.52	
2017-June	2140944.34		2140944.34	
2017-July	2407827.06		2407827.06	
2017-August	2397444.47		2397444.47	
2017-September	2267720.74		2267720.74	
2017-October	2394416.66		2394416.66	
2017-November	2565679.06		2565679.06	
2017-December	2906949.88	30476293	2906949.88	30476293
2018-January	3154453.34		3169199.84	
2018-February	2837336.59		2823838.78	
2018-March	2821527.57		2832634.68	
2018-April	2370132.65		2365210.80	
2018-May	2232510.42		2249947.60	
2018-June	2158053.64		2162125.47	
2018-July	2425716.52		2426893.43	
2018-August	2413902.59		2415026.30	
2018-September	2263147.78		2257627.01	
2018-October	2399231.13		2415828.85	
2018-November	2563974.56		2568799.68	
2018-December	2895653.77	30535640	2959106.38	30646238

3.1.9 DETERMINATION OF CUSTOMER FORECAST

CHEI has used a simple geometric mean function to determine the forecasted number of customers of 2017 and 2018. The geometric mean is more appropriate to use when dealing with percentages and rates of change. Although the formula is somewhat simplistic, it is reasonably representative of CHEI's natural customer growth. The geometric mean results were analyzed by CHEI and then further adjusted for known particulars – in CHEI's case the MicroFit related consumption was removed from the Wholesale Purchases. Historical customer counts and projected customer counts for 2017 and 2018 are presented in Table 11 below. A variance analysis of customer counts and projections is presented at 3.3.10.

Table 11 - Customer Forecast

	Residential		General Service < 50 kW		General Service > 50 to 4999 kW		USL		Streetlighting	
Date	Customers or Connections	Growth Rate	Customers or Connections	Growth Rate	Customers or Connections	Growth Rate	Customers or Connections	Growth Rate	Customers or Connections	Growth Rate
2007	1689		162		12		18		406	
2008	1743	1.0320	162	1.0000	12	1.0000	20	1.1111	409	1.0086
2009	1757	1.0080	153	0.9444	11	0.9167	19	0.9500	409	1.0000
2010	1777	1.0114	151	0.9869	11	1.0000	19	1.0000	409	1.0000
2011	1785	1.0045	158	1.0464	11	1.0000	19	1.0000	409	1.0000
2012	1788	1.0017	157	0.9937	11	1.0000	19	1.0000	409	1.0000
2013	1790	1.0011	159	1.0127	11	1.0000	19	1.0000	409	1.0000
2014	1800	1.0053	159	1.0000	11	1.0000	19	1.0000	409	1.0000
2015	1847	1.0261	165	1.0377	11	1.0000	19	0.9737	430	1.0513
2016	1927	1.0433	163	0.9879	11	1.0000	18	0.9459	505	1.1733
Geomean		1.0147		1.0007		0.9904		0.9969		1.0246
2017	1874		165		11		17		517	
2018	1901		165		11		17		530	
Adjusted										
2017	2040		165		11		17		517	
2018	2100		165		11		17		530	

3.1.10 DETERMINATION OF WEATHER NORMALIZED FORECAST

Allocation to specific weather sensitive rate classes (Residential, GS<50, GS>50) is based on the share (%) of each classes' actual retail kWh (exclusive of distribution losses) and a share of actual wholesale kWh. Weather normalized wholesale kWh, for historical years, are allocated to these classes based on these historical shares. Forecast values for 2016 and 2018 are allocated based on the most recent year's (2016) actual share. For those rate classes that use kW consumption as a billing determinant, sales for these customer classes are then converted to kW based on the historical volumetric relationship between kWh and kW. The utility then forecasts a consumption per customer and adds new customer's load to the total consumption for the class.

Allocation to specific non-weather sensitive rate classes (GS>50, USL and Streetlights) is based on an average of demand/customer. The utility then uses an appropriate historical average to determine an average demand per customer. This average is then applied to the customer count for the bridge and test year. [6]

3.1.11 LOAD FORECAST BY CLASS.

The following section presents class specific adjusted historical and forecast values for those classes that have weather sensitive load. Historic class, specific kWh consumption is allocated based on each class' share in wholesale kWh, exclusive of distribution losses. Forecast class values are allocated based on the class share for 2015.

Table 12 to 17 show historical and forecasted details for each of the weather sensitive classes.

[6] MFR - For consumption and demand - explanation to support how kWh are converted to kW for applicable demand-billed classes, year-over-year variances in kWh and kW by rate class and for system consumption overall (kWh) with explanations for material changes in the definition of or major changes over time (should be done for both historical actuals against eachother and historical weather-normalized actuals over time), explanations of the bridge and test year forecasts by rate class, variance analysis between the last OEB-approved and the actual and weather-normalized actual results

Table 12 - Residential Forecast (Weather Sensitive)

Residential						
Year	Residential Metered kWh	Wholesale Purchases	Weather Normalized	*Ratio%* *	Weather Normal	Per customer
2007	19,386,628	29,814,696	65.02%	29,720,954	19,325,674	11,442
2008	19,644,024	30,200,534	65.05%	29,974,902	19,497,261	11,186
2009	19,949,142	30,345,587	65.74%	29,782,057	19,578,678	11,143
2010	19,868,483	30,101,478	66.01%	29,840,077	19,695,945	11,084
2011	19,799,668	30,321,059	65.30%	29,442,446	19,225,934	10,771
2012	19,634,780	30,128,196	65.17%	30,243,327	19,709,812	11,023
2013	19,650,696	30,360,992	64.72%	30,138,226	19,506,514	10,897
2014	19,479,913	30,241,782	64.41%	30,476,269	19,630,955	10,631
2015	19,377,540	29,988,135	64.62%	30,222,148	19,528,753	10,137
2016	19,268,403	29,764,983	65.12%	31,427,034	20,463,869	10,922
2017			65.12%	30,476,293	19,844,790	10,591
2018		Avg	65.12%	30,646,239	19,955,450	10,496

Load corrected based on utility input						
Residential		Per Customer Weather Normalized				
Year	New Customer		Added Load			Total
2017	114	10,591	1,202,110			21,046,900
2018	60	10,496	629,747			21,676,646

Table 13 - General Service <50 Forecast (Weather Sensitive)

Year	GS<50 Metered kWh	Wholesale Purchases	Weather Normalized	*Ratio%* *	Weather Normal	Per customer
2007	4,791,862	29,814,696	16.07%	29,720,954	4,776,796	29,486
2009	4,914,869	30,200,534	16.27%	29,974,902	4,878,149	30,112
2009	4,828,893	30,345,587	15.91%	29,782,057	4,739,218	30,975
2010	4,729,493	30,101,478	15.71%	29,840,077	4,688,422	31,049
2011	4,584,672	30,321,059	15.12%	29,442,446	4,451,822	28,176
2012	4,742,923	30,128,196	15.74%	30,243,327	4,761,047	30,325
2013	4,699,450	30,360,992	15.48%	30,138,226	4,664,969	29,339
2014	4,701,954	30,241,782	15.55%	30,476,269	4,738,412	29,801
2015	4,594,197	29,988,135	15.32%	30,222,148	4,630,048	28,061
2016	4,538,610	29,764,983	15.25%	31,427,034	4,792,042	29,399
2017			15.64%	30,476,293	4,767,365	28,873
2018		Avg	15.64%	30,646,239	4,793,949	29,015

Load corrected based on utility input						
GS<50						
Year	New Customer	Per Customer Weather Normalized	Added Load			Total
2017	5	28,873	147,625			4,941,575
2018	4	29,015	116,058			5,057,633

Table 14 - General Service >50 (kWh) (Weather Sensitive)

Year	GS>50 Metered kWh	Wholesale Purchases	Weather Normalized	*Ratio%* *	Weather Normal	Per customer
2007	6,509,020	29,814,696	21.83%	29,720,954	6,488,555	540,713
2009	3,938,140	30,200,534	13.04%	29,974,902	3,908,718	325,726
2009	4,153,840	30,345,587	13.69%	29,782,057	4,076,701	370,609
2010	4,088,586	30,101,478	13.58%	29,840,077	4,053,081	368,462
2011	4,053,345	30,321,059	13.37%	29,442,446	3,935,891	357,808
2012	4,292,894	30,128,196	14.25%	30,243,327	4,309,299	391,754
2013	4,289,465	30,360,992	14.13%	30,138,226	4,257,992	387,090
2014	4,346,251	30,241,782	14.37%	30,476,269	4,379,951	398,177
2015	4,316,369	29,988,135	14.39%	30,222,148	4,350,052	395,459
2016	4,274,953	29,764,983	14.36%	31,427,034	4,513,663	410,333
2017			14.70%	30,476,293	4,480,483	411,274
2018		Avg	14.70%	30,646,239	4,505,468	417,585

Load corrected based on utility input						
GS>50						
Year	New Customer	Per Customer Weather Normalized	Added Load			Total
2017	-2	411,274	-822,547			3,657,936
2018	0	417,585	0			2,835,388

Table 15 - General Service >50 Demand (kW) (Non-Weather Sensitive)

Year	kWh	kWh	kW
2007	6,509,020	13,561	0.00208
2008	3,938,140	12,578	0.00319
2009	4,153,840	12,095	0.00291
2010	4,088,586	11,793	0.00288
2011	4,053,345	11,861	0.00293
2012	4,292,894	12,486	0.00291
2013	4,289,465	12,639	0.00295
2014	4,346,251	12,214	0.00281
2015	4,316,369	12,238	0.00284
2016	4,274,953	12,169	0.00285
2017	4,480,483	12,701	0.00283
2018	4,505,468	12,772	0.00283
Avg			0.00283

1 **Table 16 - Street Lighting (Non-Weather Sensitive)**

Year	kWh	kWh	kW	Customer/ Connection	kWh per connection	KW per connection
2007	379,503	987	406	936	2.4340	0.00260
2008	388,274	1,007	409	949	2.4621	0.00259
2009	350,654	1,003	409	857	2.4523	0.00286
2010	381,018	1,003	409	932	2.4523	0.00263
2011	357,291	1,003	409	874	2.4523	0.00281
2012	355,537	1,003	409	869	2.4523	0.00282
2013	359,464	1,003	409	879	2.4523	0.00279
2014	359,464	1,003	409	879	2.4523	0.00279
2015	373,173	1,050	430	868	2.4419	0.00281
2016	376,348	576	505	746	1.1417	0.00153
2017	385,594	590	517	746	1.1414	0.00153
2018	395,068	605	530	746	1.1424	0.00153
Avg				894	1.1417	0.00153

2

3

Table 17 - Unmetered Scattered Load (Non-Weather Sensitive)

Year	kWh	Customer/ Connection	kWh per connection
2007	88,330	18	4,907
2009	93,536	20	4,677
2009	92,676	19	4,878
2010	89,786	19	4,726
2011	89,208	19	4,695
2012	89,208	19	4,695
2013	89,208	19	4,695
2014	89,075	19	4,688
2015	94,284	19	5,096
2016	94,284	18	5,388
2017	92,045	19	4,844
2018	92,045	19	4,844
Avg - Years =		*19*	*4,844*

3.1.12 FINAL NORMALIZED LOAD FORECAST

Table 18 below presents historical and projected weather normalized Load Forecast by customer class.

Table 18 - Final Load Forecast (not CDM adjusted)

	Year	2017	2018
Residential	Cust/Conn	2,040	2,100
	kWh	21,046,900	21,676,646
	kW		
General Service < 50 kW	Cust/Conn	168	172
	kWh	4,941,575	5,057,633
	kW		
General Service > 50 to 4999 kW	Cust/Conn	9	9
	kWh	3,657,936	2,835,388
	kW	12,701	12,772
USL	Cust/Conn	17	17
	kWh	82,356	82,356
	kW	-	-
Street Lighting	Cust/Conn	517	530
	kWh	385,594	395,068
	kW	590	605
Total	Cust/Conn	2,751	2,828
	kWh	30,114,361	30,047,092
	kW	13,291	13,377

3.2 IMPACT AND PERSISTENCE FROM HISTORICAL CDM PROGRAMS[7]

3.2.1 LOAD FORECAST CDM ADJUSTMENT WORK FORM

While the forecast as presented in the previous section assumes some level of embedded "natural conservation," it does not take into account the impacts on energy purchases arising from CDM programs undertaken by CHEI's customers. The load forecast is a projection of the expected level of electricity purchases that would occur over the specified period in the absence of any CDM initiatives. Therefore, in accordance with the filing requirements, the forecasted energy purchases are further adjusted to reflect CDM reductions.

The schedule to achieve CDM targets are presented in Table 19 below:

[7] MFR - Quantification of any impacts arising from the persistence of historical CDM programs as well as the forecasted impacts arising from new programs in the bridge and test years through the current 6-year CDM framework.

Table 19 – OEB Appendix 2-I

2011-2014 CDM Program - 2014, last year of the current CDM plan					
4 Year (2011-2014) kWh Target:					
1,200,000					
	2011	2012	2013	2014	Total
2011 CDM Programs	4.63%	4.63%	4.63%	4.63%	18.50%
2012 CDM Programs		14.59%	14.59%	14.33%	43.52%
2013 CDM Programs			14.33%	14.33%	28.66%
2014 CDM Programs				9.38%	9.38%
Total in Year	4.63%	19.22%	33.55%	42.67%	100.07%
kWh					
2011 CDM Programs	71,000	71,000	71,000	71,000	284000
2012 CDM Programs	- 2,000	224,000	224,000	220,000	666000
2013 CDM Programs	-	-	220,000	220,000	440000
2014 CDM Programs	-	-	1,000	144,000	145000
Total in Year	69,000.00	295,000.00	516,000.00	655,000.00	1,535,000.00

2015-2020 CDM Program - 2015, first year of the current CDM plan									
6 Year (2015-2020) kWh Target:									
1,790,000									
	2015	2016	2017	2018	2019	2020	Total		
%									
2015 CDM Programs	96.13%	96.13%	96.13%	96.13%	96.13%	88.33%	568.97%		
2016 CDM Programs		2.33%	2.33%	2.33%	2.33%	2.33%	11.67%		
2017 CDM Programs			2.33%	2.33%	2.33%	2.33%	9.34%		
2018 CDM Programs				2.33%	2.33%	2.33%	7.00%		
2019 CDM Programs					2.33%	2.33%	4.67%		

2020 CDM Programs						2.33%	2.33%		
Total in Year	96.13%	98.46%	100.80%	103.13%	105.47%		603.99%		
kWh									
2015 CDM Programs	1,720,706.00	1,720,706.00	1,720,706.00	1,720,706.00	1,720,706.00	1,581,029.00	1,581,029.00		
2016 CDM Programs		41,794.20	41,794.20	41,794.20	41,794.20	41,794.20	41,794.20		
2017 CDM Programs			41,794.20	41,794.20	41,794.20	41,794.20	41,794.20		
2018 CDM Programs				41,794.20	41,794.20	41,794.20	41,794.20		
2019 CDM Programs					41,794.20	41,794.20	41,794.20		
2020 CDM Programs						41,794.20	41,794.20		
Total in Year	1,720,706.00	1,762,500.20	1,804,294.40	1,846,088.60	1,887,882.80	1,790,000.00	1,790,000.00		
Weight Factor for Inclusion in CDM Adjustment to 2014 Load Forecast									
	2011	2012	2013	2014	2015	2016	2017	2018	
Weight Factor for each year's CDM program impact on 2014 load forecast	0	0	0	0	0	0.5	1	0.5	Distributor can select "0", "0.5", or "1" from drop-down list
Default Value selection rationale.									
2011-2014 and 2015-2020 LRAMVA and 2015 CDM adjustment to Load Forecast									
	2011	2012	2013	2014	2015	2016	2017	2018	Total for 2018
	kWh								
Amount used for CDM threshold for LRAMVA (2014)	-	-	220,000.00	144,000.00	1,720,706.00				2,084,706.00

2011 CDM adjustment (per Board Decision in 2011 Cost of Service Application)	-	-	-	-		-			
Amount used for CDM threshold for LRAMVA (2015)						41,794.20	41,794.20	41,794.20	125,382.60
Manual Adjustment for 2015 Load Forecast (billed basis)	-				-	20,897.10	41,794.20	20,897.10	83,588.40

The values entered in the 2011-2014 report originate from the OPA issued report; 2006-2010 Final OPA CDM Results. The report provides a portfolio-level summary of the annual resource savings (demand and energy, net and gross for each) for the 2006–2010 program portfolios for CHEI. CHEI used the Q4 report from the OPA. The most recent annual results of OPA CDM programs and the Q4 results are presented as an appendix to this Exhibit.[8]

The values entered in the 2015-2020 originate from CHEI's approved CDM plan which shows CHEI's targets to be 4.17 GWh.

[8] MFR - CDM Adjustment - account for CDM in 2017 load forecast. Consider impact of persistence of historical CDM and impact of new programs. Adjustments may be required for IESO reported results which are full year impacts

3.2.2 ALLOCATION OF CDM RESULTS

The overall CDM adjustment for 2015, as calculated above, is allocated on a pro-rata basis (using kWh forecast) per class. Table 20 below presents the method behind CHEI's allocation of CDM reduction in consumption.

Table 20 - CDM adjustments to Load Forecast

		2017	2018		Share	Target	Final Adjusted (kWh)
Residential	Cust/Conn	2,040	2,100				2,100
	kWh	21,046,900	21,676,646		72.14%	60,303	21,616,344
	kW						
General Service < 50 kW	Cust/Conn	168	172				172
	kWh	4,941,575	5,057,633		16.83%	14,070	5,043,563
	kW						
General Service > 50 to 4999 kW	Cust/Conn	9	9				9
	kWh	3,657,936	2,835,388		9.44%	7,888	2,827,501
	kW	12,701	12,772				12,736
USL	Cust/Conn	17	17				17
	kWh	82,356	82,356		0.27%	229	82,127
	kW	-	-				-
Street Lighting	Cust/Conn	517	530				530
	kWh	385,594	395,068		1.31%	1,099	393,969
	kW	590	605				603
Total	Cust/Conn	2,751	2,828				2,828
	kWh	30,114,361	30,047,092				29,963,504
	kW	13,291	13,377			83,588.40	13,339

The following table shows the per class allocation of the amount used for CDM threshold for LRAMVA (2018).

1 **Table 21 - Allocation of amount used for CDM threshold for LRAMVA[9]**

	Year	Share	Target
Residential			
	kWh	72.14%	1,503,954
General Service < 50 kW			
	kWh	16.83%	350,905
General Service > 50 to 4999 kW			
	kWh	9.44%	196,723
USL			
	kWh	0.27%	5,714
Street Lighting			
	kWh	1.31%	27,410
Total	kWh		2,084,706.00

2

3 3.2.3 FINAL CDM ADJUSTED LOAD FORECAST

4 below provides details of the Final Customer and Volume Load Forecast for each of the years.
5 This summary of the billing determinants by rate class will be used to develop CHEI's proposed
6 rates.

[9] MFR - CDM savings for 2017 LRAMVA balance and adjustment to 2017 load forecast; data by customer class and for both kWh and, as applicable, kW. Provide rationale for level of CDM reductions in 2017 load forecast

Table 22 - Final Customer and Volume Load Forecast

	Year	2014	2015	2016	2017	2018	2018 CDM Adjusted
Residential	Cust/Conn	1,800	1,847	1,927	2,040	2,100	2,100
	kWh	19,479,913	19,377,540	19,268,403	21,046,900	21,676,646	21,616,344
	kW						
General Service < 50 kW	Cust/Conn	159	165	163	168	172	172
	kWh	4,701,954	4,594,197	4,538,610	4,941,575	5,057,633	5,043,563
	kW						
General Service > 50 to 4999 kW	Cust/Conn	11	11	11	9	9	9
	kWh	4,346,251	4,316,369	4,274,953	3,657,936	2,835,388	2,827,501
	kW	12,214	12,238	12,169	12,701	12,772	12,736
USL	Cust/Conn	19	19	18	17	17	17
	kWh	89,075	94,284	94,284	82,356	82,356	82,127
	kW	-	-	-	-	-	-
Street Lighting	Cust/Conn	409	430	505	517	530	530
	kWh	359,464	373,173	376,348	385,594	395,068	393,969
	kW	1,003	1,050	576	590	605	603
Total	Cust/Conn						
	kWh	2,398	2,471	2,623	2,751	2,828	2,828
	kW	28,976,657	28,755,563	28,552,598	30,114,361	30,047,092	29,963,504
		13,217	13,288	12,745	13,291	13,377	13,339

3.3 ACCURACY OF LOAD FORECAST AND VARIANCE ANALYSIS

3.3.1 VARIANCE ANALYSIS OF LOAD FORECAST[10]

Table 23 below shows the yearly change in consumption for the Residential class.

Table 23 - Residential Variance

Residential				
Year	**Cust**	**%chg**	**kWh**	**%chg**
2007	1,689		19,386,628	
2008	1,743	3%	19,644,024	1%
2009	1,757	1%	19,949,142	2%
2010	1,777	1%	19,868,483	0%
2011	1,785	0%	19,799,668	0%
2012	1,788	0%	19,634,780	-1%
2013	1,790	0%	19,650,696	0%
2014	1,800	1%	19,479,913	-1%
2015	1,847	3%	19,377,540	-1%
2016	1,927	4%	19,268,403	-1%
2017	2,040	6%	21,046,900	9%
2018	2,100	3%	21,676,646	12%

The residential customer class has been growing slowly but steadily since 2007 but increasing more in 2016/2017 and 2018. Being only a 30-minute drive from Ottawa, Embrun is becoming an attractive bedroom community for commuters who work in Ottawa. Residential counts are expected to grow by 172 from 2016 to 2018.

[10] MFR - For customer/connection counts - identification as to whether customer/connection count is shown in year end or average format, year-over-year variances in changes of customer/connection counts with explanation of major changes, explanations of bridge and test year forecasts by rate class, for last rebasing variance analysis between last OEB-approved and actuals with explanations for material differences

Table 24 below shows the yearly change in consumption for the GS<50 kW class.

Table 24 - GS <50 kW Variance

GS<50				
Year	**Cust**	**%chg**	**kWh**	**%chg**
2007	162		4,791,862	
2008	162	0%	4,914,869	3%
2009	153	-6%	4,828,893	-2%
2010	151	-1%	4,729,493	-2%
2011	158	5%	4,584,672	-3%
2012	157	-1%	4,742,923	3%
2013	159	1%	4,699,450	-1%
2014	159	0%	4,701,954	0%
2015	165	4%	4,594,197	-2%
2016	163	-1%	4,538,610	-1%
2017	168	3%	4,941,575	9%
2018	172	2%	5,057,633	2%

The number of customers in the GS<50 kW class has also been modestly growing over the past 10 years at a rate of 1-2 customers per year. CHEI anticipates a modest increase of 5 customers for 2017 and 5 more customers in 2018.

Table 25 below shows the yearly change in consumption for the GS>50kW class.

Table 25 - GS>50 Variance

GS>50						
Year	**Cust**	**%chg**	**kWh**	**%chg**	**kW**	**%chg**
2007	12		6,509,020		13,561	
2008	12	0%	3,938,140	-39%	12,578	-7%
2009	11	-8%	4,153,840	5%	12,095	-4%
2010	11	0%	4,088,586	-2%	11,793	-2%
2011	11	0%	4,053,345	-1%	11,861	1%
2012	11	0%	4,292,894	6%	12,486	5%
2013	11	0%	4,289,465	0%	12,639	1%
2014	11	0%	4,346,251	1%	12,214	-3%
2015	11	0%	4,316,369	-1%	12,238	0%
2016	11	0%	4,274,953	-1%	12,169	-1%
2017	9	-18%	3,657,936	-14%	12,701	4%
2018	9	0%	2,835,388	-22%	12,772	1%

The customer count for the GS>50 kW class has seen very little change over the last 10 years. CHEI projects a small decrease due to two customers being reclassified to the GS < 50 class in 2016. The consumption in this rate class is decreasing only because of the two customers that moved down a class, therefore, no further changes are projected for 2017 and 2018.

Table 26 below shows the yearly change in consumption for the Streetlight class.

Table 26 - Street Lights Variance

StreetLights						
Year	**Cust**	**%chg**	**kWh**	**%chg**	**kW**	**%chg**
2007	406		379,503		987	
2008	409	1%	388,274	2%	1,007	2%
2009	409	0%	350,654	-10%	1,003	0%
2010	409	0%	381,018	9%	1,003	0%
2011	409	0%	357,291	-6%	1,003	0%
2012	409	0%	355,537	0%	1,003	0%
2013	409	0%	359,464	1%	1,003	0%
2014	409	0%	359,464	0%	1,003	0%
2015	430	5%	373,173	4%	1,050	5%
2016	505	17%	376,348	1%	576	-45%
2017	517	2%	385,594	2%	590	2%
2018	530	2%	395,068	2%	605	3%

CHEI projects an increase of 25 connections between 2016 and 2018. These street light connections will be added to the new subdivision. The Town together with CHEI have discussed a streetlight LED retrofit program, but there is no indication that the Town will commit to this conversion in the near future.

Table 27 below shows the yearly change in consumption for the USL class.

Table 27 - USL Variance

USL						
Year	**Cust**	**%chg**	**kWh**	**%chg**		
2007	18		88,330			
2008	20	11%	93,536	6%		
2009	19	-5%	92,676	-1%		
2010	19	0%	89,786	-3%		
2011	19	0%	89,208	-1%		
2012	19	0%	89,208	0%		
2013	19	0%	89,208	0%		
2014	19	0%	89,075	0%		
2015	19	-3%	94,284	6%		
2016	18	-5%	94,284	0%		
2017	17	0%	82,356	-13%		
2018	17	0%	82,356	0%		

CHEI anticipates a small decrease of one connection in USL for a total of 17 in the 2018 Test year.

In summary, for customer counts, CHEI expects an increase in the Residential, GS<50, and Street Lights classes, and small decreases in the GS>50 categories and USL.

Energy consumption that does not depend on the weather (often referred to as "baseload" energy consumption) is often offset by the additional transitioning to energy efficient lighting, appliances and other energy efficient changes. Table 30 provides details of the variances by rate class.

Table 28 – OEB Appendix 2-IA[11]

	Calendar Year (for 2017 Cost of Service)	Customers / Connections		Consumption (kWh) (3) Weather-actual	Consumption (kWh) (3) Weather-normalized		Demand (kW or kVA) Weather-actual	Demand (kW or kVA) Weather-normalized		Revenues Weather-actual	Revenues Weather-normalized
Historical	2012	2384		30091478	30243327		13489	13489			
Historical	2013	2388		30301350	30138226		13642	13642		769895	
Historical	2014	2398	Board-approved (2)	30157452	30476269	Board-approved (2)	13217	19738	Board-approved (2)	792808	
Historical	2015	2471		29896472	30222148		13288	13288		792971	
Historical	2016	2623		29672839	31427034		12978	12978		829112	
Bridge Year (Forecast)	2017	2751			30047092			13291			820815
Test Year (Forecast)	2018	2828			29963504			13339			1107885

Due to its length when printed, CHEI has filed the OEB Appendix 2-IB at Appendix A of this Exhibit.[12]

[11] MFR - Completed Appendix 2-I
[12] MFR - Completed Appendix 2-IB; the customer and load forecast for the test year must be entered on RRWF, Tab 10

Table 3.32 below presents the actual average use per customer, by customer class, and historical and adjusted forecast average use per customer generated using the load forecast. As can be seen from the results below, the predicted use per customer follows the trend created from its historical usage per customer.[13]

Table 29 - Average per customer use

Average per customer								
	Residential	**GS<50**	**GS>50**		**USL**		**StreetLights**	
Year	**kWh/cust**	**kWh/cust**	**kWh/cust**	**kW/cust**	**kWh/cust**	**kW/cust**	**kWh/conn**	**kW/conn**
2007	11,442	29,486	540,713	1,130	4,907	0	936	2
2008	11,186	30,112	325,726	1,048	4,677	0	949	2
2009	11,143	30,975	370,609	1,100	4,878	0	857	2
2010	11,084	31,049	368,462	1,072	4,726	0	932	2
2011	10,771	28,176	357,808	1,078	4,695	0	874	2
2012	11,023	30,325	391,754	1,135	4,695	0	869	2
2013	10,897	29,339	387,090	1,149	4,695	0	879	2
2014	10,631	29,801	398,177	1,110	4,688	0	879	2
2015	10,137	28,061	395,459	1,113	5,096	0	868	2
2016	10,922	29,399	410,333	1,106	5,388	0	746	1
2017	10,591	28,873	411,274	1,411	4,721	0	746	1
2018	10,496	29,015	417,585	1,419	4,736	0	746	1

The next section details a variance analysis of the utility's past and projected revenues.

[13] MFR - With respect to average consumption, for each rate class, distributors are to provide weather-actual and weather-normalized average annual consumption or demand per customer as applicable for last OEB approved and historical, weather normalized average annual consumption or demand per customer for the bridge and test years, explanation of the net change in average consumption from last OEB-approved and actuals from historical, bridge and test years based on year-over-year variances and any apparant trends in data

3.3.2 VARIANCE ANALYSIS OF DISTRIBUTION REVENUES[14]

The tables below provides details of the Final Customer and Volume Load Forecast for each of the years. This summary of the billing determinants by rate class will be used to develop CHEI's proposed rates.

[14] MFR - For revenues - calculation of bridge year forecast of revenues at existing rates, calculation of test year forecasted revenues at existing and proposed rates, year-over-year variances in revenues comparing historical actuals and bridge and test year forecasts

Table 30 - Variance Analysis of Revenues

The table below shows year over year of CHEI's revenues. A detailed analysis follows.

	Year	2014 Board Approved	2014	2015	Variance	2016	Variance	2017	Variance	2018	Variance
Residential	Fixed	$14.56	$14.56	$14.77	$0.21	$18.25	$3.48	$21.87	$3.62	$31.99	$10.12
	Variable	$0.0136	$0.0136	$0.0138	$0.00	$0.0106	-$0.00	$0.0072	-$0.00	$0.0046	-$0.00
	Cust/Conn	2,048	1,809	1,884	75	1,965	81	2,040	75	2,100	60
	kWh	22,293,395	19,479,913	19,377,540	-102373	19,268,403	-109137	21,046,900	1778497	21,616,344	569444
	Revenues	$661,017	$580,995	$601,330	$20,335	$634,580	$33,250	$686,915	$52,335	$905,860	$218,945
			-12%	4%	16%	6%	2%	8%	3%	32%	24%
General Service < 50 kW	Fixed	$16.98	$16.98	$17.23	$0.25	$17.57	$0.34	$17.90	$0.33	$21.68	$3.78
	Variable	$0.0140	$0.0140	$0.0142	$0.00	$0.0145	$0.00	$0.0148	$0.00	$0.0112	-$0.00
	Cust/Conn	168	165	165	0	161	-4	168	7	172	4
	kWh	5,055,559	4,699,450	4,594,197	-105253	4,547,781	-46416	4,941,575	393794	5,043,563	101988
	Revenues	$105,010	$99,413	$99,353	-$60	$99,888	$535	$109,246	$9,358	$101,117	-$8,129
			-5%	0%	5%	1%	1%	9%	9%	-7%	-17%
General Service > 50 kW - 4999 kW	Fixed	$189.25	$189.25	$191.99	$2.74	$195.73	$3.74	$199.45	$3.72	$199.45	$0.00
	Variable	$3.5066	$3.5066	$3.5574	$0.05	$3.6268	$0.07	$3.6957	$0.07	$3.9545	$0.26
	Cust/Conn	11	11	11	0	11	0	9	-2	9	0
	kWh	4,276,256	4,189,855	4,316,369	126514	4,242,389	-73980	3,657,936	-584453	2,827,501	-830435
	kW	12,633	18,735	12,238	-6497	12,058	-180	12,701	643	12,736	35
	Revenues	$69,280	$90,677	$68,878	-$21,799	$69,568	$690	$68,479	-$1,090	$71,906	$3,427
			31%	-24%	-55%	1%	25%	-2%	-3%	5%	7%

Unmetered Scattered Load	Fixed	$20.08	$20.08	$20.37	$0.29	$20.77	$0.40	$21.16	$0.39	$21.16	$0.00
	Variable	$0.0052	$0.0052	$0.0053	$0.00	$0.0054	$0.00	$0.0055	$0.00	$0.0174	$0.01
	Cust/Conn	20	18	18	0	17	-1	17	0	17	0
	kWh	91,446	89,075	94,284	5209	93,284	-1000	82,356	-10928	82,127	-229
	Revenues	$5,295	$4,800	$4,900	$99	$4,741	-$159	$4,883	$142	$5,847	$965
			-9%	2%	11%	-3%	-5%	3%	6%	20%	17%
Streetlighting	Fixed	$1.88	$1.88	$1.91	$0.03	$1.95	$0.04	$1.99	$0.04	$1.99	$0.00
	Variable	$7.6728	$7.6728	$7.7841	$0.11	$7.9359	$0.15	$8.0867	$0.15	$17.4164	$9.33
	Cust/Conn	425	409	451	42	558	107	517	-41	530	13
	kWh	382,524	359,464	373,173	13709	321,015	-52158	385,594	64579	393,969	8375
	kW	1,023	1,003	1,050	47	917	-133	590	-327	603	13
	Revenues	$17,434	$16,923	$18,510	$1,587	$20,334	$1,824	$17,115	-$3,220	$23,154	$6,040
			-3%	9%	12%	10%	0%	-16%	-26%	35%	51%
Total	**Cust/Conn**	**2,672**	**2,412**	**2,529**	117	**2,712**	183	**2,751**	39	**2,828**	77
	kWh	**32,099,180**	**28,817,757**	**28,755,563**	-62194	**28,472,872**	-282691	**30,114,361**	1641489	**29,963,504**	-150857
	kW	**13,656**	**19,738**	**13,288**	-6450	**12,975**	-313	**13,291**	316	**13,339**	49
		$858,035	**$792,808**	**$792,971**	**$163**	**$829,112**	**$36,140**	**$886,637**	**$57,525**	**$1,107,885**	**$221,248**

2014 Actual VS 2015 Actual

The total distribution revenue in 2015 of $792,971 was a marginal $165 more than the 2014 Actual therefore no explanation is required.

2015 Actual VS 2016 Actual

The total distribution revenue in 2016 of $829,112 was $36,140 greater than the 2015 Actual. The main reason for the increase was an increase in the residential customer count which in turn increased the revenues from this class by $33,250.

2016 Actual VS 2017 Actual

The total distribution revenue in 2017 of $820,815 was a marginal $57,525 less than the 2016 Actual therefore no explanation is required.

2017 Actual VS 2018 Actual

The total distribution revenue in 2018 of $1,107,885 is projected to be 221,248 greater than 2017. This revenue is necessary in order to meet the reliability standards that are expected from the regulator and customer and to maintain the level of customer service at current level.

Table 31 - Revenues at proposed rates

2018 Rates at 2018 Load

	Test Year Projected Revenue from Proposed Variable Charges							
Customer Class Name	Variable Distribution Rate	per	Test Year Volume	Gross Variable Revenue	Transform. Allowance Rate	Transform. Allowance kW's	Transform. Allowance $'s	Net Variable Revenue
Residential	$0.0046	kWh	21,616,344	$99,712.48			$0.00	$99,712.48
General Service < 50 kW	$0.0112	kWh	5,043,563	$56,340.53			$0.00	$56,340.53
General Service > 50 to 4999 kW	$3.9545	kW	12,736	$50,365.01	0.00		$0.00	$50,365.01
Unmetered Scattered Load	$0.0174	kWh	82,127	$1,431.59			$0.00	$1,431.59
Street Lighting	$17.4164	kW	603	$10,507.59			$0.00	$10,507.59
Total Variable Revenue			26,755,373	$218,357.19	0	0	$0.00	$218,357.19

2018 Rates at 2018 Load

	Test Year Projected Revenue from Proposed Fixed Charges							
Customer Class Name	Fixed Rate	Customers (Connections)	Fixed Charge Revenue	Variable Revenue	TOTAL	% Fixed Revenue	% Variable Revenue	% Total Revenue
Residential	$31.9900	2,100	$806,148.00	$99,712.48	$905,860.48	88.99%	11.01%	81.76%
General Service < 50 kW	$21.6800	172	$44,776.88	$56,340.53	$101,117.41	44.28%	55.72%	9.13%
General Service > 50 to 4999 kW	$199.4500	9	$21,540.60	$50,365.01	$71,905.61	29.96%	70.04%	6.49%
Unmetered Scattered Load	$21.1600	17	$4,415.87	$1,431.59	$5,847.45	75.52%	24.48%	0.53%
Street Lighting	$1.9900	530	$12,646.72	$10,507.59	$23,154.31	54.62%	45.38%	2.09%
Total Fixed Revenue		2,828	$889,528.07	$218,357.19	$1,107,885.26			

3.4 OTHER REVENUES

3.4.1 OVERVIEW OF OTHER REVENUE

Other Distribution Revenues are revenues that are distribution related but are sourced from means other than distribution rates. For this reason, other revenues are deducted from CHEI's proposed revenue requirement. Further details on the derivation of the Revenue Requirement is presented in Exhibit 6.

Other Distribution Revenues includes items such as:

- Specific Service Charges
- Late Payment Charges
- Other Distribution Revenues
- Other Income and Expenses

CHEI is proposing one change to the Microfit Service Charges as explained in 3.4.3

OEB APPENDIX 2-H OTHER OPERATING REVENUES

A detailed breakdown by USoA account is shown in Table 32 - OEB Appendix 2-H presented on the next page. Year over year variance analysis follow at Ex.3/Tab 4/Sch.2 - Other Revenue Variance Analysis.

Table 32 – OEB Appendix 2-H[15]

	Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
		2014	2014	2015	2016	2017	2018
	USoA Description	Board Approved					
4235	4235-Miscellaneous Service Revenues	-$14,200	-$14,580	-$16,185	-$18,595	-$19,721	-$20,041
4225	4225-Late Payment Charges	-$6,000	-$7,963	-$9,946	-$11,283	-$11,320	-$11,400
4082	4082-Retail Services Revenues	-$4,130	-$3,343	-$3,398	-$3,151	-$3,239	-$3,245
4084	4084-Service Transaction Requests (STR) Revenues	$13	-$2	-$2	-$8	-$9	-$10
4210	4210-Rent from Electric Property	$0	-$6,561	-$5,917	-$6,452	-$6,482	-$6,593
4240	4240-Provision for Rate Refunds	$0	$21,935	$20,000	$20,000	$20,000	$20,000
4375	4375-Revenues from Non-Utility Operations	$0	-$31,129	-$9,347	-$3,215	-$75,000	-$30,000
4380	4380-Expenses of Non-Utility Operations	$0	$21,859	$0	$3,215	$75,000	$30,000
4390	4390-Miscellaneous Non-Operating Income	$0	$0	-$7,443	-$12,331	-$5,000	-$5,500
4405	4405-Interest and Dividend Income	$0	-$28,723	-$23,486	-$22,161	-$11,000	-$2,000
	Total	-$30,317	-$48,507	-$55,725	-$53,980	-$36,770	-$28,789

	Specific Service Charges	-$14,200	-$14,580	-$16,185	-$18,595	-$19,721	-$20,041
	Late Payment Charges	-$6,000	-$7,963	-$9,946	-$11,283	-$11,320	-$11,400
	Other Distribution/Operating Revenues	-$4,117	$12,029	$10,683	$10,389	$10,271	$10,152
	Other Income or Deductions	$0	-$37,993	-$40,276	-$34,491	-$16,000	-$7,500
	Total	-$24,317	-$48,507	-$55,725	-$53,980	-$36,770	-$28,789

[15] MFR - Completed Appendix 2-H

3.4.2 OTHER REVENUE VARIANCE ANALYSIS[16]

Table 33 to 37 below presents year over year variances of other operating revenues:

Table 33 - Variance Analysis of Other Operating Revenues

2014 BA – 2014

		2014	2014	Var
	USoA Description	**Board Approved**		
4235	**4235-Miscellaneous Service Revenues**	-$14,200	-$14,580	-$380
4225	**4225-Late Payment Charges**	-$6,000	-$7,963	-$1,963
4082	4082-Retail Services Revenues	-$4,130	-$3,343	$787
4084	4084-Service Transaction Requests (STR) Revenues	$13	-$2	-$15
4210	4210-Rent from Electric Property	$0	-$6,561	-$6,561
4240	4240-Provision for Rate Refunds	$0	$21,935	$21,935
4375	4375-Revenues from Non-Utility Operations	$0	-$31,129	-$31,129
4380	4380-Expenses of Non-Utility Operations	$0	$21,859	$21,859
4390	4390-Miscellaneous Non-Operating Income	$0	$0	$0
4405	4405-Interest and Dividend Income	$0	-$28,723	-$28,723
	Total	-$30,317	-$48,507	-$18,190

	Specific Service Charges	-$14,200	-$14,580	-$380
	Late Payment Charges	-$6,000	-$7,963	-$1,963
	Other Distribution/Operating Revenues	-$4,117	$12,029	$16,146
	Other Income or Deductions	$0	-$37,993	-$37,993
	Total	-$24,317	-$48,507	-$24,190

The main contributor to the decrease is that CHEI did not forecast any income and deductions in its 2014 Cost of Service.

[16] MFR - Variance analysis - year over year, historical, bridge and test

Table 34 - Variance Analysis of Other Operating Revenues

2014-2015

		2014	2015	Var
	USoA Description			
4235	**4235-Miscellaneous Service Revenues**	-$14,580	-$16,185	-$1,605
4225	**4225-Late Payment Charges**	-$7,963	-$9,946	-$1,983
4082	4082-Retail Services Revenues	-$3,343	-$3,398	-$54
4084	4084-Service Transaction Requests (STR) Revenues	-$2	-$2	-$1
4210	4210-Rent from Electric Property	-$6,561	-$5,917	$644
4240	4240-Provision for Rate Refunds	$21,935	$20,000	-$1,935
4375	4375-Revenues from Non-Utility Operations	-$31,129	-$9,347	$21,782
4380	4380-Expenses of Non-Utility Operations	$21,859	$0	-$21,859
4390	4390-Miscellaneous Non-Operating Income	$0	-$7,443	-$7,443
4405	4405-Interest and Dividend Income	-$28,723	-$23,486	$5,237
	Total	-$48,507	-$55,725	-$7,217

	Specific Service Charges	-$14,580	-$16,185	-$1,605
	Late Payment Charges	-$7,963	-$9,946	-$1,983
	Other Distribution/Operating Revenues	$12,029	$10,683	-$1,346
	Other Income or Deductions	-$37,993	-$40,276	-$2,283
	Total	-$48,507	-$55,725	-$7,217

2014 to 2015 - The Other Revenues variance reflects a marginal decrease of $7,217 over 2014 which is mostly due to unexpected costs in account 4390- Miscellaneous Non-Operating Income.

Table 35 - Variance Analysis of Other Operating Revenues

2015 – 2016

		2015	2016	Var
	USoA Description			
4235	**4235-Miscellaneous Service Revenues**	-$16,185	-$18,595	-$2,410
4225	**4225-Late Payment Charges**	-$9,946	-$11,283	-$1,337
4082	4082-Retail Services Revenues	-$3,398	-$3,151	$246
4084	4084-Service Transaction Requests (STR) Revenues	-$2	-$8	-$6
4210	4210-Rent from Electric Property	-$5,917	-$6,452	-$534
4240	4240-Provision for Rate Refunds	$20,000	$20,000	$0
4375	4375-Revenues from Non-Utility Operations	-$9,347	-$3,215	$6,132
4380	4380-Expenses of Non-Utility Operations	$0	$3,215	$3,215
4390	4390-Miscellaneous Non-Operating Income	-$7,443	-$12,331	-$4,887
4405	4405-Interest and Dividend Income	-$23,486	-$22,161	$1,325
	Total	-$55,725	-$53,980	$1,745

	Specific Service Charges	-$16,185	-$18,595	-$2,410
	Late Payment Charges	-$9,946	-$11,283	-$1,337
	Other Distribution/Operating Revenues	$10,683	$10,389	-$293
	Other Income or Deductions	-$40,276	-$34,491	$5,785
	Total	-$55,725	-$53,980	$1,745

The forecast for the 2017 shows a marginal increase of 1,745 over the previous year. Year over year balances are comparable.

Table 36 - Variance Analysis of Other Operating Revenues

2016 – 2017

		2016	2017	Var
	USoA Description			
4235	**4235-Miscellaneous Service Revenues**	-$18,595	-$19,721	-$1,126
4225	**4225-Late Payment Charges**	-$11,283	-$11,320	-$37
4082	4082-Retail Services Revenues	-$3,151	-$3,239	-$87
4084	4084-Service Transaction Requests (STR) Revenues	-$8	-$9	-$1
4210	4210-Rent from Electric Property	-$6,452	-$6,482	-$30
4240	4240-Provision for Rate Refunds	$20,000	$20,000	$0
4245	4245-Government Assistance Directly Credited to Income	$0	$0	$0
		$0	$0	$0
4375	4375-Revenues from Non-Utility Operations	-$3,215	-$75,000	-$71,785
4380	4380-Expenses of Non-Utility Operations	$3,215	$75,000	$71,785
4390	4390-Miscellaneous Non-Operating Income	-$12,331	-$5,000	$7,331
4405	4405-Interest and Dividend Income	-$22,161	-$11,000	$11,161
	Total	-$53,980	-$36,770	$17,210

	Specific Service Charges	-$18,595	-$19,721	-$1,126
	Late Payment Charges	-$11,283	-$11,320	-$37
	Other Distribution/Operating Revenues	$10,389	$10,271	-$118
	Other Income or Deductions	-$34,491	-$16,000	$18,491
	Total	-$53,980	-$36,770	$17,210

The forecast for the 2017 Other revenues reflects an increase of $17,210 overall. All the accounts are very comparable with the exception of #4405, Interest and Dividend Income which continues to decrease as the bank balances decreases.

Table 37 - Variance Analysis of Other Operating Revenues

2017 – 2018

		2017	2018	Var
	USoA Description			
4235	**4235-Miscellaneous Service Revenues**	-$19,721	-$20,041	-$320
4225	**4225-Late Payment Charges**	-$11,320	-$11,400	-$80
4082	4082-Retail Services Revenues	-$3,239	-$3,245	-$7
4084	4084-Service Transaction Requests (STR) Revenues	-$9	-$10	-$1
4210	4210-Rent from Electric Property	-$6,482	-$6,593	-$112
4240	4240-Provision for Rate Refunds	$20,000	$20,000	$0
4245	4245-Government Assistance Directly Credited to Income	$0	$0	$0
		$0	$0	$0
4375	4375-Revenues from Non-Utility Operations	-$75,000	-$30,000	$45,000
4380	4380-Expenses of Non-Utility Operations	$75,000	$30,000	-$45,000
4390	4390-Miscellaneous Non-Operating Income	-$5,000	-$5,500	-$500
4405	4405-Interest and Dividend Income	-$11,000	-$2,000	$9,000
	Total	-$36,770	-$28,789	$7,981

	Specific Service Charges	-$19,721	-$20,041	-$320
	Late Payment Charges	-$11,320	-$11,400	-$80
	Other Distribution/Operating Revenues	$10,271	$10,152	-$120
	Other Income or Deductions	-$16,000	-$7,500	$8,500
	Total	-$36,770	-$28,789	$7,981

The forecast for the 2018 Other revenues reflects an increase of $7,981 overall. All the accounts are very comparable with the exception #4405, Interest and Dividend Income which continues to decrease as the bank balances decreases.

3.4.3 PROPOSED SPECIFIC SERVICE CHARGES[17]

CHEI is proposing no changes to the current specific services charges except for the microFIT service charge. CHEI incurs a $10.00 monthly fee per microFIT meter point from CHEI's vendor Utilismart and would like to pass this charge onto its microFIT customers. This increase in the customer charge from $5.40 to $10.00 was also agreed to in St. Thomas Energy Inc. (EB-2014-0113) Cost of Service Application as well as Renfrew Hydro Inc.

Other than the MicroFit class, no other class or discrete customer groups that may be materially impacted by changes to other rates and charges.[18]

3.4.4 REVENUE FROM AFFILIATE TRANSACTIONS, SHARED SERVICES, CORPORATE COST ALLOCATION.

CHEI does not have any affiliates and as such does not have any affiliate transactions, shared services and corporate cost allocation.[19]

[17] MFR – Any new proposed specific service charges
[18] MFR - Distributors must identify any discrete customer groups that may be materially impacted by changes to other rates and charges
[19] MFR - Revenue from affiliate transactions, shared services, corporate cost allocation

APPENDICES

Appendix A	OEB Appendix 2-BI

File Number:	0
Exhibit:	
Tab:	
Schedule:	
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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	30,091,478	30,243,327		
Historical	*2013*		Actual	30,301,350	30,138,226		
Historical	*2014*		Actual	30,157,452	30,476,269	Board-approved	
Historical	*2015*		Actual	29,896,472	30,222,148		
Historical	*2016*		Actual	29,672,839	31,427,034		
Bridge Year	*2017*		Forecast		30,476,293		
Test Year	*2018*		Forecast		2,959,106		

Variance Analysis	**Year**	**Year-over-year**			**Versus Board-approved**
	2012				
	2013	0.7%	-0.3%		
	2014	-0.5%	1.1%		
	2015	-0.9%	-0.8%		
	2016	-0.7%	4.0%		
	2017		-3.0%		
	2018		-90.3%		
	Geometric Mean		642.1%		

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	1,788		
Historical	2013	Actual	1,790		
Historical	2014	Actual	1,800	Board-approved	2048
Historical	2015	Actual	1,847		
Historical	2016	Actual	1,927		
Bridge Year	2017	Forecast	2,040		
Test Year	2018	Forecast	2,100		

	Consumption (kWh) [3] Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	19,634,780	19,709,812		
Actual	19,650,696	19,506,514		
Actual	19,479,913	19,630,955	Board-approved	22293395.2
Actual	19,377,540	19,528,753		
Actual	19,268,403	20,463,869		
Forecast		21,046,900		
Forecast		21,676,646		

	Consumption (kWh) per Customer Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	10981.421	11023.3847		
Actual	10978.042	10897.4937		
Actual	10825.181	10909.1165	Board-approved	10885.44688
Actual	10494.2	10576.0916		
Actual	10001.766	10622.3043		
Forecast	0	10317.1076		
Forecast	0	10322.2125		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved
	2012			2012				2012			
	2013	0.1%		2013	0.1%	-1.0%		2013	0.0%	-1.1%	
	2014	0.5%		2014	-0.9%	0.6%		2014	-1.4%	0.1%	
	2015	2.6%		2015	-0.5%	-0.5%		2015	-3.1%	-3.1%	
	2016	4.3%		2016	-0.6%	4.8%		2016	-4.7%	0.4%	
	2017	5.9%		2017		2.8%		2017		-2.9%	
	2018	2.9%	2.5%	2018		3.0%	-2.8%	2018		0.0%	-5.2%
	Geometric Mean	1.5%	0.8%	Geometric Mean		92.7%	-0.9%	Geometric Mean		105.4%	-1.8%

	Calendar Year (for 2018 Cost of Service		Revenues		
Historical	2012	Actual			
Historical	2013	Actual			
Historical	2014	Actual	$ 580,995	Board-approved	$ 661,016.73
Historical	2015	Actual	$ 601,330		
Historical	2016	Actual	$ 634,580		
Bridge Year (Foreca	2017	Forecast	$ 686,915		
Test Year (Forecast	2018	Forecast	$ 905,860		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2012		
	2013		
	2014		
	2015	3.5%	
	2016	5.5%	
	2017	8.2%	
	2018	31.9%	37.0%
	Geometric Mean		11.1%

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	157			Actual	4,742,923	4,761,047			Actual	30209.701	30325.1432		
Historical	2013	Actual	159			Actual	4,699,450	4,664,969			Actual	29556.289	29339.427		
Historical	2014	Actual	159	Board-approved	168	Actual	4,701,954	4,738,412	Board-approved		Actual	29572.038	29801.3316	Board-approved	0
Historical	2015	Actual	165			Actual	4,594,197	4,630,048			Actual	27843.618	28060.8966		
Historical	2016	Actual	163			Actual	4,538,610	4,792,042			Actual	27844.233	29399.0315		
Bridge Year	2017	Forecast	168			Forecast		4,941,575			Forecast	0	29414.1362		
Test Year	2018	Forecast	172			Forecast		5,057,633			Forecast	0	29404.8432		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved
	2012			2012				2012			
	2013	1.3%		2013	-0.9%	-2.0%		2013	-2.2%	-3.3%	
	2014	0.0%		2014	0.1%	1.6%		2014	0.1%	1.6%	
	2015	3.8%		2015	-2.3%	-2.3%		2015	-5.8%	-5.8%	
	2016	-1.2%		2016	-1.2%	3.5%		2016	0.0%	4.8%	
	2017	3.1%		2017		3.1%		2017		0.1%	
	2018	2.4%	2.4%	2018		2.3%		2018		0.0%	
	Geometric Mean	#NUM!	0.8%	Geometric Mean		95.3%		Geometric Mean		102.5%	

	Calendar Year (for 2018 Cost of Service	Revenues			
Historical	2012	Actual			
Historical	2013	Actual			
Historical	2014	Actual	$ 99,413	Board-approved	$ 105,010.00
Historical	2015	Actual	$ 99,353		
Historical	2016	Actual	$ 99,888		
Bridge Year (Foreca	2017	Forecast	$ 109,246		
Test Year (Forecast	2018	Forecast	$ 101,117		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2012		
	2013		
	2014		
	2015	-0.1%	
	2016	0.5%	
	2017	9.4%	
	2018	-7.4%	-3.7%
	Geometric Mean		-1.3%

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	11		
Historical	*2013*	Actual	11		
Historical	*2014*	Actual	11	Board-approved	
Historical	*2015*	Actual	11		
Historical	*2016*	Actual	11		
Bridge Year	*2017*	Forecast	9		
Test Year	*2018*	Forecast	9		

Consumption (kWh) [3]	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	4,292,894	4,309,299		
Actual	4,289,465	4,257,992		
Actual	4,346,251	4,379,951	Board-approved	
Actual	4,316,369	4,350,052		
Actual	4,274,953	4,513,663		
Forecast		3,657,936		
Forecast		2,835,388		

Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	390263.09	391754.432		
Actual	389951.36	387090.188		
Actual	395113.73	398177.336	Board-approved	
Actual	392397.18	395459.264		
Actual	388632.09	410332.977		
Forecast	0	406437.297		
Forecast	0	315043.155		

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	-18.2%	
	2018	0.0%	
	Geometric Mean	#NUM!	

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	-0.1%	-1.2%	
2014	1.3%	2.9%	
2015	-0.7%	-0.7%	
2016	-1.0%	3.8%	
2017		-19.0%	
2018		-22.5%	
Geometric Mean		139.8%	

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	-0.1%	-1.2%	
2014	1.3%	2.9%	
2015	-0.7%	-0.7%	
2016	-1.0%	3.8%	
2017		-0.9%	
2018		-22.5%	
Geometric Mean		119.0%	

	Calendar Year (for 2018 Cost of Service)	Revenues			
Historical	*2012*	Actual			
Historical	*2013*	Actual			
Historical	*2014*	Actual	$ 90,677	Board-approved	
Historical	*2015*	Actual	$ 68,878		
Historical	*2016*	Actual	$ 69,568		
Bridge Year (Foreca	*2017*	Forecast	$ 68,479		
Test Year (Forecast	*2018*	Forecast	$ 71,906		

Demand (kW)	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	12,486	12,486		
Actual	12,639	12,639		
Actual	12,214	12,214	Board-approved	
Actual	12,238	12,238		
Actual	12,169	12,169		
Forecast		12,701		
Forecast		12,772		

Demand (kW) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual				
Actual				
Actual	0.1346935	0.13469347	Board-approved	
Actual	0.1776834	0.17768344		
Actual	0.1749273	0.17492727		
Forecast	0	0.18546868		
Forecast	0	0.17761429		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2012		
	2013		
	2014		
	2015	-24.0%	
	2016	1.0%	
	2017	-1.6%	
	2018	5.0%	
	Geometric Mean		

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	1.2%	1.2%	
2014	-3.4%	-3.4%	
2015	0.2%	0.2%	
2016	-0.6%	-0.6%	
2017		4.4%	
2018		0.6%	
Geometric Mean		#NUM!	

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013			
2014			
2015	31.9%	31.9%	
2016	-1.6%	-1.6%	
2017		6.0%	
2018		-4.2%	
Geometric Mean			

4 **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	409		
Historical	2013	Actual	409		
Historical	2014	Actual	409	Board-approved	
Historical	2015	Actual	430		
Historical	2016	Actual	505		
Bridge Year	2017	Forecast	517		
Test Year	2018	Forecast	530		

Consumption (kWh) [3]	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	355,537	355,537		
Actual	359,464	359,464		
Actual	359,464	359,464	Board-approved	
Actual	373,173	373,173		
Actual	376,348	376,348		
Forecast		385,594		
Forecast		395,068		

Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	869.28362	869.283619		
Actual	878.88509	878.885086		
Actual	878.88509	878.885086	Board-approved	
Actual	867.84419	867.844186		
Actual	745.98216	745.982161		
Forecast	0	745.83063		
Forecast	0	745.411407		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2012		
	2013	0.0%	
	2014	0.0%	
	2015	5.1%	
	2016	17.3%	
	2017	2.5%	
	2018	2.5%	
	Geometric Mean	#NUM!	

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	1.1%	1.1%	
2014	0.0%	0.0%	
2015	3.8%	3.8%	
2016	0.9%	0.9%	
2017		2.5%	
2018		2.5%	
Geometric Mean		91.9%	

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	1.1%	1.1%	
2014	0.0%	0.0%	
2015	-1.3%	-1.3%	
2016	-14.0%	-14.0%	
2017		0.0%	
2018		-0.1%	
Geometric Mean		113.1%	

	Calendar Year (for 2018 Cost of Service)	Revenues			
Historical	2012	Actual			
Historical	2013	Actual			
Historical	2014	Actual	$ 16,923	Board-approved	
Historical	2015	Actual	$ 18,510		
Historical	2016	Actual	$ 20,334		
Bridge Year (Foreca	2017	Forecast	$ 17,115		
Test Year (Forecast	2018	Forecast	$ 23,154		

Demand (kW)	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	1,003	1,003		
Actual	1,003	1,003		
Actual	1,003	1,003	Board-approved	
Actual	1,050	1,050		
Actual	576	576		
Forecast		590		
Forecast		605		

Demand (kW) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual				
Actual				
Actual	0.0592685	0.05926845	Board-approved	
Actual	0.0567261	0.05672609		
Actual	0.0283269	0.02832694		
Forecast	0	0.03447268		
Forecast	0	0.02612939		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2012		
	2013		
	2014		
	2015	9.4%	
	2016	9.9%	
	2017	-15.8%	
	2018	35.3%	
	Geometric Mean		

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	0.0%	0.0%	
2014	0.0%	0.0%	
2015	4.7%	4.7%	
2016	-45.1%	-45.1%	
2017		2.4%	
2018		2.5%	
Geometric Mean		#NUM!	

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013			
2014			
2015	-4.3%	-4.3%	
2016	-50.1%	-50.1%	
2017		21.7%	
2018		-24.2%	
Geometric Mean			

5 **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				Consumption (kWh) [3]					Consumption (kWh) per Customer			
							Actual (Weather actual)	Weather-normalized		Weather-normalized		Actual (Weather actual)	Weather-normalized	Weather-normalized
Historical	2012	Actual	19			Actual	89,208	89,208			Actual	4695.1579	4695.15789	
Historical	2013	Actual	19			Actual	89,208	89,208			Actual	4695.1579	4695.15789	
Historical	2014	Actual	19	Board-approved		Actual	89,075	89,075	Board-approved		Actual	4688.1579	4688.15789 Board-approved	
Historical	2015	Actual	19			Actual	94,284	94,284			Actual	5096.4324	5096.43243	
Historical	2016	Actual	18			Actual	94,284	94,284			Actual	5387.6571	5387.65714	
Bridge Year	2017	Forecast	17			Forecast		82,356			Forecast	0	4844.49905	
Test Year	2018	Forecast	17			Forecast		82,356			Forecast	0	4844.49905	

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved
	2012			2012				2012			
	2013	0.0%		2013	0.0%	0.0%		2013	0.0%	0.0%	
	2014	0.0%		2014	-0.1%	-0.1%		2014	-0.1%	-0.1%	
	2015	-2.6%		2015	5.8%	5.8%		2015	8.7%	8.7%	
	2016	-5.4%		2016	0.0%	0.0%		2016	5.7%	5.7%	
	2017	-2.9%		2017		-12.7%		2017		-10.1%	
	2018	0.0%		2018		0.0%		2018		0.0%	
	Geometric Mean	#NUM!		Geometric Mean		106.6%		Geometric Mean	97.5%		

	Calendar Year (for 2018 Cost of Service	Revenues			
Historical	2012	Actual			
Historical	2013	Actual			
Historical	2014	Actual	$ 4,800	Board-approved	
Historical	2015	Actual	$ 4,900		
Historical	2016	Actual	$ 4,741		
Bridge Year (Foreca	2017	Forecast	$ 4,883		
Test Year (Forecast	2018	Forecast	$ 5,847		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2012		
	2013		
	2014		
	2015	2.1%	
	2016	-3.2%	
	2017	3.0%	
	2018	19.7%	
	Geometric Mean		